SOUTHWEST GAS CORPORATION

Application 19-08-___

Application of
Southwest Gas Corporation
(U 905 G)
For Authority to Increase Rates and
Charges for Natural Gas Service in California,
Effective January 1, 2021

Volume III

TESTIMONY

SOUTHWEST GAS CORPORATION
(U 905 G)

<u>VOLUME III</u>

TESTIMONY

General Rate Case Application
Recorded Years 2012 through 2018
Estimated Years 2019 and 2020
Test Year 2021
Post-Test Years 2022 through 2025

Witnesses

Brandy Little

Valerie J. Ontiveroz

Timothy S. Lyons

Bradley C. Anderson

Kevin M. Lang

Byron C. Williams

Theodore K. Wood

Robert B. Hevert

Celine Louise R. Apo

Company Witness:
Brandy Little

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

APPLICATION [19-08-XXX]

PREPARED DIRECT TESTIMONY

OF

BRANDY LITTLE

ON BEHALF OF

SOUTHWEST GAS CORPORATION

August 30, 2019

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of
BRANDY LITTLE

Southwest Gas Corporation
Application [19-08-XXX]

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
<u>BRANDY LITTLE</u>

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Brandy Little. 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 Demand Planning Department. My title is 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 No.

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

A. 5 I sponsor the Company's billing determinants (number of bills and therms) for the Southern California, Northern California, and South Lake Tahoe rate jurisdictions presented in Chapter 9, Billing Determinants, of the rate case filing. For each rate jurisdiction, Chapter 9 includes: (1) a summary of the methodology used to develop the billing determinants; (2) the number of bills and recorded therms for calendar year 2018; and (3) the forecasted number of bills and therms for 2019, 2020, and for test year 2021.

Q. 6 Please summarize your prepared direct testimony.

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

- The regression analysis utilized to forecast the sales volumes for the heat sensitive customer classes;
- The development of forecasts utilized in sales volume projections for non-heat sensitive customers and for transportation customers; and
- The methodology utilized to forecast the number of bills.

II. REGRESSION ANALYSIS

Q. 7 Please describe the technique relied upon to forecast the sales volumes for the heat sensitive customer classes.

A. 7 The forecasted sales volumes were developed at the operating district level within each rate jurisdiction, by customer class. The rate jurisdictions include Southern California (Barstow, Victorville, Big Bear & Needles), Northern California (Truckee & Northern California), and South Lake Tahoe (South Lake Tahoe). Sales volumes were developed as the multiplicative product of forecasted number of bills and forecasted consumption per customer. Regression analysis was used to forecast consumption per customer for the heat-sensitive customer classes.

The regression equations include monthly heating degree day variables (monthly dummy variables multiplied by heating degree days) to capture the varying sensitivity of consumption to temperature between months. Other explanatory variables considered during the equation specification process included monthly dummy variables to account for varying consumption across months not significantly affected by temperature. A careful review of the regression statistics for each equation were conducted and the plausibility of the forecasts were carefully reviewed.

III. FORECASTED SALES VOLUME PROJECTIONS

Q. 8 Please describe the technique relied upon to forecast the sales volumes for both the non-heat sensitive sales and transportation customers.

A. 8 The sales projections for the non-heat sensitive customer classes and the transportation customers were developed based upon customer-specific information. Historical usage patterns and customer contact information provided by division personnel in the operating divisions conversant with local conditions were utilized to develop the projections.

IV. FORECASTED METHODLOGY

Q. 9 Please describe the methodology utilized to forecast the number of bills.

A. 9 The forecasted number of bills were developed at the operating district level by customer class. The forecasts were produced based on recent customer levels and trends and customer growth information provided by division personnel conversant with local conditions.

Q. 10 Is the forecast methodology for therms and number of bills in this rate case filing the same as the methodology used in Southwest Gas' prior California rate cases?

A. 10 Yes. Southwest Gas has consistently utilized the same forecasting methodology to develop the billing determinants. The California Public Utilities Commission

(Commission) has accepted Southwest Gas' methodological approach for forecasting therm sales volumes and number of bills since at least 1985.

Q. 11 What heating degree day normal did Southwest Gas utilize to forecast heat-sensitive consumption per customer?

A. 11 Southwest Gas utilized ten-year arithmetic averages of heating degree days to represent normal weather conditions.

Q. 12 Is the use of the ten-year average heating degree day assumption consistent with Southwest Gas' prior practices for general rate cases in California?

A. 12 Yes. Just as the forecasting methodology has remained consistent, Southwest Gas has consistently utilized, and the Commission has accepted, a ten-year average heating degree day assumption to forecast test period sales in every California general rate case filed since 1985.

Q. 13 Does this conclude your prepared direct testimony in this matter?

A. 13 Yes.

SUMMARY OF QUALIFICATIONS
BRANDY LITTLE

I graduated from the University of Nevada, Las Vegas, with a Bachelor of Arts degree in Economics in 2007 and a Master of Arts degree in Economics in 2011.

I joined Southwest Gas as an Analyst I in Demand Planning in the System's Planning Department in January 2010. I subsequently was promoted to Analyst II and then to my current position as Economist in Demand Planning.

My main responsibilities as an Economist include the development of demand forecasting for rate cases and system's planning, development of weather normalized billing determinants for rate cases, performing bill frequency analysis, and providing economic analysis and research for a variety of activities and projects for Southwest Gas.

I am a member and former president of the Southern Nevada Area Population and Projection Estimation Committee (SNAPPE), a member of the National Association for Business Economics (NABE), and a member of the American Economic Association (AEA). I am also a forecaster for the WP Carey Western Blue Chip.

Company Witness:
Valerie J. Ontiveroz

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 19-08-___

PREPARED DIRECT TESTIMONY
OF
VALERIE J. ONTIVEROZ

ON BEHALF OF
SOUTHWEST GAS CORPORATION

AUGUST 30, 2019

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of
VALERIE J. ONTIVEROZ

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
VALERIE J. ONTIVEROZ

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Valerie J. Ontiveroz. 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 Regulatory Manager/California.

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 Company's compliance with various Commission decisions and state legislation issued and or enacted since the Company's last general rate case, Application (A.) 12-12-024. 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 Company's compliance with Decision (D.) 14-06-028, as modified by D.17-06-006, issued in the its last general rate case, A.12-12-024
- Overview of the Company's application for rate relief.
- The Company's incorporation of a risk-based decision-making[1] framework into its general rate case in response to Commission Decisions (D.) 14-12-025 and 19-04-020, including the proposal to implement three risk-based infrastructure projects.
- The Company's proposal to incorporate a third residential baseline season responsive to Senate Bill (SB) 711, enacted in 2017, to minimize bill volatility for residential customers.
- The Company's adjustment to base year expenses to exclude certain officer compensation from rates in accordance with SB 901, enacted in 2018.
- Revisions to the Company's California Gas Tariff to reflect proposals addressed in this application, Pipeline and Hazardous Materials Safety Administration (PHMSA) rule changes, as well as to incorporate revisions to correct minor inconsistencies and other ministerial updates.

II. COMPLIANCE WITH D.14-06-028, AS MODIFIED BY D.17-06-006

Q. 7 Provide a brief overview of D.14-06-028 and D.17-06-006 as it relates to this application.

A. 7 D.14-06-028 was issued in the Company's last general rate case, A.12-12-024, and authorized rate increases for test year 2014, as well as Post-Test Year

[1] The "risk-based decision-making" is also referred to as "risk-informed decision-making".

Margin (PTYM) adjustments of 2.75% for years 2015 through 2018 for the Company's three rate jurisdictions: Southern California, Northern California and South Lake Tahoe.[2] D.14-06-028 also directed Southwest Gas to file its next general rate case by September 1, 2017 with a 2019 test year.[3] In 2017, the Commission issued D.17-06-006 granting the Company's petition to modify D.14-06-028 to file its next general rate by September 1, 2019, with a 2021 test year.[4] D.17-06-006 authorized Southwest Gas to maintain its existing rate structure through 2020, as authorized in D.14-06-028, including the 2.75% PTYM adjustments for years 2019 and 2020.[5]

Q. 8 Did D.17-06-006 direct the Company to establish memorandum accounts?

A. 8 Yes. In D.17-06-006, the Commission directed the Company to establish two memorandum accounts, the Tax Memorandum Account (TMA) and the Officer Compensation Memorandum Account (OCMA).[6] The Company established these two memorandum accounts through advice letters, effective July 14, 2017 and August 27, 2017, respectively.[7]

Q. 9 Please describe the TMA and OCMA.

A. 9 The purpose of the TMA is to track any revenue difference resulting from differences between the Company's authorized income tax expenses and its actually-incurred income tax expenses, including repair deductions and bonus depreciation. The account shall have separate line items detailing the differences resulting from (1) net revenue changes, (2) mandatory tax law

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[2] D.14-06-028, Ordering Paragraphs (OP) 2 and 3, at pg. 94.
[3] Id. OP 18, at pg. 95.
[4] D.17-06-006, OP 1, at pg. 14.
[5] Id.
[6] Id., Ops 3 and 5, at pgs. 15-17.
[7] Advice Letter Nos. 1043 and 1044.

changes, tax accounting changes, tax procedural changes, tax policy changes, and (3) elective tax law changes, tax accounting changes, tax procedural changes, or tax policy changes.

The purpose of the OCMA is to track California allocable compensation paid or owed to the Company's officers in the event of a triggering event. A triggering event occurs if, after January 1, 2013, an electrical corporation or gas corporation violates a federal or state safety regulation with respect to the plant and facility of the utility and, as a proximate cause of that violation, ratepayers incur a financial responsibility in excess of five million dollars ($5,000,000).[8]

Q. 10 Is the Company requesting to maintain the TMA and OCMA in its tariff?

A. 10 The Company is not requesting any changes to the TMA. However, as discussed later in my testimony, the Company is requesting removal of the OCMA from its tariff.

Q. 11 Were there other compliance directives in either D.14-06-028 or D.17-06-006.

A. 11 No.

III. OVERVIEW OF THE COMPANY'S APPLICATION FOR RATE RELIEF

Q. 12 Please provide an overview of the Company's application.

A. 12 In this application, Southwest Gas is requesting a five-year general rate case cycle, with a 2021 test year for the projected 12-month period ending December 31, 2021, and four attrition years from 2022 through 2025. The Company is requesting test year 2021 base rate increases of $6.8 million for Southern California, $1.5 million for Northern California, and $4.5 million for South Lake

[8] Cal. PU Code § 706(a)(2).

Tahoe. The Company is also requesting to maintain its PTYM adjustments of 2.75% in each of its three rate jurisdictions.

Q. 13 What are the primary drivers for the requested rate increases?

A. 13 As discussed more fully in the prepared direct testimony of Company witness Timothy S. Lyons regarding revenue requirement, the primary drivers for the rate increases are due to increases in Operations and Maintenance expenses as a result of increases in labor and non-labor costs, higher depreciation and amortization expenses, property and income taxes and financing costs on new capital investments, which are largely related to the Company's continuing need to invest in facilities to provide safe and reliable service for existing and new customers. The Company's need to invest in facilities to provide safe and reliable service has been more pronounced in South Lake Tahoe than in its Southern California and Northern California divisions. However, offsetting the higher income taxes is a decrease in the federal tax rate implemented as part of the Tax Cuts and Jobs Act of 2017 (TCJA).

Q. 14 Briefly explain why the Company has needed to invest more heavily in South Lake Tahoe than in the Southern California and Northern California divisions.

A. 14 When the Company acquired its South Lake Tahoe facilities from its previous operator in 2005, there had not been a rate increase in South Lake Tahoe in approximately twenty years and the system was comprised largely of aging pipe and infrastructure that needed to be rebuilt. For example, in the Company's first rate case following the acquisition,[9] the average South Lake Tahoe rate base

[9] Decision 08-11-048 in Application 07-12-022, effective January 1, 2009.

was just $609 per customer. In the same rate case, the average rate base per customer for Northern California was $2,090 per customer, or approximately 3.4 times more invested on a per customer basis than in South Lake Tahoe. Since that time, as referenced above, the Company has needed to expend much more on a per customer basis to provide the same level of service to its South Lake Tahoe customers as it provides to customers in Northern California and Southern California. This is illustrated by comparing the Company's proposed investment per customer in this case of $2,949 for South Lake Tahoe to the proposed amount for Northern California of $3,566, which is only 1.2 times more than South Lake Tahoe. The above comparisons demonstrate the need for more significant investment in South Lake Tahoe.

IV. COMPLIANCE WITH COMMISSION DECISIONS AND STATE LEGISLATION

Q. 15 Please provide a brief overview of Commission D.14-12-025 and D.19-04-020.

A. 15 D.14-12-025, issued in December 2014, adopted various changes to the Commission's Rate Case Plan to incorporate a risk-based decision-making framework for the large energy utilities' general rate cases to assist the Commission and interested parties when evaluating the various proposals that the energy utilities use for assessing their safety risks, and to manage, mitigate, and minimize such risks. For the large energy utilities, D.14-12-025 adopted two new procedures, which will assist the Commission in evaluating the utilities' funding requests for safety-related activities in their general rate cases. The two procedures are the Safety Model Assessment Proceeding (S-MAP) and a Risk Assessment Mitigation Phase (RAMP). However, D.14-12-025 directed the small energy utilities,[10] including Southwest Gas, to include a risk-based decision-making framework in their general rate case applications beginning three years from the effective date of the decision, or December 4, 2017.

D.19-04-020, issued in May 2019, approved a "Voluntary Risk-Based Decision-Making Framework" for use by Southwest Gas and the other small utilities in their general rate case applications.

Q. 16 Has the Company incorporated a risk-based decision-making framework into this general rate case application?

A. 16 Yes. As discussed more fully in the prepared direct testimony of Company witness Bradley C. Anderson, Southwest Gas incorporated a risk-based decision-making framework into this general rate case by creating a risk register, evaluation of controls and mitigations to address the risks, including the development of risk-spend efficiencies.

Q. 17 Is the Company proposing any programs as a result of the risk-based process?

A. 17 Yes. As discussed more fully in the prepared direct testimony of Company witness Kevin M. Lang from an operations perspective, the Company is proposing three new programs derived from this risk assessment process: 1) Meter Protection Program; 2) COYL Program[11]; and 3) Targeted Pipe Replacement Program for Driscopipe™ 7000 plastic pipe (M7000) and select distribution and high-pressure steel pipe (Southern California only). Company

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[10] Bear Valley Electric Service, Liberty Utilities, and PacifiCorp (dba, Pacific Power).

[11] The COYL program consists of the Residential/Commercial COYL program and the School COYL program.

witness Bradley C. Anderson discusses these three programs from a risk perspective in his prepared directed testimony.

Q. 18 How is the Company proposing to recover the costs associated with the three risk-based infrastructure programs?

Q. 18 As discussed in the prepared directed testimony of Company witness Timothy S. Lyons regarding rate design, the Company is proposing to recover the costs associated with the three programs through the Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM).

Q. 19 What is SB 711?

A. 19 SB 711, enacted in October 2017, requires the Commission to make efforts to minimize bill volatility for residential customers, explicitly authorizing the Commission to do so by modifying the length of baseline seasons or defining additional baseline seasons.

Q. 20 Was the Company contacted by Commission Staff regarding SB 711?

A. 20 Yes. In 2018, the Commission's Energy Division Staff made contact regarding SB 711, inquiring about the Company's summer and winter baseline seasons, how many bill volatility complaints received, and whether, in the Company's opinion, there was a more optimal summer and winter baseline structure for the Company's residential customers that would mitigate winter monthly bill volatility.

Q. 21 What was the result of the communication?

Q. 21 Although Commission Staff expressed satisfaction with information regarding the Company's baseline seasons for the time being, the Company informed Staff it would perform an analysis of its baseline seasons in this general rate case application to determine if an additional baseline season was deemed necessary.

Q. 22 What was the result of the Company's baseline analysis?

A. 22 As discussed more fully in the prepared direct testimony of Company witness Timothy S. Lyons regarding rate design, Southwest Gas is proposing to create three residential baseline seasons for the Company's seven climate zones in its three rate jurisdictions to help mitigate winter season bill volatility. Additionally, and as a result of the baseline analysis, the Company is also proposing to increase its residential basic service charge by $0.75 to $5.75, which will also help mitigate winter season bill volatility.

Q. 23 What is SB 901?

A. 23 SB 901, enacted in September 2018, primarily related to wildfire-related items, repeals California Public Utilities (PU) Code § 706 (enacted by Assembly Bill 1266, 2015) and adds new language prohibiting an electrical or gas corporation from recovering from ratepayers any annual salary, bonus, benefits, or other consideration of any value paid to an officer of the electrical corporation or gas corporation, and requires that compensation instead be funded solely by shareholders of the utility.

Q. 24 Did the Commission define the term officer?

A. 24 Yes. In Commission Resolution E-4963, issued in December 2018, the Commission directed the gas and electric utilities to establish memorandum accounts and defined officer for the purpose of the memorandum accounts to mean those employees in positions with titles of Vice President or above, consistent with Rule 240.3b-7 of the Securities Exchange Act.[12]

Q. 25 Did the Company establish a memorandum account in compliance with Resolution E-4963?

Q. 25 Yes. The Company established the Officer Compensation Memorandum Account-2019 (OCMA-2019), effective January 1, 2019, to track the difference between compensation for officers of the utility that is authorized in general rate cases or resolutions and all compensation as defined by PU Code 706.[13]

Q. 26 Are there other provisions in Resolution E-4963 related to OCMA-2019?

A. 26 Yes. Resolution E-4963 requires that amounts recorded in the OCMA-2019 will be reviewed and refunded to ratepayers in general rate cases. Additionally, Resolution E-4963 denied the closure of utilities existing officer compensation memorandum accounts, since "…there may be a chance that that those accounts will carry non-zero balances and would be closed prematurely."[14]

Q. 27 Did the Company record any balances to its Officer Compensation Memorandum Account (OCMA) established pursuant to D.17-06-006?

A. 27 No. Southwest Gas did not record any balances to its OCMA because it did not have a triggering event as described above. Therefore, as discussed later in my testimony, the Company is proposing to remove the OCMA from its tariff.

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[12] Resolution E-4963 – Commission Resolution to establish memorandum accounts to track compensation paid to an officer of an electrical or gas corporation pursuant to Senate Bill 901, Op 2, at pgs. 8-9.

[13] Advice Letter No. 1089.

[14] Resolution E-4963 at pg. 5.

Q. 28 Is the Company making an adjustment to base year expenses as a result of SB 901?

Q. 28 Yes. As discussed in the prepared direct testimony of Timothy S. Lyons, an adjustment has been made to base year 2018 expenses to project for test year 2021 rates.

V. PROPOSED TARIFF REVISIONS

Q. 29 Please describe the Company's proposed revisions to its California Gas Tariff.

A. 29 In addition to a variety of housekeeping revisions to clarify its tariff and correct minor inconsistencies between the tariff and the Company's current business practices,[15] the Company is proposing tariff modifications that conform with the various proposals made in this application, clarify the disposition/adjustment of rates sections of various balancing and/or memorandum accounts, clarifies the scope of services the Company provides to its customers and incorporates PHMSA rule changes with respect to Excess Flow Valves (EFV). The Company's proposed tariff revisions, in both clean and redlined versions, are included in Chapter 21 of the application.

Q. 30 Please describe the Company's proposed revisions to the Preliminary Statement of the California Gas Tariff.

A. 30 The Company proposes the following revisions to its Preliminary Statement:

[15] Rule No. 3-Application for Service; Rule No. 6-Establishment and Reestablishment of Credit; Rule No. 7-Deposits; and Rule No. 8-Notices.

Preliminary Statement	Proposed Revision
18. Environmental Compliance Cost Memorandum Account (ECCMA)	Company proposes to revise the “Disposition” section to clarify that the December 31 balance at the end of the last estimated calendar year, will be used for amortization in the development of rates in a general rate case or other ratesetting application.
20. Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM)	Company proposes to revise the “Revision Date” section to reflect that an advice letter will be filed with the proposed IRRAM surcharge adjustments on November 30 (instead of October 31), consistent with the Company’s other balancing account updates effective January 1.
21. Pension Balancing Account (PBA)	Company proposes to revise the “Disposition” section to clarify that the December 31 balance at the end of the most recently recorded calendar year, will be used for amortization in the development of rates in a general rate case or other ratesetting application. Additionally, the Company is requesting continuation of the PBA.
22. Mobilehome Park Conversion Balancing Account (MHPCBA)	Update the “Revision Date” and “MHPCBA” Adjustment Rates” section to use month ended September 30 MHPCBA balance for the adjustment of rates. Additionally, the “MHPCBA Adjustment Rates” section is revised to incorporate the ratemaking treatment related to “Beyond the Meter” expenses.
23. Greenhouse Gas Memorandum Account (GHGMA)	Company proposes to revise the “Disposition” section to clarify that the December 31 balance at the end of the last estimated calendar year, will be used for amortization in the development of rates in a general rate case or other ratesetting application.
27. Natural Gas Leak Abatement Program Memorandum Account (NGLAPMA)	Company proposes to revise the “Disposition” section to clarify that the December 31 balance at the end of the most recently recorded calendar year, will be used for amortization in the development of rates in a general rate case or other ratesetting application.
29. Tax Memorandum Account (TMA)	Company proposes to revise the “Disposition” section to clarify that the December 31 balance at the end of the last estimated calendar year, will be used for amortization in the development of rates in a general rate case or other ratesetting application.

Preliminary Statement	Proposed Revision
30. Officer Compensation Memorandum Account (OCMA)	As discussed above, the Company proposes to remove the OCMA from its tariff due to the repeal of PU Code § 706 by SB 901; additionally, no balances have been recorded to this account.
31. Officer Compensation Memorandum Account-2019 (OCMA-2019)	Company proposes to revise the "Disposition" section to clarify that the December 31 balance at the end of the most recently recorded calendar year, will be used for amortization in the development of rates in a general rate case or other ratesetting application.
32. Dairy Biomethane Pilot Solicitation Development Memorandum Account (DBPPSDMA)	Company proposes to remove the DBPPSDMA from its tariff since it was created pursuant to D.17-12-004 to record expenditures for solicitation development in relation to Health & Safety Code Section 39730.7(d)(2), which directed gas corporations to implement not less than five dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system. The Company have any dairy biomethane pilot projects within its service territories nor did it record costs to this account.

Q. 31 Please describe the Company's proposed revisions to the Schedules section of its California Gas tariff.

Q. 31 Consistent with the Company's proposal to incorporate a third residential baseline season, the following rate schedules will be revised:

- Schedule Nos. GS-10/GN-10/SLT-10 – Residential Gas Service
- Schedule No. GS-11 – Residential Air-Conditioning Gas Service
- Schedule Nos. GS-12/GN-12/SLT-12 – CARE Residential Gas Service
- Schedule Nos. GS-20/GN-20/SLT-20 – Multi-Family Master-Metered Gas Service
- Schedule Nos. GS-25/GN-25/SLT-25 – Multi-Family Master-Metered Gas Service – Submetered

Q. 32 Is the Company proposing other revisions to the Schedules section of its California Gas Tariff?

A. 32 Yes. In Schedule Nos. GS-20/GN-20/SLT-20 – Multi-Family Master-Metered Gas Service, the Company is removing reference to the California Alternate Rates for

Energy (CARE) discount, since customers on this schedule to not qualify for the discount. Additionally, Schedule No. GS-VIC – City of Victorville Gas Service, reference to the contracts is being removed in the Applicability section. Also, the Company proposes to remove Schedule No. GS-LUZ – LUZ Solar Partners LTD. Natural Gas Service given that the only customer served under this schedule will discontinue service in late 2020.

Q. 33 Please describe the Company's proposed revisions to Rule No. 16 – Gas Service Extensions with respect to EFVs.

Q. 33 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 the Company is operationally compliant, it must revise its tariff to correspond with these pipeline safety changes.

Q. 34 Does this conclude your prepared direct testimony?

A. 34 Yes.

SUMMARY OF QUALIFICATIONS
VALERIE J. ONTIVEROZ

I am a graduate of Southern Methodist University having received a Bachelor of Arts in Psychology in 1995.

From 2001 to present, I have been employed by Southwest Gas Corporation, initially as an analyst in the State Regulatory Affairs department. I was subsequently promoted to various positions within State Regulatory Affairs. In 2014, I was promoted to my current position of Regulatory Manager/California within the Regulation and Energy Efficiency department. My responsibilities include strategic leadership, guidance, and direction in the alignment of the Company's regulatory strategy, while ensuring technical accuracy, and regulatory compliance.

Company Witness:

Timothy S. Lyons

(Revenue Requirement)

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 19-08-____

PREPARED DIRECT TESTIMONY
OF
TIMOTHY S. LYONS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

AUGUST 30, 2019

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of
TIMOTHY S. LYONS

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
TIMOTHY S. LYONS

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Timothy S. Lyons. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. 2 Please describe your current position.

A. 2 I am a Partner at ScottMadden, Inc. ("ScottMadden").

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

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

Q. 4 What is the purpose of your pre-filed direct testimony in this proceeding?

A. 4 The purpose of my pre-filed direct testimony is to sponsor Southwest Gas Corporation's (Southwest Gas or the Company) test year 2021 revenue requirements for the Company's three California rate jurisdictions: Southern California, Northern California, and South Lake Tahoe. Specifically, my testimony supports the following:

- Development of test year 2021 revenue requirements, consisting of test year Rate Base, Operations and Maintenance (O&M) and Administrative and General (A&G) expenses for each rate jurisdiction;

- Development of allocators to assign system allocable plant and associated costs and A&G expenses to each rate jurisdiction;
- Development of rate escalation factors used for the Company's proposed Post-Test Year Margin (PTYM) adjustments for the years 2022, 2023, 2024 and 2025. The rate escalation factors will be applied to each rate jurisdiction;
- Development of test year 2021 regulatory amortizations; and
- Summary of historical financial statements and data.

Q. 5 Please summarize your testimony.

A. 5 The Company's test year 2021 revenue requirements analysis shows that the current base rates do not provide the Company with a reasonable opportunity to earn its proposed rate of return of 7.44 percent for Southern California, and 7.76 percent for Northern California and South Lake Tahoe. Specifically, the analysis supports an increase in base rates of $6.8 million for Southern California, $1.5 million for Northern California, and $4.5 million for South Lake Tahoe. Base rate or margin revenues exclude gas supply revenues and expenses since they are treated separately for ratemaking purposes through the Purchased Gas Cost Balancing Account (PGA).

Except as described in this testimony, the revenue requirement analysis was developed consistent with the methodologies described in the Company's last general rate case filing, Application (A.) 12-12-024, and is generally consistent with industry practices.

In addition, the Company proposes PTYM adjustments of 2.75 percent for attrition years 2022 through 2025.

II. DEVELOPMENT OF TEST YEAR 2021 REVENUE REQUIREMENT

Q. 6 When were current base rates established?

A. 6 The current base rates were authorized in Decision (D.) 14-06-028 issued in the Company's last general rate case, A.12-12-024. D.14-06-028 also authorized PTYM adjustments for years 2015 through 2018.[1]

Q. 7 What is the test year used by the Company in this rate case filing?

A. 7 The test year is the projected 12-month period ending December 31, 2021. The revenue requirements are summarized for each rate jurisdiction in Chapter 6, including test year 2021 revenues, expenses and rate base. The methodologies used to develop the test year 2021 revenue requirements are consistently applied across the three rate jurisdictions. The revenue requirements are based on the capital structure and cost of debt proposed in the pre-filed direct testimony of Company witness Theodore K. Wood.

The Company also requests PTYM adjustments of 2.75 percent for years 2022 through 2025.

Chapter 6 also includes a gross revenue conversion factor (GRCF) for each rate jurisdiction. The GRCF is the ratio of the gross revenue required to produce a one-dollar change in net operating income for the 2021 test year. The GRCF is 1.41069 for Southern California, 1.41793 for Northern California and 1.41793 for South Lake Tahoe.

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[1] The PTYM adjustments were extended for 2019 and 2020 in D.17-06-006, Ordering Paragraph 1 at pg. 14.

Q. 8 What are the primary drivers for the proposed rate increases?

A. 8 The primary drivers for the proposed rate increases are the costs associated with the Company's net plant investments in facilities to serve new and existing customers. The costs associated with the Company's net plant investments include financing costs, depreciation and amortization expenses, property and income taxes.

Q. 9 Please discuss the increases in the Company's facilities.

A. 9 The Company plans to substantially increase its net plant investments in facilities to serve customers since the Company's last general rate case, A.12-12-024, as shown in Figure 1.

Figure 1: Net Plant Increases

Net Plant ($Millions)		2021 Test Year		2014 Test Year	Compound Annual Growth Rate
Southern California	$	337.7	$	180.0	9.4%
Northern California		124.9		85.1	5.6%
South Lake Tahoe		72.0		27.2	14.9%
Total	$	534.6	$	292.3	9.0%

The Figure shows that net plant investment in the three California jurisdictions will increase from $292.3 million in 2014 to $534.6 million in 2021. The increase in net plant investment of $242.3 million represents a compound annual growth rate (CAGR) of approximately 9.0 percent.

For Southern California, the Company plans to increase net plant from $180.0 million in 2014 to $337.7 million in 2021, or a CAGR of 9.4 percent.

For Northern California, the Company plans to increase net plant from $85.1 million in 2014 to $124.9 million in 2021, or a CAGR of 5.6 percent.

For South Lake Tahoe, the Company plans to increase net plant from $27.2 million in 2014 to $72.0 million in 2021, or a CAGR of 14.9 percent.

The costs associated with the Company's net plant investments will similarly increase, including financing costs, depreciation and amortization expenses, and property and income taxes.

III. DEVELOPMENT OF TEST YEAR RATE BASE

Q. 10 Please describe the development of test year 2021 rate base.

A. 10 Test year 2021 rate base consists of two components: (1) System Allocable rate base; i.e., plant investment and associated costs that are incurred at the Corporate level and shared across rate jurisdictions, such as the Company's software and general plant investments; and (2) jurisdictional or direct rate base; i.e., plant investment and associated costs that are dedicated to each rate jurisdiction and utility operation, such as mains, services and meters investments.

Q. 11 What is System Allocable plant?

A. 11 System Allocable plant represents plant investment and associated costs that are allocated across all of the Company's three state jurisdictions (California, Arizona and Nevada). System Allocable plant includes intangible plant (software development projects and software applications) and general plant.

Q. 12 Please describe the development of System Allocable rate base.

A. 12 The development of System Allocable test year rate base is included in Chapter 8B. The Chapter calculates System Allocable plant, annual depreciation and amortization expenses, and accumulated provision for depreciation and amortization. Chapter 8B includes GPIS and Accumulated Depreciation balances for each jurisdiction that are adjusted for: (1) projected plant additions;

(2) projected plant retirements and transfers; and (3) projected salvage and removal costs. These cost components are provided for 2012 through the 2021 test year.

Q. 13 Please describe the development of System Allocable projected plant additions.

A. 13 System Allocable projected plant additions were grouped into two categories: (1) routine investments; and (2) special projects.

Q. 14 Please describe the development of routine investment plant additions.

A. 14 Routine investment plant additions reflect investments that occur on a fairly consistent basis. These plant additions were projected based on the Company's past experience.

Q. 15 Please describe the development of special projects plant additions.

A. 15 Special projects plant additions are based on the Company's estimate of project spending and includes the Company's investment in a new Corporate Office Location.

Q. 16 Please describe the development of System Allocable projected retirements, transfers, salvage and removal costs.

A. 16 Projected retirements, transfers, salvage and removal costs were based on the seven-year average of costs for the historical period 2012 through 2018.

Q. 17 Were overheads applied to System Allocable plant additions?

A. 17 No, there were no overheads applied to System Allocable plant additions.

Q. 18 How were depreciation and amortization expenses associated with System Allocable GPIS calculated?

A. 18 Test year 2021 depreciation and amortization expense is based on an annual depreciation provision, with a half-year convention being applied to plant added during the year. The depreciation rates used for System Allocable GPIS in the test year are based on the depreciation rates approved in the most recent Nevada rate case.[2] This is the same approach adopted in the Company's most recent rate case, A.12-12-024.

Q. 19 What amortization period is used for intangible plant?

A. 19 The amortization period for intangible plant generally ranges from 5 to 10 years, depending on the expected useful life. The Company's Work Management System, however, is amortized over 15 years due to its longer expected useful life.

Q. 20 What methodology was used to allocate System Allocable plant, depreciation and amortization expenses and accumulated provision for amortization and depreciation to each rate jurisdiction?

A. 20 The System Allocable plant, annual depreciation and amortization expense and accumulated provision for depreciation and amortization are allocated to each rate jurisdiction based on the 4-factor allocation methodology developed in Chapter 8C.

Q. 21 Please describe the development of jurisdictional rate base.

A. 21 The development of jurisdictional rate base is included in Chapter 17. Chapter 17 provides the calculation of jurisdictional plant investment, annual depreciation and amortization expenses, and accumulated provision for depreciation and amortization. Jurisdictional rate base includes plant investment and costs

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[2] In the Matter of the Application of Southwest Gas Corporation for Authority to Increase its Retail Natural Gas Utility Service Rates and to Reset Gas Infrastructure Replacement Rates in its Southern and Northern Nevada Rate Jurisdictions, Before the Public Utilities Commission of Nevada, Docket No. 18-05031

associated with serving each rate jurisdiction and utility operation. These costs are included in Chapter 17 beginning in 2012 through the 2021 test year.

Chapter 17 also includes Gas Plant-in-Service (GPIS) and Accumulated Provision for Depreciation and Amortization (Accumulated Depreciation) balances for each rate jurisdiction that are adjusted for: (1) projected plant additions, including overheads; (2) projected plant retirements and transfers; and (3) projected salvage and removal costs.

Test year depreciation and amortization expense is based on an annual depreciation provision, with a half-year convention being applied to plant added during the year. The depreciation rates used in the 2021 test year are based on the depreciation study submitted to the Public Advocates Office on August 28, 2019. Working capital consists of materials and supplies, customer advances and cash working capital, which is based on the lead-lag study performed for this application. The working capital calculation is described below.

Q. 22 Please describe the development of projected plant additions.

A. 22 Projected plant additions were grouped into three categories: (1) customer growth; (2) special projects; and (3) routine investments. The plant additions reflect an escalation of costs over the projected period of 2019 through the Test Year 2021.

Q. 23 Please describe the development of customer growth plant additions.

A. 23 Customer growth plant additions include investments in mains, services and meters to extend service to new customers. Customer growth plant additions are based on a projected increase in the number of customers.

Q. 24 Please describe the development of special projects plant additions.

A. 24 Special projects plant additions include capital expenditure investments in materials and equipment that are not measurable through historical averages. These projects do not occur consistently from one year to the next. There is one special project each in Southern California and Northern California and one benefitting all three California jurisdictions. In Southern California, the Company is constructing a new Operations Center in Victorville. In Northern California, the Company is constructing the North Lake Tahoe Lateral, and proposing to begin cost recovery for this project as part of the Company's PTYM adjustment (as discussed later in my testimony). Finally, the Company is proposing a radio upgrade project across all of its service territories. The special projects category represents 11.5 percent, 82.9 percent, and 0.1 percent of the three-year projected capital expenditures for Southern California, Northern California, and South Lake Tahoe, respectfully.

Q. 25 Please describe the development of routine investments plant additions.

A. 25 Routine investments plant additions include investments that occur on a relatively consistent basis. These plant additions were projected based on the Company's past experience.

Q. 26 Please describe the development of projected retirements, transfers, salvage and removal costs.

A. 26 Projected retirements, transfers, salvage and removal costs were based on a seven-year average of costs for the historical period 2012 through 2018.

Q. 27 Please describe the development of overheads.

A. 27 Plant additions are adjusted for overheads, which reflect the indirect costs associated with the plant additions, including supervision and engineering, administrative and general, property taxes, and Allowance for Funds Used During Construction (AFUDC). The overhead rate was based on the seven-year average of overhead rates for the historical period 2012 through 2018.

Q. 28 How were depreciation and amortization expenses associated with jurisdictional GPIS calculated?

A. 28 Depreciation and amortization expenses associated with jurisdictional GPIS were calculated by applying the depreciation rates approved in the Company's last rate case (A.12-12-024) to jurisdictional GPIS in 2019 and 2020 and applying the depreciation rates included in the depreciation study noted above to jurisdictional GPIS in 2021.

Q. 29 What methodology was used to derive the regulatory amortization?

A. 29 Test year regulatory amortization expenses were projected for California Air Resources Board (CARB), the Tax Memorandum Account (TMA), the Greenhouse Gas Memorandum Account (GHGMA), the Mobile Home Park Conversion Balancing Account (MHPCBA) for "To the Meter" (TTM) and "Beyond the Meter" (BTM) program costs, and the Pension Balancing Account (PBA).

Q. 30 Please explain how CARB was projected.

A. 30 The CARB payments expected to be deferred through 2020 were considered in making this projection. To date, payments have been made through 2018 and the 2019 invoice has been received. The projected total of $968,178 is requested to be recovered as a regulatory amortization over the requested five-year rate case cycle. Each California jurisdiction is allocated a portion of this amount based on its weighted 4-Factor relative to the Total California 4-Factor.

Q. 31 What is the TMA?

A. 31 The TMA is a one-way memorandum account for the purpose of tracking revenue requirement impacts of the TCJA. The TMA tracks the differences between the Company's authorized income tax expenses and its actually-incurred income tax expenses, including repair deductions and bonus depreciation for 2019 and 2020. The TMA was established pursuant to D.17-06-006. The projected totals of $(1,242,703) for Southern California, $(528,330) for Northern California and $(198,746) for South Lake Tahoe are requested to be returned to customers as a regulatory amortization over the requested five-year rate case cycle.

Q. 32 Please explain how the GHGMA was projected.

A. 32 The GHGMA costs expected to be deferred through 2020 were considered in making this projection. The GHGMA was authorized pursuant to D.14-12-040 and D.15-10-032. To date, costs total $3,257 through 2018 and the projected costs for 2019 and 2020 have been included in the projected Regulatory Amortization balance. The projected total of $63,527 is requested to be recovered as a regulatory amortization over the requested five-year rate case cycle. Each California rate jurisdiction is allocated a portion of this amount based on its weighted 4-Factor relative to the Total California 4-Factor.

Q. 33 What is the MHPCBA?

A. 33 The MHPCBA is a two-way balancing account for the purpose of recording and recovering the incremental revenue requirement associated with converting mobile home parks from master-metered to direct utility service. The Company was authorized to establish the MHPCBA pursuant to D.14-03-021. D.14-03-021 approved the following ratemaking treatment for TTM versus BTM:

> actual, prudently incurred program costs shall be entered in a balancing account for recovery in the first year following cut over of service; "to the meter" construction costs must be capitalized based on actual (not forecast) expenditures at the utility's then-current authorized return on rate base; "beyond the meter" construction costs must be capitalized based on actual (not forecast) expenditures and consistent with their status as a regulatory asset, these costs must be amortized over ten years at a rate equivalent to the utility's then-current authorized return on rate base.[3]

In accordance with D.14-03-021, the MHPCBA TTM revenue requirement is projected for each rate jurisdiction through December 31, 2020. The projected totals of $1,551,684 for Southern California, $36,095 for Northern California and $73,718 for South Lake Tahoe are requested to be amortized over the five-year rate case cycle.

The MHPCBA BTM revenue requirement is also projected for each rate jurisdiction through December 31, 2020. The projected totals of $1,240,852 for Southern California, $21,096 for Northern California and $20,404 for South Lake Tahoe are requested to be amortized over 10 years per D.14-03-021. The MHPCBA BTM also includes a line item for the annual amortization of the BTM investment since the revenue requirement deferrals on these assets cease at December 31, 2020, and these investments are not included in the Company's GPIS balances. The amounts requested are $279,779 for Southern California, $3,593 for Northern California and $4,141 for South Lake Tahoe.

Q. 34 What is the PBA?

A. 34 The PBA is a two-way balancing account for the purpose of tracking the difference between the authorized and actual amounts associated with the Company's pension funding. Pursuant to D.14-06-028, the PBA will continue

[3] D.14-03-021, OP 8, at pg. 77.

through the effective date of rates approved in the Company's next general rate case. The PBA balance requested to be amortized is based on the balance at December 31, 2018 of $(2,713,843) for Southern California, $(275,565) for Northern California and $(231,582) for South Lake Tahoe. The forecast for PBA is not known and measurable at this time; however, the Company will continue to track the difference between actual and authorized in the PBA. The PBA balance for each rate jurisdiction is requested to be amortized over the five-year rate case cycle.

Q. 35 Is the Company requesting a continuation of the PBA?

A. 35 Yes, the Company requests continued authorization of the PBA. The PBA has worked as expected since its implementation and will continue to prevent both customers and shareholders from bearing the risk of fluctuating pension costs.

Q. 36 What methodology was used to derive Working Capital?

A. 36 Working capital consists of materials and supplies; customer advances; and a cash working capital component determined by a lead-lag study.

Materials and supplies are projected based on seven-year historic average of 13-month average balances, consistent with the Company's methodology in A.12-12-024. In this case, the Company is also proposing to include system-allocable materials and supplies. The system allocable materials and supplies are projected based on seven-year historic average of 13-month average balances and allocated to each jurisdiction based on the 4-factor allocation methodology.

Customer Advances are projected based on seven-year historic average of 13-month average balances, consistent with the Company's methodology in A.12-12-024.

Cash working capital is based on the results of a lead-lag study performed for this application applied to test year expenses.

Q. 37 Please describe the development of the lead lag study.

A. 37 The lead-lag study compares differences between the Company's revenue lag and expense leads. The revenue lag measures the number of days from the time natural gas service is provided to customers to the time payment is received from customers. The expense leads measure the number of days from the time goods and services used to provide natural gas service are provided to the Company to the time payments are made by the Company for those goods and services. The lag and leads are measured in days for individual expenses, converted to "dollar-days" that reflect a weighting by expense amount, and then summed across all expenses.

Q. 38 Please describe the development of the revenue lag.

A. 38 The revenue lag measures the number of days from the time natural gas service is provided to customers to the time payment is received from customers. The revenue lag consists of three components: (1) the service lag; (2) the billing lag; and (3) the collection lag.

The service lag measures the average number of days in the service period; i.e., the time between the start and end of the billing month. The point in time at which meters are read indicates the end of the billing month. The service lag in this lead-lag study was based on the midpoint of the service period, which reflects that natural gas is delivered evenly over the service period.

The billing lag measures the number of days from the time meters are read to the time bills are recorded and sent to customers. The billing lag was based on the Company's meter reading schedule.

The collection lag measures the number of days from the time bills are recorded and sent to customers to the time customer payments are received (i.e., funds are available to the Company). The collection lag in this lead-lag study was based on analysis of the Company's accounts receivables data.

Q. 39 Please describe the development of the expense lead.

A. 39 Lead days for O&M expenses were determined by first separating the expenses into four groups: (1) Cost of Gas; (2) Operations and Maintenance ("O&M") expenses, separated between labor and non-labor expenses; (3) Income Taxes and (4) Taxes Other than Income Taxes. The lead days for each group were measured separately.

Lead days for cost of gas expenses were based on the service lead (i.e., the midpoint of the service period) and payment lead (i.e., the number of days between the end of the service period and payment date). Lead days were based on the number of days from the midpoint of the service period to the payment date.

Lead days for labor or payroll expenses were based on the Company's salary and wage payment schedule, which pays employees on a bi-weekly and monthly basis. The lead days for regular payroll expenses were based on the number of days from the midpoint of the pay period to the payment date. The study made an adjustment for vacation pay. The adjustment reflects that vacation pay is earned before it is taken. The vacation pay adjustment is measured as the midpoint of the calendar year and the lead days for regular payroll expenses. The study also made an adjustment for incentive payments. The adjustment measures the number of days from the midpoint of the performance period to the payment date.

Lead days associated with other O&M expenses were based on a stratified sample of invoices paid by the Company from January 1, 2018 through December 31. 2018. Lead days were measured for each invoice in the sample as the number of days from the midpoint of the service period to the payment date. Invoices were then dollar-weighted to determine lead days for Other O&M expenses.

Lead days associated with federal and state income taxes were measured as the number of days from the midpoint of the calendar year to the payment date. The study used the midpoint of the calendar year because federal and state income taxes are based on annual earnings.

Lead days associated with taxes other than income taxes were measured separately for the following groups: (1) Property taxes; and (2) Payroll-related taxes (FICA, Federal Unemployment, and State Unemployment).

Lead days associated with property taxes were based on an analysis of property tax payments from January 1, 2018 through December 31, 2018. Lead days were measured as the number of days from the midpoint of the taxing period (i.e., the period for which the tax was assessed) to the payment date.

Lead days associated with payroll-related taxes were measured as the number of days from the midpoint of the applicable work period to the payment date.

Q. 40 Please describe the development of Other Working Capital Requirement.

A. 40 Other Working Capital Requirement was calculated using a thirteen-month average of balances, ended December 31, 2018. System Allocable amounts were allocated using the 4-factor allocation method.

IV. DEVELOPMENT OF TEST YEAR 2021 EXPENSES

Q. 41 Please describe the development of test year 2021 expenses.

A. 41 Test year 2021 expenses consist of two components: (1) System Allocable expenses; i.e., costs that are incurred at the corporate level and allocated across each of the Company's rate jurisdictions, such as the Company's A&G expenses.; and (2) Direct expenses; i.e., costs that are specific to each rate jurisdiction or are allocated to each rate jurisdiction, such as customer and distribution expenses

Q. 42 What are System Allocable expenses?

A. 42 System Allocable expenses are included in Chapter 8, Tab A. System Allocable expenses are costs that are incurred at the corporate level and allocated across the Company's three state jurisdictions, such as the Company's A&G expenses.

Q. 43 Please describe the development of test year System Allocable A&G expenses.

A. 43 Test year System Allocable expenses for Accounts 921-924 and 930-931 are based on the historical period 2012 through 2018. Test year System Allocable expenses for Account 925 (Injuries and Damages) and Account 926 (Employee Pension and Benefits) are based on adjusted historical expenses.

For Account 925, self-insured retention was projected based on a 7-year average normalization of settlements. For Account 926, the projections were based on a seven-year normalization of 2013 through 2019 pension, post-employment benefits other than pension, and supplemental executive retirement plan costs for the projected periods.

Q. 44 Please describe the development of test year System Allocable A&G expenses and Maintenance of General Plant expenses.

A. 44 Test year System Allocable A&G labor and materials and expenses (Account 920) and Maintenance of General Plant labor and materials and expenses (Account 935) are based on the historical period 2012 through 2018. Labor loading expenses are based on the labor loading factor described below.

Q. 45 What is the Company's method to allocate System Allocable expenses to its rate jurisdictions?

A. 45 Southwest Gas uses the Modified Massachusetts Formula (MMF) to allocate a portion of common costs to its Federal Energy Regulatory Commission (FERC) regulated jurisdictions: Paiute Pipeline Company and Southwest Gas Transmission Company. The remaining costs are allocated to the three state jurisdictions based on the 4-factor methodology, with two exceptions.

Property Insurance (Account 924) is allocated to each state jurisdiction based on Factor II, average gross plant in service, since insurance premiums are based on insurable property.

Administrative Expenses Transferred to Capital (Account 922) is allocated to each state jurisdiction based on the A&G Overhead factor, since the expenses reflect capital costs. This approach is described in more detail in the narrative to Chapter 8.

Q. 46 Please describe the development of Direct test year expenses.

A. 46 The development of Direct test year expenses is included in the following chapters:

- Chapter 11B (Gas Supply and Distribution expenses)

- Chapter 12 (Customer Accounts expenses)
- Chapter 13 (Customer Service and Information expenses)
- Chapter 14 (Sales expenses)
- Chapter 15 (A&G expenses)

Direct test year expenses are based on recorded costs as of December 31, 2018

Labor expenses are escalated based on historical labor escalation factors, while non-labor expenses are escalated based on a forecast of the Consumers Price Index (CPI). The CPI forecast for 2019 and 2020 is based on the recent Blue Chip Economic Indicators report,[4] and the forecast for 2021 is based on the recent Blue Chip Financial Forecasts report.[5] The approach is consistent with the approach adopted in A.12-12-024.

Q. 47 Please describe the development of test year Other Gas Supply Expenses (Account 813).

A. 47 Test year 2021 Other Gas Supply labor expenses (Account 813) are based on the recorded expenses as of December 31, 2018 and escalated based on historical labor escalation factors. Labor loading expenses are based on the labor loading factor described below. Test year Other Gas Supply Distribution materials and expenses were based on the recorded balance as of December 31, 2018 and escalated based on the CPI forecast.

Q. 48 Please describe the development of test year Distribution Expenses.

A. 48 Test year Distribution labor expenses (Accounts 870-871, 874-875, 879-881, 885-887, 889, 892-894) are based on the recorded expenses as of December

[4] Blue Chip Economic Indicators, Vol. 44, No. 8, August 10, 2019, at pg. 2-3
[5] Blue Chip Financial Forecasts, Vol. 38, No. 6, June 1, 2019, at pg. 14

31, 2018 and escalated based on historical labor escalation factors. Labor loading expenses are based on the labor loading factor described below. Test year Distribution materials and expenses are based on the recorded expenses as of December 31, 2018 and escalated based on the CPI forecast.

Q. 49 Please describe the development of test year Customer Accounts Expenses.

A. 49 Test year Customer Accounts labor expenses (Accounts 901-903, 905) were based on the recorded expenses at December 31, 2018 and escalated based on historical labor escalation factors. Labor loading expenses are based on the labor loading factor described below. Test year Customer Accounts materials and expenses were based on the recorded expenses at December 31, 2018 and escalated based on the CPI forecast.

Q. 50 Please describe the development of test year Uncollectible expenses.

A. 50 Test year Uncollectible expenses (Account 904) represent only the margin portion of uncollectible expense since the gas cost portion of uncollectible expense is recovered through the PGA. Test year Uncollectible expenses were based on the recorded expenses at December 31, 2018 and escalated based on the CPI forecast.

Q. 51 Please describe the development of test year Customer Service and Information expenses.

A. 51 Test year Customer Service labor expenses (Accounts 908-910) were based on the historical period 2018 and escalated based on historical labor escalation factors. Labor loading expenses are based on the labor loading factor described below. Test year Customer Accounts materials and expenses were based on the historical period 2018 and escalated based on the CPI forecast.

Q. 52 Has the Company included test year Sales expenses in its revenue requirement?

A. 52 No. The Company has not included test year 2021 Sales expenses in its revenue requirement, consistent with the Company's approach in A.12-12-024.

Q. 53 Please describe the development of test year Direct Administrative and General (A&G) expenses.

A. 53 Test year Direct A&G expenses for Accounts 923 and 930 are based on the historical period 2012 through 2018 and escalated based on historical labor escalation factors. Test year Local Franchise Taxes (Account 927) are based on the historical period 2012 through 2018 and adjusted to 2021 based on projected 2021 revenues. Consistent with the regulatory treatment in A.12-12-024, the non-gas cost portion of local franchise taxes are recovered through base rates, while the gas cost portion of local franchise taxes are recovered through the PGA.

Test year Regulatory Commission expenses (Account 928) are based on the difference between: (1) rate case expenses assigned to each rate jurisdiction amortized over five years; and (2) 2018 recorded expenses.

Test year Maintenance of General Plant labor expenses (Account 935) are based on the historical period 2018. Labor loading expenses are based on the labor loading factor described below. Test year Maintenance of General Plant material expenses are based on the historical period 2018 and escalated based on a forecast of the CPI forecast.

Q. 54 Was there any adjustment made to the 2018 recorded O&M expenses?

A. 54 Yes. For Northern California and South Lake Tahoe jurisdictions, adjustments were made to 2018 recorded O&M expenses that reflect expense amounts inadvertently charged to Northern Nevada District 22. This resulted in an increase in 2018 recorded O&M expenses by $0.5 million for Northern California, and $0.3 million for Salt Lake Tahoe.

Q. 55 Please describe the development of test year 2021 Property Taxes.

A. 55 Test year 2021 property taxes are based on the average increase in property taxes over the prior 2-year period (years 2019 and 2020).

Q. 56 Please describe the development of test year 2021 benefits expenses – as well as the labor loading factor referenced earlier.

A. 56 Test year 2021 benefits expenses are included in Chapter 18, which provides an itemized list of benefits, including paid time off, that are included in the labor loading percentage. Most benefits expenses are incurred on a Company-wide or System Allocable basis, which are then assigned to the rate jurisdictions through a "labor loading" mechanism.

Specifically, a labor loading percentage was applied to labor expenses for each account. The labor loading percentage reflects benefits corresponding to labor expenses. Payroll taxes were not included in the labor loading percentage. The approach is described in more detail in the narrative to Chapter 18.

The labor loading percentage was based on a seven-year average of historical expenses from 2012 through 2018.

Q. 57 Please describe the development of the labor, labor loading and material and expenses escalation factors.

A. 57 Test year escalation factors for labor and materials and expenses are described in Chapter 7. The labor escalation factors for 2019 were based on approved wage increases; labor escalation factor for 2020 and 2021 were based on a seven-year average of historical wage increases. Escalated labor loading escalation costs were based on applying the labor loading percentage to escalated labor costs. Materials and expenses escalation factors for 2019-2021 were based on the CPI Forecast.

Q. 58 Are there other adjustments to base year expenses?

A. 58 Yes. The Company is making an adjustment to base year expenses in relation to Senate Bill (SB) 901.

Q. 59 Please describe SB 901.

A. 59 SB 901 was enacted on September 21, 2018. SB 901 repeals PU Code § 706, and adds new language prohibiting an electrical or gas corporation from recovering from ratepayers any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of the electrical corporation or gas corporation, and requires that compensation instead be funded solely by shareholders of the utility.

Q. 60 Did the Company establish a memorandum account in compliance with the Commission regulations implementing SB 901?

A. 60 Yes. In compliance with Commission Resolution E-4963, OP 1, on December 20, 2018, the Company filed a Tier 1 advice letter with the Commission establishing an Officer Compensation Memorandum Account (OCMA-2019).

Q. 61 What is the current balance in the OCMA-2019 account?

A. 61 The current balances are as follows:

The credit entries into the authorized compensation subaccount are $445,694 for Southern California, $72,792 for Northern California and $40,547 for South Lake Tahoe through June 2019.

The debit entries into the total compensation subaccount are $309,477 for Southern California, $42,450 for Northern California, and $24,212 for South Lake Tahoe through June 2019.

Q. 62 Describe the SB 901 adjustment to the Company's cost of service in this rate case.

A. 62 The Company made an adjustment to 2018 base year expenses to remove $6,637,775 of labor and certain benefits from Account 920 before allocation, $376,158 of benefits before allocation, and $28,891 and $14,981 of direct labor from Northern California and South Lake Tahoe respectively. This results in a reduction of expenses of approximately $533,473 in Southern California, $133,255 in Northern California and $98,028 in South Lake Tahoe in accordance with SB 901.

Q. 63 Do the Company's tax schedules reflect the return of Excess Accumulated Deferred Income Taxes (EADIT) to customers?

A. 63 Yes. As referenced in the prepared direct testimony of Company witness Byron C. Williams, the Company's tax schedules (Chapter 16) reflect a return to customers of plant and non-plant EADIT. The reduction to revenue requirements is reflected in the deficiency schedule (Chapter 6).

Q. 64 How does the Company propose to flow back the annual plant-related EADIT amortization to customers?

A. 64 As referenced in the prepared direct testimony of Company witness Byron C. Williams, the Company proposes an annual adjustment to reflect the actual Average Rate Assumption Method (ARAM). As part of its annual Post Test Year Margin (PTYM) Adjustment, the Company will include an adjustment for EADIT amortization. The EADIT amortization included in the PTYM Adjustment will lag by a year due to the timing of the Company's calendar year federal income tax return. For example, the EADIT amortization amount calculated using the ARAM method for the calendar year 2018 is not finalized until October 2019. The difference between the EADIT amount included in base rates and actual EADIT would flow back to customers as an offset to the PTYM Adjustment.

V. DEVELOPMENT OF TEST YEAR MARGIN REVENUES

Q. 65 Please describe development of test year margin revenues.

A. 65 Test year margin revenues are based on the authorized 2020 margin.

VI. PTYM ADJUSTMENT

Q. 66 Please describe the Company's currently approved PTYM adjustment.

A. 66 The Commission approved the PTYM annual adjustment of 2.75 percent for the years 2015 through 2018 in Decision 14-06-028.[6] The Commission found that this level of adjustment would likely mitigate the rate impacts on its customers, and also promote productivity and efficiency increases.[7] The 2.75 percent PTYM adjustment was extended for 2019 and 2020 in D.17-06-006.[8]

Q. 67 From the Company's perspective, have the annual attrition adjustments been effective?

A. 67 Yes. The Company believes that the 2.75% annual PTYM adjustments have worked well over the past seven years. Specifically, the benefits of the attrition adjustments include:

- Stabilizes customer bills by implementing gradual changes in rates;
- Provides funding to maintain a safe and reliable distribution system; and

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[6] D.14-06-028, at pg. 24-25.
[7] Id., at page 25.
[8] D.17-06-006, at pg. 1.

- Reduces the number of rate cases, allowing for better use of Company and Commission staff resources, and saves the Company's customers the costs associated with filing and litigating a general rate case.

Q. 68 Is the Company proposing changes to the annual attrition adjustment percentage or the PTYM adjustment mechanism?

A. 68 The Company is proposing to maintain the 2.75% PTYM attrition adjustments for each rate jurisdiction. As discussed above, the Company is proposing to include adjustments for EADIT in the PTYM beginning in 2022. In addition, for the Northern California rate jurisdiction, the Company proposes to recover the PTYM revenue requirement for its North Lake Tahoe Lateral expansion project. For example, the Company projects it will spend $20 million annually on the project in 2020 and 2021. Due to the average test year rate base convention, only $30 million will be included in 2021 test year rates. Under the Company's proposal, the remaining $30 million in revenue requirement would be recovered through the Company's PTYM adjustment, as discussed further below.

Q. 69 How would the cost of service for the North Lake Tahoe Lateral be recovered through the PTYM adjustment mechanism?

A. 69 As costs are recorded to plant in service, the Company would calculate the cost of service including: depreciation expense, carrying charges and property taxes. The cost of service dollar amount would then be divided by the current year's Northern California authorized margin and the resulting percentage added to the 2.75% PTY adjustment for recovery from customers. Recovery of the cost of service for the North Lake Tahoe Lateral would continue in this fashion until the project is completed.

Q. 70 When does the Company expect the full cost of service for the North Lake Tahoe Lateral to be included in rates through the PTYM adjustment mechanism?

A. 70 The Company anticipates that the entire cost of service for the project will be included in rates by the 2024 PTYM adjustment. The project is expected to take three years to complete with annual investments of approximately $20 million beginning in 2020 and extending through 2022. As discussed above, approximately $30 million of the project costs will be included in the Company's 2021 test year rates. The balance of actual costs recorded to plant in service through September 2021 (the Company uses September ending balances to calculate rates effective January 1 of the following year) will be included in the Company's 2022 PTY adjustment as described above. The cost of service for the Company's actual costs recorded to plant in service through September 2022 will be included in the 2023 PTYM adjustment, and the cost of service for remaining costs recorded to plant in service through September 2023 would be recovered in the 2024 PTYM adjustment.

Q. 71 Does this conclude your pre-filed direct testimony?

A. 71 Yes.

SUMMARY OF QUALIFICATIONS
TIMOTHY S. LYONS

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rate and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim was Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony before 17 state regulatory commissions. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Recent Assignments

- Sponsored cost of service/rate design testimony for a Mid-Atlantic gas utility. Testimony included a proposal for new residential and commercial rate classes and introduction of a block break rate design.
- Sponsored cost of service/rate design testimony for a Midwest gas utility. Testimony included a proposal for new commercial rate classes and a revenue decoupling mechanism.
- Sponsored cost of service/ rate design and lead-lag testimony for a Midwest gas utility. The testimony included proposals for Revenue Decoupling/ Weather Normalization Mechanism and Tracker Accounts for certain O&M expenses and capital costs.
- Sponsored rate design testimony for a Northeast gas utility. The testimony included: a proposal for zonal rates to promote expansion of natural gas service in the state; market analysis; and financial modeling.
- Led a study for the Massachusetts Department of Energy Resources to evaluate the benefits, costs and policies options associated with natural gas expansion by Massachusetts gas utilities. The study included: (a) research on state regulatory policies; (b) financial modeling and analysis of the economic and environmental impacts of pursuing various policy options; and (c) a survey of Massachusetts homeowners on their opinion of home heating fuels.
- Prepared a transmission and distribution (T&D) avoided cost study and report for a Midwest electric utility. The study was used to support the utility's energy efficiency programs.
- Prepared a review and evaluation of cost of service/ rate design studies for an electric utility. The assignment included review of proposed rate designs that address cost shifting concerns with serving residential distribution generation customers through introduction of higher customer charges, a demand charge and time-of-use energy charges.

- Assisted in the development of an electric portfolio of cost of service, rate design, and rate planning tools. The tools were used to evaluate the impact of future rate filings and resource portfolio decisions on individual rate classes.
- Prepared a market analysis for a utility to evaluate natural gas expansion into new areas, including: (a) survey of homes and businesses; (b) estimate of construction and operating costs; (c) analysis of alternative supply options (including pipeline, LNG and CNG); and (d) financial modeling.
- Directed a process review of natural gas expansion projects for a gas utility. The assignment included a review, evaluation and recommendations related to: (a) policies and procedures; (b) process steps and personnel; (c) financial models and analysis; (d) project decisions and schedules; and (e) post-construction review and evaluation.
- Sponsored lead-lag testimony for several electric and gas utilities.

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Maine Public Utilities Commission			
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Missouri Public Service Commission			
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
New Hampshire Public Utilities Commission			
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
New Jersey Board of Public Utilities			
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Corporation Commission of Oklahoma			
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The

Sponsor	Date	Docket No.	Subject
			testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.

Company Witness:
Timothy S. Lyons
(Class Cost of Service/Rate Design)

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 19-08-___

PREPARED DIRECT TESTIMONY
OF
TIMOTHY S. LYONS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

AUGUST 30, 2019

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Prepared Direct Testimony
of
TIMOTHY S. LYONS

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
TIMOTHY S. LYONS

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Timothy S. Lyons. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. 2 Please describe your current position.

A. 2 I am a Partner at ScottMadden, Inc. ("ScottMadden").

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 previously sponsored testimony before 17 regulatory commissions. My testimony experience is summarized in Appendix A.

Q. 5 What is the purpose of your pre-filed direct testimony in this proceeding?

A. 5 The purpose of my pre-filed direct testimony is to sponsor Southwest Gas' (Southwest Gas or the Company) proposed rates for the Company's three California rate jurisdictions: Southern California, Northern California and South Lake Tahoe. The testimony includes:

- Overview of current and proposed rate design;

- Development of the Class Cost of Service Study (CCOSS) that was used to develop the proposed rates;
- Development of the proposed rates;
- Development of the proposed three-season baseline rate design and bill impact analysis comparing customer bills based on the proposed and current rates; and
- Development of the proposed IRRAM charge.

Q. 6 Please summarize your testimony.

A. 6 The results of the Company's CCOSS show that the current rate design produces a disparity in class rates of return ("ROR") for the Southern California, Northern California and South Lake Tahoe rate jurisdictions. Figures 1, 2 and 3 illustrate the disparity in class RORs for Southern California, Northern California and South Lake Tahoe, respectively. The Figures demonstrate each rate class's "unit" ROR (where "unit" ROR is the class ROR as a percentage of the system or overall ROR).

Figure 1: Class ROR vs. System ROR (Southern California Jurisdiction)

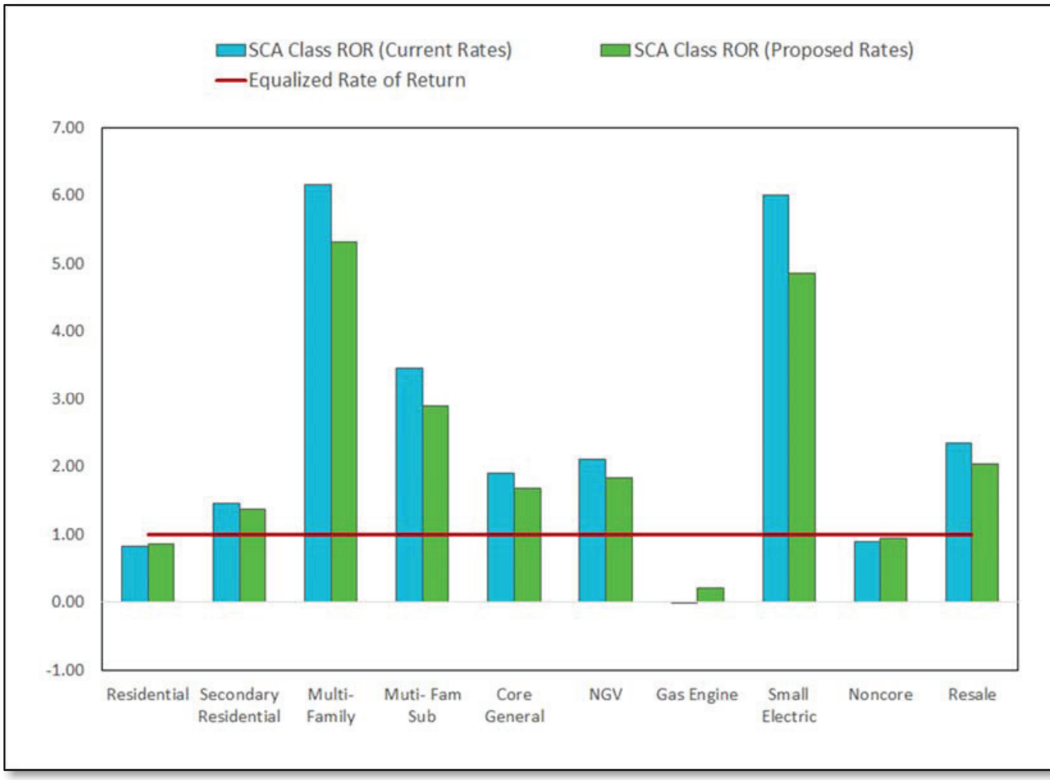

Figure 1 (for Southern California) shows that the Residential, Gas Engine and Noncore rate classes produce RORs at current rates that are less than the system ROR (i.e., unit ROR is less than 1.00 percent), indicating the rates recover less than their cost of service. The remaining rate classes produce RORs that are higher than the system ROR (i.e., unit ROR is greater than 1.00 percent), indicating the rates recover more than their cost of service.

Figure 2: Class ROR vs. System ROR (Northern California Jurisdiction)

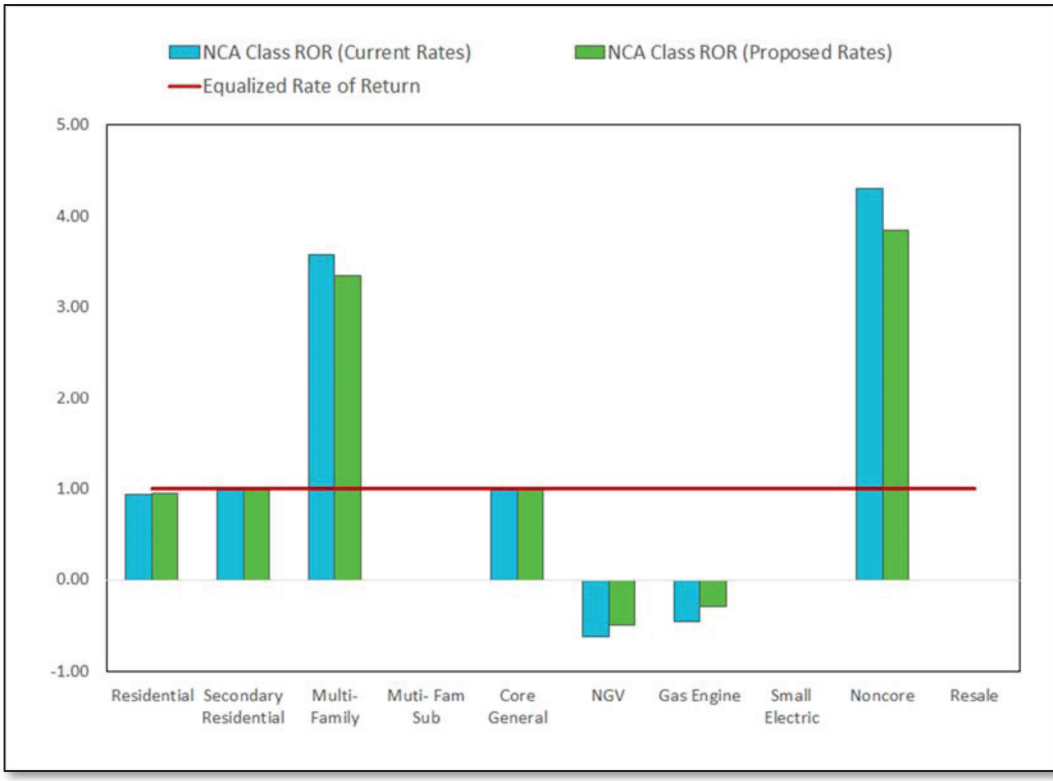

Figure 2 (for Northern California) shows that the Residential, Natural Gas Vehicle ("NGV") and Gas Engine rate classes produce RORs at current rates that are less than the system ROR (i.e., unit ROR is less than 1.00 percent), indicating the rates recover less than their cost of service. The remaining rate classes produce RORs that are higher than the system ROR (i.e., unit ROR is greater than 1.00 percent), indicating the rates recover more than their cost of service.

Figure 3: Class ROR vs. System ROR (South Lake Tahoe)

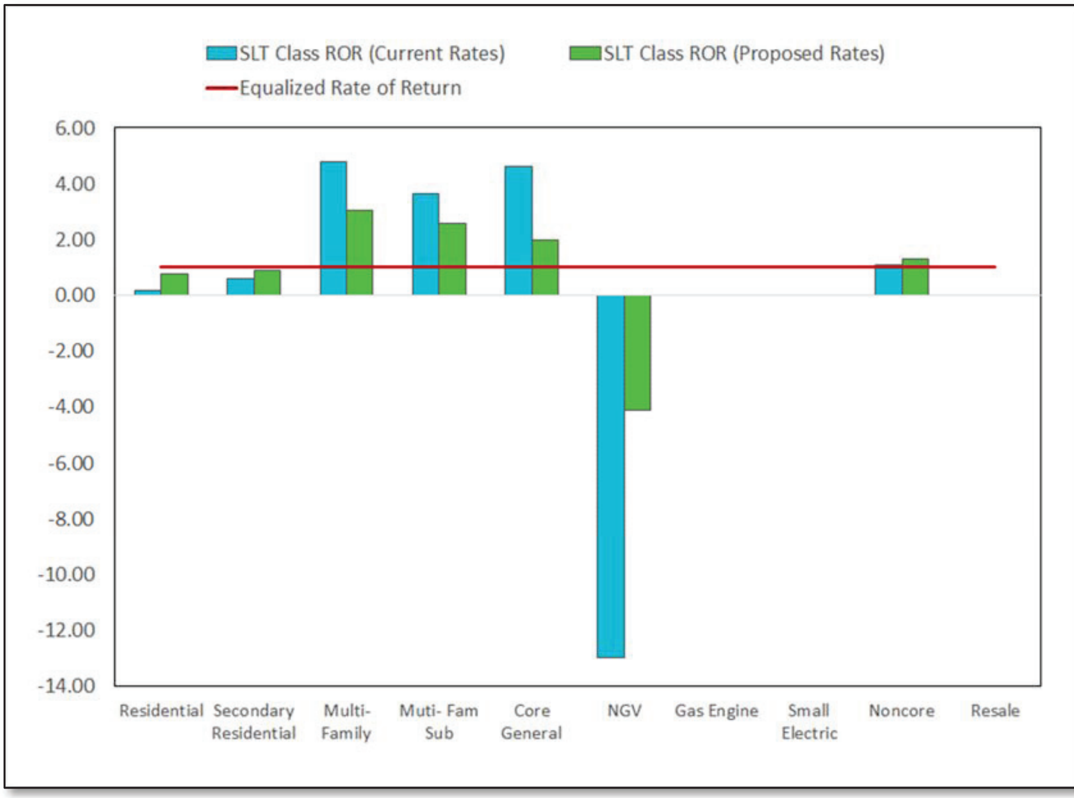

Figure 3 (for South Lake Tahoe) shows that the Residential, Secondary Residential, NGV, and Noncore rate classes produce RORs at current rates that are less than the system ROR (i.e., unit ROR is less than 1.00 percent), indicating the rates recover less than their cost of service. The remaining rate classes produce RORs that are higher than the system ROR (i.e., unit ROR is greater than 1.00 percent), indicating the rates recover more than their cost of service.

The CCOSS was developed by identifying the relationship between the service requirements for each rate class and their respective cost drivers. This approach is well established in industry literature. Except as described in my prepared direct testimony, the CCOSS was developed consistent with the methodologies filed in the Company's most recent general rate case filing, Application (A.) 12-12-024.

The results of the Company's CCOSS support a movement toward a more equitable rate structure where class RORs move closer to the system ROR. To meet that objective, the proposed rate increases for the Residential, Gas Engine and Noncore rate classes are slightly higher than the overall rate increase. However, the proposed movement to the system ROR was subject to certain limitations to address customer bill impact considerations. The proposed rates for the remaining rate classes also move the class RORs closer to the system ROR.

The proposed revenue targets for each rate class are based on the Company's Proportional Cost Responsibility Method (PRCM) that moves each rate class closer to the system ROR subject to limitations to address customer bill impact considerations, consistent with the Company's approach adopted by the Commission in A.12-12-024.

The proposed revenue targets move each rate class closer to the system ROR, as shown in Figures 1, 2 and 3. The Figures shows that certain rate classes produce unit RORs at proposed rates that are higher than the unit RORs at the current rates. The remaining rate classes produce unit RORs at proposed rates that are lower than the unit RORs at the current rates.

The proposed Residential rates reflect an increase in the residential customer charges and volumetric rates that incorporate a proposed change in the baseline seasons (described below) and associated baseline quantities.

The Company prepared a bill impact analysis to evaluate the impact of the proposed rate changes. The bill impact analysis evaluated a wide range of customer monthly usage across the rate classes.

The impact of the proposed base rates increase on Residential monthly bills varies depending on jurisdiction and season, as shown in Figure 4. Specifically, the Figure shows the proposed base rates will increase Winter bills for the average Residential customer in Barstow using 64 therms by $3.37 per month, or 6.0 percent. The Figure also shows the proposed base rates will increase Winter Off-Peak bills for the average Residential customer in Barstow using 32 therms by $3.26 per month, or 11.1 percent. Finally, the Figure shows the proposed base rates will increase Summer bills for the average Residential customer in Barstow using 13 therms by $1.81 per month, or 12.0 percent

Figure 4: Monthly Bill Impact Analysis

Residential Bill Comparison 'Base Rates Only'	Average Monthly Usage	Prop. Monthly Bill 3-Seasons At $5.75 BSC	Current Monthly Bill 2-Seasons At $5.00 BSC	$ Diff	% Diff
Winter					
Barstow District	64	$ 59.73	$ 56.35	$ 3.37	6.0%
Victorville District	72	68.61	63.50	5.11	8.1%
Big Bear District	88	80.40	75.40	5.00	6.6%
Needles District	25	26.83	24.29	2.54	10.5%
North Lake Tahoe	108	90.77	95.01	(4.24)	-4.5%
Truckee	124	103.35	109.40	(6.04)	-5.5%
South Lake Tahoe	230	159.73	99.65	60.08	60.3%
Witner Off-Peak					
Barstow District	32	$ 32.74	$ 29.48	$ 3.26	11.1%
Victorville District	39	38.86	34.83	4.02	11.5%
Big Bear District	41	40.33	36.36	3.97	10.9%
Needles District	13	16.71	14.94	1.77	11.8%
North Lake Tahoe	69	59.57	60.59	(1.01)	-1.7%
Truckee	66	56.63	58.17	(1.54)	-2.6%
South Lake Tahoe	140	98.95	59.67	39.28	65.8%
Summer					
Barstow District	13	$ 16.93	$ 15.12	$ 1.81	12.0%
Victorville District	16	20.10	17.92	2.18	12.1%
Big Bear District	16	19.67	17.92	1.75	9.8%
Needles District	9	13.77	12.23	1.54	12.6%
North Lake Tahoe	26	26.55	26.59	(0.04)	-0.2%
Truckee	24	24.50	24.76	(0.26)	-1.0%
South Lake Tahoe	52	40.48	26.35	14.13	53.6%

The proposed rates reflect three important rate design principles: (a) rates should recover the overall cost of providing service; (b) rates should be fair, minimizing inter- and intra-class inequities to maximum the extent possible; and (c) rate changes should be tempered by rate continuity concerns.

II. DEVELOPMENT OF THE CCOSS

Q. 7 Please describe the purpose of a CCOSS.

A. 7 The purpose of a CCOSS is to allocate a utility's overall cost of service to each rate class in a manner that reflects its underlying cost of service. The CCOSS sponsored in this testimony was developed by identifying the relationship between the service requirements for each rate class and their respective cost drivers. This approach is well established in industry literature[1] and is consistent with the Company's approach adopted by the Commission in A.12-12-024.

Q. 8 How was the CCOSS developed?

A. 8 The CCOSS was developed utilizing the model adopted by the Commission in A.12-12-024. Each rate base and expense item in the CCOSS was assigned to a rate class based on the three-step process described above. Three CCOSS studies developed for each of the Company's three rate jurisdictions: Southern California, Northern California and South Lake Tahoe.

Q. 9 Please describe the approach used to develop the CCOSS.

A. 9 The approach used to develop the CCOSS consisted of a three step process: (1) functionalization, or cost assignment into functional categories, largely related to production, storage, transmission and distribution; (2) classification, or cost assignment according to whether costs are related to serving peak

[1] *See* "Principles of Public Utility Rates" by James C. Bonbright.

demands, customer service requirements, or energy demands; and (3) allocation, or cost assignment to rate classes consistent with the functionalization and classification steps described above.

Q. 10 Please describe the data used to prepare the CCOSS.

A. 10 The CCOSS is based on test year data for the period January 1, 2021 through December 31, 2021. The CCOSS includes the number of customers, sales and revenues by rate class. Sales reflect normal weather conditions. Revenues at present rates reflect the Company's authorized margin. The CCOSS also includes rate base items, including intangible plant, distribution and general plant-in-service as well as (a) additions to rate base, including cash working capital, and materials and supplies, and (b) reductions to rate base, including deferred income taxes, excess accumulated deferred income taxes, and customer deposits. The CCOSS also includes operations and maintenance (O&M) expenses, including distribution, customer service, customer account, sales, and administrative and general expenses as well as taxes other than income, such as payroll and property taxes, and income taxes.

Q. 11 What is Functionalization?

A. 11 Functionalization consists of separating rate base and expense items into operational components that include production, storage, transmission and distribution. Southwest Gas does not have any storage and only a small amount of transmission in its three California rate jurisdictions. Therefore, the Company functionalizes all cost of service as distribution. Additionally, gas commodity costs, which include production and pipeline charges and related costs, are generally recovered through the Company's Purchase Gas Adjustment (PGA) and thus are not a component of the cost of service study.

Q. 12 What is Classification?

A. 12 Classification consists of separating rate base and expense items into categories based on cost drivers. Distribution-related costs are generally classified as demand-related or customer-related. Demand-related costs are driven by the requirement to serve customer peak demands, while customer-related costs are driven by the requirement to connect and provide customer-related services, such as metering and billing services.

Q. 13 Please describe the classification process used to develop the cost of service study.

A. 13 The cost of service is classified into one of the following three categories:

- Customer-related – costs associated with providing customer access to the natural gas system as well as providing on-going customer services, such as meter reading and billing services.
- Demand-related – costs associated with meeting customer peak demand requirements
- Energy- or commodity-related – costs associated with meeting customer energy or commodity requirements.

In some cases, costs were classified into only one of the three categories. The cost of meter reading, for example, was classified as customer related. In other cases, costs were classified into more than one category. The cost of distribution mains, for example, was classified as both customer- and demand-related.

Q. 14 Please discuss the classification of distribution mains.

A. 14 Distribution mains typically represents the largest plant investment for a natural gas utility. The classification of distribution mains reflects two cost drivers. The first driver is the number of customers. Distribution mains are designed to provide customer access to the natural gas system. The second driver is peak or design day demand.

The classification of distribution mains in the proposed CCOSS reflects the Company's same approach authorized A.12-12-024: 50 percent of distribution mains is customer-related, and 50 percent is demand-related.

Q. 15 Please discuss the classification of other rate base items.

A. 15 Other rate base items were similarly classified based on their underlying cost drivers. For example, meter cost, meter installation, service cost, and regulator investments were classified as customer-related since they provide customer access to the natural gas system. Rate base items not directly associated with one of the classification categories, such as general plant, were classified through a composite classifier based on the related costs.

Q. 16 Please discuss classification of operations and maintenance (O&M) expenses.

A. 16 O&M expenses were classified in a manner similar to their respective plant items. For example, Maintenance of Services (Account 892) was allocated based on the allocation of Services plant (Account 380).

O&M expense items not directly associated with one of the classification categories, such as administrative and general expenses, were classified through a composite classifier based on related costs.

Q. 17 What is Allocation?

A. 17 Allocation consists of assigning rate base and expense items to individual rate classes based on allocators that reflect their underlying cost of service.

Q. 18 Please describe the allocation process used in developing the CCOSS.

A. 18 Costs were allocated to each rate class based on the costs incurred to serve that class. In short, cost allocation follows cost causation. This is an established industry approach and is consistent with the Company's approach authorized in A.12-12-024. Additionally, this approach requires development of cost allocators that reflect the design of the natural gas system.

The CCOSS in this filing was developed based on three types of allocators

1. Class determinants – class characteristics, such as number of customers, consumption and revenues by rate class;
2. Special studies – detailed analysis of specific plant or expense items, such as meters; and
3. Internal – composite of how other costs are allocated.

Q. 19 Please describe the process used to develop the demand allocators.

A. 19 The demand allocator is based on January demands. The allocator reflects each rate classes' responsibility to January sales, consistent with the Company's approach adopted in A.12-12-024.

Q. 20 Please describe the process used to develop the special studies allocators.

A. 20 There were four special studies developed to allocate meter investments, meter installations, service investments, regulators, and industrial customer investments. The allocators were developed separately for each of the Company's three rate jurisdictions as follows:

- Meters and Meter Installation investments were allocated based on the current cost of meters by meter type in each rate class weighted by the number of meters. The calculation recognizes there are certain types of meter costs specific to each rate class and establishes a weighting based on current records
- Service investment was allocated based on the current cost of service line installations for an average service line length required to serve customers in each rate class. The calculation recognizes there are certain types of service installation costs specific to each rate class and establishes a weighting based on current records.
- Industrial customer investment was allocated based on the investment in meters to serve the largest customers on the system.

Q. 21 Please describe the process to allocate rate base items to the customer classes.

A. 21 The process used to allocate rate base to customer classes is included in Chapter 19 workpapers. First, plant investment by individual FERC account is allocated to each rate class based on an allocator that most closely reflects the underlying cost driver. Then, additions and deletions to net plant investment are allocated to each rate class on the basis of an allocator that most closely reflects the underlying cost driver to form rate base.

In general, the allocation of rate base followed the Company's methodologies adopted by the Commission in A.12-12-024. Plant investment designed to meet customer peak demands was allocated to each rate class based on the demand allocator. Plant investment designed to connect customers to the distribution system and meet their service requirements was allocated to each rate class based on number of customers and/or one of the special studies described above.

Q. 22 Please describe the allocation of O&M expenses to the customer classes.

A. 22 The process used to allocate O&M expenses to customer classes is included in Chapter 19. As discussed earlier, special studies were used in some cases to assign specific costs to customer classes.

Q. 23 Please describe the overall results of the Company's CCOSS.

A. 23 The results of the CCOSS are shown in Figures 1, 2 and 3. The Figures compare the calculated ROR for each rate class based on current rates to the system or overall ROR.

Q. 24 What conclusions can be reached when a rate class ROR is higher or lower than the system ROR?

A. 24 If a rate class produces a ROR that is lower than the system ROR, then the revenues recovered from the rate class are less than its cost of service. Conversely, if a rate class produces a ROR that is higher than the system ROR, then the revenues recovered from the rate class are more than its cost of service. As discussed below, the CCOSS results were used to establish revenue targets for each rate class, subject to bill stability concerns, that move the Company's proposed rates in aggregate closer to the system ROR to achieve more fair and equitable rates across customer classes.

III. OVERVIEW OF THE COMPANY'S RATE CLASSES AND RATES

Q. 25 Please provide an overview of the Company's rates.

A. 25 Customers are presently served under one of several rate classes based on type of service and load characteristics. The Company's current rate structure consists of base rates, PGA, and several surcharges. The base rates include monthly customer charges and commodity charges. Certain rate classes have commodity charges with block or step rates, including the Residential class with a baseline and Tier II rate and the Core General class with four steps with declining rates.

IV. DEVELOPMENT OF THE RATE DESIGN

Q. 26 Please describe the principles used to guide the proposed rate design.

A. 26 The proposed rate design was guided by several principles common throughout the industry, including: (a) rates should recover the overall cost of providing service; (b) rates should be fair, minimizing inter- and intra-class inequities to the maximum extent possible; and (c) rate changes should be tempered by rate continuity concerns.[2]

Because these principles can conflict, the rate design process also includes a level of judgment to balance these principles.

Q. 27 How were the principles applied in this application?

A. 27 First, rates were designed to recover the overall cost of service. This was done by developing customer and consumption charges based on test year bills and usage. In addition, rates were designed to be fair and equitable. This was done

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[2] See Bonbright, James, Danielsen, Albert, and Kamerschen, David. "Principles of Public Utility Rates." Public Utilities Reports, Inc. pp. 377-407 (2nd Ed. 1988).

by setting revenue targets at a level that moves each rate class closer to the system ROR. As discussed earlier, the results of the CCOSS show that some rate classes produce less than the overall ROR. The proposed rate design in this application reduces that deficiency. Another rate design objective is to maintain pricing stability by minimizing the impact of changes in rates on customers. This objective was considered during both the setting of revenue targets, and again in reviewing the impact of proposed rates on customers' bills at various usage levels within customer classes.

Q. 28 What is the total revenue requirement that you used as a starting point for the rate design?

A. 28 I relied on information from the overall cost of service presented above, which indicates a total revenue requirement of approximately $77.0 million, $20.8 million and $10.4 million for Southern California, Northern California and South Lake Tahoe, respectively.

Q. 29 Please describe the process used to set the revenue requirement targets for each customer rate class.

A. 29 Since each customer rate class presently produces a ROR that is different than the system ROR, as shown in Figures 1, 2 and 3, the starting point for setting the revenue targets for each customer rate class was based on the relationship between the current revenues and revenues at equalized rates of return. Specifically, the proposed revenue targets for each customer rate class were based on the Company's PCRM that moves each customer rate class close to the system ROR subject to limitations to address customer bill impact considerations. The PCRM approach adjusts the percentage increase for each customer rate class by multiplying the system percentage increase by the ratio of the margin at the system ROR to the margin at the current ROR for each customer rate class. The PCRM contains rate caps to limit the rate increase for individual customer rate classes. Specifically, the Company proposes that no customer rate class receive a rate increase more than twice the overall rate increase. The proposed rate caps would apply to each of the Company's three rate jurisdictions.

The proposed revenue targets result in higher-than-system rate increases for those customer rate classes where class RORs are less than the system ROR and lower-than-system rate increases for those customer rate classes where class RORs are more than the system ROR.

Q. 30 Please describe the proposed rate design for each customer rate class.

A. 30 The proposed rate design for each customer rate class is described below.

Residential

<u>Basic Service Charge</u>

The Company is proposing a $0.75 increase to the residential basic service charge. The residential basic service charge will increase to $5.75 per month for all three jurisdictions.

For low-income (CARE) residential customers, the basic service charge will remain at $4.00 per month, or a 30 percent discount. Currently, California state law mandates a 20 percent discount from otherwise-applicable residential rates which would result in a basic service charge of $4.60. However, given low income customer rate continuity concerns, an increase to the basic service charge for CARE is not being proposed at this time.

Commodity Charges

The Company is proposing to continue its currently approved "two-part" residential commodity charge. The commodity charge is consistent with Section 739.7 which states that the commodity charge must be a two-part rate with a baseline rate for an initial block of usage followed by a higher rate for any consumption above the baseline quantity. Only primary residential customers are eligible for the lower, Tier I rate while secondary residential customers pay a single rate.

As discussed above, the Company calculates baseline daily quantities for each jurisdiction for the Winter (Peak), Winter (Off-Peak), and Summer seasons.

Other Rate Classes

For all other customer rate classes, the Company has set rates consistent with the approach adopted in A.12-12-024. Additionally, the Company proposes to eliminate the GS-LUZ customer rate class since the only customer served under this schedule plans to discontinue operations prior to the start of the 2021 test year.

Q. 31 Have you examined the impact of the proposed changes in rates on customers within each rate class by rate jurisdiction?

A. 31 Yes. The Company prepared a bill impact analysis to evaluate the impact of the proposed rate changes. The bill impact analysis evaluated a wide range of customer monthly usage across the rate classes.

The impact of the proposed base rate increases on residential monthly bills varies depending on jurisdiction and season, as shown in Figure 4.

V. PROPOSED CHANGES TO RESIDENTIAL BASELINE SEASONS

Q. 32 Why has the Company proposed changes to the Residential baseline seasons?

A. 32 The Company proposed changes to the Residential baseline seasons in response to Senate Bill (SB) 711, which was approved by Governor Brown in 2017 in response to winter season bill volatility. SB 711 directed the Commission to make efforts to minimize bill volatility for residential customers: "Those methods may include modifying the length of the baseline seasons or defining additional baseline seasons."[3]

Q. 33 What are the proposed changes to the Residential baseline seasons?

A. 33 The proposed changes to the Residential baseline seasons create three seasons for the Company's seven climate zones in its three rate jurisdictions.

Presently, the Company has two seasons: Winter Season and Summer Season. The Winter Season includes six months (November through April) for the three "Warmer" climate zones (Barstow, Needles and Victorville)[4] and eight months (October through May) for the four "Colder" climate zones (Big Bear, North Lake Tahoe, South Lake Tahoe and Truckee).[5] The Summer Season includes six months (May through October) for the three "Warmer" climate zones and four months (June through September) for the four "Colder" climate zones.

The Company's proposal would create three seasons for the Company's seven climate zones.

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[3] Senate Bill No. 711, *See* § 739 (a) (1)

[4] Warmer climate zones: Barstow, Needles and Victorville's normal annual heating degree days are 2,255, 2,647, 2,255, respectively.

[5] Colder climate zones: Big Bear, North Lake Tahoe, South Lake Tahoe and Truckee's normal annual heating degree days are 5,940, 7,397, 7,876, 7,141, respectively.

1. Winter (Peak) Season
    a. December through February for the three “Warmer” climate zones.
    b. December through March for the four “Colder” climate zones.
2. Winter (Off-Peak) Season
    a. March, April and November for three “Warmer” climate zones.
    b. April, May and November for the four “Colder” climate zones.
3. Summer Season
    a. May through October for the three “Warmer” climate zones.
    b. June through October for the four “Colder” climate zones.

Q. 34 Do the proposed Residential baseline seasons change the baseline allowances?

A. 34 Yes. The proposed Residential baseline seasons were used to calculate the baseline allowances by climate zone based on a 70 percent factor in the Winter (Peak) and Winter (Off-Peak) Season and a 60 percent factor in the Summer Season. Comparison of the proposed and current baseline allowances are shown in Chapter 20 in this application.

Q. 35 Have you evaluated the effect of the proposed three-season baseline rate design?

A. 35 Yes. I compared monthly bills at the proposed residential class revenue requirement under the currently effective two-season baseline rate design to bills under the proposed three-season rate design, as shown in Figure 5.

Figure 5: Comparison of Bills under Proposed Three Season versus Current Two Season Baselines

Residential Bill Comparison 'Base Rates Only'	Average Monthly Usage	Prop. Monthly Bill 3-Seasons At $5.00 BSC	Prop. Monthly Bill 2-Seasons At $5.00 BSC	$ Diff	% Diff
Winter					
Barstow District	64	$ 60.80	$ 63.59	$ (2.78)	-4.4%
Victorville District	72	69.64	71.68	(2.05)	-2.9%
Big Bear District	88	82.10	85.33	(3.23)	-3.8%
Needles District	25	26.80	27.07	(0.27)	-1.0%
North Lake Tahoe	108	91.55	92.51	(0.96)	-1.0%
Truckee	124	104.37	106.62	(2.25)	-2.1%
South Lake Tahoe	230	160.40	161.20	(0.80)	-0.5%
Witner Off-Peak					
Barstow District	32	$ 32.90	$ 33.02	$ (0.12)	-0.4%
Victorville District	39	39.19	39.15	0.04	0.1%
Big Bear District	41	40.75	40.90	(0.15)	-0.4%
Needles District	13	16.34	16.38	(0.05)	-0.3%
North Lake Tahoe	69	59.87	58.83	1.03	1.8%
Truckee	66	56.96	56.49	0.47	0.8%
South Lake Tahoe	140	99.14	96.90	2.24	2.3%
Summer					
Barstow District	13	$ 16.52	$ 16.56	$ (0.04)	-0.3%
Victorville District	16	19.69	19.74	(0.04)	-0.2%
Big Bear District	16	19.32	19.74	(0.42)	-2.1%
Needles District	9	13.22	13.24	(0.03)	-0.2%
North Lake Tahoe	26	26.12	25.98	0.14	0.5%
Truckee	24	24.11	24.19	(0.08)	-0.3%
South Lake Tahoe	52	40.06	40.26	(0.20)	-0.5%

The Figure shows that the three-season baseline rate design results in lower bills during the peak winter season. The Figure also shows that monthly bills during the off-peak winter season (when customer bill are less than during the peak winter months) increases in certain cases under the three-season baseline rate design.

Q. 36 Did you evaluate whether changes to the monthly basic service charge can contribute to winter bill stability?

A. 36 Yes. I evaluated whether increasing the monthly basic service charge above can further reduce peak winter bills, as shown in Figure 6.

Figure 6: Comparison of Bills under Three Season Baseline with Higher Basic Service Charge (BSC)

Residential Bill Comparison 'Base Rates Only'	Average Monthly Usage	Prop. Monthly Bill 3-Seasons At $5.75 BSC	Prop. Monthly Bill 3-Seasons At $5.00 BSC	$ Diff	% Diff
Winter					
Barstow District	64	$ 59.73	$ 60.80	$ (1.08)	-1.8%
Victorville District	72	68.61	69.64	(1.02)	-1.5%
Big Bear District	88	80.40	82.10	(1.71)	-2.1%
Needles District	25	26.83	26.80	0.04	0.1%
North Lake Tahoe	108	90.77	91.55	(0.78)	-0.9%
Truckee	124	103.35	104.37	(1.01)	-1.0%
South Lake Tahoe	230	159.73	160.40	(0.68)	-0.4%
Witner Off-Peak					
Barstow District	32	$ 32.74	$ 32.90	$ (0.16)	-0.5%
Victorville District	39	38.86	39.19	(0.34)	-0.9%
Big Bear District	41	40.33	40.75	(0.42)	-1.0%
Needles District	13	16.71	16.34	0.38	2.3%
North Lake Tahoe	69	59.57	59.87	(0.29)	-0.5%
Truckee	66	56.63	56.96	(0.33)	-0.6%
South Lake Tahoe	140	98.95	99.14	(0.19)	-0.2%
Summer					
Barstow District	13	$ 16.93	$ 16.52	$ 0.41	2.5%
Victorville District	16	20.10	19.69	0.41	2.1%
Big Bear District	16	19.67	19.32	0.35	1.8%
Needles District	9	13.77	13.22	0.55	4.2%
North Lake Tahoe	26	26.55	26.12	0.42	1.6%
Truckee	24	24.50	24.11	0.39	1.6%
South Lake Tahoe	52	40.48	40.06	0.42	1.0%

The Figure shows that a $0.75 per month increase in the basic service charge can reduce monthly winter bills by up to $1.71. Increasing the basic service charge also reduces the above-mentioned increases to off-peak winter season bills.

Q. 37 Why is it appropriate to increase the residential basic service charge to $5.75 per month?

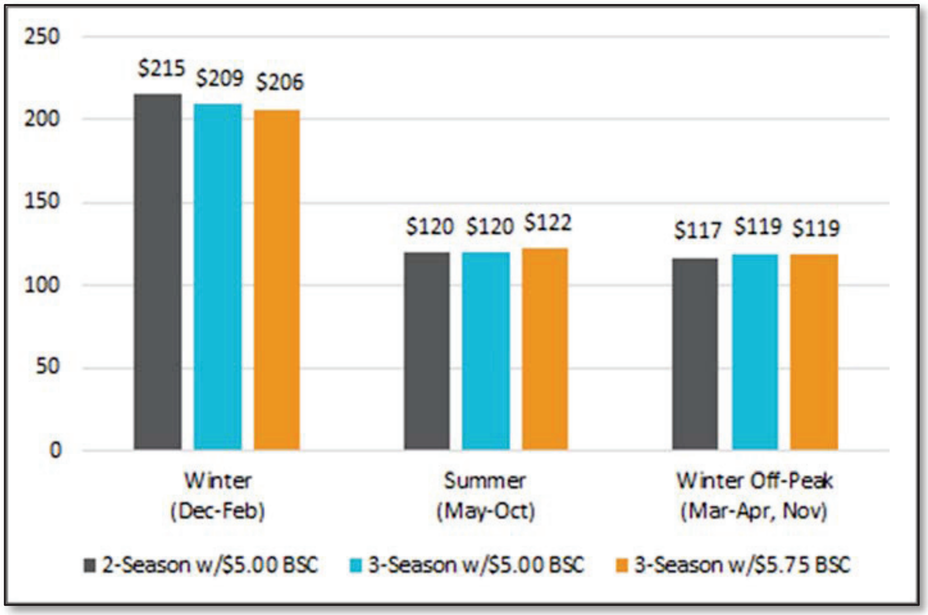
A. 37 It is appropriate to increase the residential basic service charge from $5.00 per month to $5.75 per month for two reasons. First, the CCOSS shows that customer-related costs are more than $5.75 per month. The proposed increase would move the customer charge closer to recovering the customer-related costs. This is important since customer-related costs not recovered through the customer charge are recovered through consumption charges, which are disproportionately recovered from high-use customers. Second, the proposed customer charge of $5.75 helps reduce winter bills.

Q. 38 Please explain how the proposed basic service charge of $5.75 helps reduce winter bills.

A. 38 Figures 7, 8 and 9 demonstrate that an increase in the basic service charge to $5.75 for the Company's three rate jurisdictions is the amount required for the decreases in peak winter month bills to be approximately equal to the maximum increase to off-peak winter month bill. Figures 7, 8 and 9 (below) provide a bill impact comparison for customers with average usage in Southern California (Victorville), which tends to reflect a warmer climate zone, Northern California (Truckee), which tends to reflect a colder climate zone, and South Lake Tahoe, which also a tends to reflect a colder climate zone. Exhibit No.__(TSL-1) provides the bill impact comparisons for the remaining service areas within the Company's three rate jurisdictions.

The bill impact comparison in Figures 7, 8 and 9 is presented under the following three scenarios: 1) the Company's existing two baseline seasons and $5.00 basic service charge; 2) the Company's proposed three baseline seasons and the existing $5.00 basic service charge; and 3) the Company's proposed three baseline seasons and increase in basic service charge to $5.75.

Figure 7: Seasonal Bill Impact Analysis (Victorville)[6]



The Figure shows that aggregate bills in the three peak winter months in Southern California (Victorville) are lower under the proposed three baseline seasons and basic service charge ($206.00) than under (a) the proposed three baseline seasons and current basic service charge ($209.00) and (b) the current two baseline seasons and current basic service charge ($215.00).

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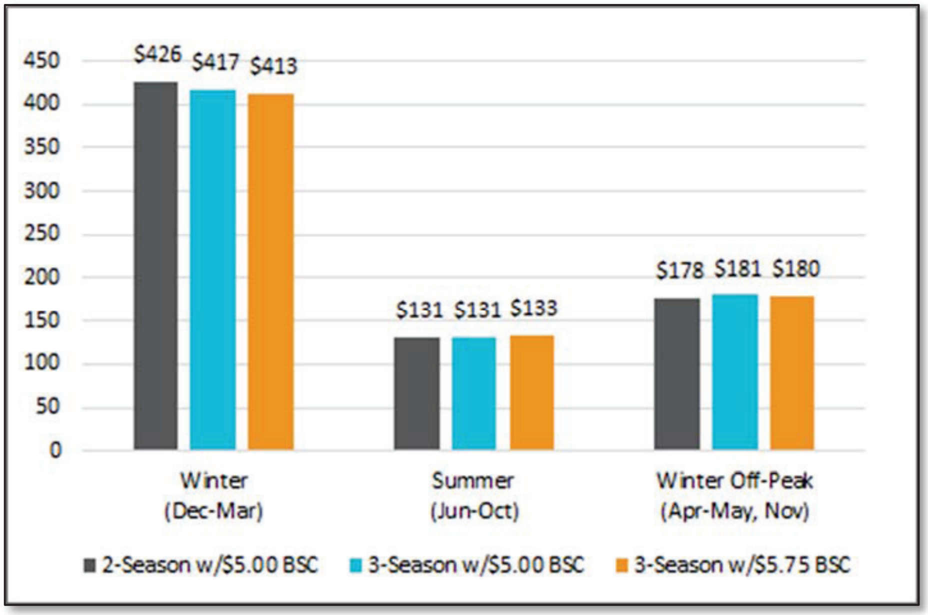
[6] Bill Impact analysis for Base Rates only which include Basic Service Charge, Baseline Usage charge, and Tier II Usage Charge.

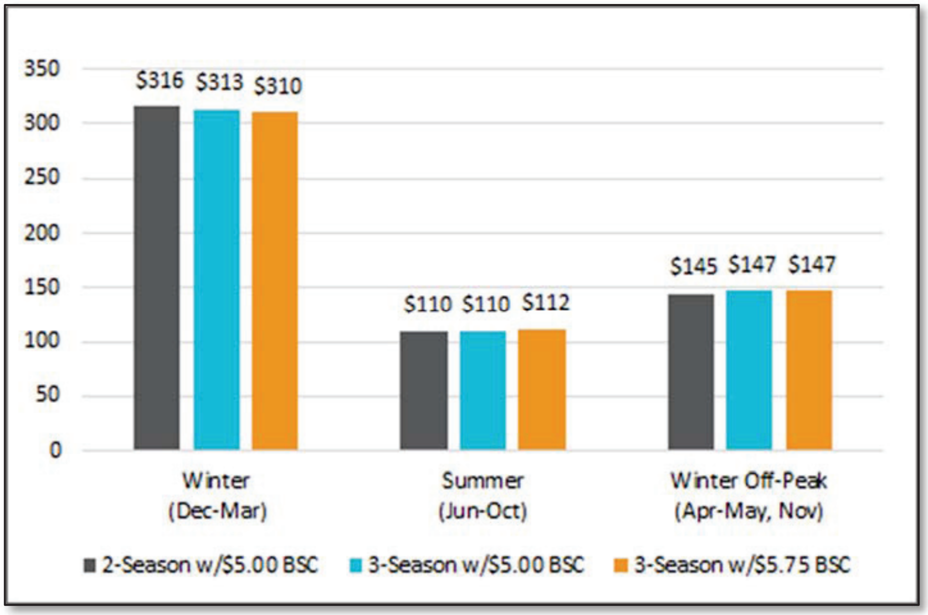
Figure 8: Seasonal Bill Impact Analysis (Truckee)[7]



The Figure shows that aggregate bills in the four peak winter months in Northern California (Truckee) are lower under the proposed three baseline seasons and basic service charge ($413.00) than under (a) the proposed three baseline seasons and current basic service charge ($417.00) and (b) the current two baseline seasons and current basic service charge ($426.00).

[7] Bill Impact analysis for Base Rates only which include Basic Service Charge, Baseline Usage charge, and Tier II Usage Charge.

Figure 9: Seasonal Bill Impact Analysis (South Lake Tahoe)[8]



The Figure shows that aggregate bills in the four peak winter months in South Lake Tahoe are lower under the proposed three baseline seasons and basic service charge ($311.00) than under (a) the proposed three baseline seasons and current basic service charge ($313.00) and (b) the current two baseline seasons and current basic service charge ($317.00).

Q. 39 Please summarize the Company's proposed changes to the residential rate design.

A. 39 As described above, the Company's proposed three season baseline and $5.75 basic service charge are responsive to SB 711 in accomplishing the goal of reducing peak winter season bill volatility.

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[8] Bill Impact analysis for Base Rates only which include Basic Service Charge, Baseline Usage charge, and Tier II Usage Charge

VI. INFRASTRUCTURE RELIABILITY AND REPLACEMENT ADJUSTMENT MECHANISM (IRRAM)

Q. 40 What is the IRRAM?

A. 40 The IRRAM, authorized in the Company's last general rate case (D.14-06-028), is a mechanism used to recover the revenue requirement associated with non-revenue producing infrastructure projects authorized by the Commission. The IRRAM allows the Company to establish rates to recover the revenue requirement on Commission-authorized projects in between general rate cases.

Q. 41 What program and associated budget did the Commission authorize to include in the IRRAM in the Company's last general rate case?

A. 41 In D.14-06-028, the Commission authorized the School Customer-Owned Yard Line (COYL) Leak Survey Program with an associated budget of $8,648.

Q. 42 Did the Company spend the authorized budget for the School COYL Leak Survey Program?

A. 42 No. Due to low participation the Company did not spend the authorized budget. The Company collected the authorized budget through the IRRAM surcharges for the Company's three rate jurisdictions, however, there were minimal offsetting costs. Therefore, the Company received authority to set the IRRAM surcharges to $.00000 to avoid the continued over-collection of program funding.[9]

Q. 43 What is the Company's proposal for the IRRAM balance?

Q. 43 The Company is proposing to use the current IRRAM balance to offset the program costs for the new School COYL program proposed in this application.

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[9] Advice Letter No. 1021, effective January 1, 2017.

Q. 44 What program costs is the Company proposing to recover through the IRRAM in this application?

A. 44 As discussed in the prepared direct testimony of Company witness Kevin M. Lang, the Company is proposing three infrastructure programs: 1) Meter Protection Program; 2) COYL Program;[10] and 3) Targeted Pipe Replacement Program for Driscopipe™ 7000 plastic pipe (M7000) and select distribution and high-pressure steel pipe (Southern California only). The total program budgets for each program by jurisdiction for this general rate case cycle are provided in the following tables:

Meter Protection Program		
		Annual Budget
Southern California		$ 1,200,000
Northern California		$ 1,291,680
South Lake Tahoe		$ 2,296,320

COYL Replacement Program		
		Annual Budget
Southern California		$ 4,390,719
Northern California		$ 1,352,375
South Lake Tahoe		$ 1,525,019

Targeted Pipeline Replacement Program *(Southern California Rate Jurisdiction only)*		
		Annual Budget
M7000 pipe		$ 17,740,800
Distribution Steel		$ 4,435,200
High Pressure Distribution Steel		$ 2,400,000

[10] The COYL program consists of the Residential/Commercial COYL program and the School COYL program.

Q. 45 Based on the above program budgets, how is the Company proposing to recover the costs recorded in the IRRAM?

A. 45 The Company proposes the following 2021 IRRAM surcharge rates of $0.02206 per therm for the Southern California rate jurisdiction, $0.01249 per therm for the Northern California rate jurisdiction, and $0.02206 per therm for the South Lake Tahoe rate jurisdiction. The calculations are shown in Chapter 20. The Company proposes to implement the IRRAM surcharge rates on January 1, 2021 and the surcharges will be updated annually in its annual balancing account Advice Letter submission.

Q. 46 Does this conclude your prepared direct testimony?

A. 46 Yes.

SUMMARY OF QUALIFICATIONS
TIMOTHY S. LYONS

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rate and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim was Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony before 17 state regulatory commissions. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Recent Assignments

- Sponsored cost of service/rate design testimony for a Mid-Atlantic gas utility. Testimony included a proposal for new residential and commercial rate classes and introduction of a block break rate design.
- Sponsored cost of service/rate design testimony for a Midwest gas utility. Testimony included a proposal for new commercial rate classes and a revenue decoupling mechanism.
- Sponsored cost of service/ rate design and lead-lag testimony for a Midwest gas utility. The testimony included proposals for Revenue Decoupling/ Weather Normalization Mechanism and Tracker Accounts for certain O&M expenses and capital costs.
- Sponsored rate design testimony for a Northeast gas utility. The testimony included: a proposal for zonal rates to promote expansion of natural gas service in the state; market analysis; and financial modeling.
- Led a study for the Massachusetts Department of Energy Resources to evaluate the benefits, costs and policies options associated with natural gas expansion by Massachusetts gas utilities. The study included: (a) research on state regulatory policies; (b) financial modeling and analysis of the economic and environmental impacts of pursuing various policy options; and (c) a survey of Massachusetts homeowners on their opinion of home heating fuels.
- Prepared a transmission and distribution (T&D) avoided cost study and report for a Midwest electric utility. The study was used to support the utility's energy efficiency programs.
- Prepared a review and evaluation of cost of service/ rate design studies for an electric utility. The assignment included review of proposed rate designs that address cost shifting concerns with serving residential distribution generation customers through introduction of higher customer charges, a demand charge and time-of-use energy charges.

- Assisted in the development of an electric portfolio of cost of service, rate design, and rate planning tools. The tools were used to evaluate the impact of future rate filings and resource portfolio decisions on individual rate classes.
- Prepared a market analysis for a utility to evaluate natural gas expansion into new areas, including: (a) survey of homes and businesses; (b) estimate of construction and operating costs; (c) analysis of alternative supply options (including pipeline, LNG and CNG); and (d) financial modeling.
- Directed a process review of natural gas expansion projects for a gas utility. The assignment included a review, evaluation and recommendations related to: (a) policies and procedures; (b) process steps and personnel; (c) financial models and analysis; (d) project decisions and schedules; and (e) post-construction review and evaluation.
- Sponsored lead-lag testimony for several electric and gas utilities.

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Maine Public Utilities Commission			
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Missouri Public Service Commission			
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
New Hampshire Public Utilities Commission			
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
New Jersey Board of Public Utilities			
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Corporation Commission of Oklahoma			
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The

Sponsor	Date	Docket No.	Subject
			testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.

Figure 1: Seasonal Bill Impact Analysis (Barstow)

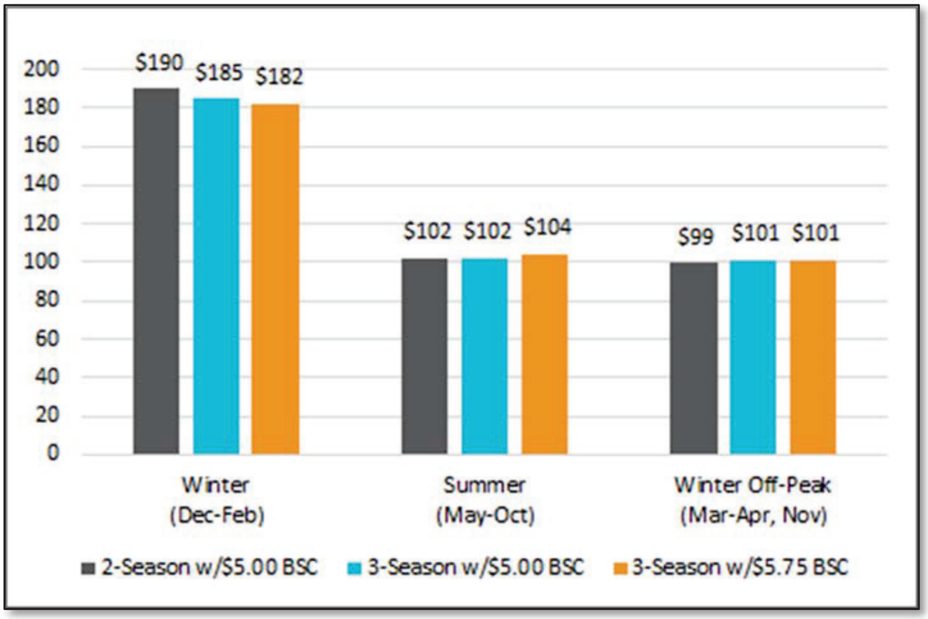


Figure 2: Seasonal Bill Impact Analysis (Victorville)

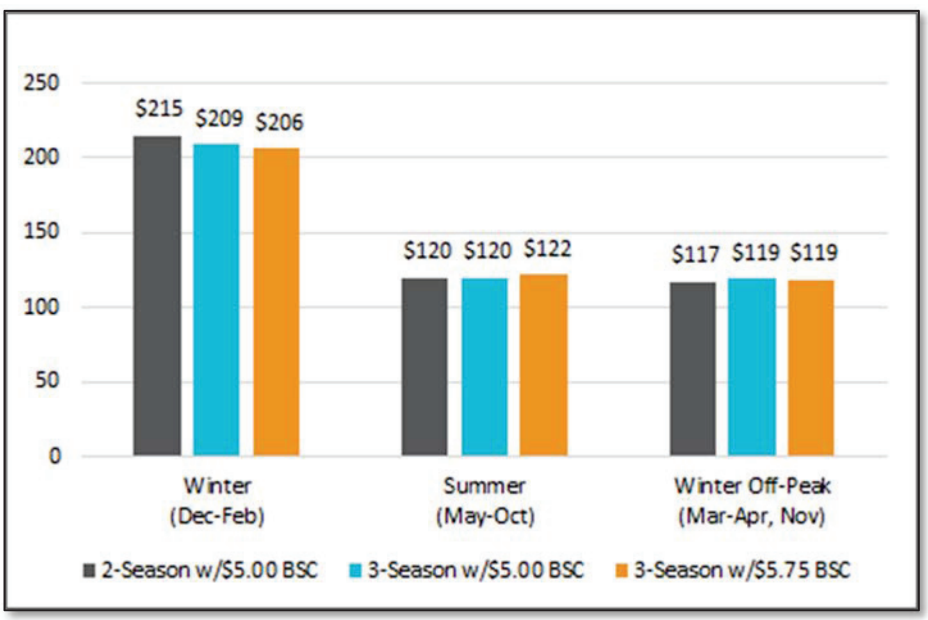


Figure 3: Seasonal Bill Impact Analysis (Big Bear)

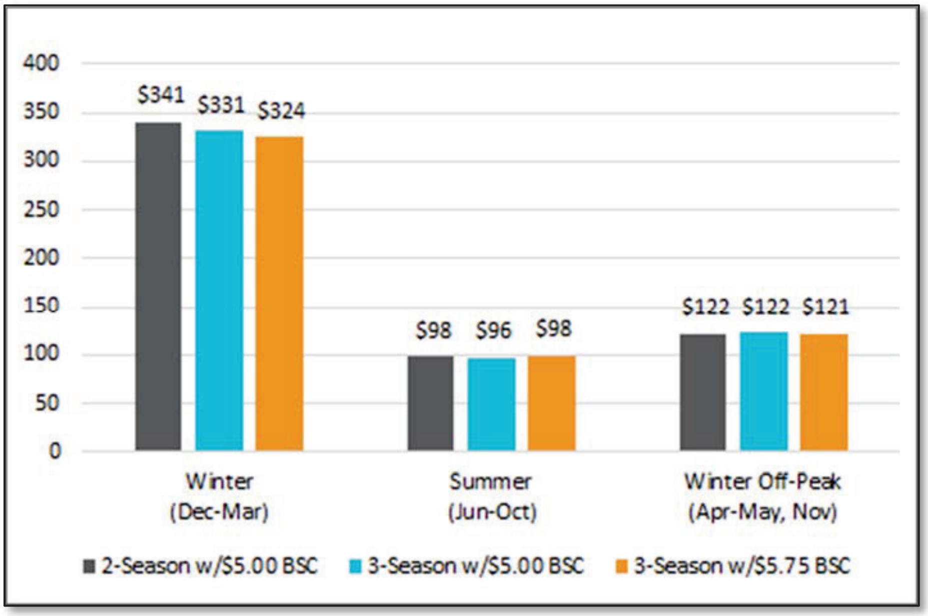


Figure 4: Seasonal Bill Impact Analysis (Needles)

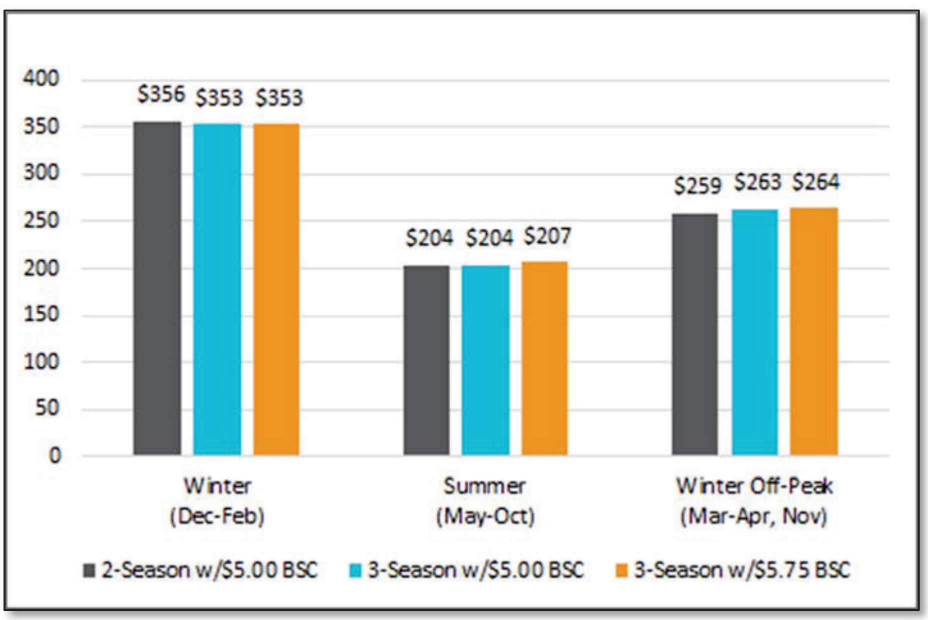


Figure 5: Seasonal Bill Impact Analysis (North Lake Tahoe)

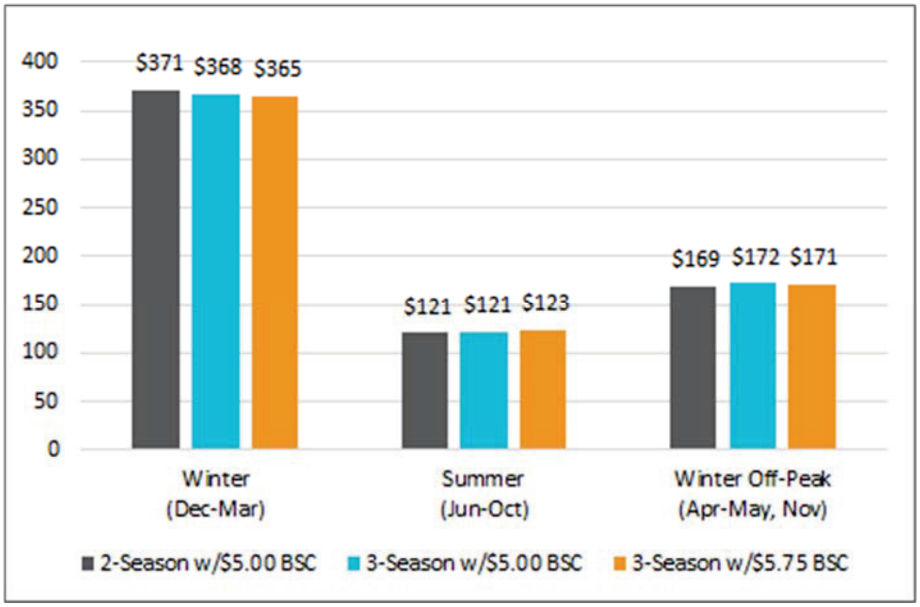


Figure 6: Seasonal Bill Impact Analysis (Truckee)

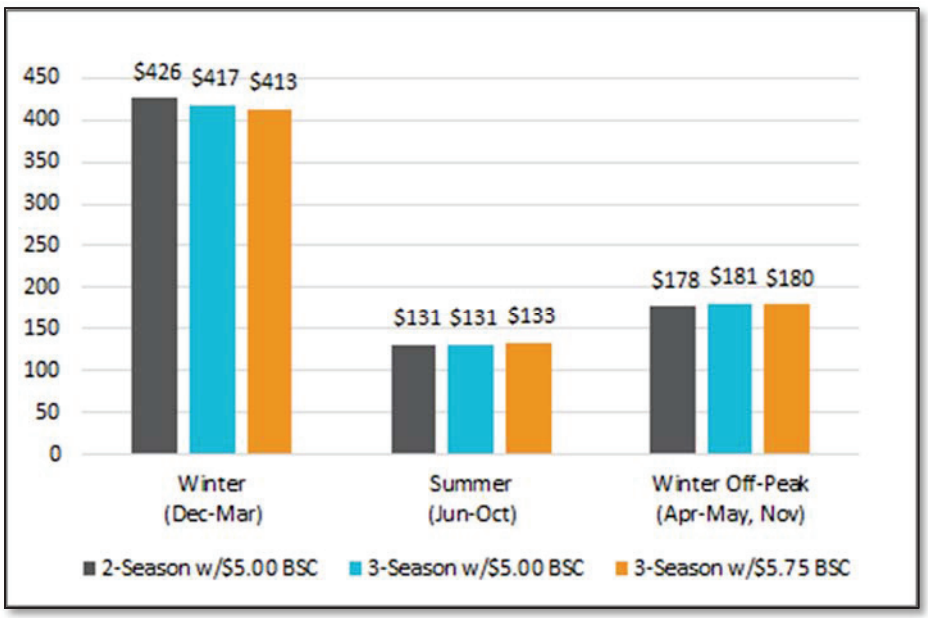
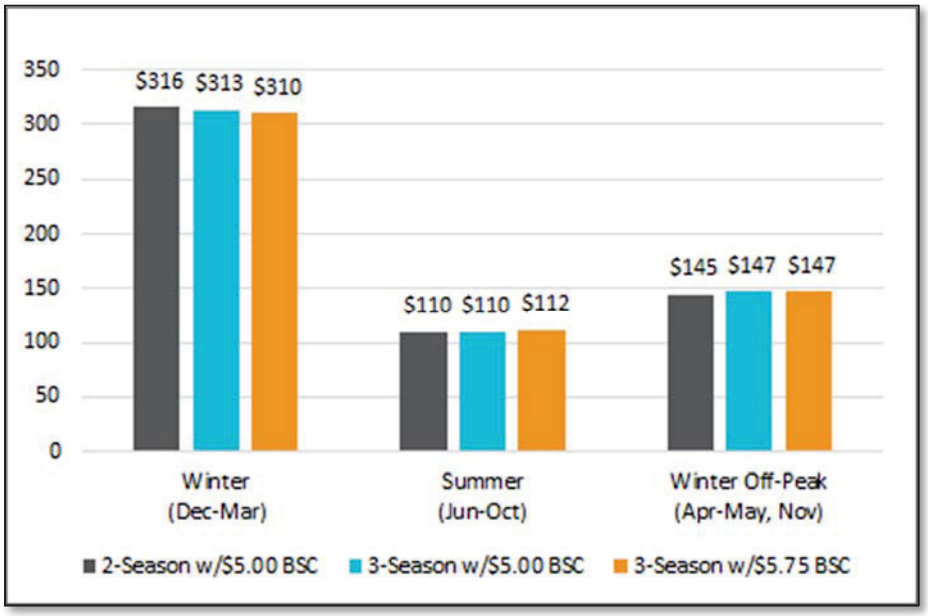


Figure 7: Seasonal Bill Impact Analysis (South Lake Tahoe)



Company Witness:
Bradley C. Anderson

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 19-08-___

PREPARED DIRECT TESTIMONY
OF
BRADLEY C. ANDERSON

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 30, 3019

Table of Contents
Prepared Direct Testimony
of
BRADLEY C. ANDERSON

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
<u>Bradley C. Anderson</u>

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Bradley C. Anderson. 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 Risk Management department. My title is Corporate Risk Manager.

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 My testimony supports the Company's risk-based decision-making framework,[1] developed in compliance with Decision No. ("D.") 14-12-025 and the Voluntary Agreement on a Risk-Based Decision-Making Framework Between the Safety

[1] The terms "risk-based" and "risk-informed" are used interchangeably throughout this testimony.

and Enforcement Division and the Small Multi-Jurisdictional Utilities ("Voluntary Agreement"), which was approved by the Commission in D.19-04-020, issued May 6, 2019.[2]

Q. 6 Please summarize your prepared direct testimony.

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

- An overview of the Company's existing Risk Management program
- The Company's approach to risk-informed decision-making
- The requested GRC funding for the Company's mitigation measures

II. SOUTHWEST GAS' EXISTING RISK MANAGEMENT PROGRAM

Q. 7 Does Southwest Gas have a Risk Management Program?

A. 7 Yes. The Company uses an enterprise risk management ("ERM") program. The program is focused on integrating ERM practices to improve the decision-making process and ensure that strategic objectives and goals are met. Identifying and understanding how risk can impact the Company is a critical step in achieving desired outcomes. Southwest Gas' ERM program is company-wide and encompasses all three states in which the Company operates.

Southwest Gas uses the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") ERM framework as the building block for its program. Southwest Gas adopted the COSO 2004 framework in 2014 and applied its principles in analyzing risk. COSO released an update to the framework, "Enterprise Risk Management Integrating Strategy and Performance," in 2017. This resulted in the Company updating portions of the

[2] Application 15-05-002.

ERM program to ensure alignment with the most current ERM COSO framework.

Q. 8 Please provide an overview of the COSO framework.

A. 8 COSO defines ERM as "the culture, capabilities, and practices, integrated with strategy-setting and performance, that organizations rely on to manage risk in creating, preserving, and realizing value."[3] As part of its ERM program, the Company focuses on identifying and mitigating risks in an effort to achieve desired strategies and business objectives.

The COSO ERM framework identifies five interrelated components and twenty principles. The components and principles are what COSO utilizes to "frame" its ERM process. The five components follow the business cycle and are as follows: Governance and Culture; Strategy and Objective-Setting; Performance; Review and Revision; and Information, Communication, and Reporting. These five components of the updated framework are supported by the twenty principles, which can be applied in different ways for different organizations.

III. THE RISK-BASED DECISION-MAKING PROCESS

Q. 9 Please provide an overview of the Commission's risk-based decision-making process.

A. 9 On November 14, 2013, the California Public Utilities Commission ("Commission") opened Rulemaking ("R.") 13-11-006 through its Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the Rate Case Plan

[3] Enterprise Risk Management – Integrating with Strategy and Performance p. 10.

for Energy Utilities ("Rulemaking"). This Rulemaking was the genesis of the decision-making framework. The purpose was to, "…integrate a risk-based decision-making framework into the Rate Case Plan (RCP) for energy utilities' General Rate Cases (GRCs) in which the utilities request funding for safety-related activities."[4] On December 4, 2014, the Commission issued D.14-12-025, which established the Safety Model Assessment Proceeding (S-MAP) and the Risk Assessment Mitigation Phase (RAMP) that are applicable to the large California utilities. The Decision also required small multi-jurisdictional utilities (SMJU), including Southwest Gas, to include a risk-based decision-making framework in their GRC applications beginning three years from the effective date of the decision. This date was later extended by the Commission in D.18-05-044. Southwest Gas' last GRC filing was in 2012 and as such, this is the first GRC where Southwest Gas is presenting a risk-based decision-making framework.

Q. 10 Did the Commission issue any additional guidance for SMJUs undertaking the risk-based decision-making process?

A. 10 Yes. D.19-04-020 also approved the Voluntary Agreement, which was the product of discussions between the Commission's Safety Enforcement Division Staff and the SMJUs.[5] The Voluntary Agreement sets forth 10 general principles to be incorporated into the SMJUs' risk-based decision-making framework, along with a template for the SMJU's GRC testimony on this issue. Southwest Gas is the first SMJU to file a GRC subsequent to the approval of the Voluntary Agreement.

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[4] D.19-04-020, at p.3.
[5] Id. at Attachment 3.

Q. 11 Please describe Southwest Gas' approach to developing a risk-informed decision-making process for this GRC.

A. 11 The Company retained the services of Accenture Consulting (Accenture) to assist with the development of its risk-based decision-making framework. Accenture reviewed the Company's existing ERM program and leveraged it to develop and implement a risk-informed decision-making framework for the Company's California operations in compliance with D.14-12-025 and the Voluntary Agreement. Accenture also worked with the Company's project team[6] to brainstorm additional risks, including those specific to the Company's California operations. Each risk was then assessed utilizing a bowtie analysis, scored, and documented with existing controls and proposed mitigation plans. A copy of Accenture's Report on Southwest Gas' Risk-Informed Decision-Making Framework ("Report") is attached as Exhibit No. __(BCA-1) to my testimony. The Report describes Accenture's engagement and the process used to develop the risk-based framework in greater detail. With the exception of witness qualifications and the purpose of testimony, which I address herein, the Report also addresses the items listed in the Voluntary Agreement's template for GRC testimony.

Q. 12 Does the Company's risk-based decision-making framework incorporate the general principles set forth in the Voluntary Agreement?

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[6] The Company's project team consisted of subject matter experts from Risk Management, Engineering Staff, Gas Operations Support Staff (GOSS), and Division Operations for the Company's California service territories, as well as a subject matter expert from the Company's cybersecurity team. A second team comprised of management-level employees, including but not limited to Director-level employees and Vice Presidents over the functional areas represented on the project team, was also assembled to review the initial scoring and proposed mitigations and offer feedback.

A. 12 Yes. The Voluntary Agreement identifies the following general principles:

1. Identify top risks
2. Describe the controls or mitigation currently in place
3. Present a plan for improving the mitigation of each risk
4. Present two alternative mitigation plans that were considered
5. Present an estimate of "risk mitigated to cost ratio" or related "risk reduction per dollar spent"
6. Identify lessons learned to apply in future filings
7. Move toward probabilistic calculations as much as possible
8. For those business areas with less data, improve the collection of data and provide a timeframe for improvement
9. Describe the company's safety culture, executive engagement, and compensation policies
10. Respond to immediate or short-term crises outside of the RAMP and GRC process

Items 1 through 5 are addressed in the Report. I discuss the remaining items below.

Q. 13 What lessons did Southwest Gas learn that it can incorporate into future filings?

A. 13 With this being the first time Southwest Gas undertook a risk-informed decision-making process, the Company identified practices that worked well, and lessons learned that it can incorporate into future filings. For example, the Company benefitted greatly from engaging Accenture to work through the process with the project team, and most significantly, to assist the Company in scoring risks and developing Risk Spend Efficiency (RSE) scores for the proposed mitigations.

However, in the future, the Company may consider including management-level employees in the project team rather than engaging them later in the process, so that they can be more involved in the initial brainstorming sessions. Even as it endeavors to gradually move toward more comprehensive and quantifiable data collection, Southwest Gas believes that gaining as much input from its subject matter experts as possible, as early-on in the process as possible, is critical to any exercise of this nature.

Q. 14 How does Southwest Gas plan to move toward probabilistic calculations as much as possible and improve data collection?

A. 14 Southwest Gas will work toward refining the risk-based decision-making process, including gradual movement toward more probabilistic calculations that are quantifiable when appropriate. The Company acknowledges that this requires more comprehensive data collection methods and will endeavor to evaluate and document various data points in the future in order to better inform the project team's work.

Q. 15 Please describe Southwest Gas' safety culture, executive engagement and compensation policies.

A. 15 The safety culture at Southwest Gas is one of ownership and leadership. It begins with the following mission statement:

> Safety is our number one priority at Southwest Gas. The Company will continually foster a culture where employees are empowered to embrace personal responsibility for the safety of themselves, their colleagues, and the communities they serve.

The Company's commitment to safety is established and modeled through its executive engagement. This "tone at the top" is demonstrated by recent changes that incorporated safety metrics into the Company's management compensation plan.[7] It is also reflected in the Company's Pipeline Safety Committee – a group of Vice Presidents and Senior Vice Presidents that meet regularly to discuss emerging issues within the industry, as well as best practices and lessons learned from the Company's own operations.

The Company's commitment to safety it also evidenced in internal and external messaging from Southwest Gas leaders. For example, in 2016, the Company's internal communications and outreach plan, "Walk the Talk", was launched with a video message to all employees from the President and CEO. This on-going initiative educates and engages employees by covering topics such as pipeline integrity management, vehicle safety and safe digging. Similarly, Southwest Gas executives express the Company's commitment to safety in external communications such as the Company's California Safety Plan and the Southwest Gas Holdings, Inc. Sustainability Report. The Company's President and CEO was also pleased to participate in the Commission's 2018 safety en banc hearing, where he presented and answered questions about the Company's safety management system (SMS) and the maturity of its SMS framework.

Southwest Gas also recognizes the importance of educating its customers and the general public about natural gas safety. The Company consistently provides safety messaging in its customer bills and on its website, as well as through broader outreach mediums such as radio spots and social media.

[7] Additional information on the safety metrics is included in the prepared direct testimony of Company witness Timothy S. Lyons.

Q. 16 Please describe how Southwest Gas will respond to immediate or short-term crises outside of the RAMP and GRC process.

A. 16 As mentioned in the Report and described in further detail in the prepared direct testimony of Company witness Kevin M. Lang, the proposed mitigations stemming from Southwest Gas' risk-informed decision-making framework focus on proactive measures that are incremental to the Company's day-to-day operations. The Company did not propose mitigations that are mandated by pipeline safety codes or other requirements, and that are embedded in the Company's current cost of service. Accordingly, the Company intends to respond to immediate or short-term safety-related crises in the manner prescribed by both regulation and its internal policies and procedures, which will ensure that customers continue to receive safe and reliable natural gas service.

IV. REQUESTED FUNDING OF MITIGATION MEASURES

Q. 17 What mitigations is the Company proposing as a result of its risk-based decision-making process?

A. 17 As discussed in the Report, Southwest Gas is proposing several mitigations that address various risks identified through the risk-based decision-making process. Southwest Gas also evaluated certain controls that it has in place (for example, controls related to dig-ins), which are extremely effective. In most cases, Southwest Gas believes that the funding included in its requested revenue requirement increase[8] is sufficient to continue the identified controls and implement the proposed mitigations. However, the Company is requesting specific funding for three (3) of its proposed mitigations – the Targeted Pipe

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[8] For additional discussion of the Company's requested revenue requirement increase, please see the prepared direct testimony of Company witness Timothy S. Lyons.

Replacement Program (TPR), a Meter Protection Program and a Customer-Owned Yardline (COYL) Program. These three mitigations are supported from an operations perspective by Company witness Kevin M. Lang. Further detail concerning the proposed ratemaking treatment for these programs is provided in the prepared direct testimony of Company witness Timothy S. Lyons.

Q. 18 Does this conclude your prepared direct testimony?

A. 18 Yes.

SUMMARY OF QUALIFICATIONS
BRADLEY C. ANDERSON

I graduated from Utah Valley State College with a Bachelor of Science in Business Administration and from the University of Nevada, Las Vegas with a Master of Science in Accounting.

Shortly after earning my Masters, I began my professional career with Deloitte & Touche ("Deloitte") as an Auditor. At Deloitte, I worked on several engagements providing auditing service to several publicly-traded companies for close to four years.

I started my career at Southwest Gas Corporation as an Internal Auditor II on May 2, 2011 and was promoted to Senior Auditor on June 17, 2015. As a Senior Auditor, I was responsible for planning, developing, and executing complex financial and operational reviews/audits. All audits were done using a risk-based audit program. As such, risk assessments were a critical part of the audit planning process.

Shortly after being promoted to Senior Auditor, I took a position as Supervisor/Risk Management in April of 2014. Over the next few years I was promoted to Administrator/Corporate Risk Management, and in October of 2016, to Corporate Risk Manager.

As the Corporate Risk Manager, I am responsible for: the day-to-day oversight of the Company's commercial insurance program; supervising the Business Continuity and Infrastructure Protection programs and staff; supervising the workers' compensation program and staff; and identifying, evaluating, and monitoring the Company's various risks in accordance with its Enterprise Risk Management program.

REPORT ON SOUTHWEST GAS' RISK INFORMED DECISION-MAKING FRAMEWORK

August 30, 2019

Contents

Introduction

On December 4, 2014, the Commission issued Decision No. (D.) 14-12-025 and ordered that Southwest Gas (SWG or Company), along with the other small utilities, transition to including a risk-based decision-making framework in their General Rate Case (GRC) application filings beginning three years from the order issuance date. A "Voluntary Agreement Between Risk Assessment Section of the Safety and Enforcement Division and Small and Multi-Jurisdictional Utilities for a Risk-Based Decision-Making Framework" (Voluntary Agreement)was approved by the CPUC, in Decision D. 19-04-020, issued May 6, 2019. The goal of Risk-informed Ratemaking is to make California safer by identifying the risk mitigations that can optimize safety. Overall, the utility should show how it will use its expertise and budget to manage, mitigate and minimize safety-related risks. To do so, each small utility should:

1. Identify its top risks
2. Describe the controls or mitigations currently in place.
3. Present its plan for improving the mitigation of each risk.
4. Present two alternative mitigation plans that it considered
5. Present an estimate of "risk mitigated to cost ratio" or related "risk reduction per dollar spent."
6. Identify lessons learned to apply in future filings.
7. Move toward probabilistic calculations as much as possible
8. For those business areas with less data, improve the collection of data and provide a timeframe for improvement.
9. Describe the company's safety culture, executive engagement, and compensation policies.
10. Respond to immediate or short-term crises outside of the RAMP and GRC process.

SWG leveraged its existing Enterprise Risk Management Program (ERM) to develop this Risk Management Program (RMP) for its Test Year 2021 GRC. The risks in the ERM were used to seed the RMP risks. These initial risks were expanded to include additional gas operations risks specific to the Company's California operations, which were identified by team brainstorming activities.

Lexicon

The following table provides the SWG Risk Management lexicon that will be utilized throughout this Report.

Term	Definition
Risk	The potential for the occurrence of an event that would be desirable to avoid, often expressed in terms of a combination of various outcomes of an adverse event and their associated probabilities. Different stakeholders may have varied perspectives on risk.
Inherent Risk	The level of risk that exists without risk controls or mitigations.
Event	An occurrence or change of a particular set of circumstances that may have potentially adverse consequences and may require action to address.
Frequency	Number of events generally defined per unit of time. (Frequency is often incorrectly treated as synonymous with probability or likelihood).
Probability	The relative possibility that an event will occur. Probability is quantified as a number between 0% and 100% (where 0% indicates impossibility and 100% indicates certainty). The higher the probability

	of an event, the more certain the event will occur. (Often informally referred to as likelihood or chance).
Impact (or Consequence)	The effect or outcome of an event affecting objectives, which may be expressed, by terms including, but not limited to: health, safety, reliability, economic and/or environmental damage.
Mitigation	Measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.
Outcome	The final resolution or end result.
Risk Driver	Factor(s) that could cause one or more risks to occur (Risk driver is also commonly referred to as “threat”).
Risk Response Plan	Collection of mitigations.
Control	Currently established measure that is modifying risk.
Alternative Analysis	Evaluation of different alternatives available to mitigate risk.
Residual Risk	Risk remaining after current controls.
Planned or Forecasted Residual Risk	Risk remaining after implementation of proposed mitigations.
Risk Score	Numerical representation of qualitative and/or quantitative risk assessment that is typically used to relatively rank risks and may change over time.
Risk Tolerance	Maximum amount of residual risk that an entity or its stakeholders are willing to accept after application of risk control or mitigation. Risk tolerance can be influenced by legal or regulatory requirements.

Background

The new and additional requirements ordered in D.14-12-025 and the Voluntary Agreement will take SWG time to fully implement and will be evolutionary as SWG gains further knowledge and experience with these processes. SWG is learning from the experiences of the larger utilities in California that are implementing the requirements of D.14-12-025. In fact, its RMP attempts to model, where feasible, what the larger and smaller utilities are currently doing, and the comments provided to them by the Safety and Enforcement Division ("SED").

Accenture was contracted to assist SWG in developing a risk-based decision-making framework that provides a process for identifying asset-related risks, consequence(s) of occurrence, frequency or likelihood of occurrence, driver(s) of the risk, and mitigation measures. Once the risk-based decision-making framework was adopted, Accenture assisted SWG in identifying the top asset-related risks and in developing additional mitigation strategies beyond those already in place to allow SWG to evaluate them for inclusion in its GRC filing.

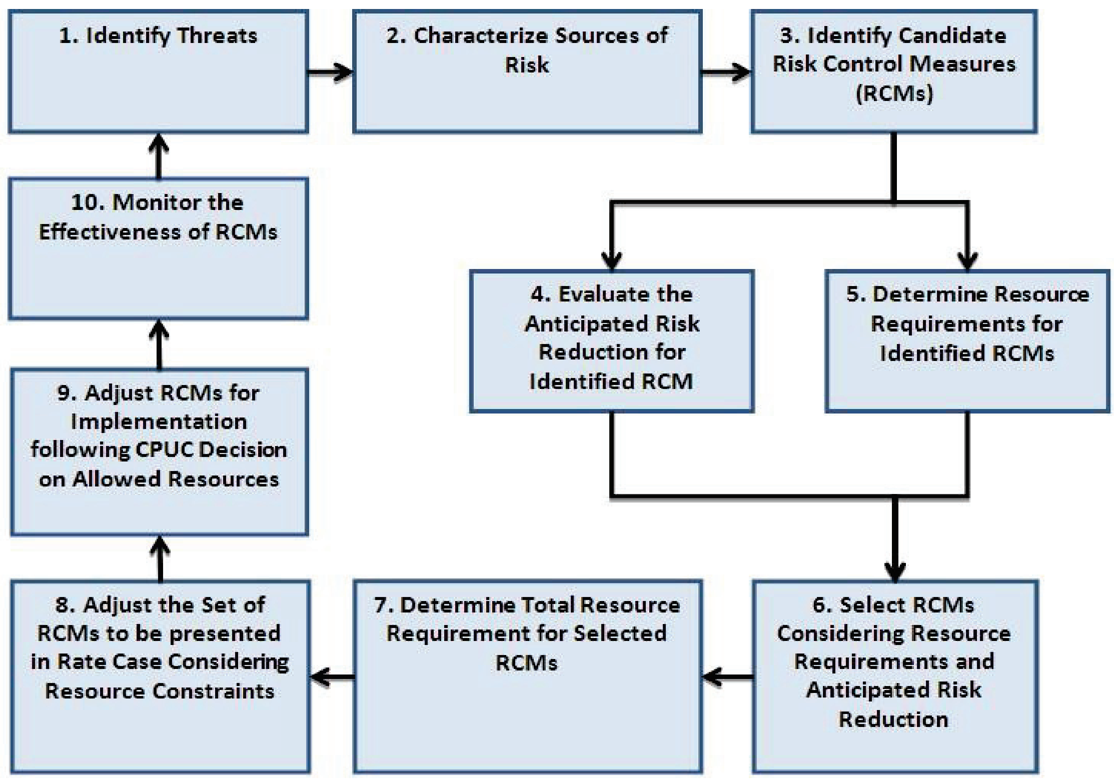
Description of the SWG Risk Management Process

SWG's approach to the risk-informed decision-making process is grounded in the basic tenets of the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and the International Standardization Organization's (ISO) "Risk Management – Principles and Guidelines" (ISO 31000). COSO is the basis for SWG's Company-wide ERM. The California-specific RMP leveraged the prior COSO- based ERM framework and also utilized the principles in ISO 31000. Following ISO 31000 helps organizations achieve objectives, improves the identification of risks, and more effectively allocates resources for risk reduction. ISO 31000 has been applied across many different industries including utilities. As such, SWG has designed a framework for the California Specific RMP that is consistent with the guidance in ISO 31000.

The risk management process incorporates the following six risk-related steps:

1. Risk identification;
2. Risk analysis;
3. Risk evaluation and scoring;
4. Risk mitigation determination;
5. Risk informed project decision making; and
6. Risk monitoring.

This risk-informed process is based upon the 10 steps of the Cycla risk management process. The following flow chart illustrates the Cycla process:



The table below maps the 6 SWG risk-related steps used for the California-specific RMP to the Cycla steps.

SWG	Cycla
1. Risk identification	Steps 1 and 2
2. Risk analysis:	
3. Risk evaluation and scoring	
4. Risk mitigation determination	Steps 3. 4, and 5

SWG	Cycla
5. Risk informed project decision making	Steps 6, 7, 8 and 9
6. Risk monitoring	Step 10

Risk Identification

Risk identification involves finding and describing risks. This includes not only the identification of threats, but also the characterization of the sources of risk. To support the step, Accenture facilitated a brainstorming session with the SWG risk project team to create an initial list of risk events from the current ERM and identified additional operational risks through brainstorming exercises. The SWG risk project team challenged the identified risks, consolidated similar risk events, and eliminated duplicate risk events. The identified risk events were then grouped by business objectives. By mapping the risk events to business objectives, risk events were aligned with risk functional ownership by assigning a risk owner for each group of risk events. Risk owners were responsible for: characterizing the worst reasonable case for each risk event, identifying the existing controls, scoring the risk event, identifying the proposed mitigations and scoring the planned risk following the implementation of the mitigations. The risk owners utilized other subject matter experts, as necessary, to accomplish these responsibilities. Risk reductions were determined based on the expert judgement of the risk owners and subject matter experts.

Risk Analysis

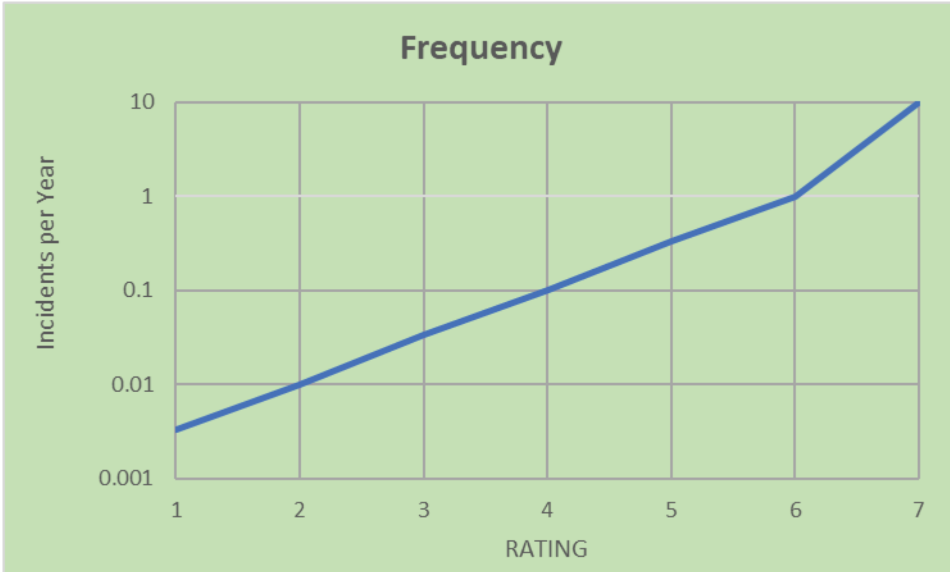
Risk analysis is the process by which a company better understands identified risks, assesses the likelihood and consequences of occurrence, and determines the magnitude. During this step, subject matter experts and the risk team populate the risk registry. The risk registry is the data file which contains the risk event, the magnitude of likelihood and consequences for each risk event, the risk mitigations that affect the risk events and the risk reduction information resulting from the mitigations. The risk team compiles and enters the following data about each risk into the risk registry:

- Title
- Owner
- Description
- Worst Reasonable Scenario
- Triggers
- Consequences

Like many utilities, SWG does not have sufficient data to run a probabilistic analysis and generate a range of potential outcomes/distributions to evaluate likelihood. As such, SWG began the risk analysis process with information from historical incidents, industry experience and other subject matter expert incident experience to identify a worst reasonable case scenario. The risk team and subject matter experts then assigned incident frequencies to define likelihood, which are reflected in the table below, using expertise and experience. While the company attempted to use quantification when feasible, the results were conveyed in term of the 7x7 matrix in accordance with the voluntary agreement.

Frequency	RATING						
	7	6	5	4	3	2	1
	Common	Regular	Frequent	Occasional	Infrequent	Rare	Remote
Frequency: Likelihood of an occurrence	> 10 times per year	1 to 10 times per year	Once every 1 to 3 years	Once every 3 to 10 years	Once every 10 to 30 years	Once every 30 to 100 years	Once every 100+ years
Min Rate	10.0000	1.0000	0.3333	0.1000	0.0333	0.0100	0.0033
Max Rate	30.0000	10.0000	1.0000	0.3333	0.1000	0.0333	0.0100

The likelihood was applied on a continuous scale from 1 to 7. The figure below identifies the relationship between incidents per year and the frequency rating values as whole numbers.



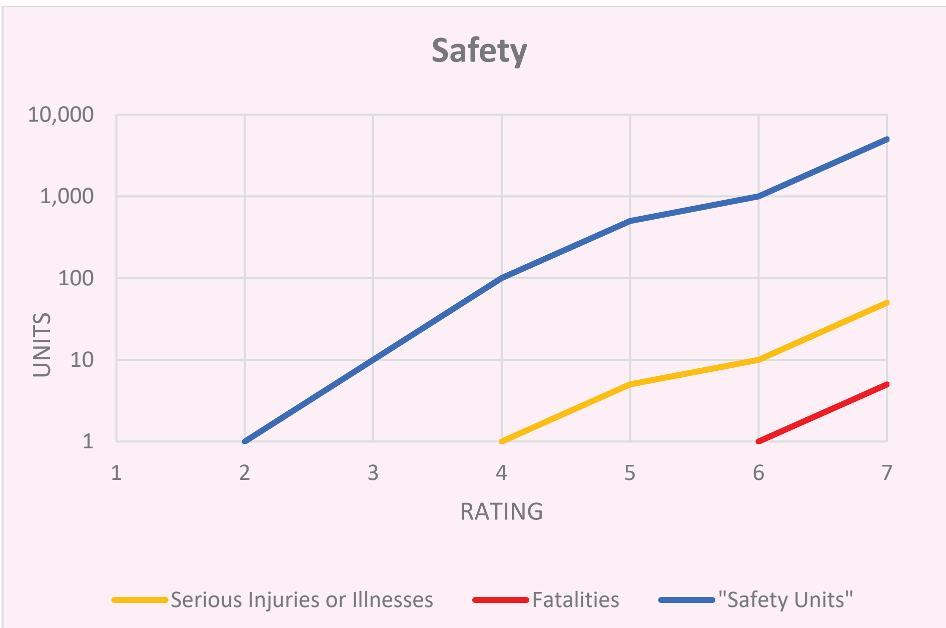
To assess consequence, SWG relied on subject matter expert knowledge to define three Impact Categories: Safety; Operational and Financial, using a pairwise comparison to determine the weights to be attributed to each of the categories. A pairwise comparison is a facilitated exercise where the risk project team compares the relative values of examples for each attribute through every possible permutation and the results of the comparisons are used in a mathematical computation to determine the relative weighting for each attribute. Based on the pairwise comparison, the Risk Project Team considered the weights used by other California utilities and assigned the final weights for each of the impact categories. The final Impact Category weights are:

Safety	Operational	Financial
60%	25%	15%

SWG then adopted a scale from one to seven, with level 1 defined as negligible and level 7 as catastrophic for each Impact Category. The table below defines the impact levels for the Safety Impact Category.

CATEGORY DESCRIPTION	WEIGHT	RATING						
		7	6	5	4	3	2	1
		Catastrophic	Severe	Extensive	Major	Moderate	Minor	Negligible
Safety: Danger to employees or the public	60%	Many fatalities and life threatening injuries	Few fatalities and life threatening injuries	Many serious injuries / illnesses	Few serious injuries / illnesses	Many minor injuries / illnesses	Few minor injuries / illnesses	No reportable injuries / illnesses
Minor Injuries or Illnesses		5,000	1,000	500	100	10	1	0
Serious Injuries or Illnesses		50	10	5	1	0	0	0
Fatalities		5	1	0	0	0	0	0
"Safety Units"		5,000	1,000	500	100	10	1	0

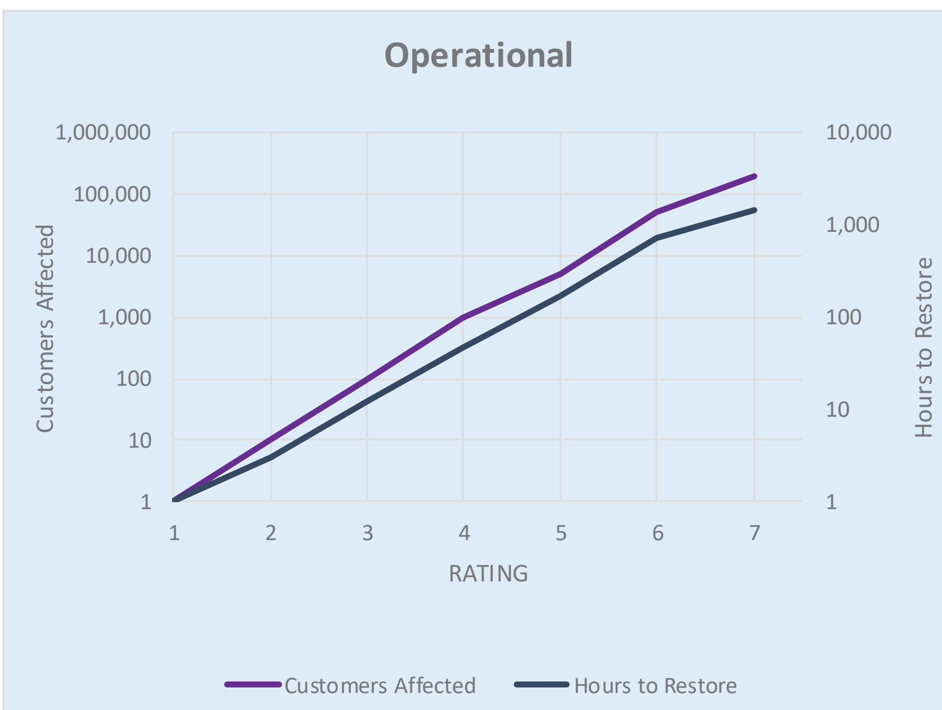
The Safety Impact Category rating was applied on a continuous scale from 1 to 7. The figure below identifies the relationship between Safety Units and the impact rating values as whole numbers.



The table below defines the impact levels for the Operational Impact Category.

CATEGORY DESCRIPTION	WEIGHT	RATING						
		7	6	5	4	3	2	1
		Catastrophic	Severe	Extensive	Major	Moderate	Minor	Negligible
Operational: Disruption to company operations that could impact customers; may be measured in quantity of impacted customers, critical locations, &/or duration	25%	Customers affected: >200k Time to restore: 60 days	Customers affected: 50k - 200k Time to restore: 30 days	Customers affected: 5k - 50k Time to restore: 1 week	Customers affected: 1k - 5k Time to restore: 2 days	Customers affected: 100 - 1k Time to restore: 12 hours	Customers affected: 10 - 100 Time to restore: 3 hours	Customers affected: <10 Time to restore: <1 hour
Customers Affected		200,000	50,000	5,000	1,000	100	10	1
Hours to Restore		1,440	720	168	48	12	3	1

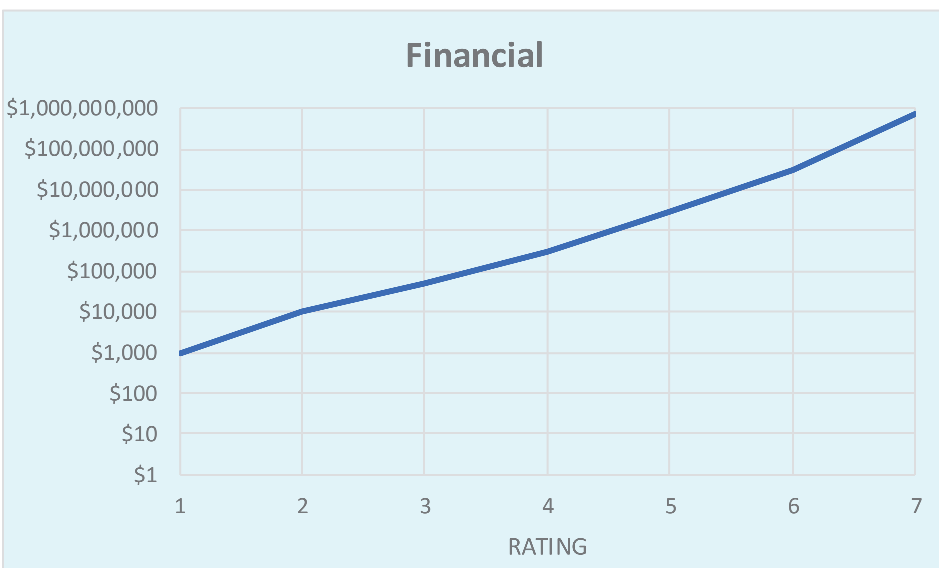
The Operational Impact Category rating was applied on a continuous scale from 1 to 7. The figure below identifies the relationship between the Customers Affected, Hours to Restore and the impact rating values as whole numbers.



The table below defines the impact levels for the Financial Impact Category.

CATEGORY DESCRIPTION	WEIGHT	RATING						
		7	6	5	4	3	2	1
		Catastrophic	Severe	Extensive	Major	Moderate	Minor	Negligible
Financial: Potential financial loss, including disallowance, legal actions, replacement energy, remediation, damage to 3rd party, properties, etc.	15%	>$750M loss	$30M - $750M loss	$3M - $30M loss	$300k - $3M loss	$50k - $300k loss	$10k - $50k loss	<$10k
Financial loss		$750,000,000	$30,000,000	$3,000,000	$300,000	$50,000	$10,000	$1,000

The Financial Impact Category rating was applied on a continuous scale from 1 to 7. The figure below identifies the relationship between the financial impact and the impact rating values as whole numbers.



Risk Evaluation and Scoring

Risk evaluation considered is the "Meter Damage from Snow Loading" risk event. For this risk event four separate and one blended alternative was considered. These included the installation of a meter shed above the meter, the installation of an excess-flow valve upstream of the meter, the upgrade of the piping attached to the meter and the replacement of the Encoder Receiver Transmitter (**ERT**) with one that provides more frequent communication of gas flow conditions. Also considered was a blended mitigation that utilizes one or more of these alternatives depending on the configuration that exists at each meter. Ultimately is was determined that the blended solution would be selected for implementation. This is also how the Company evaluated the "Distribution Failure" risk. It considered separate mitigations for the replacement of M7000 pipe, distribution steel pipe and high- pressure distribution steel pipe and also considered, and ultimately selected, a single mitigation that offers a suite of pipe replacement options and provides operational flexibility in addressing the identified risk.

The risk owner then developed a risk mitigation plan, which describes the risk, existing control/mitigation plans, and proposed mitigations. The risk owner and the risk team will update the mitigation periodically to reflect any changes to the status of the risk and the associated mitigations. The projected risk score for each event is determined based on the planned change in frequency and impact resulting from implementation of the risk mitigation. The next step involves the evaluation of the anticipated risk reduction and the determination of the resource requirements for the identified risk mitigations. The effectiveness of the mitigation is quantified using the risk spend efficiency, which is the change in risk score from the mitigation divided by the cost to implement the mitigation.

Risk informed project decision making

The risk-informed investment-decision process allows SWG to review investment opportunities and adjust its portfolio of projects based on the result of the first four risk processes in terms of the resource requirements and anticipated risk reduction. The portfolio of mitigations is consolidated for review by SWG leadership, who consider the risk analysis and evaluation and assess possible constraints on budget, execution, systems, and resources. Resource and other constraints can drive adjustments to the proposed project portfolio when compared to the total resource requirements for the selected risk mitigation measures.

Risk Monitoring

Once the organization has completed the first five processes of risk management, it must monitor progress. The Risk Monitoring process includes review of all aspects of risk management and supports SWG's efforts at continuous improvement of its framework.

Continuous monitoring and review of risk events ensures that risk owners understand the residual risk appropriately and evaluate the effectiveness of controls. New risks can appear while other risks may no longer exist (i.e., discontinued operations). Changes in business conditions may also change the risk frequency or velocity. The dynamic nature of risks requires the risk team to develop measures for monitoring risks and identifying such changes.

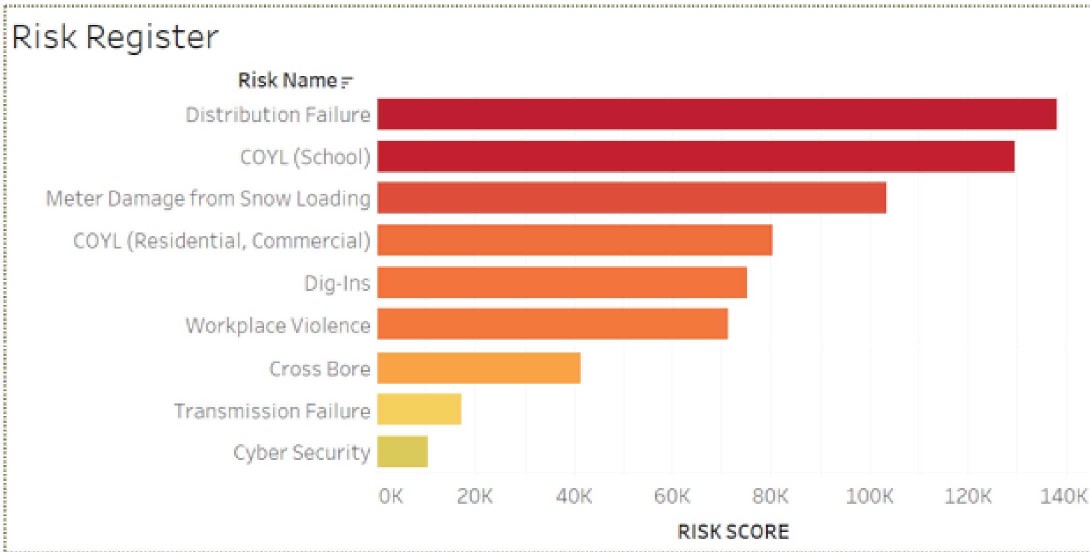
Top Risks

The table below identifies the SWG Top Risks based on risk scores and the judgement of the Risk Team. All these risk events scored higher than four for Safety except for Cyber Security. Cyber Security was included as a top risk due to the potential impact on large numbers of customers.

Risk Name	Description
Dig-Ins	The possibility of catastrophic damage involving dig-ins resulting in loss of life or significant property damage.
Transmission Failure	The possibility of a gas transmission pipeline failure with ignition and the associated impact to customer and employee safety.
Cyber Security	The possibility of a cybersecurity breach that results in the exposure and/or destruction of critical data
Distribution Failure	The possibility of catastrophic failure involving a gas distribution pipeline resulting in risk or threat to the safety of life and property.
Workplace Violence	The possibility of a workplace violence event and the associated impact on the employee safety.
COYL (Residential, Commercial)	Leaks on customer-owned pipelines that are neglected by customers
COYL (School)	Leaks on customer-owned pipelines that are neglected by customers
Cross Bore	Sewer line punctured by insertion of new gas line which can lead to rupture of gas line when sewer line is addressed
Meter Damage from Snow Loading	Ice or snow falls off the roof line, breaks the meter off at house and gas migrates into the house resulting in an explosion

The tables in Appendix A delineate how each risk event is characterized and scored. They provide the Risk Event Name, Event Description, Worst Reasonable Scenario, Event Triggers, Consequences, Impact and Likelihood Scoring, and Risk Scores.

The following figure illustrates the relative risk score results for each risk event.



Risk Controls and Mitigations

Risk Event	Control/Mitigation Name	Mitigation or Control	Description
Dig-Ins	SWG Preventative Activity	Control	Activity includes: standby, patrols, call before you dig (811), public outreach initiatives, tear-tape installation, excavation standby (for facilities >60 psi or cross-trenching), repeat offender training, situational awareness of employees ("see something say something"), excavator mailers, damage prevention administrators.
Workplace Violence	Security Assessment and Additional Resource	Control	Assessment of current security and implement recommendations revealed by the assessment. Implementations could include: increasing security (perimeter security, walls), etc.
Cross Bore	Cross Bore Program (SLIP Program)	Control	Send cameras inside the lines. Current program for SWG as part of O&M, and will continue until complete in 2021 or 2022. Part of DIMP Program; Additional accelerated action.
COYL (School)	COYL Program (School)	Mitigation	COYL Program (similar to what SWG has in AZ and NV) Program would be to replace the lines with facilities owned and maintained by SWG. (Target the mitigation for schools).
Cyber Security	Cyber Security Program	Mitigation	Cyber security program designed to minimize risk and is consequential in protecting the confidentiality, integrity, and availability of SWG's customer, employee and stakeholder data.
Meter Damage from Snow Loading	Targeted Mitigation for Meter Condition	Mitigation	Given the array of mitigations available for meters susceptible to snow load (meter shed, EFV, and daily metering), apply the mitigation optimal for the meter's specific condition
COYL (Residential, Commercial)	COYL Program (Res/Commercial)	Mitigation	COYL Program similar to what SWG has in AZ and NV) Program would be replace the lines with facilities owned and maintained by SWG. (Broad COYL program for residential/commercial).
Distribution Failure	Targeted Pipe Replacement	Mitigation	Hybrid replacement strategy of pipe replacements: pre-1961 distribution pressure pipe, and plastic pipe replacement.
Transmission Failure	Replace pipe	Mitigation	Replace with more robust pipe, which also renders transmission pipe to be classified as distribution. Deemed to merely change risk to distribution

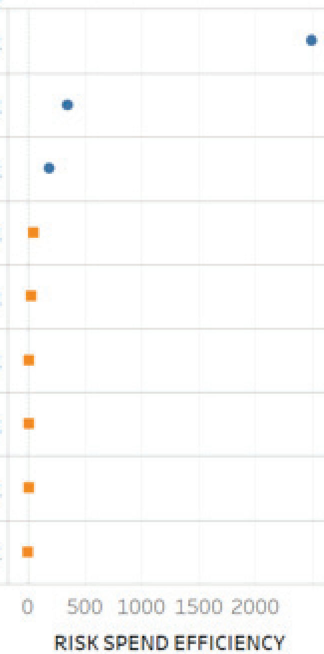
Risk Spend Efficiencies (RSE)

SWG quantified the risk reduction relative to the cost of the mitigation by developing a Risk Spend Efficiency (RSE) measure so that an analysis of the effectiveness of the risk reduction could be made relative to the cost. For the cost the Risk Team identified the total lifecycle cost for the mitigation including initial mitigation cost and future O&M costs. The net present value of the lifecycle cost was used in the RSE calculations. The following graph illustrates the results of these analyses. The RSE for each of the existing SWG controls rank the highest, which illustrates the practices in place to prevent dig-ins, workplace violence and cross bore incidents are effective.

Control Mitigation RSE 0 2,496

Risk-Spend-Efficiencies

Mitigation Name	Risk Mitigated / Controlled	Lifetime Risk Mitigation	NPV ($k)
SWG Preventative Activity	Dig-Ins	33,780,000	$13,532k
Security Assessment and Additional Resource	Workplace Violence	742,935	$2,112k
Cross Bore Program (SLIP Program)	Cross Bore	414,006	$2,143k
COYL Program (School)	COYL (School)	1,210,285	$21,140k
Cyber Security Program	Cyber Security	52,365	$1,574k
Targeted Mitigation for Meter Condition	Meter Damage from Snow Loading	344,990	$20,823k
COYL Program (Res/Commercial)	COYL (Residential, Commercial)	201,095	$17,765k
Targeted Pipe Replacement	Distribution Failure	966,013	$106,880k
Replace pipe	Transmission Failure	0	$965k



The following table provides the RSE numerical value for each control and mitigation.

Risk Event	Control/Mitigation Name	RSE
Dig-Ins	SWG Preventative Activity	2,496.3
Workplace Violence	Security Assessment and Additional Resource	351.7
Cross Bore	Cross Bore Program (SLIP Program)	193.2
COYL (School)	COYL Program (School)	57.3
Cyber Security	Cyber Security Program	33.3
Meter Damage from Snow	Targeted Mitigation for Meter Condition	16.6
COYL (Residential, Commer	COYL Program (Res/Commercial)	11.3
Distribution Failure	Targeted Pipe Replacement	9.0
Transmission Failure	Replace pipe	0.0

Conclusions

SWG has implemented a RMP for Gas Operations in California in compliance with the Commission issued Decision No.("D") 14-12-025, and the "Voluntary Agreement Between Risk Assessment Section of the Safety and Enforcement Division and Small and Multi-Jurisdictional Utilities for a Risk-Based Decision-Making Framework" issued on May 6, 2019. The RMP will be used to include a risk-based decision-making framework into their General Rate Case application filing.

The RMP allowed SWG to:

- Identify its top risks
- Describe the controls or mitigations currently in place
- Present its plan for improving the mitigation of each risk
- Present two alternative mitigation plans that it considered
- Present an estimate of "risk mitigated to cost ratio" or related "risk reduction per dollar spent", and
- Move toward probabilistic calculations as much as possible

Appendix A:

Risk Event Characterization and Scoring

The following pages provide the Risk Event Name, Event Description, Worst Reasonable Scenario, Event Triggers, Consequences, Impact and Likelihood Scoring, and Inherent Risk Scores for each risk event.

Risk: Dig-Ins
Description: The possibility of catastrophic damage involving dig-ins resulting in loss of life or significant property damage.
Risk Owner: Joel Martell
Data Source: Damage Cause Database (DCD)
Comments:

Worst Reasonable Scenario

Dig-in causes building to fill with gas, resulting in explosion, causing injuries, fatalities, property damage, financial loss, regulatory impact, and reputational damage

Safety	*Minor Injuries or Illnesses*	*Serious Injuries or Illnesses*	*Fatalities*	*Value (Safety Units)*	*7x7 Rating*	*Impact Score*	*Rationale*
	0	8	2	2,800	6.6	2,617,519	Based on elementary school example

Operational	*Customers Affected*	*Hours to Restore*	*7x7 Rating (Customers)*	*7x7 Rating (Hours)*	*Impact Score*	*Rationale*
	2,500	120	4.6	4.7	13,470	Biggest isolation area = 2,500 customers; 5 day restoration

Financial	*Financial Loss*	*7x7 Rating*	*Impact Score*	*Rationale*
	$500,000,000	6.9	1,122,345	Independent estimate/assessment of

Frequency	*# Events*	*Time Period (Years)*	*7x7 Rating*	*Frequency (Incidents/Yr)*	*Frequency Value*	*Rationale*
	1	50	2.6	0.0	0.0	Based off historical events and SME input

IMPACT RATING	*FREQUENCY RATING*	*RISK SCORE*
6.2	2.6	75,067

Triggers		Consequences	
A.	No dig ticket	A.	Employee / Public injury / fatality
B.	Mismarks	B.	Infrastructure damage
C.	Failure to follow laws/procedures	C.	Outage
D.	Inaccurate documentation	D.	Public property damange
E.	Failure to protect the facility	E.	Regulatory consequence
F.	Exemptions to One-Call	F.	Reputational damage
		G.	Financial loss; claims

Risk: Transmission Failure
Description: The possibility of a gas transmission pipeline failure with ignition and the associated impact to customer and employee safety.
Risk Owner: Mary Bartholomew
Data Source: TRIMP data sources
Comments: 800 ft of transmission in California, no HCA's

Worst Reasonable Scenario

Sabotage of a regulator station resulting in a gas release.

Safety	*Minor Injuries or Illnesses*	*Serious Injuries or Illnesses*	*Fatalities*	*Value (Safety Units)*	*7x7 Rating*	*Impact Score*	*Rationale*
	0	0	2	2,000	6.4	1,617,439	Present employees result in fatalities. (There are likely

Operational	*Customers Affected*	*Hours to Restore*	*7x7 Rating (Customers)*	*7x7 Rating (Hours)*	*Impact Score*	*Rationale*
	0	0	0.0	0.0	0	No interruptions

Financial	*Financial Loss*	*7x7 Rating*	*Impact Score*	*Rationale*
	$20,000,000	5.8	100,000	Society's financial loss. Includes fatalities, replacing

Frequency	*# Events*	*Time Period (Years)*	*7x7 Rating*	*Frequency (Incidents/Yr)*	*Frequency Value*	*Rationale*
	1	100	2.0	0.0	0.0	732 ft T-line; remote locations. SWG has limited

IMPACT RATING	*FREQUENCY RATING*	*RISK SCORE*
4.7	2.0	17,174

Triggers		**Consequences**	
A.	Excavation damage	A.	Employee / Public injury / fatality
B.	External corrosion	B.	Infrastructure damage
C.	Material failure	C.	Outage
D.	Natural forces	D.	Public property damange
E.	Failure to follow procedures	E.	Regulatory consequence
F.	Outside force (e.g. car impact, vandalism)	F.	Reputational damage
		G.	Financial loss; claims

Risk: Cyber Security
Description: The possibility of a cybersecurity breach that results in the exposure and/or destruction of critical data
Risk Owner: Stephen Votta, Carl Landre
Data Source: Customer Information Systems (CIS)
Comments:

Worst Reasonable Scenario

A party infilatrates SWG's digital environment causing a data breach resulting in loss of customer information.

Safety	Minor Injuries or Illnesses	Serious Injuries or Illnesses	Fatalities	Value (Safety Units)	7x7 Rating	Impact Score	Rationale
	0	0	0	0	1.0	6	One SCADA control point in California

Operational	Customers Affected	Hours to Restore	7x7 Rating (Customers)	7x7 Rating (Hours)	Impact Score	Rationale
	0	0	0.0	0.0	0	

Financial	Financial Loss	7x7 Rating	Impact Score	Rationale
	$32,000,000	6.0	157,087	Figure derived from Ponnemen's recent report

Frequency	# Events	Time Period (Years)	7x7 Rating	Frequency (Incidents/Yr)	Frequency Value	Rationale
	1	15	3.6	0.1	0.1	2018 data breach hit 18 utilities (not as catastrophic);

IMPACT RATING	FREQUENCY RATING	RISK SCORE
1.5	3.6	10,473

Triggers		Consequences	
A.	Admin configuration error	A.	Infrastructure damage
B.	Phishing	B.	Customer outage
C.	Drive-by download	C.	Data breach
D.	USB	D.	Reputational damage
E.	Compromised credentials	E.	Regulatory penalties, additional regulation
F.	Vendor	F.	Civil liabilities
G.	Insider threat	G.	Reputation impact from security skepticism
H.	Lost equipment	H.	Financial impact (credit moitoring costs)
I.	Missing patch / vulnerability		
J.	Lack of encryption / tokenization		

Risk: Distribution Failure
Description: The possibility of catastrophic failure involving a gas distribution pipeline resulting in risk to the safety of life and property.
Risk Owner: Joel Martell
Data Source: DIMP data
Comments: Compared scenarios using both household and multi-family (e.g., apartment). Adjusted frequency of multi-family unit to be less freqent than house but more impactful in terms of deaths and financial impact. House is the WRS based on score comparison.

Worst Reasonable Scenario

Distribution pipe at household leaks and explodes, causing fatalities and loss of property.

Safety	*Minor Injuries or Illnesses*	*Serious Injuries or Illnesses*	*Fatalities*	*Value (Safety Units)*	*7x7 Rating*	*Impact Score*	*Rationale*
	0	2	2	2,200	6.5	1,853,734	Assume family of four; two survivors

Operational	*Customers Affected*	*Hours to Restore*	*7x7 Rating (Customers)*	*7x7 Rating (Hours)*	*Impact Score*	*Rationale*
	3	8	1.5	2.7	127	Three customers (one affected and two adjacent);

Financial	*Financial Loss*	*7x7 Rating*	*Impact Score*	*Rationale*
	$50,000,000	6.2	216,166	Loss of life, litigation

Frequency	*# Events*	*Time Period (Years)*	*7x7 Rating*	*Frequency (Incidents/Yr)*	*Frequency Value*	*Rationale*
	1	15	3.6	0.1	0.1	Based on company/industry history

IMPACT RATING	*FREQUENCY RATING*	*RISK SCORE*
5.5	3.6	138,002

Triggers		Consequences	
A.	Improper backfill, rock impingement	A.	Fatality / Serious injury
B.	Tree-root impingement	B.	Property damage / loss
C.	Material defect	C.	Reputational damage / poor media coverage
D.	Excavation damage	D.	Regulatory impact
E.	Poor workmanship	E.	Financial impact

Risk: Workplace Violence
Description: The possibility of a workplace violence event and the associated impact on the employee safety.
Risk Owner: Bill Brincefield, Brad Anderson
Data Source: Industry data (e.g. Spire in Missouri)
Comments:

Worst Reasonable Scenario

Targeted shooter event at Victorville resulting in major loss of life.

Safety	Minor Injuries or Illnesses	Serious Injuries or Illnesses	Fatalities	Value (Safety Units)	7x7 Rating	Impact Score	Rationale
	0	2	2	2,200	6.5	1,853,734	Incident would likely affect most personnel onsite.

Operational	Customers Affected	Hours to Restore	7x7 Rating (Customers)	7x7 Rating (Hours)	Impact Score	Rationale
	0	0	0.0	0.0	0	Delays, yet no significant operational impact

Financial	Financial Loss	7x7 Rating	Impact Score	Rationale
	$75,000,000	6.3	288,904	Civil litigation; societal impact

Frequency	# Events	Time Period (Years)	7x7 Rating	Frequency (Incidents/Yr)	Frequency Value	Rationale
	1	30	3.0	0.0	0.0	Impact and frequency based on SCE workplace violence

IMPACT RATING	FREQUENCY RATING	RISK SCORE
4.8	3.0	71,421

Triggers		Consequences	
A.	Lack of access control	A.	Post traumatic stress
B.	Disgruntled employee	B.	Civil litigation
C.	Disgruntled customer	C.	Reputational damage
D.	Domestic violence	D.	Consequences from OSHA
E.	Lack of response training	E.	Financial impact

Risk: COYL (Residential, Commercial)
Description: Leaks on customer-owned pipelines that are neglected by customers
Risk Owner: Paul Krahl, Matthew Helmers
Data Source: FOMS; 299 Dispatch log
Comments: Not reportable so not in GO-112F Grade 1 (customer-owned lines)

Worst Reasonable Scenario

Catastrophic leak in COYL with migration into structure with ignition, resulting in injuries/fatalities, property damage, and reputational damage.

Safety	*Minor Injuries or Illnesses*	*Serious Injuries or Illnesses*	*Fatalities*	*Value (Safety Units)*	*7x7 Rating*	*Impact Score*	*Rationale*
	0	2	2	2,200	6.5	1,853,734	Same as Distribution Failure

Operational	*Customers Affected*	*Hours to Restore*	*7x7 Rating (Customers)*	*7x7 Rating (Hours)*	*Impact Score*	*Rationale*
	3	8	1.5	2.7	127	3 customers; 1 day (8 hours) to restore and make system

Financial	*Financial Loss*	*7x7 Rating*	*Impact Score*	*Rationale*
	$32,000,000	6.0	157,087	Cost to society for injuries and fatalities and structure.

Frequency	*# Events*	*Time Period (Years)*	*7x7 Rating*	*Frequency (Incidents/Yr)*	*Frequency Value*	*Rationale*
	1	25	3.2	0.0	0.0	More frequent than the schools because of more

IMPACT RATING	*FREQUENCY RATING*	*RISK SCORE*
5.5	3.2	80,438

Triggers		Consequences	
A.	Customers failure to maintain COYL	A.	Serious injury / Fatality
B.	Lack of cathodic protection	B.	Property damage
C.	Lack of leak survey	C.	Reputational consequences
D.	Substandard installation	D.	Financial loss
E.	Excavation damage; poor response to locate-and-mark		

Risk: COYL (School)
Description: Leaks on customer-owned pipelines that are neglected by customers
Risk Owner: Paul Krahl, Matthew Helmers
Data Source: FOMS; 299 Dispatch log
Comments: Not reportable so not in GO-112F Grade 1 (customer-owned lines)

Worst Reasonable Scenario

Catastrophic leak in COYL with migration into portable classroom at a school with ignition, resulting in injuries/fatalities, property damage, and reputational damage.

Safety	*Minor Injuries or Illnesses*	*Serious Injuries or Illnesses*	*Fatalities*	*Value (Safety Units)*	*7x7 Rating*	*Impact Score*	*Rationale*
	0	42	8	12,200	7.0	6,000,000	Avg classroom ~25 ppl, assume a fraction result in

Operational	*Customers Affected*	*Hours to Restore*	*7x7 Rating (Customers)*	*7x7 Rating (Hours)*	*Impact Score*	*Rationale*
	1	8	1.0	2.7	127	Single customer; 1 day (8 hours) to restore

Financial	*Financial Loss*	*7x7 Rating*	*Impact Score*	*Rationale*
	$150,000,000	6.5	474,342	Cost to society for injuries and fatalities.

Frequency	*# Events*	*Time Period (Years)*	*7x7 Rating*	*Frequency (Incidents/Yr)*	*Frequency Value*	*Rationale*
	1	50	2.6	0.0	0.0	Far less severe occurrences occur ~1/yr; very small COYL

IMPACT RATING	*FREQUENCY RATING*	*RISK SCORE*
5.9	2.6	129,489

Triggers		Consequences	
A.	Customers failure to maintain COYL	A.	Serious injury / Fatality
B.	Lack of cathodic protection	B.	Property damage
C.	Lack of leak survey	C.	Reputational consequences
D.	Substandard installation	D.	Financial loss
E.	Excavation damage; poor response to locate-and-mark		

Risk: Cross Bore
Description: Sewer line punctured by insertion of new gas line which can lead to rupture of gas line when sewer line is addressed
Risk Owner: Joel Martell
Data Source: Cross Bore Investigation Database
Comments: Not all sewer lines mapped. Septic lines also may not be and/or mapped correctly; inspections susceptible to human error.

Worst Reasonable Scenario

Gas line broken inside sewer line, gas migrates into home, ignites and causes fatalities in home

Safety	*Minor Injuries or Illnesses*	*Serious Injuries or Illnesses*	*Fatalities*	*Value (Safety Units)*	*7x7 Rating*	*Impact Score*	*Rationale*
	0	2	2	2,200	6.5	1,853,734	Similar safety impact as comparable risks

Operational	*Customers Affected*	*Hours to Restore*	*7x7 Rating (Customers)*	*7x7 Rating (Hours)*	*Impact Score*	*Rationale*
	3	8	1.5	2.7	127	One customer and two adjacent customers; one day

Financial	*Financial Loss*	*7x7 Rating*	*Impact Score*	*Rationale*
	$50,000,000	6.2	216,166	Loss of life, litigation

Frequency	*# Events*	*Time Period (Years)*	*7x7 Rating*	*Frequency (Incidents/Yr)*	*Frequency Value*	*Rationale*
	1	50	2.6	0.0	0.0	SME judgment on frequency. Similar incident with mobile

IMPACT RATING	*FREQUENCY RATING*	*RISK SCORE*
5.5	2.6	41,401

Triggers		Consequences	
A.	Plumber / Homeowner runs cleaning tool intc	A.	Fatality / Serious injury
B.	Failure to scope prior to work	B.	Residential damage
		C.	Reputational damage
		D.	Financial loss
		E.	Regulatory impact

Risk: Meter Damage from Snow Loading
Description: Ice or snow falls off the roof line, breaks the meter off at house and gas migrates into the house resulting in an explosion
Risk Owner: Matt Helmers, Paul Krahl
Data Source: Historical snow/ice incidents (currently being captured)
Comments:

Worst Reasonable Scenario

Ice or snow falls off the roof line, breaks the meter off at house and gas migrates into the house resulting in an explosion

Safety	Minor Injuries or Illnesses	Serious Injuries or Illnesses	Fatalities	Value (Safety Units)	7x7 Rating	Impact Score	Rationale
	0	2	2	2,200	6.5	1,853,734	Assume occupied by a family during ignition

Operational	Customers Affected	Hours to Restore	7x7 Rating (Customers)	7x7 Rating (Hours)	Impact Score	Rationale
	1	4	1.0	2.2	40	Single customer; restoration not immediately applicable

Financial	Financial Loss	7x7 Rating	Impact Score	Rationale
	$50,000,000	6.2	216,166	Fatality / Serious injury costs

Frequency	# Events	Time Period (Years)	7x7 Rating	Frequency (Incidents/Yr)	Frequency Value	Rationale
	1	20	3.4	0.1	0.1	Far less severe incidents ~30/season; explosion with

IMPACT RATING	FREQUENCY RATING	RISK SCORE
5.4	3.4	103,497

Triggers		Consequences	
A.	Plumber runs cleaning tool into gas line	A.	Serious injury / Fatality
B.	Failure to scope prior to work	B.	Property damage
C.	Pipe thickness too small	C.	Loss of service
		D.	Financial loss

Company Witness:

Kevin M. Lang

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION [19-XX-XXX]

PREPARED DIRECT TESTIMONY
OF
KEVIN M. LANG

ON BEHALF OF
SOUTHWEST GAS CORPORATION

AUGUST 30, 2019

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of
KEVIN M. LANG

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
KEVIN M. LANG

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Kevin M. 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 provided testimony to the California Public Utilities Commission (Commission), the Arizona Corporation 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 Targeted Pipe Replacement Program; a Meter Protection Program, and a Customer-Owned Yard Line (COYL) Program.

Q. 6 Please summarize your prepared direct testimony.

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

- Targeted Pipe Replacement Program of select distribution and high-pressure steel and Driscopipe™ 7000 plastic pipes.
- A Meter Protection Program that includes a suite of protection options for the Company's heavy snow load areas in Big Bear and Lake Tahoe areas.
- A COYL Replacement Program that targets risky and unmaintained COYLs in schools, commercial, and residential areas and proposes to replace them with Company owned and maintained facilities.

II. RISK-INFORMED DECISION-MAKING PROCESS

Q. 7 What is the Risk-Informed Decision-making Process?

A. 7 As discussed more fully in the prepared direct testimony of Company witness of Bradley C. Anderson, Southwest Gas, along with the other small and multi-jurisdictional utilities in California were directed to transition to including a risk-informed decision-making process into their general rate case applications beginning in 2017.[1] Through this process, the Company identified and evaluated several risks and controls and mitigations to address the identified risks.

Q. 8 Are the programs proposed in your prepared direct testimony a direct result of the risk-informed decision-making process?

A. 8 Yes. The Company's proposals for a Targeted Pipe Replacement Program, a Meter Protection Program, and a COYL Program all were derived as a result of the risk-informed decision-making process. Additional specific details on the scoring and ranking of these three identified items is located in the Prepared

[1] Decision (D.) 14-12-025, Ordering Paragraph 4, at pg. 55.

Direct Testimony of Bradley C. Anderson.

III. TARGETED PIPE REPLACEMENT PROGRAM

Q. 9 Please describe the Company's proposed Targeted Pipe Replacement Program.

A. 9 Southwest Gas is proposing to implement a Targeted Pipe Replacement Program that focuses on three primary classifications of vintage pipelines:

- Pre-1961 vintage distribution steel pipelines
- Pre-1961 vintage distribution high-pressure steel pipelines
- Driscopipe™ 7000 distribution plastic pipelines

Q. 10 Why is it important to proactively replace pipe before it leaks?

A. 10 Although no immediate safety concern exists on vintage pipelines such as the ones the Company has identified for its Targeted Pipe Replacement Program, Southwest Gas realizes it has aging infrastructure. It is prudent to proactively replace aging infrastructure 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. 11 What is the Company proposing with regards to select distribution and high-pressure steel pipe replacement?

A. 11 Southwest Gas is proposing to accelerate the replacement of approximately 10 miles per year of pre-1961 distribution and approximately 1.2 miles per year of pre-1961 high-pressure steel distribution pipelines. For the purpose of this proposal, distribution pipelines are all pipelines that are not classified as transmission under Part 192.13 and the current California General Order 112-F.

Furthermore, the designator “high-pressure” applies to those pipelines that operate at pressures greater than 60 psig.

California has had some form of state pipeline safety code as early as 1961.[2] In contrast, the federal pipeline safety code requirements were not formally established until 1970. Prior to 1961, there was no formal state pipeline safety code for pipeline construction practices, material selection, material and pipeline testing, cathodic protection requirement, recordkeeping requirements, and other key elements of modern pipeline construction requirements. Older pipelines do not have all of the safety features associated with modern pipelines such as improved coatings, enhancements to steel pipe quality and performance standards, more comprehensive welding procedures, and enhanced testing requirements. Prior to the promulgation of state and federal pipeline safety regulations, operators utilized industry consensus standards and other industry practices of the time to govern pipeline construction practices, material selection, and material and pipeline testing. These consensus standards were voluntary and not as comprehensive as the mandatory pipeline safety standards in place today.

Steel pipe is prone to corrosion which can lead to leaks in a piping system. Corrosion can be mitigated through the adequate application of cathodic protection on steel pipe. Cathodic protection is achieved through the combination of a protective coating system and the application of an electric current in order to modify the electric potential of the metal surface to prevent corrosion. Federal and state pipeline safety rules mandated the cathodic

[2] Decision No. 61269 adopted California General Order 112 on December 28, 1960 with a July 1, 1961 effective date.

protection of all steel pipe after 1970. The possible lack of cathodic protection on pre-1961 vintage steel pipe therefore presents a potential corrosion risk to the pipe. In addition, before the implementation of state and federal pipeline safety codes, pipeline installation records were not as complete and were not always retained for the same length of time as they are today.

The accelerated replacement of pre-1961 vintage steel pipe will address all of these factors by allowing the Company to bring all of its steel system up to modern construction and recordkeeping standards.

Q. 12 What is Driscopipe™ 7000 pipe?

A. 12 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. Driscopipe model 7000 pipe was installed for use for distribution pressure mains and services, typically between one-half inch and four inches in diameter and was installed between 1974 and 1980. The Company has approximately 360 miles of 7000 pipe in its Southern California Districts 11 and 12 as of March 1, 2019.

Q. 13 What is the Company proposing with regards to its 7000 pipe replacement program?

A. 13 The Company is proposing to proactively replace approximately 40 miles per year of 7000 pipe in its Southern California service territory. This plastic distribution pipe is at least 40 years old and is showing signs that it is no longer performing as expected. Similar to the Company's proposal for pre-1961 vintage steel, Southwest Gas has already replaced all of its known early vintage plastic pipe types (PVC, Aldyl-HD, Tenite) in its California distribution system and 7000 pipe is the next oldest plastic pipe type. The Company approach to proactively replacing aging infrastructure before it becomes a safety concern has yielded a distribution system with very low leak rates.

Q. 14 Is Southwest Gas proposing to accelerate the replacement of pre-1961 vintage steel and 7000 distribution plastic pipe because they are unsafe to operate?

A. 14 No. The pre-1961 vintage steel and 7000 distribution plastic pipe in the Company's distribution system do not present an immediate safety concern. The Company maintains vigorous programs to ensure the distribution system is operated in a safe and reliable manner. Instead, the Company's proposal seeks to proactively replace this aging infrastructure before it becomes unsafe, and to enhance the safety and reliability of the existing system through a systematic and measured program.

Q. 15 What does Southwest Gas do to address the unsafe pipe in its system?

A. 15 Unsafe pipe, regardless of age or pipe type, is replaced immediately in accordance with the Company's Operations Manual. The Company's distribution and transmission integrity management programs work to identify those pipelines that may represent a safety concern and address those concerns through additional or accelerated actions and preventative and mitigative measures. Furthermore, the Company's integrity management programs and Operations Manual are designed to meet or exceed current federal and state pipeline safety requirements.

Q. 16 Please describe the Company's distribution integrity management program.

A. 16 The Company's distribution integrity management program involves a risk-based process to gather and evaluate information about the Company's distribution system and to prioritize and implement actions based upon that information to maintain the safety and integrity of those systems. Southwest Gas conducts an annual evaluation and assessment that assists in the determination of whether to schedule a particular pipe segment for replacement or whether to implement other risk control practices such as additional leak surveys.

Q. 17 Does the proposed Targeted Pipe Replacement Program override the processes established through the Company's distribution integrity management programs?

A. 17 No, it complements these processes. The Company's distribution integrity management programs will continue to identify and address potential safety concerns through normal operations. The Company's proposed Targeted Pipe Replacement Program will complement and build upon the success of the Company's distribution integrity management plans by combining the risk-based approach of integrity management with a proactive approach to modernize the Company's infrastructure.

Q. 18 Why is Southwest Gas proposing a Targeted Pipe Replacement Program if no safety concern exists and the Company has a functional integrity management program that addresses potential safety concerns in its system?

A. 18 As mentioned previously, Southwest Gas has approximately 159 miles of pre-1961 steel pipe and approximately 360 miles of 7000 pipe in its Southern

California service territory. Given these inventory amounts, Southwest Gas recommends a program be developed to start working towards modernizing these facilities in a systematic and methodical approach that does not unduly burden Southwest Gas or its customers. In addition, the proposed Targeted Pipe Replacement Program will serve to modernize the Company's distribution pipe facilities to current industry safety standards. Further, this modernization program will also provide enhanced safety and reliability of the Company's distribution systems through enhanced record keeping and documentation regarding pipeline construction practices, material selection, material and pipeline testing, as well as improved pipe quality and performance standards of newer facilities.

Q. 19 Why is the Company not proposing a Targeted Pipe Replacement Program for its Northern California service territories?

A. 19 The Company is focusing its Targeted Pipe Replacement Program in Southern California where it has the largest percentage of these two vintage pipe types. In addition, the Southern California service territories are located in semi-arid desert areas. While the Company anticipates that it will eventually have to target replacement of 7000 plastic pipe in its Northern California and South Lake Tahoe service territories, it has seen a higher leakage rate in its desert regions.

Q. 20 What is the breakdown of the Targeted Pipe Replacement Program costs by rate jurisdiction?

A. 20 Exhibit No.__(KML-01) provides a breakdown of the estimated pipe replacement mileage and incremental costs for the Company's Targeted Pipe Replacement Program for the Southern California Division. The Company is not proposing any work under this Program for its Northern California or Needles service territories.

IV. METER PROTECTION PROGRAM

Q. 21 Please describe the Company's proposed Meter Protection Program.

A. 21 Due to Southwest Gas having service territory in heavy snow load areas, it has identified the need to implement a comprehensive and proactive program to protect the Company's meter sets from the threat of snow and ice loading damage. During the winter season of 2018/2019, the Company experienced 52 numbers of incidents and facilities damages caused by the snow and ice loading on Company meter sets. These incidents highlight a need for further protection of existing Company facilities in heavy snow load areas.

Southwest Gas requires customers to implement extra precautions to ensure that gas piping, meters, and outdoor appliances remain safe in heavy snow load areas. This includes the requirement for customers to install a meter snow shelter (meter shed) above the gas meter to prevent snow and ice accumulation. The Company currently requires all new customer meters and any customer who requires their existing meter or service line location to be relocated to install a meter shed. The Company provides meter shed designs on the Southwest Gas website for customer reference. The Company currently does not require customers to retrofit their existing meter sets with a protective meter shed.

The Company's proposed Meter Protection Program would include a suite of safety options that are aimed at enhancing the protection of existing meters in heavy snow load areas that currently do not have an adequate form of meter protection against snow load. These four options would include retrofitting meter sheds for current customers without such protection; upgrading certain meter sets acquired by Southwest Gas with more robust piping; evaluating and installing an Excess Flow Valve (EFV) on certain service lines; and upgrading the meter encoder receiver transmitter (ERT) device to allow for daily meter usage monitoring. This suite of protection options will provide both a proactive as well as reactive level of protection against damage from snow and ice loading.

Q. 22 Please describe the Company's heavy snow load areas?

A. 22 The Company considers its California service territories located in Big Bear Lake, North Lake Tahoe, South Lake Tahoe and Truckee to be heavy snow load areas. These areas commonly receive five (5) feet or 60 inches of snowfall or more annually. For example, the United States Climate Data website (www.usclimatedata.com) reports average annual snowfall totals based upon data collected from 1981 through 2010. The average annual snowfall reported for the City of Big Bear Lake is approximately 67 inches; the North Lake Tahoe area including Tahoe City is approximately 184 inches; the City of Truckee is approximately 202 inches; and the City of South Lake Tahoe is approximately 408 inches.

Q. 23 What is a meter shed?

A. 23 A meter shed is a structurally engineered shelter that is installed above the natural gas meter that protects the meter from snow and ice loading damage. Starting in approximately 2009, the Company began requiring that all new customers and those customers which required a meter or service relocation to install meter shed. If a customer's meter is damaged by snow and ice loading, the customer is required to install a meter shed before service is restored to the home or business.

Q. 24 Has the Company installed meter sheds for any of its California customers previously?

A. 24 Yes. While meter sheds are required to be installed and maintained by the customer for all new services, in D.14-06-021, the Commission authorized Southwest Gas to include the installation of meter sheds in the "to the meter" construction when converting mobile home parks (MHP) under the California Mobilehome Park Utility Upgrade Program (MHP Program).[3] Upon cutover to the Company's gas distribution system, the meter shed is owned and maintained by the MHP Owner/Operator or resident. Southwest Gas demonstrated that it had approximately 15 MHPs in heavy snow fall areas within its California services territories.

Q. 25 Is the Company requesting authorization for meter sheds in its proposed Meter Protection Program similar to the authorization received by the Commission in D.14-03-021?

A. 25 Yes. The Company is requesting to install the meter sheds as it deems necessary and subsequent to installation, the meter shed will be owned and maintained by the customer.

Q. 26 Is the Company proposing to install meter sheds for all of its customers in heavy snow load areas?

A. 26 No. The Company's proposed Meter Protection Program would focus on meter shed installations on those existing unprotected customer meters where the

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[3] The MHP Program is a voluntary program offered to eligible master-metered submetered MHPs or manufactured housing communities to convert their sub-metered spaces and common-use services from master-metered sub-metered gas distribution to direct Company gas distribution service subject to the requires and limitations set forth in the Company's tariff Rule No. 23 – Mobilehome Park Utility Upgrade Program.

meter is located on the eave side of the house. The eaves are the edges of the roof which overhang the face of a wall and generally project beyond the side of a building or home. The eave side of the home is generally where the highest risk of snow and ice damage occurs to a meter set assembly as it falls off the roof.

Q. 27 Does the Company educate and make its customers aware of the potential damages from snow and ice loading on its meter sets?

A. 27 Yes. The Company provides bi-annual notifications to its customers in heavy snow load areas, which inform of the potential risk of damage by snow and ice loads for gas piping, meter, and outdoor appliances. The Company also makes this same information available online and through local newspapers and other media types such as radio-based public awareness messaging. A copy of the Company's current Snow Season Safety brochure is provided as Exhibit No.__(KML-02).

Q. 28 What is the Company proposing with regards to upgrading certain meter sets with more robust piping?

A. 28 The Company requires thicker, more robust meter set piping to be installed on all new and replaced meter sets. This thicker piping helps to protect the meter set assembly against forces from excessive snow and ice loading. The meters located in the South Lake Tahoe area that were acquired from Avista Corporation in 2005 were not all constructed to this more rigorous standard. While the more robust piping cannot provide adequate protection against snow and ice loading by itself, when paired with a meter shed it serves as an additional level of protection against potential snow and ice damage.

Q. 29 What is an Excess Flow Valve?

A. 29 An Excess Flow Valve, or EFV, is a device that automatically closes and restricts the flow of natural gas if an underground service pipe is broken, completely cut, or torn apart. Such damage usually results from some type of excavation or digging activity. An EFV may also restrict the flow if the gas meter is damaged, which could result from a vehicle impact or from a large snow or ice load.

Q. 30 How will the installation of an EFV serve to protect a meter from snow and ice damage?

A. 30 An EFV can serve as a second source of defense in the event that a meter is damaged from snow or ice loading, specifically if the Company's aboveground piping leading up to the meter is completely severed resulting in a release of gas large enough to trigger the EFV. An EFV works by detecting large releases of natural gas that exceed the normal expected flow conditions for the Company's service piping and triggers a ball or plug to stop off/restrict flow through the piping. The EFV is typically installed as close to the Company's gas main piping as possible, thereby providing maximum protection to the downstream service line.

Q. 31 Does Southwest Gas currently install EFVs in its system?

A. 31 Yes. The Company currently installs EFVs on all new service lines meeting certain sizing parameters,[4] fully replaced service lines, and anytime the Company exposes the main-to-service connection for maintenance. The installation of an EFV on these types of situations is mandated by federal

[4] In situations such as commercial installation or extremely large residential installations where the natural gas service load demand is larger than the rated capacity of the Company's currently available EFVs, Southwest Gas will install a service-line shut-off valve which requires manual intervention to stop off flow.

regulation. Southwest Gas has installed EFVs in its distribution system over the past decade as federal laws changed to expand their requirement in specific instances.

The Company's proposed Meter Protection Program would target those vintage service lines in its heavy snow load areas that were installed when EFVs were not required. The Company plans to further target those service lines where the homes may be unoccupied during the winter months. These homes are occupied as vacation homes during the summer months and likely would not have an occupant available during the winter to properly clear ice and snow from around the meter set as described in Exhibit No.__(KML-02), the Company's instructions and public awareness messaging to customers in heavy snow load areas.

Q. 32 What is enhanced metering?

A. 32 Enhanced metering employs the latest electronic meter reading technologies which allow the Company to obtain near-real time hourly usage data from a customer's gas meter. Southwest Gas has utilized electronic meter reading technologies since the late 1990's in parts of its service territories that are difficult to read manually. In the 2006-2008 timeframe, the Company embarked on a project to install electronic meter reading devices, or ERTs, on every gas meter.

The early versions of these ERT devices only collected composite usage data and would relay it to a hand-held device for meter reading and billing purposes. The latest technology in ERTs capture hourly data and are capable of data logging in up to 1-minute increments. The ability to remotely capture hourly or more frequent usage data in heavy snow load areas following an extreme snow fall event would provide the Company with the ability to target certain neighborhoods and evaluate the customer usage data. A targeted data analysis would look for unusual increases in natural gas usage through the meter or other anomalies that could be indicative of a damage to the Company's meter set assembly or the customer-owned piping downstream of the Company's meter.

While the Company is not proposing to implement a full Advanced Metering Infrastructure (AMI) system where it can remotely access customer usage data in near-real time. The Company's proposal will utilize ERT devices compatible with this technology to allow the Company to employ more frequent meter reads during heavy snow load events. The Company can then use this more frequent data to run analytics to look for potential leaks or damaged meter set assemblies.

Q. 33 Please describe the Company's proposed enhanced metered under the Meter Protection Program.

A. 33 Southwest Gas is currently installing the most up-to-date technology of ERT devices for all new meter set installations and any time a meter is removed from the field and replaced. The Company's proposal, as part of its Meter Protection Program, would identify those meters in heavy snow load areas that do not have the most current type of ERT device installed and target those for replacement. This meter reading technology upgrade would work in concert with the application of a meter shed, meter set piping material upgrade, and an EFV to provide maximum protection from the threat of snow and ice loading.

Q. 34 How will the four proposed safety options under the Meter Protection Program work in concert with each other?

A. 34 The installation of a meter shed and the upgrade to more robust meter material piping both serve to proactively prevent snow and ice loading from damaging Company facilities resulting in the unexpected release of natural gas in close proximity to the structure. The installation of an EFV coupled with enhanced meter reading technology would serve as a reactive measure to identify or limit the effect of a natural gas release should the Company's meter set assembly or customer-owned piping be damaged from excessive snow and ice loading. In some parts of the Lake Tahoe region for example, local building design codes currently require structures such as roofs to withstand a snow loading force of up to 300 pounds per square inch. These local building codes have evolved over the years and are much more stringent today that they were decades ago. The Company's proposed Meter Protection Program would identify those meters in heavy snow load areas that are most vulnerable to damage from snow and ice loading and apply a combination of safety options to lessen the likelihood of damage.

Q. 35 What is the breakdown of the Meter Protection Program costs by rate jurisdiction?

A. 35 Exhibit No.__(KML-01) provides a breakdown of the estimated incremental costs for the Company's Meter Protection Program by rate jurisdiction.

<u>V. CUSTOMER-OWNED YARD LINE (COYL) PROGRAM</u>

Q. 36 What is a COYL?

A. 36 A COYL is the primary customer gas piping that begins from the service point of delivery at the outlet of the Company's meter located at the property line or public right-of-way, and extends underground from the meter to the house, building, or gas utilization equipment where gas is consumed. By definition, a COYL is pipe downstream from the Company's meter, and is not owned by Southwest Gas. The customer is solely responsible for inspecting and maintaining a COYL. Exhibit No.__(KML-03) provides a schematic of a typical COYL. For the purpose of the COYL Program, a COYL does not include other secondary COYLs that may branch off the primary COYL or that may exist further downstream on the customer's houseline pipe facilities.

Q. 37 What is Southwest Gas' responsibility for COYLs?

A. 37 Pursuant to Southwest Gas' tariff Rule Nos. 16 and 19, Southwest Gas has no obligation to inspect or maintain facilities beyond the point of delivery, including COYLs which are owned, operated and maintained by the customer. However, Southwest Gas is required by federal regulation (49 C.F.R. § 192.16) to notify a customer at least once in writing of the following information:

- Southwest Gas does not maintain the customer's buried piping;
- If the customer's piping is not maintained, it may be subject to the potential hazards of corrosion and leakage;
- Buried gas piping should be:
  - Periodically inspected for leaks;
  - Periodically inspected for corrosion if the piping is metallic; and
  - Repaired if any unsafe condition is discovered.
- When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand; and

- Provide resources for locating, inspecting and repairing customer's buried piping.

Southwest Gas accomplishes this notification requirement for new customers through a brochure. In addition, Southwest Gas reminds customers about COYLs through information provided on the back of their monthly bills (or through Southwest Gas' website links for those customers receiving electronic bills).

Q. 38 What options do customers currently have when leaks are found on COYLs?

A. 38 Currently, the customers' options when leaks are found on COYLs include: replacing the COYL with a Southwest Gas-owned facility and relocating the meter at the customer's expense; calling a licensed plumber to replace or repair the COYL at the customer's expense; or discontinuing gas service.

Q. 39 Why is Southwest Gas proposing a COYL Program?

A. 39 The Company proposed a COYL Program in its last general rate case, Application 12-12-024. The Company was authorized to implement a school COYL leak survey program for the schools within its service territories. The program required customer acceptance to perform the voluntary leak survey and required the school to replace or repair the leaking COYL if a leak was detected during the Company's leak survey.

Q. 40 Was the Company's initial program successful?

A. 40 No, the Company made every reasonable attempt to advertise this no-cost leak detection survey to those schools with COYL piping, however, only a small number of schools allowed the Company to perform the survey given that any leak found would result in the full shut-down of the natural gas supply to the school pending repair or replacement by the school of the leaking COYL.

Q. 41 What is Southwest Gas' proposal regarding COYLs?

A. 41 In an effort to help customers manage their COYLs, Southwest Gas is proposing a program to prioritize and replace all known COYLs in its California jurisdictions. The Company will offer to relocate the customer's meter and replace the COYL with facilities that are owned and maintained by Southwest Gas. The program is subdivided into two COYL categories; non-school COYLs and school COYLs.

Q. 42 Does the Company's proposal include a COYL leak survey?

A. 42 No. Based upon the lessons learned from the Company's long-standing program in Arizona, Southwest Gas is proposing a program to proactively identify and replace COYLs in California before they leak and cause an unsafe condition for the customer.

Q. 43 Please summarize the timeline for Southwest Gas' COYL Program proposal.

A. 43 Southwest Gas will conduct field surveys to confirm, to the greatest extent possible, the number of confirmed COYLs in its California service territories. Upon Commission approval of the COYL Program, Southwest Gas proposes the following:

1) Conduct a verification survey to confirm the inventory of school and non-school COYLs;

2) Prioritize school COYLs by contacting each school COYL owner and verify interest in a school COYL Program;

3) Prioritize non-school COYLs by contacting each non-school COYL owner and verify interest in a non-school COYL Program;

4) Recover the incremental costs associated with the COYL Program through the IRRAM, as discussed in the prepared direct testimony of Company witness Timothy S. Lyons;

6) Southwest Gas will report its findings to the Commission on an annual basis.

Q. 44 Why is Southwest Gas proposing to conduct an initial field verification of potential COYL customers?

A. 44 The Company proposes an initial field verification of potential COYL customers as the Company does not own these facilities nor maintain records of their location or which service addresses have a COYL. Therefore, the Company can only approximate the location of COYLs downstream of its meter set facilities. The Company uses non-standard meter location codes as a relative proxy for potential COYL customers. The field verification survey would identify those accounts where Southwest Gas suspects a COYL is present based upon the non-standard meter location codes such (e.g.: lot line or alley way) and perform a field visit to verify the presence of a COYL meeting the scope of the Program. Field verification is necessary to confirm the number and location of COYLs so that the COYL Program can be directly offered to those customers that have COYLs by allowing the Company to specifically target those customers with known and confirmed COYLs.

Q. 45 Why does Southwest Gas' proposed COYL Program differentiate between non-school COYLs and school COYLs?

A. 45 The potential impact of a leaking COYL located at a school is significantly higher than that of a leaking residential or commercial COYL. In addition, some large commercial or industrial customers may already perform some level of general maintenance including leak detection surveys of their COYL. Southwest Gas has identified 2 instances in 2019 where a leak on a school COYL has resulted in a shutdown of natural gas service to a school due to a leaking COYL. The Company proposes to complete replacement of identified school COYLs over the next five years.

Q. 46 Please describe the non-school program.

A. 46 The non-school COYL portion of the program will be completed within a 10-year time period assuming 100% of the customers choose to participate in the Program. Non-school COYL customers will be identified for potential replacement pending acceptance of the program by the customer. If a COYL is found to be leaking within this time period, Southwest Gas will offer to relocate the Company's meter adjacent to the customer's residence or business and replace the COYL with Southwest Gas-owned facilities. Unlike the current meter relocation process, customers who choose to have the Company relocate their meter and replace their leaking COYL in conjunction with the program will not be charged any upfront costs by the Company.

Q. 47 Please describe the school COYL program.

A. 47 As with the non-school COYLs, with the consent of the customer, all known school COYLs will be replaced over a five-year time period assuming that 100% of the customers choose to participate in the Program. If a school COYL is found to be leaking, the customer will be offered an opportunity to have the COYL replaced with Southwest Gas-owned facilities and meter(s) relocated adjacent to the school structure(s). In essence, Southwest Gas is proposing a long-term plan for enhancing the safety and integrity of school COYLs by abandoning them and installing Company-owned and maintained facilities up to the structure thereby eliminating any customer-buried piping from the meter to the structure.

Q. 48 What is the breakdown of replacement costs by rate jurisdiction?

A. 48 Exhibit No.__(KML-01) provides a breakdown of the estimated number of COYLS and the range of incremental replacement costs for both non-school and school COYL categories by rate jurisdiction.

Q. 49 Does this conclude your prepared direct testimony?

A. 49 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.

California Customer Owned Yard Line (COYL) Program

	Southern California (Count)	Northern California (Count)	South Lake Tahoe (Count)	California Total (Count)
Commercial/Industrial	449	99	112	**660**
Master Meter - Multi-Family Residential	5	2	3	**10**
Mobile Home-Residential	1153	5	6	**1164**
Multi-Family Residential	128	1	2	**131**
Residential	2749	362	409	**3520**
School	65	29	32	**126**
Total COYLs - California	**4548**	**498**	**564**	**5610**

	Southern California (Estimated Cost)	Northern California (Estimated Cost)	South Lake Tahoe (Estimated Cost)	California Total (Estimated Cost)
5-Year Total COYL w/10% contingency	$ 21,953,594	$ 6,761,875	$ 7,625,093	**$ 36,340,563**
Estimated annual COYL	$ 4,390,719	$ 1,352,375	$ 1,525,019	**$ 7,268,113**

California Meter Protection Program

	Southern California	Northern California	South Lake Tahoe	California Total
Meter Shed	$ 3,000,000	$ 2,160,000	$ 3,840,000	**$ 9,000,000**
EFV	$ 1,500,000	$ 2,959,200	$ 5,260,800	**$ 9,720,000**
ERTs	$ 1,500,000	$ 1,339,200	$ 2,380,800	**$ 5,220,000**
Total Meter Protection - California	**$ 6,000,000**	**$ 6,458,400**	**$ 11,481,600**	**$ 5,220,000**

Note: Estimated costs include a 20% contingency

California Targeted Pipeline Replacement Program

(Southern California Rate Jurisdiction Only)

	Mains	Services	SCA Total
M7000	$ 62,092,800	$ 26,611,200	**$ 88,704,000**
Distribution Steel	$ 15,523,200	$ 6,652,800	**$ 22,176,000**
High-Pressure Distribution Steel	$ 12,000,000	$ -	**$ 12,000,000**
Total Estimated Pipe Replacement Cost	**$ 89,616,000**	**$ 33,264,000**	**$ 122,880,000**

Note: Estimated costs include a 20% contingency

SNOW SEASON Safety

Heavy snow and ice falling from roofs can damage natural gas meters, regulators, and associated natural gas piping. Special care must be taken when clearing roofs to prevent impact. Also, ice and snow accumulation, whether natural or manmade, can damage gas meters and outdoor appliances and create a hazardous leak.

METER WITH SNOW SHELTER

METER WITHOUT SNOW SHELTER

TIPS TO HELP PROTECT AGAINST POTENTIAL DAMAGE:

- Install a structurally engineered shelter above your natural gas meter to prevent snow and ice accumulation. For more information on how to build a snow shelter or for a contractor referral, please visit Southwest Gas at www.swgas.com/safety or call 1-800-654-2765.
- Use a broom, instead of a shovel where possible, to clear snow or ice off natural gas meters and outdoor appliances, including regulators, associated piping, and propane appliances.
- When shoveling or plowing, don't pile snow on gas meters or outdoor appliances.
- Keep all outside gutters free of leaves and debris, including those above or near the natural gas meter and outdoor appliances.
- Natural gas appliances require proper exhaust and ventilation. It's important to know the location of air supply and exhaust ducts, and keep them free of snow, ice, leaves, or other debris. Keeping vents clear can prevent operational problems for appliances and the accumulation of carbon monoxide in buildings.
- If you live in California, make sure your residence has functioning carbon monoxide alarms as required by Health and Safety Code §17926.

SOUTHWEST GAS

Southwest Gas wants to remind you that it's important to maintain and protect natural gas meters and appliances because failure to do so can result in damages and injuries, and possibly the discontinuance of natural gas service.

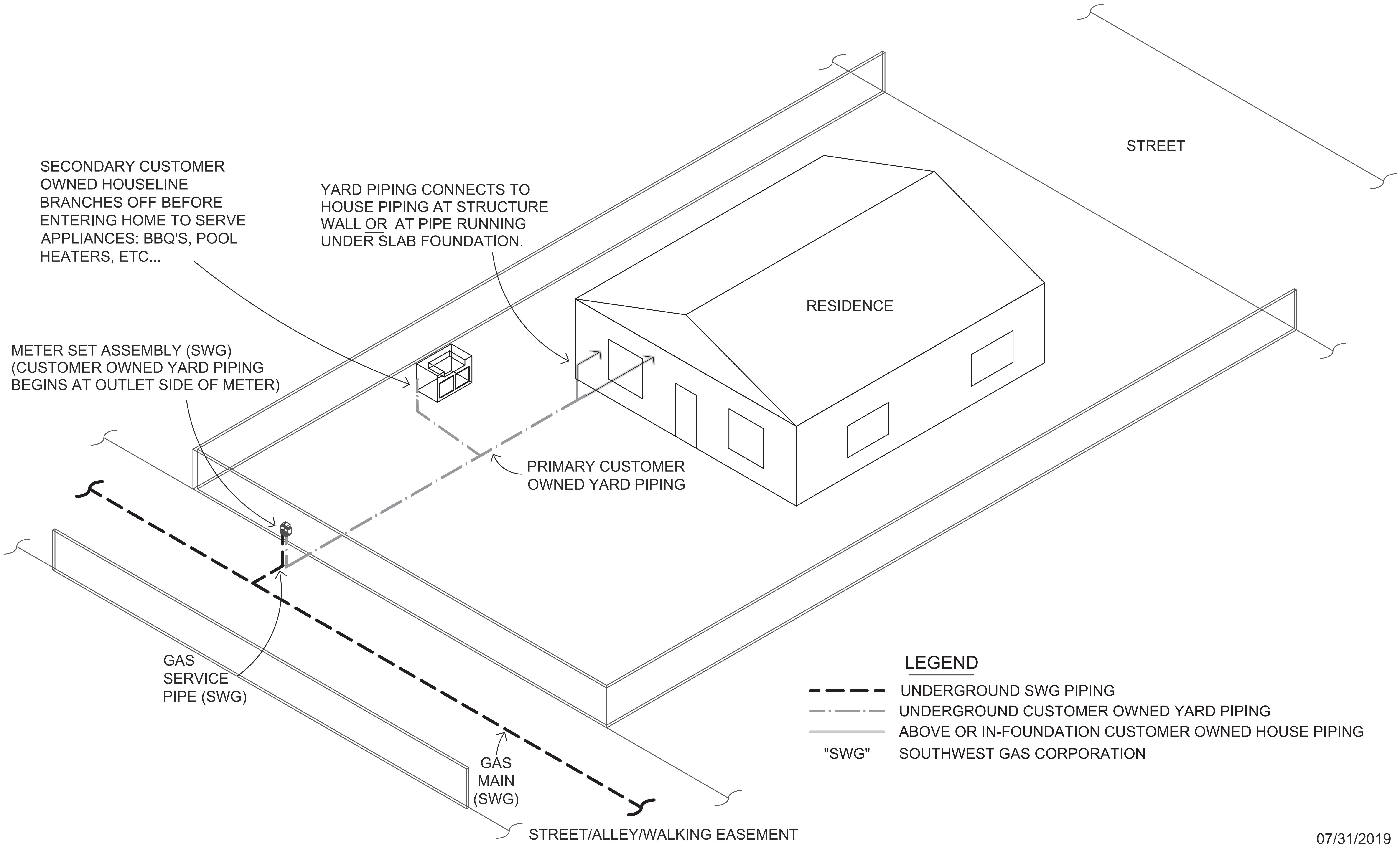
A leak may be present if you:

SMELL - an odor similar to rotten eggs, even if it's faint or momentary.
HEAR - a hissing or roaring coming from the ground, above-ground piping, or a natural gas appliance.
SEE - dirt or water blowing into the air, unexplained dead or dying vegetation or grass, or standing water continuously bubbling.

If you suspect a leak: from a safe place, call **911** and **Southwest Gas** immediately at **1-877-860-6020**.

For more information about natural gas safety, visit www.swgas.com/safety or call 1-877-860-6020.

CUSTOMER OWNED YARD INSTALLATION (TYPICAL)



07/31/2019

Company Witness:
Byron C. Williams

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 19-08-___

PREPARED DIRECT TESTIMONY
OF
BYRON C. WILLIAMS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

AUGUST 30, 2019

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of
BYRON C. WILLIAMS

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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.

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 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 Arizona Corporation Commission, the Public Utilities Commission of Nevada, and the Federal Energy Regulatory Commission.

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

A. 5 I sponsor all areas of the Company's federal and state income tax and state and local taxes, including schedules and supporting workpapers found in Chapters 15 and 16 of Southwest Gas' general rate case filing, with the exception of those related to payroll taxes.

Q. 6 Please summarize your prepared direct testimony.

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

- An overview of the tax information and related schedules in this application.
- An explanation regarding the impact of the Tax Cuts and Jobs Act (TCJA) on the calculation of federal income taxes.
- The Company's calculation and amortization of its Excess Accumulated Deferred Income Taxes.
- A description of taxes, other than income taxes, that are included in this application.

II. OVERVIEW OF TAX INFORMATION AND RELATED SCHEDULES

Q. 7 Please discuss how the tax information is presented in this application.

A. 7 The tax information is organized into schedules for the Southern California, Northern California and South Lake Tahoe rate jurisdictions. For each rate jurisdiction, the narrative summary at the beginning of Chapters 15 and 16 provides a general description and additional details regarding the schedules that I am sponsoring.

Q. 8 Please summarize the schedules provided in Chapter 16.

A. 8 Chapter 16 (Sheets 1 and 2) provides a summary of significant tax accounting methods including (as applicable) use of full normalization accounting, contributions and advances, and the methods of projecting property taxes. Chapter 16 also provides the calculation of net federal and California income taxes on operations, as well as taxes other than income taxes. In addition, Chapter 16 provides the computations of the balance of deferred income taxes projected for the end of the test period and shown elsewhere in the filing as an adjustment to rate base, as well as the amortization of Excess Accumulated Deferred Income Taxes.

Q. 9 Please describe the adjustments made to federal and state income taxes.

A. 9 The calculation of federal and California income taxes on operations is shown on Sheet 7 of Chapter 16. In this filing Southwest Gas uses the statutory 21 percent federal income and 8.84 percent California corporate franchise tax rates.

Q. 10 Please discuss the calculation of federal and California deferred income tax liabilities at the end of the test year.

A. 10 Chapter 16 provides the calculation of deferred federal and state income tax liabilities. The calculation is performed by adding the deferred tax adjustments resulting from the projection of Schedule M differences to the December 31, 2018 deferred income tax balances in the general ledger. Chapter 16 also shows the calculation of deferred income taxes and provides the calculation and allocation of System Allocable taxes to the applicable rate jurisdiction.

III. INCOME TAXES AND THE TCJA

Q. 11 What impact did the TCJA have on the corporate federal income tax rate?

A. 11 As part of the TCJA, the corporate federal income tax rate was reduced 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. 12 What other significant changes resulted from the TCJA?

A. 12 The TCJA does not allow bonus depreciation for the Company's public utility property placed into service after September 27, 2017 (with some exceptions). Because of these changes, bonus depreciation was not calculated for any public 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 used.

IV. EXCESS ACCUMULATED DEFERRED INCOME TAXES

Q. 13 What is Excess Accumulated Deferred Income Taxes (EADIT)?

A. 13 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. 14 What are plant-related (protected) and non-plant (unprotected) EADIT?

A. 14 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 Internal Revenue Service (IRS) normalization rules and related penalties in the event of their violation. Non-plant EADIT is total EADIT less plant-related EADIT and is not subject to the IRS normalization rules and violation penalties.

Q. 15 What is the balance of the Company's protected and unprotected EADIT?

A. 15 The California plant-related EADIT balances are approximately $19 million, $10 million, and $5 million for the Southern California, Northern California, and South Lake Tahoe rate jurisdictions, respectively. The California non-plant EADIT balances are approximately $900,000, ($1 million), and $400,000 for the

Southern California, Northern California, and South Lake Tahoe rate jurisdictions, respectively.

Q. 16 How will the Company's EADIT be returned to customers?

A. 16 The Company proposes to adjust the revenue requirement by the maximum amount of plant-related EADIT amortization in 2018 allowed using the Average Rate Assumption Method (ARAM) as defined in the Internal Revenue Code and associated Treasury Regulations. In addition, the Company proposes an annual adjustment to reflect the actual ARAM amounts once finalized. The Company also proposes to adjust the revenue requirement to fully amortize the non-plant EADIT over the Company's five-year rate case cycle. These adjustments are addressed in the prepared direct testimony of Company witness Timothy S. Lyons.

Q. 17 What is the ARAM?

A. 17 Under federal income tax law provisions, the ARAM is the methodology used to calculate the maximum amount of plant-related EADIT returned to customers without triggering penalties for a normalization violation. Please refer to the prepared direct testimony of Company witness Timothy S. Lyons for details regarding the amortization of EADIT included in the Company's cost of service.

Q. 18 How does the ARAM calculate the amortization of EADIT?

A. 18 The ARAM calculation consists of two parts: (1) the entity calculates the ratio of aggregate deferred taxes for the property to the aggregate timing differences for the property; and (2) the resulting percentage ratio calculated is multiplied by the amount of timing differences turning around during the year.

Q. 19 Why must Southwest Gas return EADIT to customers over time, rather than immediately?

A. 19 The Internal Revenue Code, as amended by the TCJA, penalizes the return of plant-related EADIT to customers more rapidly, or to a greater extent, than the amount computed using the ARAM. A refund in excess of ARAM limitations is recognized as a normalization violation according to the Internal Revenue Code and Treasury Regulations. The estimated turnaround required by ARAM for the Company's plant-related EADIT is approximately 40 years (i.e., the book life of the underlying property).

Q. 20 What are the penalties for a normalization violation if the EADIT is returned to customers too quickly?

A. 20 The penalties for a normalization violation are severe and include the following: (1) a current tax penalty equal to the amount by which the entity returned the EADIT to customers more rapidly than permitted under ARAM; and (2) the entity will no longer be able to claim accelerated depreciation for income tax purposes. These penalties would increase cash tax payments, potentially leading to increased borrowing costs and future customer rate increases.

Q. 21 Has the Company begun to amortize its EADIT since the implementation of the TCJA?

A. 21 No. Southwest Gas has not recorded any amortization of its EADIT for California in the Company's financial statements. The Company proposes to begin amortizing its California EADIT in 2021, the test year contemplated in this application.

Q. 22 What are some of the benefits of the Company's proposed treatment of its EADIT?

A. 22 The Company's 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. 23 Have any of the Company's other rate jurisdictions agreed with this proposed methodology for the amortization of EADIT?

A. 23 Yes. The Public Utilities Commission of Nevada implemented a similar methodology, commencing in January 2019. The Company has also proposed this methodology in its pending general rate case application before the Arizona Corporation Commission.

V. OTHER TAXES

Q. 24 Please discuss the taxes other than income taxes included in this application.

A. 24 Sheets 3 through 6 of Chapter 16 provide a summary and supporting calculations of taxes other than income taxes, including California property tax specifically related to jurisdiction plant and payroll taxes. Payroll taxes are sponsored by Company witness Timothy S. Lyons. Local franchise taxes imposed by various counties or cities are included in Chapter 15.

Q. 25 What is included in Other Taxes on Sheet 3, Column (c), Line 9?

A. 25 This line includes various non-income taxes, including a jurisdictional allocation of the common portion of the Company's Modified Business Tax (MBT) liability.

Q. 26 How is the MBT calculated?

A. 26 The MBT is based on total gross wages, less employee health care benefits paid by the employer, 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 the corporate headquarters in Las Vegas, Nevada, and perform job functions that benefit the Company in all its jurisdictional service territories. This calculation is similar to the calculation for the Company's other system allocable expenses.

Q. 27 Why is a portion of the MBT being allocated to California?

A. 27 Because a portion of the MBT liability is a cost of the corporation function, it should be allocated as a common expense amongst all jurisdictions. The Company proposes that the relevant portion be allocated to the California rate jurisdictions using the 4-factor methodology.

Q. 28 Does this conclude your prepared direct testimony?

A. 28 Yes.

SUMMARY OF QUALIFICATIONS
BYRON C. WILLIAMS

I am a graduate of Brigham Young University having received a Bachelor of Sciences 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. In 2010, I joined the Las Vegas office, and was promoted to Director in 2011. In 2013, I joined Southwest Gas Corporation 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 Public Accountants, as well as the Nevada Society of CPAs.

Company Witness:
Theodore K. Wood

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 19-08-___

PREPARED DIRECT TESTIMONY
OF
THEODORE K. WOOD

ON BEHALF OF
SOUTHWEST GAS CORPORATION

AUGUST 30, 2019

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of
THEODORE K. WOOD

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
<u>THEODORE K. WOOD</u>

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 (ACC), the Public Utilities Commission of Nevada (PUCN), the California Public Utilities Commission (Commission) 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 rates of return (RORs), also referred to as cost of capital, which are displayed in Chapter 24 of the rate case filing, for the Company's three California rate jurisdictions: Southern California; Northern California; and South Lake Tahoe. Specifically, my prepared direct testimony supports:

- the development of the requested capital structure and the embedded cost of long-term debt used for determining the appropriate cost of capital;
- the importance of the proposed overall RORs on the Company's credit ratings and financial profile; and
- the continued use of the Automatic Trigger Mechanism (ATM), used to adjust the Company's overall RORs between general rate cases.

The development of the Company's requested cost of common equity used to determine the overall RORs is provided in the prepared direct testimony of Company witness Robert B. Hevert.

Q. 6 Please summarize your prepared direct testimony.

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

- The development of the overall requested RORs for the Company's three rate jurisdictions, based on a 2021 test period. The Company is requesting overall rates of return of 7.44 percent and 7.76 percent, for its Southern California rate jurisdiction and for both the Northern California and South Lake Tahoe rate jurisdictions, respectively.
- A review of the Company's financial profile, addressing the Company's credit ratings and the importance of these ratings in accessing the capital markets, and, additionally the need for Southwest Gas to offer a competitive rate of return to continue to attract capital. I also discuss how Southwest Gas' overall RORs are necessary to support and sustain the Company's financial profile and credit ratings.

- The Company's requested capital structure for ratemaking. The Company is requesting a target capital structure comprised of 53.0 percent common equity and 47.0 percent long-term debt.
- The development of the Company's embedded cost of long-term debt. For the 2021 test year, the projected embedded cost of debt for the Company's Southern California rate jurisdiction is 3.99 percent and for both the Northern California and South Lake Tahoe rate jurisdictions, the projected embedded cost of debt is 4.67 percent. The lower embedded cost of debt for the Southern California rate jurisdiction is due to the inclusion of the jurisdiction-specific Big Bear Industrial Development Revenue Bonds (IDRBs).
- The Company's request to continue the ATM, as authorized in Decision (D.) 14-06-028, for adjustments to the Company's authorized cost of capital between general rate cases given preset changes in the level of utility bond yields.

Q. 7 Are you sponsoring any schedules and exhibits in support of your prepared direct testimony?

A. 7 Yes. I am sponsoring the supporting financial exhibits, Exhibit Nos.__(TKW-1) through __(TKW-3), which are attached. These schedules were prepared by me or under my supervision.

<u>II. SOUTHWEST GAS' REQUESTED OVERALL RATES OF RETURN</u>

Q. 8 Have you determined overall RORs necessary for Southwest Gas to have an opportunity to earn a fair and reasonable return on its California distribution properties?

A. 8 Yes. Southwest Gas' proposed overall requested RORs for the Company's Southern California rate jurisdiction and for both the Northern California and South

Lake Tahoe rate jurisdictions, are 7.44 percent and 7.76 percent, respectively. These overall requested RORs are reasonable and properly reflect the Company's level of business, financial and regulatory risks. These overall requested RORs are developed as follows:

SOUTHERN CALIFORNIA RATE JURISDICTION

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	47.00%	3.99%	1.87%
Common Equity	53.00%	10.50%	5.57%
Total	100.00%		7.44%

NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTIONS

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	47.00%	4.67%	2.19%
Common Equity	53.00%	10.50%	5.57%
Total	100.00%		7.76%

Q. 9 Why are the overall requested RORs appropriate and necessary for Southwest Gas?

A. 9 These overall requested RORs are necessary to maintain the Company's financial integrity, allow the Company to attract new capital, and provide Southwest Gas' equity holders an opportunity to earn a fair and reasonable return on their investment.

Moreover, the overall requested RORs meet the standard of reasonableness set forth 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.

The overall requested RORs also meet the comparability standard set forth 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 overall RORs in this proceeding are 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 a 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 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

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[1] SEC, "Report on the Role and Function of Credit Rating Agencies in the Operation of the Securities Markets", January 24, 2003.

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 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 a credit rating outlook, 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".

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[2] Standard & Poor's Ratings Direct, *Credit FAQ: Standard & Poor's Assessments Of Regulatory Climates For U.S Investor-Owned Utilities,* November 25, 2008, p. 2.

[3] Moody's Investors Service, Moody's Rating Methodology, *Regulated Electric and Gas Utilities*, June 2017, p. 6.

Q. 15 How do the Company's credit ratings compare to the credit ratings of the proxy group of companies that were used to estimate the cost of common equity?

A. 15 The proxy group consisting of six natural gas local distribution companies used in the prepared direct testimony of Company witness Robert B. Hevert have an average Moody's rating of A2 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 to the Company's S&P rating, the proxy group has an average rating that is one notch higher (A- versus BBB+).[4]

Q. 16 What is the Company's target credit rating?

A. 16 The Company's long-run goal is to achieve an "A" credit rating on average from the ratings agencies. The short-run goal, at a minimum, is to maintain its current strong investment grade credit ratings. The Company believes that an "A" credit rating provides the Company with a greater amount of financial flexibility. The Company would be able to attract capital at reasonable prices during both normal and turbulent market conditions. In addition, an "A" credit rating would be in a range that has been generally found to minimize the long-run average pre-tax cost of capital paid by customers.[5]

B. <u>Holding Company Reorganization</u>

Q. 17 Please discuss the Company's reorganization into a holding company structure.

A. 17 On January 1, 2017, Southwest Gas reorganized and implemented a holding

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[4] Exhibit No.__(TKW-1).

[5] Roger A. Morin, *New Regulatory Finance*, (Arlington, Virginia: Public Utilities Reports, Inc., 2006), pp. 505-15, demonstrates using simulation analysis and under a wide range of cost of common equity models that an "A" credit rating generally results in the lowest pre-tax cost of capital for electric utilities.

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 D.16-01-037 (Application (A.) 15-10-004). As part of the holding company reorganization, Centuri 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. 18 How have the rating agencies viewed the reorganization?

A. 18 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 the unregulated businesses.[6]

C. <u>Tax Reform</u>

Q. 19 What impact does tax reform have on the Company's credit rating?

A. 19 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

[6] Moody's Investors Service, *Credit Opinion: Southwest Gas Corporation,* January 5, 2018, p.3-4.

of the utility's revenue requirement, the reduction in the tax rate has a positive impact on customer rates. 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 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

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[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.

[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.

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.

Q. 20 What can be done to mitigate the negative credit rating impact resulting from the Tax Act?

A. 20 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

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[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.

[12] Id. at p.1.

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. 21 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. 21 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 prior establishment of a $150 million Equity Shelf Program (ESP) in March 2017 and a new $300 million ESP in May 2019.[13] From January 2017 through June 2019, the Company issued 2,802,602 shares of common stock under this program, raising net proceeds of approximately $222.8 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 June 30, 2019, the Company had approximately $225 million of

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[13] On May 8, 2019, Southwest Gas Holdings, Inc. filed with the Securities and Exchange Commission ("SEC") an automatic shelf registration statement on Form S-3 (File No. 333-231297), which became effective upon filing, for the offer and sale of up to $300 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 May 8, 2019, 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.

remaining ESP capacity.

In addition, approximately $34.2 million of capital contributions from the 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. Infrastructure Replacement Programs

Q. 22 Please briefly describe the Company's approved Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM) and Customer Owned Yard Line (COYL) program.

A. 22 In D.14-06-028, issued in the Company's last general rate case (A.12-12-024), the Commission approved the IRRAM and a limited COYL program. The Company requested the IRRAM in the Company's last general rate case to address the Company's investment in certain non-revenue producing gas infrastructure and pipeline replacement programs, and the funding of unfunded government mandates between general rate cases. The specific details of the Company's three proposed programs under the IRRAM are described in the prepared direct testimony of Company witness Kevin M. Lang.

Q. 23 How will the Company's IRRAM help sustain the Company's improved financial profile?

A. 23 The proposed capital investments under the IRRAM would improve Southwest Gas' ability to recover costs associated with its non-revenue producing infrastructure investments on a more-timely basis, which would over time help maintain Southwest Gas' financial metrics, including its ability to earn its authorized RORs, and increase the opportunity for Southwest Gas to improve its credit ratings. From a capital attraction standpoint, the IRRAM would continue to make Southwest Gas more comparable to other natural gas utilities that have similar mechanisms or other mechanisms that allow for timely recovery of replacement costs.

Q. 24 How do rating agencies view capital tracking mechanisms such as IRRAM as a factor for the Company's credit rating?

A. 24 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.[14]

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.[15]

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

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[14] Standard & Poor's RatingsDirect, U.S. Utilities' Capital Spending Is Rising, And Cost Recovery Is Vital, May 14, 2012.

[15] Moody's Investors Service, Special Comment, *Pipeline Safety Costs Rising As Alternative Rate Designs Sought*, April 25, 2012, p. 1.

> 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 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.[16]

Q. 25 Please summarize the importance of the potential credit rating impacts resulting from this proceeding to Southwest Gas.

A. 25 The importance to the Company's credit rating is due to the capital-intensive nature of the natural gas distribution business. Southwest Gas needs to make continuing and substantial investments to provide reliable and safe service to customers. On a total company basis, Southwest Gas anticipates capital expenditures over the next three-year period ending December 31, 2021, to be approximately $2.1 billion. Accordingly, Southwest Gas needs to have continuing access to capital and credit capacity at reasonable costs. Commission approval of the Company's proposed spending under the IRRAM and approval of these requested RORs will give the Company the opportunity to sustain, and the ability to improve, its credit ratings, which benefits both its customers and its investors.

E. <u>Capital Attraction</u>

Q. 26 Please describe the importance of the capital-attraction function of utility ratemaking.

A. 26 The Company must compete with other utilities and other investment opportunities in fully competitive global capital markets to attract capital. For

[16] Moody's Investors Service, *Credit Opinion: Southwest Gas Corporation,* March 24, 2015, p.2

Southwest Gas to successfully attract capital, it must demonstrate an ability to achieve an adequate return on that capital. The importance of the capital-attraction standard of utility ratemaking was described by Professor James C. Bonbright, a recognized expert on the principles of utility ratemaking, as follows:

> This is one of the most prominent and most widely recognized functions of public utility rates. Public utility companies are permitted to impose charges for their services largely in order to induce and enable them to supply these services and to make provision for their continuation and for their required expansion. If denied the opportunity to levy compensatory charges, they could not long continue operation in the absence of tax-financed subsidies.
>
> This production-motivation function of prices gives rise to the capital attraction standard of reasonable public utility rates. By this standard, reasonable rates are rates adequate to yield revenues that will cover all legitimate operating expenses plus a return on investment sufficient to maintain sound corporate credit and to attract required amounts of new capital. Rates below this level are deemed deficient because, at least in the long run, they will not enable the company to live up to its obligations to serve the community.[17]

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, $257 million of common stock has been issued through the parent company's ESP and contributed 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 10.50 percent, considering the Company's specific risk factors and costs of

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[17] Bonbright, J.C., Danielsen, A.L. and Kamerschen, D.R., *Principles of Public Utility Rates* (Second Edition), Public Utilities Reports, 1988, pp. 92-93.

common equity for proxy groups of similar natural gas utilities.

Q. 27 What is the amount of external capital Southwest Gas has acquired over the past two years?

A. 27 Over the past two-year period ended June 30, 2019, Southwest Gas has had to access the capital markets to fund utility capital expenditures. In addition to the $257 million of equity capital received from common stock issuances by its parent company, Southwest Gas also completed two public debt issuances totaling $600 million in gross proceeds.[18] This demonstrates the Company's actual experience and the significance of the need to have access to the capital markets.

Q. 28 How does the overall ROR balance the interests of both customers and investors of the Company?

A. 28 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, Inc., is important for the parent company's existing shareholders and for its future ability to issue additional common equity. If the overall authorized ROR

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[18] On March 15, 2018, Southwest Gas completed a public offering of $300 million aggregate principal amount of 3.70% Senior Notes due 2028 and on May 31, 2019, Southwest Gas completed a public offering of $300 million aggregate principal amount of 4.150% Senior Notes due 2049.

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 RORs 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.

With the regulatory support of the Commission in approving the Company's proposed overall RORs, Southwest Gas can maintain, with the opportunity to improve, its financial profile and credit ratings. Such improvement benefits Southwest Gas' customers by reducing the long-run average capital costs embedded in customer rates.

IV. RECOMMENDED CAPITAL STRUCTURE

Q. 29 What is Southwest Gas' current Commission-authorized ratemaking capital structure and overall RORs?

A. 29 The Company's authorized RORs were established in D.14-06-028, based on a 2014 test year. The capital structure and weighted cost of capital last authorized for the Company's California three rate jurisdictions are as follows:

SOUTHERN CALIFORNIA RATE JURISDICTION

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	45.00%	2.83%	1.27%
Common Equity	55.00%	10.10%	5.56%
Total	100.00%		6.83%

NORTHERN CALIFORNIA/SOUTH LAKE TAHOE RATE JURISDICTIONS

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	45.00%	5.84%	2.63%

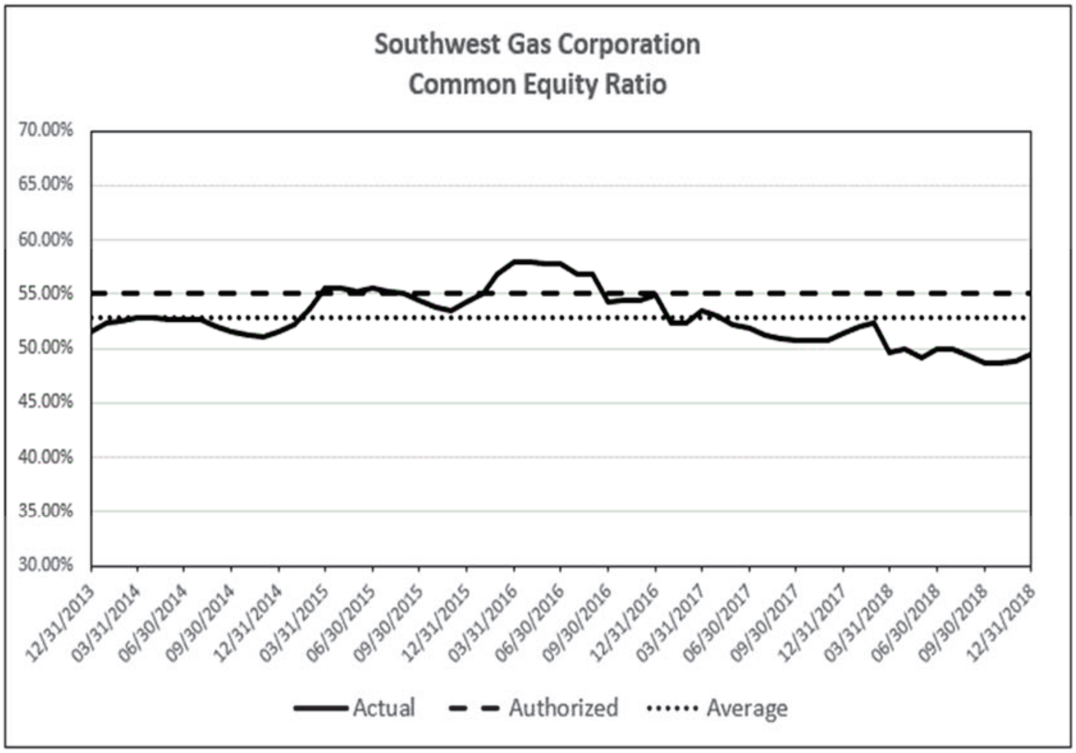
Common Equity	55.00%	10.10%	5.56%
Total	100.00%		8.13%

Q. 30 Was the capital structure authorized by the Commission in Southwest Gas' last general rate case the Company's actual capital structure?

A. 30 No. The Company proposed a target capital structure the Company expected to achieve during the 2014-2018 period, which would have been the time that new rates would be in place. The Company proposed a capital structure with a 57% common equity ratio. The Commission approved a target capital structure with a 55% common equity ratio for ratemaking purposes.

Q. 31 Please discuss the actual common equity ratio achieved during the 2014-2018 period.

A. 31 During this period, the Company had a monthly average of common equity ratio 52.9%, achieving a maximum common equity ratio of 58 percent. The following graph displays the common equity ratio during the period 2014-2018.



While the Company's equity ratio increased from December 2013 through March 2016, reaching a high of 58 percent, it has since declined. The factors causing the decline in the equity ratio are the Company's elevated capital expenditures, in combination with the negative cash flow impacts of tax reform, given the loss of bonus depreciation. Southwest Gas anticipates that capital expenditures will level off over the 2021-2025 period and that the common equity ratio will improve, through retained earnings and periodic equity contributions from the parent company, Southwest Gas Holdings, Inc., through the proceeds of additional common stock issuances.

Q. 32 Please discuss the recommended capital structure used to develop the overall proposed RORs in this proceeding.

A. 32 The recommended capital structure used to determine the RORs consists of 47.0 percent long-term debt and 53.0 percent common equity. The recommended capital structure is the target capital structure the Company reasonably expects to achieve on average during the 2021-2025 period when new rates will be in effect as authorized through this application.

Q. 33 How does the recommended equity component of the target capital structure compare to the average and median projected common equity ratios for the proxy group companies?

A. 33 The *Value Line Investment Survey* average and median projected common equity ratios for the proxy group companies for 2019, 2020, and 2022-2024 periods are displayed in the following table:

PROXY GROUP OF SIX VALUE LINE GAS DISTRIBUTION COMPANIES
PROJECTED COMMON EQUITY RATIO

	Projected Common Equity Ratio			
	2019	2020	2022-2024	Average
Average	54.92%	55.50%	57.08%	56.33%
Median	56.00%	57.00%	60.00%	58.60%

The projected average and median common equity ratios for the proxy group indicates an increasing common equity ratio over the period 2019-2024 and the Company's target common equity ratio of 53 percent is lower relative to the proxy group. The Company's lower common equity ratio indicates higher financial risk relative to the proxy group. Exhibit No.__(TKW-2) displays the projected common equity ratios for the individual proxy group companies.

Q. 34 How does the Company's requested target common equity ratio of 53 percent compare to the requested common equity ratios of the four California major energy utilities?

A. 34 From the consolidated proceeding for the cost of capital applications (test year 2020) of the four California major energy utilities (A.19-04-014, et al.), also known as the "generic cost of capital proceeding", the requested common equity ratios are as follows:

CALIFORNIA 2020 GENERIC COST OF CAPITAL PROCEEDING

Company	Common Equity Ratio %
Southern California Gas Company	56.00%
San Diego Gas & Electric Company	56.00%
Southern California Edison Company	52.00%
Pacific Gas and Electric Company	52.00%
Average	54.00%

The Company's requested capital structure, with a common equity ratio of 53 percent, is in alignment with the range of the common equity ratios requested in the generic cost of capital proceeding by the four major California energy utilities. Such alignment was cited as an important factor in the Company's last general rate in approving a target capital structure for ratemaking.[19] Exhibit No.__(TKW-3) displays the capital structures, capital costs by type of capital, and the overall weighted costs of capital requested by the four California major energy utilities in

[19] D.14-06-028, pp. 32-33.

the A.19-04-014, et al.

Q. 35 Please summarize the support factors for the Company's proposed target capital structure in this proceeding.

A. 35 The Company's proposed target capital structure, with a 53 percent common equity ratio, is the expected average capital structure that will be in place during the 2021-2025 period and is in alignment with the Company's actual 2014-2018 average capital structure (52.9 percent common equity ratio). This capital structure for ratemaking purposes is also consistent in supporting the Company's strong investment grade credit ratings. In addition, the requested target capital structure, while having a lower relative common equity ratio, is reasonable in comparison to both: (1) the projected capital structures for the proxy group companies used to estimate the cost of common equity in this proceeding (average common equity of 57.1 percent for 2022-24); and (2) the average common equity requested by the four California major energy utilities in A.19-04-014, et al. (average common equity ratio of 54 percent).

V. EMBEDDED COST OF LONG-TERM DEBT

Q. 36 Have you determined the appropriate cost rate for long-term debt capital based on the 2021 test year?

A. 36 Yes. For the Southern California rate jurisdiction, the appropriate cost of long-term debt is 3.99 percent, which includes the cost of the jurisdiction-specific Big Bear Industrial Development Revenue Bonds (IDRBs). For both the Northern California and South Lake Tahoe rate jurisdictions, the appropriate cost rate for long-term debt is 4.67 percent. The cost of long-term debt is comprised of the cost of fixed-rate debentures, fixed-rate medium-term notes, and a variable-rate term facility, with the Southern California rate jurisdiction also including the Big

Bear IDRBs. For the Southern California rate jurisdiction, the components of the embedded cost of long-term debt for the 2021 test year are displayed in Tab A, Schedule 5, Sheet 2 of 4, of Chapter 24. For the Northern California and South Lake Tahoe rate jurisdictions, the components of the embedded cost of long-term debt for the 2021 test year are displayed in Tab A Schedule 5, Sheet 1 of 3, of Chapter 24.

Q. 37 Please describe the development of the cost rates of the debentures and notes.

A. 37 The Company anticipates having ten outstanding debentures and notes issues totaling approximately $2.2 billion of gross principal, during the 2021 test year. The debentures and notes have a weighted average cost of 4.64 percent.

Q. 38 Please describe the cost rate of the medium-term notes.

A. 38 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 all of its medium-term note program and will have outstanding three remaining medium-term note issues for the 2021 test year totaling approximately $57.4 million of gross principal. For the 2021 test year, the medium-term notes have a weighted average cost of 7.78 percent.

Q. 39 How are the effective cost rates of debentures, notes, and medium-term notes calculated?

A. 39 The effective cost rates of debentures, notes, and medium-term notes are calculated through the use of the yield-to-maturity (YTM) or effective interest rate method.

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. 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 classifies it as long-term debt. Southwest Gas uses the remaining $250 million of the facility to fund recurring, seasonal working capital needs.

For the 2021 test year, the Company anticipates having approximately $141.4 million outstanding on average as part of the long-term debt portion of the facility. Of this amount, all of the $141.4 million will be outstanding as London Interbank Offered Rate (LIBOR) loans. For the LIBOR loans, an average one-month LIBOR rate of 2.50 percent was used for 2021, which was obtained from the IHS Markit July 2019 key interest rate forecast for 2021. The all-in effective rate of the long-term debt portion of the facility for the 2021 test year is 3.61 percent. This all-in rate includes the interest on the loans, an annual fee, any unused commitment fees and amortization of debt expenses incurred to establish the facility.

Q. 41 Why are the Clark County IDRBs excluded from the Southern California, Northern California, and South Lake Tahoe rate jurisdictions, and the Big Bear IDRBs excluded from the Northern California and South Lake Tahoe rate jurisdictions in calculating the cost of debt?

A. 41 Southwest Gas issued IDRBs in two of its rate jurisdictions. The IDRB issues and applicable rate jurisdictions are as follows: (1) the Clark County, Nevada IDRBs (2003 Series A, 2008 Series A and 2009 Series A) for its 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 the IRS rules could result in the loss of the IDRB tax-exempt status, which would, in turn, require the Company to refinance its debt at a much higher cost.

Q. 42 How have regulatory jurisdictions 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 ACC, and the FERC have accepted this treatment for IDRBs in past regulatory proceedings.

Q. 43 Please describe and discuss the development of the cost of IDRBs for the Southern California rate jurisdiction.

A. 43 For the 2021 test year, the anticipated effective cost of the $50 million variable rate Big Bear IDRBs is 2.77 percent. The interest rate on the IDRBs is set weekly by a remarketing agent. The weekly rates are set close to the Securities Industry and Financial Markets Association (SIFMA) Municipal Swap Index rate[20], also known by market participants simply as the SIFMA rate. The actual Big Bear rate spread above SIFMA has been approximately 4 basis points. The projected rate for 2021 is based on a regression analysis of the historical average monthly SIFMA rates as a function of the 1-month LIBOR rates, plus the 4 basis points spread. The regression equation is then used to forecast SIFMA rates for 2021, using the IHS Markit forecast of the average 1-month LIBOR rate for 2021. In addition, the Big Bear IDRBs are credit-enhanced with a back-up line of credit. The annual credit facility fees are included to determine the effective cost.

Q. 44 Please explain how the embedded cost of debt for the Southern California rate jurisdiction is calculated.

A. 44 Due to the $50 million in gross principal of the Big Bear IDRBs, which are specific to the Southern California rate jurisdiction, the embedded debt cost is the weighted cost of the Big Bear IDRBs, combined with the Company's other long-term debt. To determine the embedded debt cost, the implicit amount of debt required to finance the Southern California jurisdictional rate base was determined by multiplying the percent of total debt in the capital structure by the amount of rate base. The implicit amount of debt is calculated as follows:

Implicit Debt = Debt to Capital Ratio X Southern California Rate Base
= 47 Percent X $295,188,996

20 The SIFMA Municipal Swap index is a 7-day high-grade market index comprised of tax-exempt Variable Rate Demand Obligations reset rates that are reported to the Municipal Securities Rule Making Board's (MSRB's) SHORT reporting system. The index is calculated on an actual/actual basis and is published every Wednesday by 4 p.m. Eastern Time. The bonds going into the index are selected from all eligible bonds reporting data through the SHORT system that meet the index criteria as set forth by SIFMA. The index is calculated by Bloomberg as the calculation agent for SIFMA. More information about the index and criteria can be obtained from the SIFMA website. This index is produced weekly, reflecting the average rate of issues of tax-exempt variable-rate debt, and serves as a benchmark floating rate in municipal swap transactions. The SIFMA index is usually 65%-75% of its taxable equivalent 1-month LIBOR.

= $138,738,828

Next, the Big Bear IDRBs are allocated first to the total amount of implicit debt. The remaining portion of other debt is calculated as the difference between the implicit amount of debt and the jurisdiction-specific Big Bear IDRBs. The other debt is comprised of the Company's non-jurisdictional specific debt, applied on a pro rata basis. For the Southern California rate jurisdiction, the amount of other debt is calculated as follows:

Implicit Amount of Debt	$138,738,828
Less Net Proceeds Big Bear IDRBs	49,769,498
= Other Debt	$ 88,969,330

The embedded debt cost is then calculated using the components of debt identified in the previous calculation to calculate the weighted cost of debt for the Southern California rate jurisdiction. The allocation process and the calculation of the weighted embedded cost of debt for the Southern California rate jurisdiction are displayed in Chapter 24, Tab A, Schedule 5, Sheet 1 of 4.

VI. CONTINUATION OF THE ATM MECHANISM

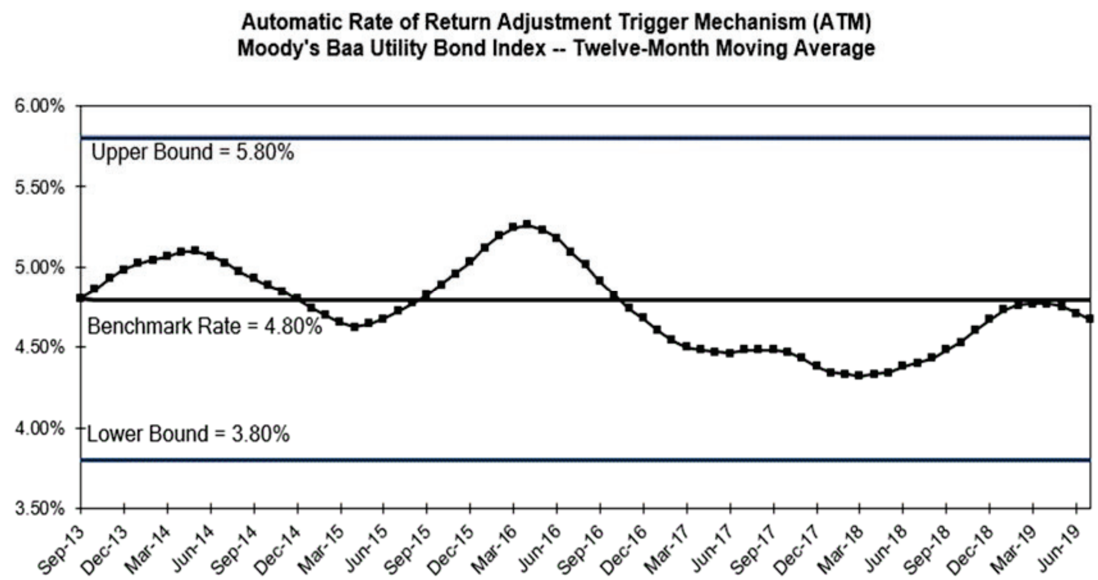
Q. 45 Is Southwest Gas making an ATM proposal in this proceeding?

A. 45 Yes. The Company is requesting the continuation of the ATM approved in D.14-06-028.[21] The ATM adjusts the authorized ROR between general rate cases as a result of changes in utility bond yields. The need for an ROR adjustment is triggered when the average benchmark yield, measured by the Moody's Baa Utility Bond yield, changes by more than 100 basis points.

21 D.14-06-028, p. 70.

Q. 46 Has the ATM been triggered since the authorized RORs were established in D.14-06-028?

A. 46 No. The current ATM benchmark rate is 4.80 percent, which was established for the twelve-month period of October 2012 to September 2013. Since that time, in no year has the twelve-month average rate for the measurement period (April to September of the same year) exceeded the benchmark rate of 4.80 percent by more than 100 basis points. The following graph displays the twelve-month rolling average of the Moody's Baa Utility Bond Index.



Q. 47 Please discuss the features of the Company's requested ATM.

A. 47 The ATM would have the following features:

- The initial benchmark for the ATM would be the twelve-month average yield of Baa utility bonds as reported by Moody's for the period October 2019 through September 2020. The annual measurement period is the twelve-month period ended September. Should the ATM be triggered, the Company will file an advice letter detailing the results of the trigger mechanism, which includes any required change in rates and revenue requirements based on the trigger mechanism.

- If, in any year, the difference between the current twelve-month average and the benchmark, exceeds 100 basis points, then an automatic adjustment in the Company's authorized ROR will result. The Company will update its cost of capital and compute a new ROR as follows:
  1. The authorized ROE in effect at the time of adjustment is adjusted by one-half of the change in the average utility bond yields that triggered the adjustment.
  2. The embedded costs of long-term debt and preferred equity are updated to reflect actual September month-end embedded costs in that year.
  3. The capital structure authorized in this application will be used to compute the updated ROR.
- In any year that the twelve-month average triggers an automatic adjustment, that average becomes the new benchmark until another automatic adjustment is triggered.
- There would be no off-ramp provision, as Southwest Gas would have the right to file a cost of capital application outside of the ATM upon an extraordinary or catastrophic event that materially impacts its cost of capital and/or capital structure.

Q. 48 What are the benefits of continuing the Company's ATM for ROR adjustments?

A. 48 The continuation of the ATM would facilitate the Company's five-year rate case cycle, as it would not require separate cost of capital reviews or participation in the four major utilities' generic cost of capital proceeding outside of a general rate case. As a result, the continuation of the ATM will allow the Company and the Commission to better utilize staff resources and avoid the litigation costs of participating in a separate cost of capital proceeding. The ATM will streamline the regulatory process and adjust the Company's authorized ROR based on changes in actual observed capital market conditions. Such a mechanism is fair and reasonable to both the Company's investors and customers. In addition, the ATM would provide Southwest Gas with a comparable cost of capital mechanism approved and utilized by the other California major energy utilities.

Q. 49 Does this conclude your prepared direct testimony?

A. 49 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.

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Application 19-08______

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to the Financial Supporting Exhibits
of
THEODORE K. WOOD

SOUTHWEST GAS CORPORATION
PROXY GROUP OF VALUE LINE GAS DISTRIBUTION COMPANIES
LIST OF COMPANIES

Line No.	Symbol (a)	Company (b)	Moody's[1] (c)	Numerical Weight (d)	S&P[1] (e)	Numerical Weight (f)	Line No.
1	ATO	Atmos Energy Corp.	A2	6	A	6	1
2	NJR	New Jersey Resources Corp.	Aa3	4			2
3	NWN	Northwest Natural Gas	Baa1	8	A+	5	3
4	OGS	ONE Gas Inc.	A2	6	A	6	4
5	SJI	South Jersey Industries, Inc.	A3	7	BBB	9	5
6	SR	Spire Inc. [2]	A1/A2	5.5	A-	7	6
7		**Proxy Group Average**	**A2**	**6.08**	**A-**	**6.60**	7
8	SWX	**Southwest Gas Corporation**	**A3**	**7.00**	**BBB+**	**8.00**	8

[1] Source: Bloomberg
[2] Reflects ratings for Spire Alabama Inc., and Spire Missouri Inc.

SOUTHWEST GAS CORPORATION
NUMERICAL WEIGHT FOR BOND RATINGS

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

SOUTHWEST GAS CORPORATION
PROXY GROUP OF VALUE LINE GAS DISTRIBUTION COMPANIES
PROJECTED COMMON EQUITY RATIO

			Projected Common Equity Ratio				
Line No.	Company	Symbol	2019	2020	2022-2024	Average	Line No.
	(a)	(b)	(b)	(c)	(d)	(e)	
1	Atmos Energy Corp.	ATO	61.00%	63.00%	65.00%	63.80%	1
2	New Jersey Resources Corp.	NJR	56.00%	57.00%	60.00%	58.60%	2
3	Northwest Natural Gas	NWN	53.00%	53.00%	53.50%	53.30%	3
4	ONE Gas Inc.	OGS	62.00%	62.00%	62.00%	62.00%	4
5	South Jersey Industries, Inc.	SJI	41.50%	41.00%	42.00%	41.70%	5
6	Spire Inc.	SR	56.00%	57.00%	60.00%	58.60%	6
7	**Average**		**54.92%**	**55.50%**	**57.08%**	**56.33%**	7
8	**Median**		**56.00%**	**57.00%**	**60.00%**	**58.60%**	8

[1] Source: Value Line Investment Survey, May 31, 2019.

CALIFORNIA 2020 GENERIC COST OF CAPITAL PROCEEDING

SOUTHERN CALIFORNIA GAS (A. 19-04-018)

Capital	Ratio	Cost	Weighted Cost
Long-Term Debt	43.60%	4.23%	1.84%
Preferred Stock	0.40%	6.00%	0.02%
Common Equity	56.00%	10.70%	5.99%
Total Capital	100.00%		7.85%

SAN DIEGO GAS & ELECTRIC (A. 19-04-017)

Capital	Ratio	Cost	Weighted Cost
Long-Term Debt	44.00%	4.59%	2.02%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity	56.00%	12.38%	6.93%
Total Capital	100.00%		8.95%

SOUTHERN CALIFORNIA EDISON (A. 19-04-014)

Capital	Ratio	Cost	Weighted Cost
Long-Term Debt	43.00%	4.74%	2.04%
Preferred Stock	5.00%	5.70%	0.29%
Common Equity	52.00%	11.45%	5.95%
Total Capital	100.00%		8.28%

PACIFIC GAS & ELECTRIC (A. 19-04-015)

Capital	Ratio	Cost	Weighted Cost
Long-Term Debt	47.50%	5.16%	2.45%
Preferred Stock	0.50%	5.52%	0.03%
Common Equity	52.00%	12.00%	6.24%
Total Capital	100.00%		8.72%

Company Witness:
Robert B. Hevert

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 19-08-___

PREPARED DIRECT TESTIMONY
OF
ROBERT B. HEVERT

ON BEHALF OF
SOUTHWEST GAS CORPORATION

AUGUST 30, 2019

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Prepared Direct Testimony
of
ROBERT B. HEVERT

Exhibit No.__(RBH- 5) CAPM Results

Exhibit No.__(RBH- 6) Bond Yield Plus Risk Premium Analysis

Exhibit No.__(RBH- 7) Expected Earnings Analysis

Exhibit No.__(RBH- 8) Flotation Cost Analysis

Exhibit No.__(RBH- 9) Senate Bill 901

Exhibit No.__(RBH- 10) Capital Structure

Exhibit No.__(RBH- 11) Effect of Leverage on Return on Equity

Exhibit No.__(RBH- 12) Capital Expenditures

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
ROBERT B. HEVERT

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Robert B. Hevert. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

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

A. 2 I am a Partner of ScottMadden, Inc.

Q. 3 On whose behalf are you submitting this testimony?

A. 3 I am submitting this prepared direct testimony before the California Public Utilities Commission ("Commission") on behalf of Southwest Gas Corporation ("Southwest Gas", or the "Company").

Q. 4 Please summarize your educational background and relevant business experience.

A. 4 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.

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. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included in Appendix B to this testimony.

Q. 5 Have you previously testified before any regulatory commission?

A. 5 Yes. 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.

Q. 6 What is the purpose of your prepared direct testimony in this proceeding?

A. 6 The purpose of my prepared direct testimony is to present evidence and provide a recommendation regarding the Company's return on equity ("ROE").[1] My analysis and conclusions are supported by the data presented in Exhibit No.__(RBH-1) through Exhibit No.__(RBH-12), which have been prepared by me or under my direction.

Q. 7 Please summarize your prepared direct testimony.

A. 7 My prepared direct testimony addresses the following topics:

- Overview of analyses and key analytical issues considered;
- Regulatory guidelines and financial considerations;
- The analytical bases for my ROE recommendation;
- Business risks and other considerations that have a direct bearing on the Company's Cost of Equity;

[1] Throughout my testimony, I interchangeably use the terms "ROE" and "Cost of Equity".

- Current capital market conditions and their effect on the Company's Cost of Equity; and
- The conclusions drawn from the analyses and information discussed above, and my resulting recommendation.

II. OVERVIEW OF TESTIMONY

Q. 8 What are your conclusions regarding the appropriate Cost of Equity?

A. 8 My analyses indicate that the Company's Cost of Equity currently is in the range of 10.00 percent to 10.70 percent. Based on the quantitative and qualitative analyses discussed throughout my prepared direct testimony, I find an ROE of 10.50 percent to be reasonable and appropriate in this proceeding.

Q. 9 Please provide a brief overview of the analyses that led to your ROE recommendation.

A. 9 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 traditional and "Empirical" forms of the Capital Asset Pricing Model ("CAPM"); (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 10.70 percent.

In addition to the methods noted above, I reviewed the Company's business risks, including those associated with the current regulatory and political climate in California (including Senate Bill 901); considered its proposed capital structure relative to the proxy group; reviewed the Company's capital expenditures relative to the proxy group; assessed evolving capital market and business conditions, including changes in Federal monetary policy; 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 prepared direct testimony, I find 10.50 percent to be a reasonable and appropriate estimate of the Company's Cost of Equity.

Lastly, it is important to keep in mind that no single model is more reliable than all others at all times and under all market conditions; all require 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 Empirical CAPM results, respectively) are not likely to be reasonable estimates of the Company's Cost of Equity.

Q. 10 Are there other factors that should be considered in determining the weight given to the methods and results summarized above?

A. 10 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. Because that model effectively assumes the market conditions supporting current utility valuations will remain in place in perpetuity, its results should be viewed with caution.

Risk Premium-based methods (such as the CAPM), 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 lockstep 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.[2] Risk 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, should be given somewhat more consideration. Additionally, as noted earlier, the Expected Earnings method provides a method of corroborating other model results. With those considerations in mind, my recommendation reasonably reflects investors' return requirements in the current market environment.

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[2] 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 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. https://www.bloomberg.com/news/articles/2016-10-13/a-critical-idea-in-valuing-stocks-is-being-made-obsolete-by-low-rates

III. 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. 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,[3] 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 prepared 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 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*

[3] The observed interest rate may be adjusted to reflect issuance costs.

Service Comm'n of West Virginia ("*Bluefield*");[4] and (2) *Federal Power Comm'n v. Hope Natural Gas Co*. ("*Hope*").[5] 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 in establishing the appropriate Return on Equity?

A. 13 The Commission has relied upon the *Hope* and *Bluefield* standards in determining the appropriate ROE for utilities.[6] Specifically, the Commission has added:

> We attempt to set the ROE at a level of return commensurate with market returns on investments having corresponding risks, and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility service obligation. To accomplish this objective we have consistently evaluated analytical financial models and risk factors prior to exercising informed judgment to arrive at a fair ROE.[7]

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

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[4] *See*, *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923).

[5] *See*, *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

[6] Docket No. 02-05-022, et al., Interim Opinion on Rates of Return on Equity for Test Year 2003, Decision No. 02-11-027, November 7, 2002, at 16-17.

[7] *Ibid*., at 17.

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, and 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 prepared 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".[8] 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." [9] 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."[10] 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…"[11] 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 estimating the Cost of Equity, and the strict adherence to any single approach, or to the specific results of any single approach, may 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.

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[8] Docket Nos. EL14-12-003 and EL15-45-000, Order Directing Briefs, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

[9] Docket No. EL11-66-001, et al., Order Directing Briefs, 165 FERC ¶ 61,030 (October 16, 2018) at para. 30.

[10] *Id*., at para. 33.

[11] *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.

IV. COST OF EQUITY ESTIMATION

Q. 16 Please briefly discuss the ROE in the context of the regulated rate of return.

A. 16 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.

Summary of Business Risks

Q. 17 Before summarizing your Cost of Equity analysis, please explain why mean and median model results for the proxy group do not provide an appropriate estimate for the Cost of Equity for Southwest Gas?

A. 17 In my view, there are additional factors that must be taken into consideration when determining where Southwest Gas' Cost of Equity falls within the range of results. Those factors include: (1) the risks associated with California's regulatory and political climate; (2) the effect of Senate Bill ("SB") 901 on the Company's cost recovery; (3) the Company's equity ratio relative to the proxy group; and (4) the Company's significant capital expenditures for the period 2019-2021. Those factors, which are discussed below, should be considered in terms of their overall effect on the Company's Cost of Equity.

Q. 18 Please briefly summarize the regulatory and political risks facing Southwest Gas.

A. 18 Southwest Gas faces several risks due to the regulatory and political climate in California. In part due to the wildfires, California utilities and regulators find themselves in an increasingly uncertain environment. As the regulatory environment in California shifts, the possibility of adverse effects on Southwest Gas becomes increasingly relevant to investors. Southwest Gas also may find itself at risk due to California's legal doctrine of "Inverse Condemnation", that may hold a utility at fault for damages despite no fault of the utility.[12] Lastly, legislators and regulators in California have begun to initiate efforts aimed at decarbonization, including efforts enabling builders to more easily develop all-electric buildings.[13]

Q. 19 What is the effect of SB 901 on Southwest Gas?

A. 19 As discussed in Section V below, SB 901 excludes certain executive compensation from ratepayer recovery,[14] effectively representing a 37 basis point reduction in the Company's *pro forma* common equity that must be absorbed by shareholders. Because the Company must compete with other utilities for the long-term capital needed to fund its utility operations, that reduced expected return places Southwest Gas at a competitive disadvantage.

Q. 20 Please summarize the Company's proposed capital structure.

A. 20 As discussed by Company Witness Theodore K. Wood, Southwest Gas proposes a capital structure of 53.00 percent common equity and 47.00 percent long-term debt.[15]

Q. 21 Please summarize Company's planned capital expenditures.

A. 21 As discussed in Section V below, the Company plans to invest approximately $211 million dollars for the period 2019-2021. As shown in Chart 4 (*see*, Section

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[12] *See*, Section V, below; *See*, *also*, *Barham v. Southern California Edison Co.,* 74 Cal, App. 4th 744, 752, (1999).
[13] California Public Utilities Commission, Order Instituting Rulemaking Regarding Building Decarbonization, Rulemaking 19-01-011, at 6-7.
[14] *See*, California Senate Bill No. 901, Chapter 626, September 21, 2018, at 7-8.
[15] Prepared Direct Testimony of Theodore K. Wood, at 3.

V below), that amount is the highest among the proxy group and over 47.00 percent higher than the proxy group median.

Proxy Group Selection

Q. 22 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. 22 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 California operations. Because the ROE is a market-based concept and given the fact that the Company's jurisdictional operations within California 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 California 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. 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. 23 Does the selection of a proxy group suggest that analytical results will be tightly clustered around average (i.e., mean) results?

A. 23 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.[16] 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. 24 Please now provide a summary profile of Southwest Gas.

A. 24 Southwest Gas provides natural gas distribution service to approximately 2,047,000 customers in Nevada, Arizona, and California. Of those customers, approximately 196,000 are located in California.[17] Southwest Gas' operations in California comprise three jurisdictions; Northern California, Southern California and South Lake Tahoe. Net income from gas distribution operations accounted for 76.17 percent of Southwest Gas' total net income in 2018.[18] In addition, 11.00 percent of the Company's operating margin was earned by its California operations.[19] Southwest Gas currently has senior unsecured ratings of A3 (outlook: Stable), BBB+ (outlook: Negative) and A (outlook: Stable) from

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[16] In Appendix A, I provide more substantive descriptions of the models used to estimate the ROE.
[17] Southwest Gas Corporation SEC Form 10-K for the fiscal year ended December 31, 2018, Exhibit 13.01, at 3.
[18] *Ibid., at 5.*
[19] *Ibid.*, at 3.

Moody's Investor Service ("Moody's"), Standard & Poor's Rating Services ("S&P") and Fitch Ratings, respectively.[20]

Q. 25 How did you select the companies included in your proxy group?

A. 25 I began with the universe of companies that Value Line classifies as Natural Gas Utilities, which includes a group of ten domestic U.S. utilities, and applied the following screening criteria:

- Because utilities generally are considered dividend-paying entities, I excluded companies that do not consistently pay quarterly cash dividends;
- 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 net operating income from regulated natural gas utility operations; and
- I eliminated companies that are currently known to be party to a merger, or other significant transaction.

Q. 26 Did you include Southwest Gas in your analysis?

A. 26 No. To avoid the circular logic that otherwise would occur, it has been my consistent practice to exclude the subject company (or its parent) from the proxy group.

[20] Source: Bloomberg Professional.

Q. 27 What companies met those screening criteria?

A. 27 The criteria discussed above resulted in a proxy group of the following six companies:

Table 1: Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries	SJI
Spire Inc.	SR

Q. 28 Do you believe that a proxy group of six companies is sufficiently large?

A. 28 Yes. The analyses performed in estimating the ROE are more likely to be representative of the subject utility's Cost of Equity to the extent that the chosen proxy companies are fundamentally comparable to the subject utility. Because all analysts use some form of screening process to arrive at a proxy group, the group, by definition, is not randomly drawn from a larger population. Consequently, there is no reason to place more reliance on the quantitative results of a larger proxy group simply by virtue of the resulting larger number of observations.

Moreover, because I am using market-based data, my analytical results will not necessarily be tightly clustered around a central point. Results that may be somewhat dispersed, however, do not suggest that the screening approach is inappropriate or the results less meaningful. In my view, including companies whose fundamental comparability is tenuous at best simply for the purpose of expanding the number of observations does not add relevant information to the analysis.

Q. 29 How does the proxy group credit rating compare to that of Southwest Gas?

A. 29 As discussed by Company Witness Theodore K. Wood, the proxy group has a credit rating of A2 and A- from Moody's and S&P, respectively.[21] Compared to the proxy group, the Company's S&P rating is one notch lower. Although credit ratings may be directionally related to the Cost of Equity over the long-term, a change in one is not a direct measure of a change in the other. As discussed below, the Company faces several unique business risks, and given the additional strain on the Company's financial metrics that can arise from those risks, the Company's credit rating relative to the proxy group indicates greater risk as seen by creditors.

Cost of Equity Estimation

Q. 30 How is the required ROE determined?

A. 30 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.[22] When faced with the task of 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.

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[21] Prepared Direct Testimony of Theodore K. Wood, at 8; Exhibit No.___(TWK-1).

[22] *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.

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 CAPM, the Bond Yield Plus Risk Premium, and the Expected Earnings approach.

Q. 31 Please briefly describe the Constant Growth DCF model.

A. 31 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. As explained in Appendix A, the model often is expressed in the familiar form $k = \frac{D(1+g)}{P_0} + g$, where 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. The Constant Growth DCF formula, which falls from the longer "present value" structure,[23] requires several simplifying assumptions, including the constancy of inputs in perpetuity.

Under the model's strict assumptions, the growth rate equals the rate of capital appreciation (that is, the growth in the stock price).[24] Given that assumption, it does not matter whether the investor holds the stock in perpetuity, or whether they hold the stock for some period of time, collect the dividends, then sell at the prevailing market price. That result also assumes the ROE result reached today will remain unchanged in perpetuity. So, if market conditions are such that the model produces an unreasonably low (or high) ROE estimate

[23] Appendix A, part A.

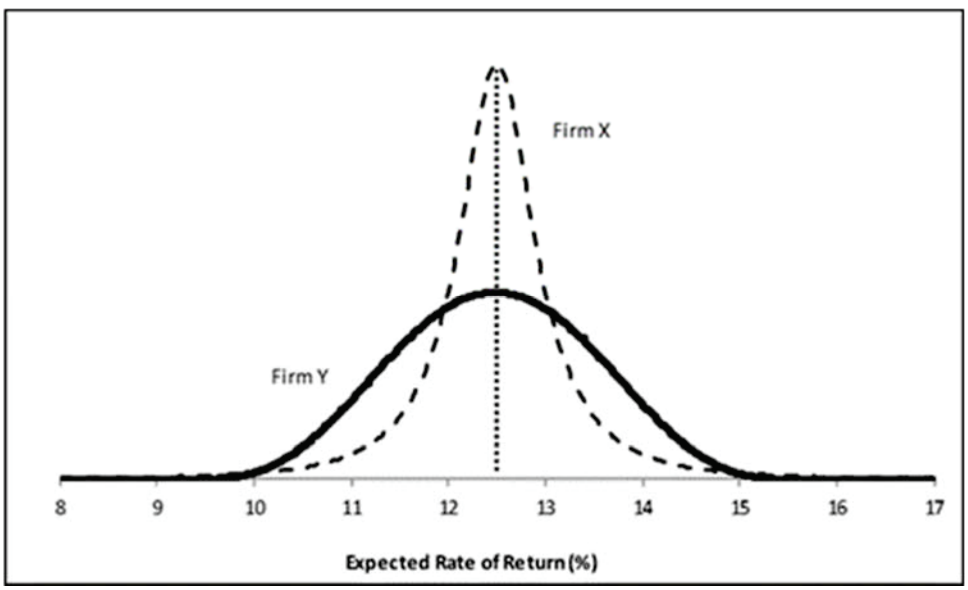
[24] As discussed in Appendix A, part A, the model assumes that earnings, dividends, book value, and the stock price all grow at the same constant rate in perpetuity. Additionally, academic research has indicated that analysts forecasts of growth are superior to other measures of growth (*see,* Appendix A, part A).

today, it assumes that estimate will be the same ROE investors require every day in the future, regardless of whether or how market conditions change.

Q. 32 Please briefly describe the Capital Asset Pricing Model.

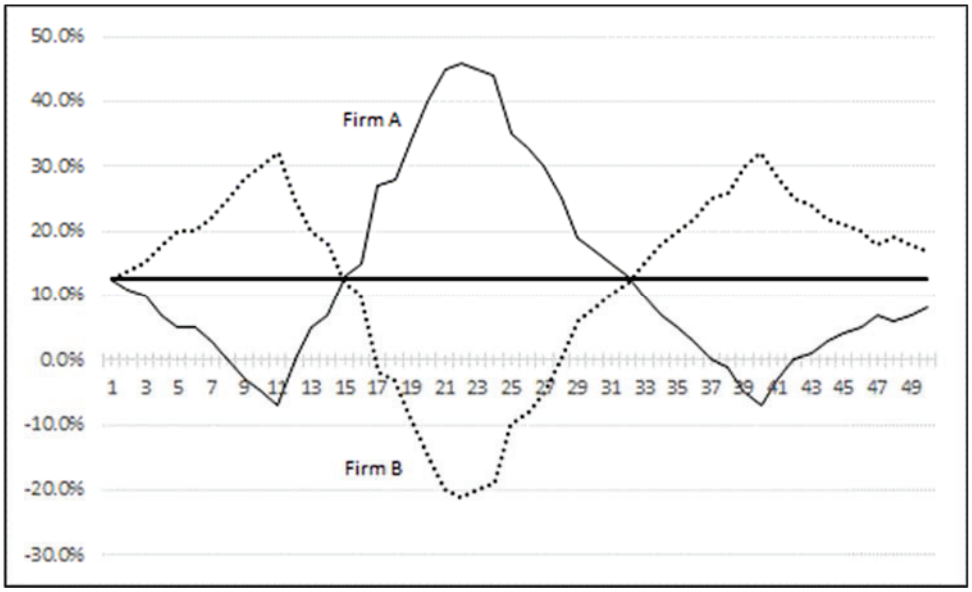
A. 32 Whereas DCF models focus on expected cash flows, Risk Premium-based models such as the CAPM focus on the additional return that investors require for taking on additional risk. In finance, "risk" generally refers to the variation in expected returns, rather than the expected return, itself. Consider 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 the security is equally 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:

$$\text{Risk} - \text{Free Rate} + (\text{Beta Coefficient x Market Risk Premiu} = \text{Required Return} \quad [2]$$

Q. 33 Please briefly describe the Bond Yield Plus Risk Premium approach.

A. 33 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. 34 Please briefly describe the Expected Earnings approach.

A. 34 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. 35 What are the results of your Constant Growth DCF?

A. 35 The results of the Constant Growth DCF are provided in Table 2, below.[25]

Table 2: Summary of DCF Results[26]

	Median	Median High
30-Day Average	9.06%	11.32%
90-Day Average	9.10%	11.36%
180-Day Average	9.17%	11.44%

Q. 36 Please now summarize your remaining analytical results.

A. 36 The Risk Premium-based results, including the CAPM and ECAPM, Bond Yield Plus Risk Premium, and Expected Earnings methods, explained in detail in Appendix A, parts B, C and D, respectively, are provided below.

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[25] *See,* Appendix A for a more detailed description of the models, assumptions, and inputs described in Section IV.

[26] For the purposes of my 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 27.00 percent from Value Line due to the company's significant losses in 2017.

Table 3a: Summary of CAPM Results

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.63%)	9.58%	9.53%
Near Term Projected 30-Year Treasury (2.70%)	9.65%	9.60%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.63%)	10.90%	10.83%
Near Term Projected 30-Year Treasury (2.70%)	10.97%	10.90%

Table 3b: Summary of ECAPM Results

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.63%)	10.91%	10.84%
Near Term Projected 30-Year Treasury (2.70%)	10.98%	10.91%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.63%)	11.89%	11.82%
Near Term Projected 30-Year Treasury (2.70%)	11.96%	11.89%

Table 4: Summary of Bond Yield Plus Risk Premium Results

Treasury Yield	Return on Equity
Current 30-Year Treasury (2.63%)	9.87%
Near Term Projected 30-Year Treasury (2.70%)	9.87%
Long Term Projected 30-Year Treasury (3.70%)	10.01%

Table 5: Expected Earnings Results

	Return on Equity
Mean	10.83%
Median	10.85%

Flotation Costs

Q. 37 What are flotation costs?

A. 37 Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs of common stock.

Q. 38 Why is it important to recognize flotation costs in the allowed ROE?

A. 38 To attract and retain new investors, a regulated utility must have the opportunity to earn a return that is both competitive and compensatory. To the extent a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing its ability to attract adequate capital on reasonable terms.

Q. 39 Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A. 39 Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and therefore are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, a considerable portion of a utility's flotation costs are incurred prior to the test year, but remain part of the cost during the test year and beyond. The recovery of flotation costs therefore is appropriate even if no new issuances are planned in the near future; failure to do so may deny Southwest Gas the opportunity to earn its required rate of return in the future.

Q. 40 Is the need to consider flotation costs eliminated because Southwest Gas is a wholly owned subsidiary?

A. 40 No. Like the Company's California 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. 41 Do the DCF and CAPM models already incorporate investor expectations of a return to compensate for flotation costs?

A. 41 No. The models used to estimate the appropriate ROE assume no "friction" or transaction costs, as these costs are not reflected in the market price (in the case of the DCF model) or risk premium (in the case of the CAPM and the Bond Yield Plus Risk Premium model). Therefore, it is appropriate to consider flotation costs when determining where within the range of reasonable results Southwest Gas' return should fall.

Q. 42 Is the need to consider flotation costs recognized by the academic and financial communities?

A. 42 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. Roger 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."[27] 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."[28] 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.[29]

Similarly, Morningstar 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

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[27] Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc., 2006, at 321.
[28] *Id.*, at 327.
[29] Shannon P. Pratt, Roger J. Grabowski, Cost of Capital: Applications and Examples, 4th Ed. (John Wiley & Sons, Inc., 2010), at 586.

that must be paid to underwriters by the issuer to attract and retain capital).[30]

Q. 43 Has Southwest Gas recently participated in a common equity offering agreement?

A. 43 Yes. As explained by Company Witness Theodore K. Wood, Southwest Gas' parent company recently entered into a $300 million Equity Shelf Program in May of 2019.[31] As discussed by Company Witness Theodore K. Wood, the proceeds from this offering, and a previous offering of $150 million, are reflected in the Company's records as a capital contribution from the parent holding company.[32] In addition to anticipated expenses of $507,860, the Company will incur a commission expense equal to 1.00 percent all shares sold ($3 million upon completion).[33]

Q. 44 Have you calculated the effect of flotation costs on the return on equity?

A. 44 Yes. I modified the DCF calculation to derive the dividend yield that would reimburse investors for direct issuance costs. Based on the weighted average issuance costs shown in Exhibit No.__(RBH-8), a reasonable estimate of flotation costs is approximately 0.07 percent (7 basis points). Although I have calculated the effect of flotation costs, I did not make any explicit adjustments to my ROE estimates to account for flotation costs. Rather, I took it into consideration in determining where the Company's Cost of Equity falls within the range of analytical results.

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[30] Morningstar, Inc. Ibbotson SBBI 2013 Valuation Yearbook, at 25.
[31] Prepared Direct Testimony of Theodore K. Wood, at 12.
[32] *Ibid*.
[33] $3,000,000 = 1.00% x $300,000,000. Source: Southwest Gas Holdings, Inc. SEC Form S-3 Registration Statement, May 8, 2019.

V. BUSINESS RISKS AND OTHER CONSIDERATIONS

Q. 45 Please describe the additional factors you considered in determining the appropriate Cost of Equity for Southwest Gas.

A. 45 As discussed earlier, it is important to assess the factors below to determine their effect on the Company, and subsequently, to determine where within my recommended range, the Cost of Equity for Southwest Gas appropriately lies. Those factors include: (1) the regulatory and political risks the Company faces within the state of California, including the effect of SB 901; (2) the Company's proposed capitalization; and (3) the Company's significant capital expenditure plan. Those factors, which are discussed below, should be considered in terms of their overall effect on the Company's Cost of Equity.

Regulatory and Political Risks

Q. 46 Please describe the concept of Inverse Condemnation.

A. 46 As the California Court of Appeals has explained, the "fundamental policy underlying the concept of inverse condemnation is to spread among the benefiting community any burden disproportionately borne by a member of that community, to establish a public undertaking for the benefit of all."[34] Although I am not an attorney, my plain reading of that language suggests utilities could be found liable for damages to private property, despite no indication of wrongdoing or negligence.

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[34] *Barham v. Southern California Edison Co.,* 74 Cal, App. 4th 744, 752, (1999).

Q. 47 Have the wildfires in California increased investor awareness of Inverse Condemnation?

A. 47 Yes. Although Southwest Gas currently does not face liabilities as a result of the wildfires in California, it is not unreasonable to expect investors would consider the uncertainty associated with Inverse Condemnation, and the regulatory climate in California.

Q. 48 Are there specific examples of negative reactions from the investment community in response to Inverse Condemnation?

A. 48 Yes. On January 23, 2019, Regulatory Research Associates ("RRA") reduced California's rating to Average/1 from Above Average/3, stating that the "lack of regulatory or legislative protections against wildfire liabilities caused by the application of inverse condemnation…prompted RRA…to reduce its regulatory rating."[35] On August 12, 2019, RRA further reduced the rating to Average/2, citing the effects of Inverse Condemnation remaining a significant issue.[36]

Q. 49 Are there other political or regulatory risks that Southwest Gas faces in California?

A. 49 Yes. Recent legislation has reflected increased focus on decarbonization, including specifically, building decarbonization. As the Commission noted, the California Energy Commission recently instituted a means by which builders of

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[35] Source: Regulatory Research Associates. As RRA explains: "RRA maintains three principal rating categories for regulatory climates: Above Average, Average, and Below Average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger rating; 2, a mid-range rating; and, 3, a weaker rating. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's utilities. The evaluation reflects our assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions."

[36] Source: Regulatory Research Associates.

all-electric buildings can more easily comply with building codes.[37] The Commission further observed "[t]he costs and benefits of building standards that support decarbonization are interdependent with many policies that fall under Commission jurisdiction" [38] As these policies advance, their effects could reduce the demand for natural gas, leaving natural gas utilities at risk of holding stranded assets.

Although they are difficult to quantify, we reasonably can conclude investors will require higher returns to accept the increased uncertainty surrounding the regulatory and political risks in California.

Senate Bill 901

Q. 50 Please summarize Senate Bill 901.

A. 50 SB 901 requires certain officer compensation to be borne solely by the shareholders:

> This bill would repeal the above provisions relating to excess annual compensation of utility officers. The bill would prohibit an electrical corporation or gas corporation from recovering from ratepayers any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of the electrical corporation or gas corporation, and would require that compensation to instead be funded solely by shareholders of the electrical corporation or gas corporation.[39]

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[37] California Public Utilities Commission, *Order Instituting Rulemaking Regarding Building Decarbonization*, Rulemaking 19-01-011, at 6-7.

[38] *Id.*, at 7.

[39] California Senate Bill No. 901, Chapter 626, September 21, 2018, at 7-8.

Q. 51 What is the current California portion of executive compensation that will be excluded from recovery for Southwest Gas?

A. 51 The 2018 California portion of executive compensation that would be excluded from recovery is approximately $897,000.[40]

Q. 52 Is $897,000 the correct amount to use in determining the additional risk SB 901 places on shareholders?

A. 52 No. $897,000 is the amount for 2018 that will be funded by shareholders. Under SB 901, however, shareholders will bear that cost in perpetuity.

Q. 53 Have you calculated the effect of SB 901 in perpetuity?

A. 53 Yes. I first calculated the present value of the $897,000 based on the Gordon Model,[41] which defines value as the expected cash-flow divided by the difference between the Cost of Equity (*i.e.,* the discount rate) and the long-term expected growth rate. I then calculated the present value of the Company's common equity, which is based on the Company's proposed test year rate base.

As shown in Exhibit No.__(RBH-9), the present value of the $897,000 excluded under SB 901 divided by the present value of the Company's test year common equity is approximately 0.37 percent (37 basis points).[42]

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[40] Source: Company-provided information.

[41] *See,* Morningstar, Inc., *2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook*, at 48-52.

[42] Because the same discount rate and terminal growth rate are applied consistently to the SB 901 amount and the test year common equity in determining present value, the resulting 37 basis point result will be the same regardless of inputs. Due to this, ROE and GDP growth inputs should be considered illustrative.

Capital Structure and Financial Leverage

Q. 54 What is Southwest Gas' recommended capital structure?

A. 54 As described in more detail in Company witness Theodore K. Wood's testimony, Southwest Gas' recommended capital structure consists of 53.00 percent common equity and 47.00 percent long-term debt.[43]

Q. 55 Did you assess the reasonableness of Southwest Gas' proposed capital structure relative to the proxy group?

A. 55 Yes. The proxy group has been selected to reflect comparable companies in terms of financial, business, and regulatory risks. Therefore, it is appropriate to compare the capital structures of the proxy group companies to that of the subject company in order to assess whether the proposed capital structure is consistent with industry standards for companies with commensurate risk profiles.

Q. 56 Please describe your analysis of Southwest Gas' capital structure relative to industry practice.

A. 56 As a measure of industry practice, I calculated the average capital structure for each of the proxy companies over the last eight fiscal quarters. As shown in Exhibit No.__(RBH-10), the proxy group average capital structure over that period includes 53.10 percent common equity and 46.90 percent long-term debt; the average common equity ratios (on a company-specific basis) range from 42.20 percent to 62.14 percent. Based on that review, it is apparent that Southwest Gas' proposed capital structure of 53.00 percent common equity is consistent with the proxy group average.

[43] Prepared Direct Testimony of Theodore K. Wood, at 3.

Q. 57 What is the basis for using average capital components rather than a point-in-time measurement?

A. 57 Measuring the capital components at a particular point in time can skew the capital structure by the specific circumstances of a particular period. Therefore, it is more appropriate to normalize the relative relationship between the components over a period of time.

Q. 58 Have you conducted any analyses between the Company's proposed common equity ratio and the Company's required ROE?

A. 58 Yes. I estimated the adjustment required for both the CAPM and DCF analyses to account for 5.00 percentage point changes in the equity ratio both above and below the proxy group projected average equity ratio of 57.08 percent (based on Value Line's projected Common Equity for the period 2022-2024.)[44] I based my adjustment to the CAPM results on the Hamada Equation,[45] which adjusts the average Beta coefficient for the level of leverage held by the underlying companies on which that measurement is made. In this case, the proxy group projected average equity ratio of 57.08 percent and the average Value Line Beta coefficient of 0.68 translate to an unlevered (or "asset") Beta coefficient of 0.42, when the tax effect of the debt portion of the capital structure is removed from the calculation. The unlevered Beta coefficient can then be re-levered to approximate the additional risk assumed by decreasing the equity ratio to any level specified.

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[44] The Company is using a Forward Test Year in their accompanying filing.

[45] Shannon P. Pratt, Robert F. Reilly, and Robert P. Schweihs, Valuing a Business, Fourth Edition, at 169.

I performed a similar adjustment to the DCF analysis based on the Modigliani-Miller Approach,[46] using the proxy group average equity and debt ratios and an assumed effective tax rate of 21.00 percent. I then adjusted the unlevered ROE to approximate the added risk assumed by changing the equity ratio in 5.00 percent increments.

As shown in Chart 3 (below) and Exhibit No.__(RBH-11), based on the CAPM and DCF analyses, an equity ratio of approximately 53.00 percent indicates a required ROE of approximately 10.91 percent to 11.38 percent. Moreover, as shown in Chart 3 (below), based on several factors, including currently observed credit spreads for utility bonds, Moody's guidelines for Debt/Total Capital, and the average capital structure of the proxy group, the optimal equity ratio with respect to overall weighted cost of capital is well above the Company's requested 53.00 percent equity ratio (*i.e.*, the point at which the WACC is minimized.)

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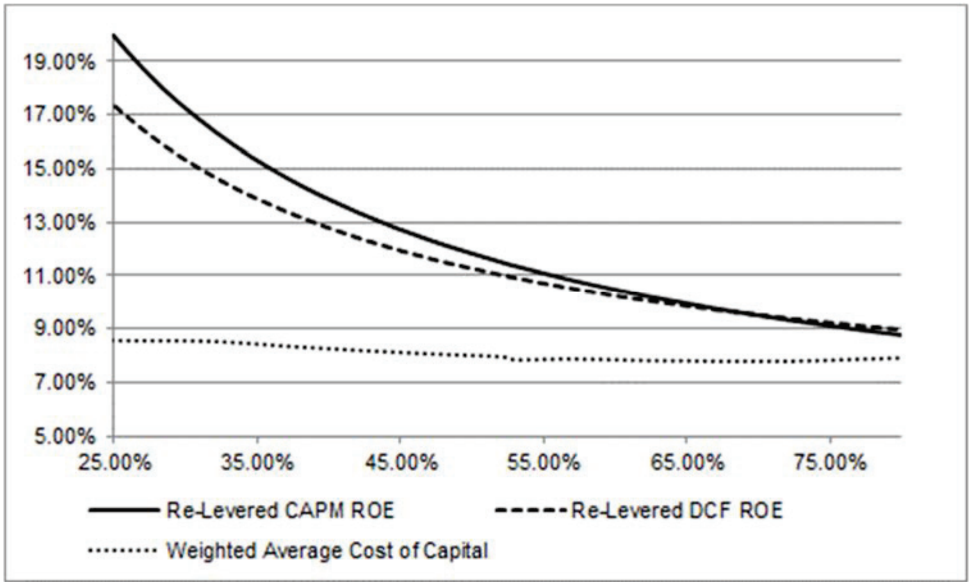
[46] Stephen A. Ross, Randolph Westerfield, and Jeffrey Jaffe, Corporate Finance, Seventh Edition, at 405-427.

Chart 3: Leverage Effect, the Cost of Equity and the Weighted Average Cost of Capital



Please note that although the Modigliani-Miller and Hamada adjustments may be used to generally measure the magnitude of the effect of incremental increases in leverage on the Cost of Equity, it is important to recognize the results are imprecise due to the complex and the dynamic nature of the relationship. It also is important to keep in mind that any measure of an "optimal" capital structure must consider numerous objectives and constraints.

Q. 59 What are your conclusions regarding the Company's proposed common equity ratio?

A. 59 Although the Company's proposed common equity ratio of 53.00 percent is consistent with the proxy group average of 53.10 percent, it falls below the 57.08 percent proxy group average projected by Value Line. Given the Company is applying a Forward Test Year, I find its proposed common equity ratio of 53.00 percent generally to be in alignment with my ROE recommendation.

Capital Expenditures and Credit Metrics

Q. 60 Please summarize Southwest Gas' capital expenditure plans.

A. 60 Southwest Gas currently plans to invest approximately $211 million dollars over the period 2019-2021.[47] That amount includes investments to maintain and improve distribution and general facilities.

Q. 61 How do Southwest Gas' expected capital expenditures compare to the proxy group?

A. 61 To reasonably make that comparison, I calculated the ratio of expected capital expenditures to net plant for each company in the proxy group (*see,* Exhibit No.__(RBH-12)). For the projected period 2019-2021, I performed that calculation using Southwest Gas' projected capital expenditures relative to its 2018 net plant. As shown in Chart 4, relative to the proxy group, Southwest Gas has the highest ratio of projected capital expenditures to net plant, and its projected capital expenditures relative to net plant are 47.71 percent higher than the proxy group median.

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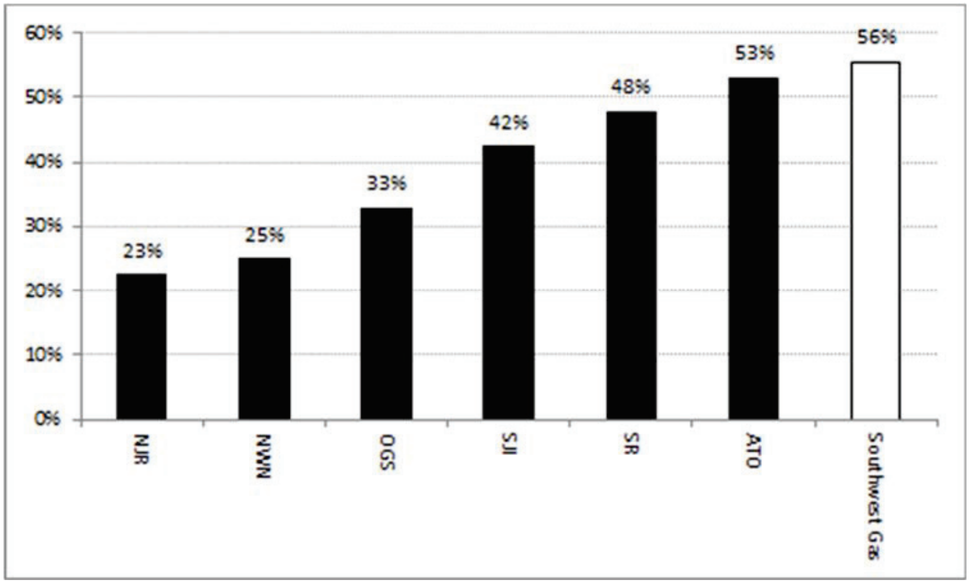
[47] Source: Company-provided data.

Chart 4: Comparison of Projected Capital Expenditures Relative to Net Plant[48]



Q. 62 Why is it important for a utility to be allowed the opportunity to earn a return that is adequate to attract capital at reasonable terms?

A. 62 The allowed ROE should enable the subject utility to finance capital expenditures and working capital requirements at reasonable rates, and to maintain its financial integrity in a variety of economic and capital market conditions. As discussed earlier in my prepared direct testimony, a return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness. To the extent a utility is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders should be disadvantaged.

The ratemaking process is based on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of, and the

[48] Sources: Value Line Investment Survey; and Company-provided data.

market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, their decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of the utility and its ratepayers.

Further, the financial community carefully monitors the current and expected financial condition of utility companies, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk. That is especially important during periods in which the utility expects to make significant capital investments and, therefore, may require access to capital markets.

Q. 63 How do those considerations apply to Southwest Gas and its capital spending plans?

A. 63 It is clear Southwest Gas' capital expenditure program is significant. It also is clear that the financial community recognizes the need for timely cost recovery for those capital expenditures. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. S&P has noted several long-term challenges for utilities' financial health including: heavy construction programs to address demand growth; declining capacity margins; and aging infrastructure and regulatory responsiveness to mounting requests for rate increases.[49] More recently, S&P noted that:

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[49] *See,* Standard & Poor's, *Industry Report Card: Utility Sectors in the Americas Remain Stable, While Challenges Beset European, Australian, and New Zealand Counterparts*, RatingsDirect, June 27, 2008, at 4.

> We assume that capital spending will remain a focus of most utility managements and strain credit metrics. It provides growth when sales are diminished by ongoing demanded efficiency from regulators and other trends, and it is welcomed by policymakers that appreciate the economic stimulus and the benefits of safer, more reliable service. The speed with which the regulatory process turns the new spending into higher rates to begin to pay for it is an important factor in our assumptions and the forecast. Any extended lag between spending and recovery can exacerbate the negative effect on credit metrics and therefore ratings.[50]

Q. 64 Have the major rating agencies raised concern as they consider the implications of the Tax Cuts and Jobs Act ("TCJA") for utilities' cash flow and credit statistics?

A. 64 The major rating agencies have observed that a reduction in utilities' revenue associated with lower income taxes and the potential return of excess accumulated deferred income taxes may reduce utilities' cash flow.[51] As Fitch pointed out "[a]bsent mitigating strategies on the regulatory front, this is expected to lead to weaker credit metrics and negative rating actions for issuers with limited headroom to absorb the leverage creep."[52] In a similar vein, S&P observed that the TCJA is "…negative for credit quality because the combination of a lower tax rate and the loss of stimulus provisions related to bonus depreciation or full expensing of capital spending will create headwinds in operating cash-flow generation capabilities as customer rates are lowered in response to the new tax code."[53] Moody's stated the following:

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[50] *See,* Standard & Poor's Rating Services, *Industry Top Trends 2017: Utilities*, RatingsDirect, February 16, 2017, at 4.

[51] *See,* S&P Global Market Intelligence, *Rating agencies warn tax reform could drag US utility sector credit quality*, January 25, 2018.

[52] FitchRatings Special Report, *Tax Reform Impact on the U.S. Utilities, Power & Gas Sector*, January 24, 2018.

[53] S&P Global Ratings, *U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound*, January 24, 2018.

> Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150 - 250 basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.[54]

All three rating agencies, therefore, have observed the negative effects of the TCJA on utilities' cash flow, and the potential consequences for their credit profiles

Q. 65 Did Moody's update its review of the utility sector?

A. 65 Yes. On June 18, 2018 Moody's changed its outlook on the U.S. regulated utility sector to "negative" from "stable". Moody's explained that its change in outlook "…primarily reflects a degradation in key financial credit ratios, specifically the ratio of cash flow from operations to debt, funds from operations (FFO) to debt and retained cash flow to debt, as well as certain book leverage ratios."[55] The sector's outlook could remain "negative" if cash flow-based metrics continue to decline, or if there emerge signs of a more "contentious" regulatory environment (which, Moody's notes, is not fully reflected in lower authorized returns). Moody's also noted that "[m]anagement teams' defensive efforts and a few initial signs of supportive regulatory responses to tax reform are important first steps in addressing the sector's increased financial risk," and explained that in its view,

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[54] Moody's Investors' Service, *Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform*, January 19, 2018.

[55] *See*, Moody's Investors Service, *Announcement: Moody's changes the US regulated utility sector outlook to negative from stable*, June 18, 2018.

"it will take longer than 12-18 months for the sector to exhibit a material financial improvement from these actions."[56]

Q. 66 What conclusions do you draw regarding the effects of the Company's capital expenditure plan and the TCJA?

A. 66 There is little question the TCJA has increased cash flow-related risks, and the potentially dilutive effects of additional equity issuances, for utilities. Those risks are manifested in the comments of financial participants such as Moody's, S&P, and Fitch. Further, because non-regulated companies may benefit from the TCJA in ways utilities cannot, it is reasonable to conclude investors have begun to see utilities as less attractive relative to other industry sectors. Lastly, the dilution in cash flow may increase short-term borrowing requirements to fund day-to-day utility operations. When paired with the Company's significant capital expenditure program relative to the proxy group, which in itself represents additional pressure on the Company's credit metrics, the effects of the TCJA should not be overlooked.

VI. CAPITAL MARKET ENVIRONMENT

Q. 67 Do economic conditions influence the required Cost of Capital and required return on common equity?

A. 67 Yes. As discussed in Section IV and in Appendix A, the models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions. Therefore, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent a given model's assumptions are misaligned with

[56] *Id*.

such data, or its results are inconsistent with basic financial principles, it is important to consider whether alternative estimation techniques are likely to provide more meaningful and reliable results.

Q. 68 Does your recommendation consider the current capital market environment?

A. 68 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.

Q. 69 Has market volatility changed with the Federal Reserve's move toward monetary policy normalization?

A. 69 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-time, mid-quote prices of S&P 500® Index (SPXSM) call and put options." [57] 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

[57] Source: http://www.cboe.com/vix.

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 19.22, which is highly consistent with the long-term standard deviation on annual market returns (19.80 percent, as reported by Duff & Phelps).[58]

Table 6, below, demonstrates the increase in market uncertainty from 2017 to 2019. As that table notes, the standard deviation (that is, the volatility of volatility) from 2018 through 2019 is about 3.24 times higher than its 2017 level (1.36).

Table 6: VIX Levels and Volatility[59]

VIX Level and Volatility	
Long-term Average	19.22
2018-2019 Average	16.37
2018-2019 Maximum	37.32
2018-2019 Minimum	9.15
2018-2019 Standard Deviation	4.41
2017 Average	11.09
2017 Maximum	16.04
2017 Minimum	9.14
2017 Standard Deviation	1.36

The increase in volatility is not surprising as market participants re-assess the Federal Reserve's long-term objective of monetary policy normalization, and the increasing risks associated with federal trade policy initiatives.

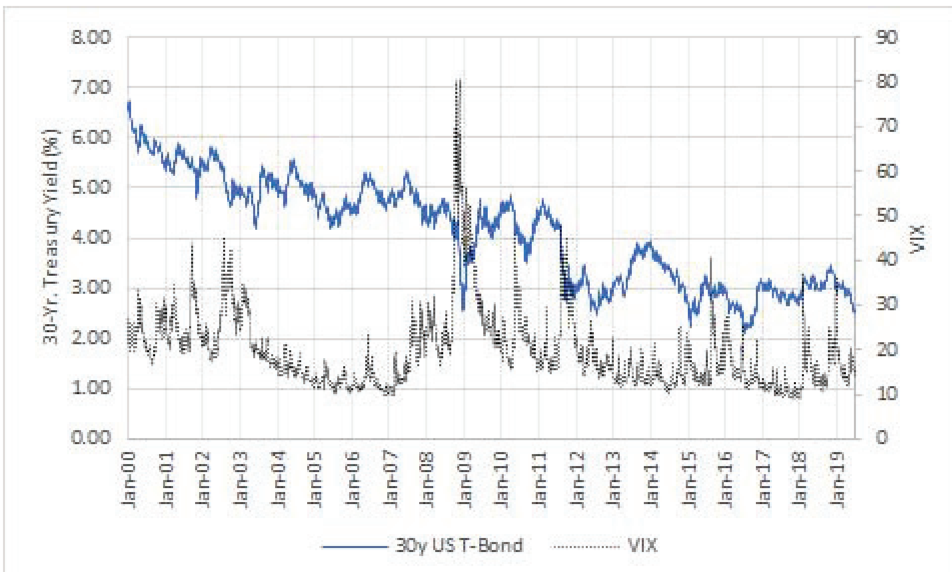
Q. 70 Is there a relationship between equity market volatility and interest rates?

A. 70 Yes. Significant and abrupt increases in volatility tend to be associated with declines in Treasury yields. That relationship makes intuitive sense; as investors

[58] Source: Duff & Phelps, 2019 SBBI Yearbook, at 6-17.
[59] Source: Bloomberg Professional.

see increasing risk, their objectives may shift principally to capital preservation (that is, avoiding a capital loss). A means of doing so is to allocate capital to the relative safety of Treasury securities, in a "flight to safety". Because Treasury yields are inversely related to Treasury bond prices, as investors bid up the prices of bonds, they bid down the yields. As Chart 5, below, demonstrates, decreases in the 30-year Treasury yield are coincident with significant increases in the VIX.

Chart 5: 30-Year Treasury Yields vs. VIX (1/2000 – 6/2019)[60]



In those instances, the fall in yields does not reflect a reduction in required returns, it reflects an increase in risk aversion and, therefore, an increase in required equity returns.

Q. 71 Is market volatility expected to increase from its current levels?

A. 71 Yes. 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:

[60] Sources: S&P Global Market Intelligence; and Yahoo! Finance.

> 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.[61]

Cboe's term structure data is upward sloping, indicating market expectations of increasing volatility. The expected VIX value in June 2020 is about 17.71, suggesting investors see a reversion to long-term average volatility over the coming months.[62]

Q. 72 Have recent declines in Treasury yields been associated with increases in market volatility?

A. 72 Yes. Since November 2018, the periods during which Treasury yields fell coincided with increases in the VIX (*see,* Chart 6, below).

Chart 6: 30-Year Treasury Yields vs. VIX (11/2018 – 6/2019)[63]

[61] Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.
[62] Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, accessed June 28, 2019.
[63] Sources: S&P Global Market Intelligence; and Yahoo! Finance.

Q. 73 What conclusions do you draw from those analyses?

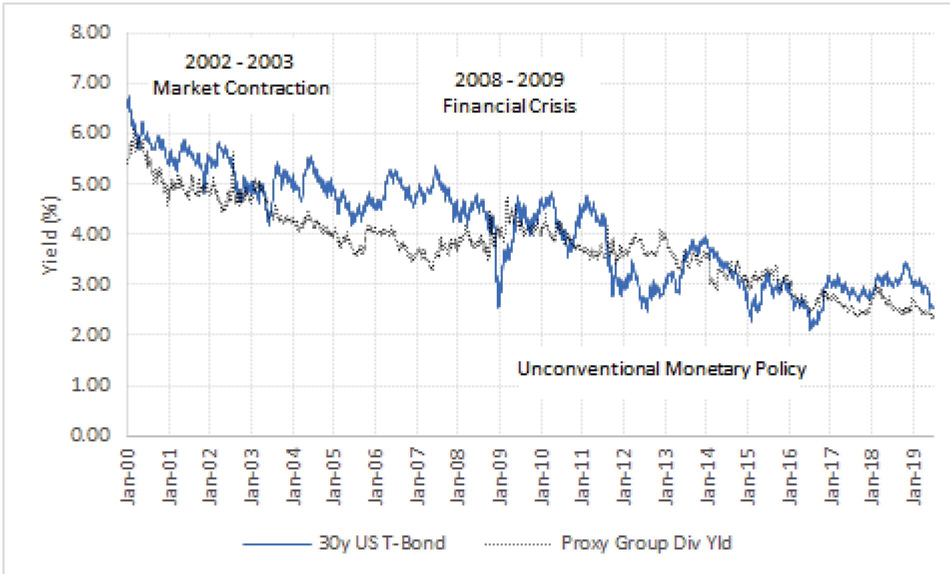
A. 73 It is important to consider whether changes in long-term interest rates reflect fundamental changes in investor sentiment, or whether they reflect potentially transitory factors. The recent, sudden decline in interest appears to be related to the increase in equity market volatility, which may be event-driven rather than a fundamental change. Because the methods used to estimate the Cost of Equity are forward-looking it is important to consider those distinctions in assessing model results.

Q. 74 Have natural gas utility dividend yields closely followed long-term Treasury yields?

A. 74 Although they have been directionally related over time, the fundamental relationship between Treasury yields and natural gas utility[64] dividend yields changed after the 2008/2009 financial crisis. From 2000 through 2008, Treasury yields generally exceeded natural gas utility dividend yields; the exception was the 2002-2003 market contraction. Then, in 2008-2009, investors sought the safety of Treasury securities, accepting lower Treasury yields in exchange for a greater likelihood of capital preservation. Once the contraction ended (in the latter half of 2009), the relationship fluctuated as the Federal Reserve implemented and maintained "unconventional" monetary policies in reaction to the financial crisis (*i.e.*, Quantitative Easing) with the intended consequence of lowering long-term interest rates (*see,* Chart 7, below). As the Federal Reserve began to "normalize" its monetary policy, the relationship was restored.

[64] Defined as the proxy group calculated as an index.

Chart 7: Utility Dividend Yields and 30-Year Treasury Yields[65]



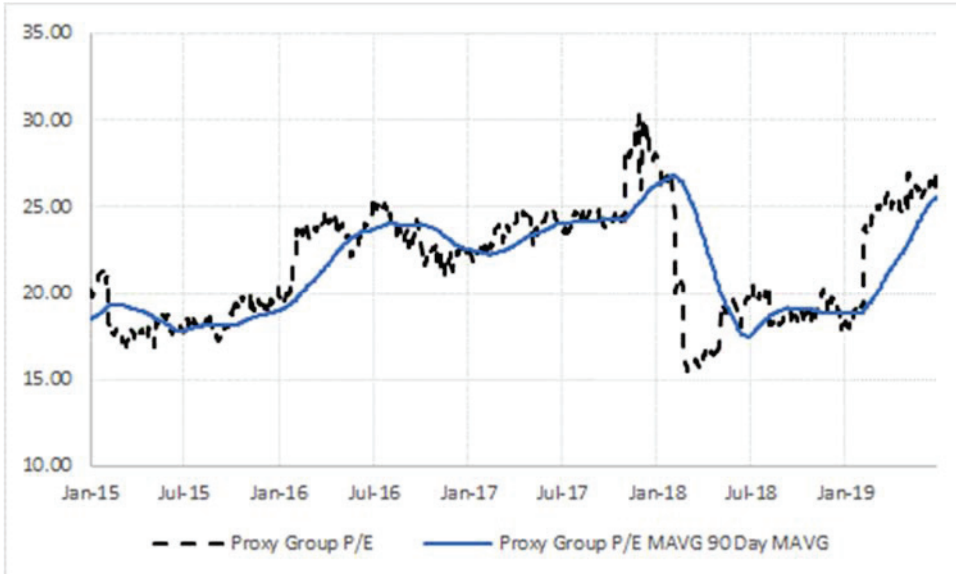
Further, as Treasury yields fell in response to central bank policies, dividend yields did not fall to the same degree (*see,* Chart 7, above). That data suggests that, although utility prices are sensitive to long-term Treasury yields, the relationship is not unbounded.

Q. 75 Is that relationship also seen in utility price/earnings ratios?

A. 75 Yes. Looking to the period following the Federal Reserve's Quantitative Easing policy, the proxy group P/E ratio has varied, often reverting once it has largely breached its 90-day moving average (*see,* Chart 8, below).

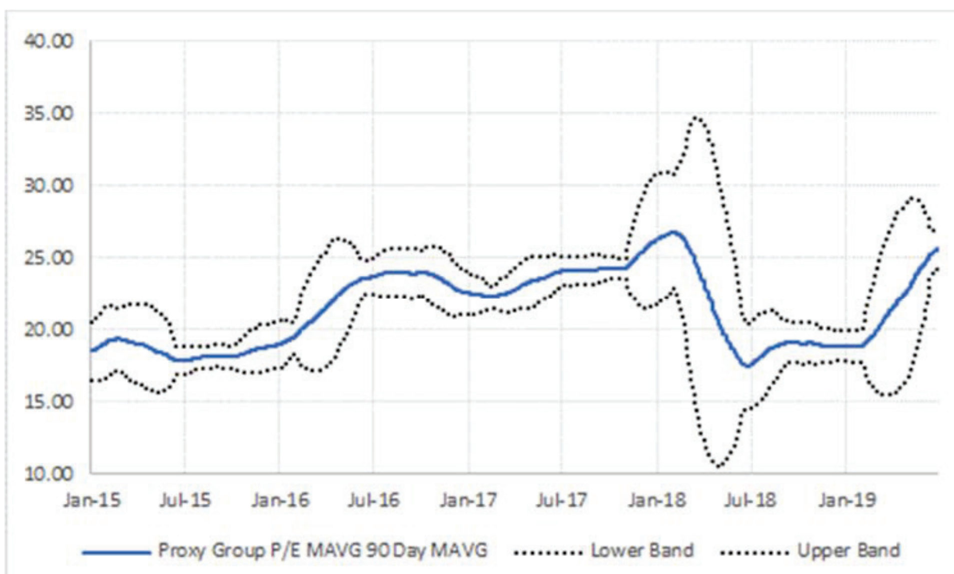
[65] Source: S&P Global Market Intelligence. Proxy Group Dividend Yield calculated as an index.

Chart 8: Proxy Group Average Price/Earnings Ratio[66]



From a somewhat different perspective, the proxy group's P/E ratio has traded within a two-standard deviation range, although that range recently has widened, indicating increasing variability in the group's valuation (*see,* Chart 9, below).

Chart 9: Proxy Group Average P/E Ratio Bands[67]



[66] Calculated as an index. Source: S&P Global Market Intelligence.

[67] Calculated as an index. Bands represent two standard deviations calculated over 90 days. Source: S&P Global Market Intelligence.

That data supports the conclusion discussed earlier, that utility stock prices are sensitive to changes in interest rates, to a degree. The "reach for yield" that sometimes occurs when interest rates fall has a limit; investors will not accept the incremental risk of capital losses when utility valuation levels become "stretched". That also may be the case when investors see interest rates reacting to market volatility that is event-driven, rather than a fundamental change in the capital market environment or investor risk tolerances. The increasing variability can be seen in Chart 9 (above), when the bands around the 90-day moving average P/E ratios widen. During those periods, the risk of capital loss increases, implying a further limit on valuation levels.

Q 76 What conclusions do you draw from your analyses of the current capital market environment, and how do those conclusions affect your ROE recommendation?

A. 76 Because certain models used to estimate the Cost of Equity require long-term assumptions, it is important to understand whether those assumptions hold. The current market environment is one in which changes in interest rates may be associated with events, more than they are a function of fundamental economic conditions. Further, utility valuations have a limit, even when investors look to them for an alternate source of income as interest rates fall.

On balance, it remains important to consider changes in market conditions, the likely causes of those changes, and how model results are affected by them. Those assessments necessarily involve the application of reasoned and experienced judgment. As discussed throughout my testimony, that judgment supports my recommended range of 10.00 percent to 10.70 percent.

VII. CONCLUSIONS AND RECOMMENDATION

Q. 77 What is your conclusion regarding the Company's Cost of Equity?

A. 77 As discussed throughout my prepared direct testimony, it is prudent and appropriate to consider multiple methods to arrive at an ROE recommendation. As discussed in Appendix A and as shown in Exhibit No.__(RBH-1) through Exhibit No.__(RBH-12), I have performed several analyses to estimate Southwest Gas' Cost of Equity. Considering those results and other relevant, observable market data, I believe an ROE in the range of 10.00 percent to 10.70 percent represents the range of returns required by equity investors under current and expected market conditions. Within that range, I conclude an ROE of 10.50 percent represents a reasonable estimate of the Cost of Equity for Southwest Gas. My recommendation reflects analytical results based on a proxy group of natural gas utilities, and takes into consideration: (1) the regulatory and political risks facing the Company; (2) the effect of Senate Bill 901 on the Company's cost recovery; (3) the Company's equity ratio relative to the proxy group; and (4) the Company's capital expenditures. In addition, I calculated the costs of issuing common stock (that is, "flotation" costs) and considered evolving capital market and business conditions.

Q. 78 Have you reviewed the authorized ROEs in place at the proxy group operating companies?

A. 78 Yes. I found the authorized ROEs in place at the proxy group operating companies to have a mean and median authorized ROE of 10.12 percent and 9.78 percent, respectively.

Q. 79 Does this conclude your prepared direct testimony?

A. 79 Yes.

VIII. APPENDIX A

A. Constant Growth Discounted Cash Flow

Q. 80 Please more fully describe the Constant Growth DCF approach.

A. 80 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:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [4]$$

where *P* represents the current stock price, $D_1 \ldots D_\infty$ 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:

$$k = \frac{D_0\ (1+g)}{P} + g \qquad [5]$$

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 annual growth rate.

Q. 81 What assumptions are inherent in the Constant Growth DCF model?

A. 81 The Constant Growth DCF model assumes: (1) earnings, book value, and dividends all grow at the same, constant rate in perpetuity; (2) a constant dividend payout ratio in perpetuity; (3) the observed P/E ratio will remain constant in perpetuity; and (4) estimated Cost of Equity will remain constant, also in perpetuity.

Q. 82 What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. 82 The dividend yield is based on each proxy company's current annualized dividend and average closing stock price over the 30-, 90-, and 180-trading day periods as of June 28, 2019, as explained more fully below.

Q. 83 Why did you use three averaging periods to calculate an average stock price?

A. 83 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. 84 Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. 84 Yes. Because utility companies tend to 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. That adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the dividends to be paid during that time.

Q. 85 Is it important to select appropriate measures of long-term growth in applying the DCF model?

A. 85 Yes. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [5] above) assumes a single growth estimate in perpetuity. Accordingly, to reduce the long-term growth rate to a single measure, one must assume a fixed payout ratio, and the same constant growth rate for earnings per share ("EPS"), dividends per share, and book value per share. Since dividend growth can only be sustained by earnings growth, the model should incorporate a variety of measures of long-term earnings growth. This can be accomplished by averaging those 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. Therefore, for the purposes of the Constant Growth DCF model, growth in EPS represents the appropriate measure of long-term growth.

Q. 86 Please summarize the findings of academic research on the appropriate measure for estimating equity returns using the DCF model.

A. 86 The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.[68] As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to

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[68] *See, for example*, Robert S. Harris, 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.[69]

Phillips' conclusion continues to hold true. 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.[70] 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."[71] Other research specifically has noted 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."[72] 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."[73] As Brigham, Shome and Vinson noted, "evidence in the current

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[69] Charles F. Phillips, Jr., The Economics of Regulation, Revised Edition, 1969, Richard D. Irwin, Inc., at 285.

[70] *See, for example*, 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.

[71] Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

[72] Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return, Financial Management, Spring 1986.

[73] *Id*.

literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data; and (ii) investors do rely on analysts' forecasts."[74]

To that point, the research of Carleton and Vander Weide found earnings growth projections had a statistically significant relationship to stock valuation levels, whereas dividend growth rates did not.[75] 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 in the Constant Growth DCF model.

Q. 87 Please summarize your inputs to the Constant Growth DCF model.

A. 87 I applied the DCF model to the proxy group of natural gas utility companies using the following inputs for the price and dividend terms:

- The average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days ended June 28, 2019, for the term P_0; and
- The annualized dividend per share as of June 28, 2019, for the term D_0.

I then calculated my DCF results using each of the following growth terms:

- The Zacks consensus long-term earnings growth estimates;
- The First Call consensus long-term earnings growth estimates;
- The Value Line long-term earnings growth estimates; and
- An estimate of retention growth.

As explained below, I calculated a median low, median, and median high DCF result for each proxy company (*see,* Exhibit No.__(RBH-1)).

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[74] 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.

[75] Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

Q. 88 What are the results of your Constant Growth DCF analysis?

A. 88 My Constant Growth DCF results are summarized in Table 7, below (*see, also,* Exhibit No.__(RBH-1)).

Table 7: Median Constant Growth DCF Results[76]

	Median Low	Median	Median High
30-Day Average	7.05%	9.06%	11.32%
90-Day Average	7.11%	9.10%	11.36%
180-Day Average	7.18%	9.17%	11.44%

B. Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Q. 89 Please briefly describe the general form of the CAPM analysis.

A. 89 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). As shown in Equation [6], the CAPM is defined by four components, each of which theoretically must be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [6]$$

where:

K_e = the required market ROE for a security;

β = the Beta coefficient of that security;

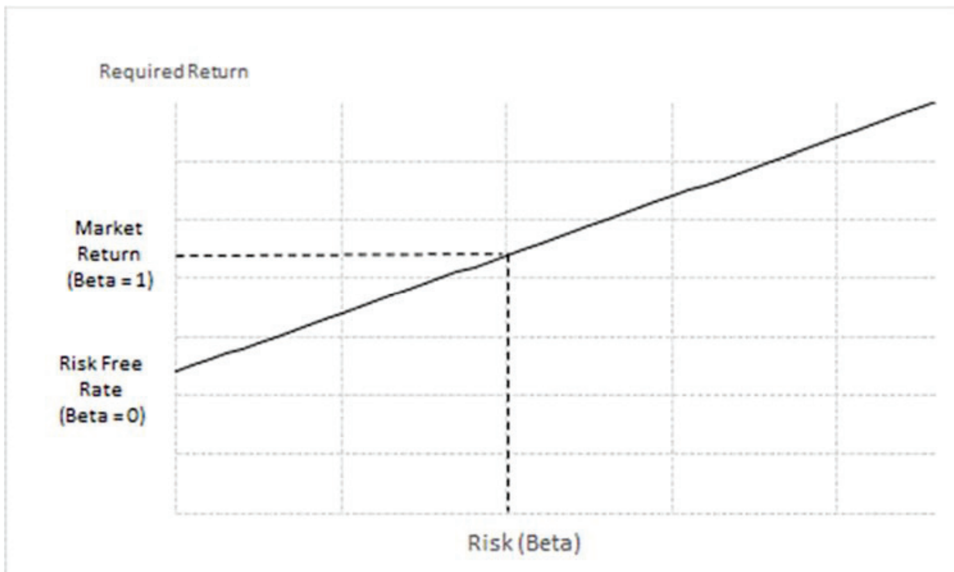
r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

[76] Exhibit No.___(RBH-1).

Equation [6] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, which is graphically depicted in Chart 10, 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. Under the CAPM, the expected Equity Risk Premium for a given security is proportional to its Beta coefficient.

Chart 10: Security Market Line



In Equation [6], the term ($r_m - r_f$) represents the Market Risk Premium.[77] According to the theory underlying the CAPM, because unsystematic risk can be diversified away by adding securities to 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:

[77] The Market Risk Premium is defined as the incremental return of the market portfolio over the risk-free rate.

$$\beta_j = \frac{\sigma_j}{\sigma_m} \times \rho_{j,m} \quad [7]$$

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.

Intuitively, companies with higher Beta coefficients have had more volatile returns, and have moved more closely with the overall market. The implication is that a company with a Beta coefficient of 1.00 is as risky as the overall market; companies with Beta coefficients less than 1.00 are less risky, and those whose Beta coefficients are greater than 1.00 have greater risk than the overall market.

Q. 90 What assumptions regarding the risk-free rate did you include in your CAPM analysis?

A. 90 Because utility assets represent long duration investments, I used two different measures of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (2.63 percent);[78] and (2) the near-term projected 30-year Treasury yield (2.70 percent).[79]

Q. 91 Why have you relied on the 30-year Treasury yield for your CAPM analysis?

A. 91 In determining the risk-free rate, it is important to select the term (or maturity) that best matches the life of the underlying investment. Natural gas utilities

[78] Bloomberg Professional.

[79] Blue Chip Financial Forecast, Vol. 38, No. 7, July 1, 2019, at 2.

typically are long-duration investments and as such, the 30-year Treasury yield is most suitable for the purpose of calculating the Cost of Equity.

Q. 92 Please describe your *ex-ante* (*i.e.*, forward-looking) approach to estimating the Market Risk Premium.

A. 92 The approach is based on the market required return, less the current 30-year Treasury 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 two sources: (1) Bloomberg and (2) Value Line. 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 S&P 500 companies for which Bloomberg provided 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. 93 How did you apply your expected Market Risk Premium and risk-free rate estimates?

A. 93 I relied on the *ex-ante* Market Risk Premia discussed above, together with the current and near-term projected 30-year Treasury yields as inputs to my CAPM analyses.

Q. 94 What Beta coefficient did you use in your CAPM model?

A. 94 As shown in Exhibit No.__(RBH-5), I considered Beta coefficients reported by two sources, Bloomberg and Value Line. Although both services adjust their calculated (or "raw") Beta coefficients to reflect the tendency to regress to the market mean of 1.00, Value Line calculates the Beta coefficient over a five-year period, whereas Bloomberg's calculation is based on two years of data.

Q. 95 What are the results of your CAPM analysis?

A. 95 As shown in Table 8, below, the CAPM analyses suggest an ROE range of 9.53 percent to 10.97 percent (*see, also*, Exhibit No.__(RBH-5)).

Table 8: Summary of CAPM Results[80]

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.63%)	9.58%	9.53%
Near Term Projected 30-Year Treasury (2.70%)	9.65%	9.60%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.63%)	10.90%	10.83%
Near Term Projected 30-Year Treasury (2.70%)	10.97%	10.90%

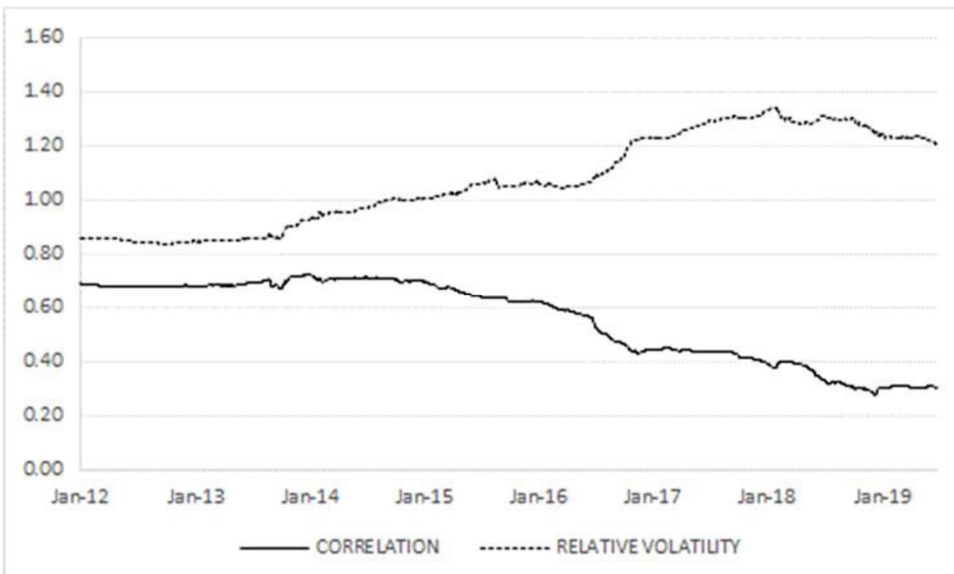
Q. 96 Does the recent decline in the proxy group average Beta coefficient imply a decrease in risk relative to the market?

A. 96 Not necessarily. Although the proxy group average Beta coefficient reported by Bloomberg has fallen from approximately 0.71 in 2014 to 0.57 in June 2019, as Chart 11, below, demonstrates, when the Beta coefficient is deconstructed into

[80] Exhibit No.___(RBH-5).

its components shown in Equation [7] above, we see that the correlation between the proxy group companies and the S&P 500 has declined, while the relative risk has increased. Given that the correlation between the proxy group companies and the S&P 500 has declined since 2014, while the relative risk has increased, the CAPM in the form presented here may not adequately reflect the expected systematic risk, and therefore, the returns required by investors for low-Beta companies such as utilities.

Chart 11: Components of Beta Coefficients Over Time[81]



Q. 97 Did you consider another form of the CAPM in your analysis?

A. 97 Yes. I also included the ECAPM approach, which calculates the product of the adjusted Beta coefficient and the Market Risk Premium, and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the Market Risk Premium, without any effect from the Beta coefficient.[82] The

[81] Calculated as an index. Source: S&P Global Market Intelligence.

[82] *See, e.g.*, Roger A. Morin, Ph.D., *New Regulatory Finance* 189-90 (2006).

results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [8] below:

$$K_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [8]$$

where*:*

K_e = the required market ROE;

β = Adjusted Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

Q. 98 What is the benefit of the ECAPM approach?

A. 98 The ECAPM addresses the tendency of the CAPM to under-estimate the Cost of Equity for companies, such as regulated utilities, with low Beta coefficients. As discussed below, the ECAPM recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM under-estimates the alpha, or the constant return term.[83]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[84] Fama and French state that "[t]he returns on the low beta portfolios are too high,

[83] *Ibid*. at 191 ("The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks.").

[84] *Ibid.* at 175. The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis.

and the returns on the high beta portfolios are too low."[85] Similarly, Dr. Roger Morin states:

> With few exceptions, the empirical studies agree that . . . low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[86]
>
> ***
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x(R_M - R_F) + (1\text{-}x)\ \beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$ [87]

Some analysts claim that using adjusted Beta coefficients addresses the empirical issues with the CAPM by increasing the expected returns for low Beta stocks and decreasing the returns for high Beta stocks, concluding that there is no need for the ECAPM approach. I disagree with that conclusion. Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. As also noted earlier, numerous studies have determined that at any given point in time, the SML described by the CAPM formula is not as steeply sloped as the predicted SML. To that point, Dr. Roger Morin states:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line

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[85] Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.
[86] Roger A. Morin, Ph.D., *New Regulatory Finance,* at 175.
[87] *Ibid*., at 190, footnote 12 (2006).

> and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary.[88]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM. As with the CAPM, my application of the ECAPM uses the Market DCF-derived *ex-ante* Market Risk Premium estimate, the current yield on 30-year Treasury securities as the risk-free rate, and two estimates of the Beta coefficient. The results of my ECAPM analyses shown on Exhibit No.__(RBH-5) and summarized in Table 9, below.

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[88] *Ibid.* at 191.

Table 9: Summary of ECAPM Results[89]

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.63%)	10.91%	10.84%
Near Term Projected 30-Year Treasury (2.70%)	10.98%	10.91%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.63%)	11.89%	11.82%
Near Term Projected 30-Year Treasury (2.70%)	11.96%	11.89%

C. Bond Yield Plus Risk Premium Approach

Q. 99 Please generally describe the Bond Yield Plus Risk Premium approach?

A. 99 This approach is based on the basic financial principle that because equity investors bear the residual risk associated with ownership, they require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders are more risky 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. As noted in my discussion of the CAPM, 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 natural gas utilities to estimate the Equity Risk Premium.

[89] Exhibit No.___(RBH-5).

Q. 100 Please explain how you performed your Bond Yield Plus Risk Premium analysis.

A. 100 As suggested above, I first defined the Risk Premium as the difference between the authorized ROE and the then-prevailing level of the long-term (*i.e.*, 30-year) Treasury yield. I then gathered data for 1,121 natural gas utility rate proceedings between January 1980 and June 28, 2019. In addition to the authorized ROE, I also calculated the average period between the filing of the case and the date of the final order (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 186 days).

Because the data cover multiple economic cycles, the analysis also may be used to assess the stability of the Equity Risk Premium. Prior research, for example, has shown that the Equity Risk Premium is inversely related to the level of interest rates. That analysis is particularly relevant given the relatively low, but increasing level of current Treasury yields.

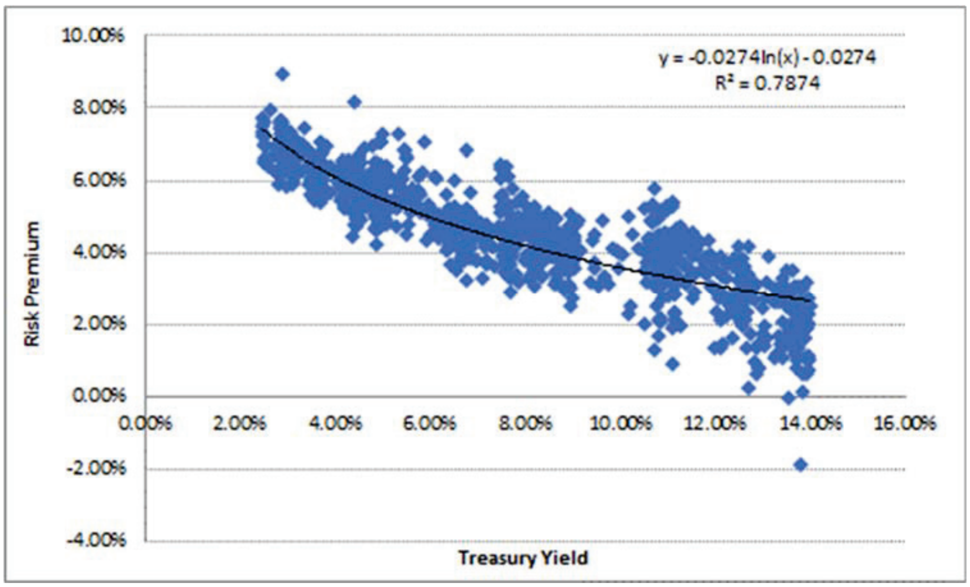
Q. 101 How did you model the relationship between interest rates and the Equity Risk Premium?

Q. 101 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:

$$RP = \alpha + \beta(LN(T_{30})) \quad [9]$$

As shown on Chart 12, 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).

Chart 12: Equity Risk Premium[90]



As Chart 12 illustrates, the Equity Risk Premium increases as interest rates fall. That finding, that there is an inverse relationship between interest rates and the Equity Risk Premium is supported by published research. For example, Dr. Roger Morin notes that: "… [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates - rising when interest rates fell and declining when interest

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[90] Exhibit No.___(RBH-6).

rates rose."[91] Consequently, simply applying the long-term average Equity Risk Premium of 4.70 percent would significantly understate the Cost of Equity and produce results well below any reasonable estimate. Based on the regression coefficients in Chart 12, however, the implied ROE is between 9.87 percent and 10.01 percent (*see,* Table 10, below, and Exhibit No.___(RBH-6)).

Table 10: Summary of Bond Yield Plus Risk Premium Results[92]

	Return on Equity
Current 30-Year Treasury (2.63%)	9.87%
Near Term Projected 30-Year Treasury (2.70%)	9.87%
Long Term Projected 30-Year Treasury (3.70%)	10.01%

D. Expected Earnings Analysis

Q. 102 Please describe the Expected Earnings analysis.

A. 102 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.

[91] Roger A: Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 128 [clarification added]

[92] Exhibit No.___(RBH-6).

Q. 103 Please explain how the Expected Earnings analysis is conducted.

A. 103 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 for the period 2022-2024, 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.[93] The results equal an average value of 10.83 percent and a median value of 10.85 percent (*see,* Exhibit No.__(RBH-7)).

[93] 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.

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

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	05/19	Southwest Gas Corporation	Docket No. G-01551A-19-0055	Return on Equity
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				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	07/19	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 17-010-FR	Response to Direct Testimony of Staff Witness Shannon Todd regarding Cost of Long Term Debt for Formula Rate Plan Rider
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				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
District of Columbia Public Service Commission				
Potomac Electric Power Company	05/19	Potomac Electric Power Company	Formal Case No. 1156	Return on Equity
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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				
Hawaiian Electric Company, Inc.	08/19	Hawaiian Electric Company, Inc.	Docket No. 2019-0085	Return on Equity
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
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				
Duke Energy Indiana, Inc.	07/19	Duke Energy Indiana, Inc.	Cause No. 45253	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Indiana Michigan Power Company	05/19	Indiana Michigan Power Company	Cause No. 45235	Return on Equity
Indiana Michigan Power Company	07/17	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
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.	06/19	Northern Utilities, Inc.	Docket No. 2019-00049	Return on Equity
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				
Washington Gas Light Company	04/19	Washington Gas Light Company	Case No. 9605	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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	06/19	Indiana Michigan Power Company	Case No. U-20359	Return on Equity
SEMCO Energy Gas Company	05/19	SEMCO Energy Gas Company	Case No. U-20479	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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				
Empire District Electric Company	08/19	Empire District Electric Company	Case No. ER-2019-0374	Return on Equity
Union Electric Company d/b/a Ameren Missouri	07/19	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2019-0335	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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				
Elizabethtown Gas Company	04/19	Elizabethtown Gas Company	Docket No. GR19040486	Return on Equity
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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				
Empire District Electric Company	03/19	Empire District Electric Company	Cause No. PUD201800133	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Otter Tail Power Company	10/08	Otter Tail Power Company	Docket No. EL08-030	Return on Equity (electric)
Texas Public Utility Commission				
AEP Texas, Inc.	05/19	AEP Texas, Inc.	Docket No. 49494	Return on Equity
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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				
Dominion Energy Utah	07/19	Dominion Energy Utah	Docket No. 19-057-02	Return on Equity
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

Matter of Arbitration, City of White Hall, Arkansas				
Liberty Utilities Corporation, White Hall Water and White Hall Sewer	04/19	Liberty Utilities Corporation, White Hall Water and White Hall Sewer	AAA Case No. 01-18-0004-0072	Return on Equity
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	$103.85	2.02%	2.10%	6.50%	6.45%	7.50%	10.20%	7.66%	8.54%	9.76%	12.32%
New Jersey Resources Corporation	NJR	$1.17	$49.18	2.38%	2.45%	7.00%	6.00%	3.50%	5.84%	5.59%	5.92%	8.03%	9.46%
Northwest Natural Holding Company	NWN	$1.90	$68.91	2.76%	2.90%	4.50%	4.00%	27.00%	6.66%	10.54%	6.81%	13.44%	30.13%
ONE Gas, Inc.	OGS	$2.00	$89.61	2.23%	2.30%	5.90%	5.00%	8.00%	5.32%	6.06%	7.29%	8.36%	10.32%
South Jersey Industries, Inc.	SJI	$1.15	$32.77	3.51%	3.64%	7.20%	5.50%	10.50%	6.12%	7.33%	9.11%	10.97%	14.19%
Spire Inc.	SR	$2.37	$84.59	2.80%	2.87%	4.90%	3.43%	5.50%	5.18%	4.75%	6.28%	7.62%	8.38%
Proxy Group Mean				2.62%	2.71%	6.00%	5.06%	10.33%	6.55%	6.99%	7.32%	9.70%	14.13%
Proxy Group Median				2.57%	2.66%	6.20%	5.25%	7.75%	5.98%	6.69%	7.05%	9.06%	11.32%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of June 28, 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 No.___(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	$101.92	2.06%	2.14%	6.50%	6.45%	7.50%	10.20%	7.66%	8.58%	9.80%	12.36%
New Jersey Resources Corporation	NJR	$1.17	$49.29	2.37%	2.44%	7.00%	6.00%	3.50%	5.84%	5.59%	5.92%	8.03%	9.46%
Northwest Natural Holding Company	NWN	$1.90	$66.83	2.84%	2.99%	4.50%	4.00%	27.00%	6.66%	10.54%	6.90%	13.53%	30.23%
ONE Gas, Inc.	OGS	$2.00	$88.32	2.26%	2.33%	5.90%	5.00%	8.00%	5.32%	6.06%	7.32%	8.39%	10.36%
South Jersey Industries, Inc.	SJI	$1.15	$31.94	3.60%	3.73%	7.20%	5.50%	10.50%	6.12%	7.33%	9.20%	11.06%	14.29%
Spire Inc.	SR	$2.37	$82.68	2.87%	2.93%	4.90%	3.43%	5.50%	5.18%	4.75%	6.35%	7.69%	8.45%
Proxy Group Mean				2.67%	2.76%	6.00%	5.06%	10.33%	6.55%	6.99%	7.38%	9.75%	14.19%
Proxy Group Median				2.61%	2.69%	6.20%	5.25%	7.75%	5.98%	6.69%	7.11%	9.10%	11.36%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of June 28, 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 No.___(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

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Retention Growth Estimate	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	$2.10	$98.65	2.13%	2.21%	6.50%	6.45%	7.50%	10.20%	7.66%	8.65%	9.87%	12.44%
New Jersey Resources Corporation	NJR	$1.17	$48.09	2.43%	2.50%	7.00%	6.00%	3.50%	5.84%	5.59%	5.98%	8.09%	9.52%
Northwest Natural Gas Company	NWN	$1.90	$65.65	2.89%	3.05%	4.50%	4.00%	27.00%	6.66%	10.54%	6.95%	13.59%	30.28%
ONE Gas, Inc.	OGS	$2.00	$85.11	2.35%	2.42%	5.90%	5.00%	8.00%	5.32%	6.06%	7.41%	8.48%	10.44%
South Jersey Industries, Inc.	SJI	$1.15	$31.28	3.68%	3.81%	7.20%	5.50%	10.50%	6.12%	7.33%	9.28%	11.14%	14.37%
Spire Inc.	SR	$2.37	$79.37	2.99%	3.06%	4.90%	3.43%	5.50%	5.18%	4.75%	6.47%	7.81%	8.57%
Proxy Group Mean				2.74%	2.84%	6.00%	5.06%	10.33%	6.55%	6.99%	7.45%	9.83%	14.27%
Proxy Group Median				2.66%	2.77%	6.20%	5.25%	7.75%	5.98%	6.69%	7.18%	9.17%	11.44%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of June 28, 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 No.___(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 2020	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%	125.00	145.00	5.02%	$ 104.10	$ 89.20	$ 96.65	48.30	2.00	10.04%	50.03%	5.02%	10.20%
New Jersey Resources Corporatior	NJR	2.50	1.33	46.80%	21.85	11.44%	5.35%	88.25	89.00	0.28%	$ 51.00	$ 43.90	$ 47.45	17.25	2.75	0.77%	63.65%	0.49%	5.84%
Northwest Natural Holding Company	NWN	3.50	2.20	37.14%	29.40	11.90%	4.42%	30.50	32.00	1.60%	$ 70.20	$ 57.20	$ 63.70	26.55	2.40	3.83%	58.32%	2.23%	6.66%
ONE Gas, Inc.	OGS	4.75	2.65	44.21%	47.90	9.92%	4.38%	53.50	55.00	0.92%	$ 90.50	$ 75.80	$ 83.15	41.05	2.03	1.86%	50.63%	0.94%	5.32%
South Jersey Industries, Inc.	SJI	2.40	1.40	41.67%	20.00	12.00%	5.00%	96.00	100.00	1.36%	$ 33.70	$ 26.60	$ 30.15	16.50	1.83	2.48%	45.27%	1.12%	6.12%
Spire Inc.	SR	5.00	2.67	46.60%	52.75	9.48%	4.42%	53.00	55.00	1.23%	$ 87.10	$ 71.70	$ 79.40	49.00	1.62	1.99%	38.29%	0.76%	5.18%
																		Average	6.55%

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]) ^ 0.33 - 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] S&P 500 Est. Required Market Return	[2] Current 30-Year Treasury (30-day average)	[3] Implied Market Risk Premium
14.88%	2.63%	12.25%

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	23,595.22	0.09%	0.88%	11.00%	11.93%	0.0109%
American Airlines Group Inc	AAL	14,506.07	0.06%	1.48%	14.51%	16.09%	0.0090%
Advance Auto Parts Inc	AAP	11,057.52	0.04%	0.16%	15.68%	15.85%	0.0068%
Apple Inc	AAPL	910,644.76	3.53%	1.51%	9.35%	10.93%	0.3855%
AbbVie Inc	ABBV	107,506.72	0.42%	5.84%	5.12%	11.11%	0.0463%
AmerisourceBergen Corp	ABC	17,919.69	0.07%	1.88%	4.99%	6.92%	0.0048%
ABIOMED Inc	ABMD	11,795.82	0.05%	0.00%	29.00%	29.00%	0.0133%
Abbott Laboratories	ABT	148,367.64	0.57%	1.46%	9.70%	11.23%	0.0645%
Accenture PLC	ACN	124,342.68	0.48%	1.60%	10.43%	12.12%	0.0584%
Adobe Inc	ADBE	143,034.53	0.55%	0.00%	17.16%	17.16%	0.0951%
Analog Devices Inc	ADI	41,734.95	0.16%	1.84%	12.10%	14.06%	0.0227%
Archer-Daniels-Midland Co	ADM	22,854.74	0.09%	3.47%	0.60%	4.08%	0.0036%
Automatic Data Processing Inc	ADP	71,956.28	0.28%	1.74%	13.50%	15.36%	0.0428%
Alliance Data Systems Corp	ADS	7,340.50	0.03%	1.76%	12.47%	14.34%	0.0041%
Autodesk Inc	ADSK	35,776.03	0.14%	0.00%	64.51%	64.51%	0.0894%
Ameren Corp	AEE	18,433.42	0.07%	2.59%	5.81%	8.48%	0.0061%
American Electric Power Co Inc	AEP	43,427.26	0.17%	3.08%	5.98%	9.15%	0.0154%
AES Corp/VA	AES	11,124.07	0.04%	3.29%	8.33%	11.76%	0.0051%
Aflac Inc	AFL	40,859.16	0.16%	1.99%	3.43%	5.45%	0.0086%
Allergan PLC	AGN	54,883.87	0.21%	1.77%	5.37%	7.18%	0.0153%
American International Group Inc	AIG	46,340.47	0.18%	2.44%	11.00%	13.57%	0.0244%
Apartment Investment & Management Co	AIV	7,459.28	0.03%	4.15%	8.76%	13.09%	0.0038%
Assurant Inc	AIZ	6,539.68	N/A	2.33%	N/A	N/A	N/A
Arthur J Gallagher & Co	AJG	16,226.22	0.06%	1.96%	9.63%	11.68%	0.0073%
Akamai Technologies Inc	AKAM	13,150.73	0.05%	0.00%	13.70%	13.70%	0.0070%
Albemarle Corp	ALB	7,460.41	0.03%	2.01%	13.41%	15.56%	0.0045%
Align Technology Inc	ALGN	21,897.34	0.08%	0.00%	22.22%	22.22%	0.0188%
Alaska Air Group Inc	ALK	7,886.49	0.03%	2.15%	13.20%	15.49%	0.0047%
Allstate Corp/The	ALL	33,873.63	0.13%	1.90%	9.00%	10.99%	0.0144%
Allegion PLC	ALLE	10,385.70	0.04%	0.96%	10.49%	11.50%	0.0046%
Alexion Pharmaceuticals Inc	ALXN	29,370.59	0.11%	0.00%	17.50%	17.50%	0.0199%
Applied Materials Inc	AMAT	42,040.47	0.16%	1.85%	9.37%	11.30%	0.0184%
Amcor PLC	AMCR	18,654.36	0.07%	4.05%	5.38%	9.54%	0.0069%
Advanced Micro Devices Inc	AMD	32,848.21	0.13%	0.00%	18.30%	18.30%	0.0233%
AMETEK Inc	AME	20,697.07	0.08%	0.63%	9.13%	9.79%	0.0078%
Affiliated Managers Group Inc	AMG	4,717.51	0.02%	1.39%	9.10%	10.55%	0.0019%
Amgen Inc	AMGN	112,398.95	0.44%	3.10%	5.70%	8.89%	0.0387%
Ameriprise Financial Inc	AMP	19,437.55	0.08%	2.62%	3.20%	5.86%	0.0044%
American Tower Corp	AMT	90,371.69	0.35%	1.83%	20.09%	22.11%	0.0774%
Amazon.com Inc	AMZN	932,294.22	3.61%	0.00%	44.95%	44.95%	1.6232%
Arista Networks Inc	ANET	19,892.74	0.08%	0.00%	21.79%	21.79%	0.0168%
ANSYS Inc	ANSS	17,190.22	0.07%	0.00%	10.60%	10.60%	0.0071%
Anthem Inc	ANTM	72,583.20	0.28%	1.14%	14.85%	16.07%	0.0452%
Aon PLC	AON	46,415.87	0.18%	0.89%	10.00%	10.94%	0.0197%
AO Smith Corp	AOS	7,884.99	0.03%	1.93%	8.00%	10.01%	0.0031%
Apache Corp	APA	10,890.42	0.04%	3.45%	-17.05%	-13.89%	-0.0059%
Anadarko Petroleum Corp	APC	35,429.50	0.14%	1.51%	16.91%	18.54%	0.0254%
Air Products & Chemicals Inc	APD	49,831.41	0.19%	2.02%	12.48%	14.63%	0.0282%
Amphenol Corp	APH	28,660.37	0.11%	0.93%	9.98%	10.96%	0.0122%
Aptiv PLC	APTV	20,840.83	0.08%	1.12%	8.89%	10.06%	0.0081%
Alexandria Real Estate Equities Inc	ARE	16,644.25	0.06%	2.79%	4.76%	7.61%	0.0049%
Arconic Inc	ARNC	11,583.60	0.04%	0.41%	9.90%	10.33%	0.0046%
Atmos Energy Corp	ATO	12,349.28	0.05%	1.99%	7.00%	9.06%	0.0043%
Activision Blizzard Inc	ATVI	36,155.52	0.14%	0.78%	10.45%	11.27%	0.0158%
AvalonBay Communities Inc	AVB	28,323.96	0.11%	2.98%	5.42%	8.47%	0.0093%
Broadcom Inc	AVGO	114,589.46	0.44%	3.68%	13.31%	17.23%	0.0765%
Avery Dennison Corp	AVY	9,765.23	0.04%	1.81%	5.55%	7.41%	0.0028%
American Water Works Co Inc	AWK	20,940.18	0.08%	1.70%	9.00%	10.77%	0.0087%
American Express Co	AXP	103,082.34	0.40%	1.31%	12.40%	13.78%	0.0550%
AutoZone Inc	AZO	26,968.58	0.10%	0.00%	12.58%	12.58%	0.0131%
Boeing Co/The	BA	204,803.10	0.79%	2.22%	12.26%	14.61%	0.1159%
Bank of America Corp	BAC	275,737.89	1.07%	2.35%	10.10%	12.57%	0.1343%
Baxter International Inc	BAX	41,860.51	0.16%	0.97%	11.90%	12.93%	0.0210%
BB&T Corp	BBT	37,632.72	0.15%	3.45%	8.48%	12.08%	0.0176%
Best Buy Co Inc	BBY	18,620.92	0.07%	2.87%	6.89%	9.85%	0.0071%
Becton Dickinson and Co	BDX	67,975.14	0.26%	1.28%	11.35%	12.71%	0.0335%
Franklin Resources Inc	BEN	17,663.08	0.07%	2.98%	10.00%	13.13%	0.0090%

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
Brown-Forman Corp	BF/B	26,396.71	0.10%	1.25%	8.41%	9.71%	0.0099%
Baker Hughes a GE Co	BHGE	25,543.81	0.10%	2.67%	41.88%	45.10%	0.0446%
Biogen Inc	BIIB	45,345.85	0.18%	0.00%	5.87%	5.87%	0.0103%
Bank of New York Mellon Corp/The	BK	42,274.39	0.16%	2.70%	6.77%	9.56%	0.0156%
Booking Holdings Inc	BKNG	81,158.72	0.31%	0.00%	16.99%	16.99%	0.0534%
BlackRock Inc	BLK	72,970.71	0.28%	2.84%	9.00%	11.96%	0.0338%
Ball Corp	BLL	23,428.83	0.09%	0.71%	6.77%	7.51%	0.0068%
Bristol-Myers Squibb Co	BMY	74,180.11	0.29%	3.63%	8.63%	12.42%	0.0357%
Broadridge Financial Solutions Inc	BR	14,828.62	N/A	1.51%	N/A	N/A	N/A
Berkshire Hathaway Inc	BRK/B	521,871.81	2.02%	0.00%	60.60%	60.60%	1.2250%
Boston Scientific Corp	BSX	59,770.24	0.23%	0.00%	8.88%	8.88%	0.0206%
BorgWarner Inc	BWA	8,701.05	0.03%	1.62%	4.37%	6.02%	0.0020%
Boston Properties Inc	BXP	19,933.06	0.08%	3.00%	4.91%	7.97%	0.0062%
Citigroup Inc	C	161,942.11	0.63%	2.80%	12.72%	15.69%	0.0984%
Conagra Brands Inc	CAG	12,886.46	0.05%	3.21%	7.17%	10.49%	0.0052%
Cardinal Health Inc	CAH	14,038.62	0.05%	4.16%	14.02%	18.47%	0.0100%
Caterpillar Inc	CAT	77,940.92	0.30%	2.65%	13.23%	16.05%	0.0485%
Chubb Ltd	CB	67,439.78	0.26%	2.06%	10.60%	12.77%	0.0333%
Cboe Global Markets Inc	CBOE	11,568.53	0.04%	1.26%	5.35%	6.64%	0.0030%
CBRE Group Inc	CBRE	17,251.04	0.07%	0.00%	7.30%	7.30%	0.0049%
CBS Corp	CBS	18,706.34	0.07%	1.53%	20.13%	21.81%	0.0158%
Crown Castle International Corp	CCI	54,191.87	0.21%	3.52%	16.33%	20.14%	0.0423%
Carnival Corp	CCL	31,749.45	0.12%	4.34%	8.47%	12.99%	0.0160%
Cadence Design Systems Inc	CDNS	19,899.73	0.08%	0.00%	10.03%	10.03%	0.0077%
Celanese Corp	CE	13,648.83	0.05%	2.24%	7.95%	10.28%	0.0054%
Celgene Corp	CELG	65,194.19	0.25%	0.00%	18.42%	18.42%	0.0465%
Cerner Corp	CERN	23,853.33	0.09%	0.33%	13.65%	14.00%	0.0129%
CF Industries Holdings Inc	CF	10,326.54	0.04%	2.58%	20.27%	23.11%	0.0092%
Citizens Financial Group Inc	CFG	16,207.45	0.06%	3.77%	8.04%	11.96%	0.0075%
Church & Dwight Co Inc	CHD	17,988.77	0.07%	1.26%	7.96%	9.27%	0.0065%
CH Robinson Worldwide Inc	CHRW	11,519.05	0.04%	2.40%	8.93%	11.44%	0.0051%
Charter Communications Inc	CHTR	98,485.91	0.38%	0.00%	44.24%	44.24%	0.1688%
Cigna Corp	CI	59,817.37	0.23%	0.06%	12.74%	12.81%	0.0297%
Cincinnati Financial Corp	CINF	16,922.04	N/A	2.31%	N/A	N/A	N/A
Colgate-Palmolive Co	CL	61,529.76	0.24%	2.40%	4.08%	6.53%	0.0156%
Clorox Co/The	CLX	19,501.29	0.08%	2.52%	4.43%	7.00%	0.0053%
Comerica Inc	CMA	11,198.24	0.04%	3.79%	12.60%	16.62%	0.0072%
Comcast Corp	CMCSA	191,900.08	0.74%	1.97%	11.42%	13.50%	0.1003%
CME Group Inc	CME	69,486.54	0.27%	2.74%	7.90%	10.75%	0.0289%
Chipotle Mexican Grill Inc	CMG	20,310.71	0.08%	0.00%	20.24%	20.24%	0.0159%
Cummins Inc	CMI	26,984.73	0.10%	2.72%	7.15%	9.96%	0.0104%
CMS Energy Corp	CMS	16,432.19	0.06%	2.64%	7.32%	10.06%	0.0064%
Centene Corp	CNC	21,676.96	0.08%	0.00%	13.90%	13.90%	0.0117%
CenterPoint Energy Inc	CNP	14,356.24	0.06%	4.07%	5.92%	10.11%	0.0056%
Capital One Financial Corp	COF	42,611.19	0.17%	1.79%	5.20%	7.04%	0.0116%
Cabot Oil & Gas Corp	COG	9,718.65	0.04%	1.46%	35.02%	36.74%	0.0138%
Cooper Cos Inc/The	COO	16,671.93	0.06%	0.02%	6.18%	6.20%	0.0040%
ConocoPhillips	COP	68,940.73	0.27%	2.04%	5.00%	7.09%	0.0189%
Costco Wholesale Corp	COST	116,218.69	0.45%	0.91%	10.51%	11.47%	0.0516%
Coty Inc	COTY	10,068.73	0.04%	3.69%	8.05%	11.89%	0.0046%
Campbell Soup Co	CPB	12,067.08	0.05%	3.51%	2.74%	6.31%	0.0029%
Capri Holdings Ltd	CPRI	5,234.57	0.02%	0.00%	7.32%	7.32%	0.0015%
Copart Inc	CPRT	17,123.90	0.07%	0.00%	20.00%	20.00%	0.0133%
salesforce.com Inc	CRM	117,557.86	0.46%	0.00%	23.01%	23.01%	0.1048%
Cisco Systems Inc	CSCO	234,284.52	0.91%	2.49%	6.96%	9.54%	0.0866%
CSX Corp	CSX	62,604.99	0.24%	1.21%	11.15%	12.42%	0.0301%
Cintas Corp	CTAS	24,813.62	0.10%	0.86%	12.02%	12.94%	0.0124%
CenturyLink Inc	CTL	12,822.09	0.05%	8.50%	1.78%	10.36%	0.0051%
Cognizant Technology Solutions Corp	CTSH	36,086.85	0.14%	1.27%	11.05%	12.39%	0.0173%
Corteva Inc	CTVA	22,142.46	N/A	1.65%	N/A	N/A	N/A
Citrix Systems Inc	CTXS	12,920.31	0.05%	1.43%	37.42%	39.11%	0.0196%
CVS Health Corp	CVS	70,787.53	0.27%	3.65%	6.04%	9.81%	0.0269%
Chevron Corp	CVX	237,025.56	0.92%	3.81%	1.32%	5.15%	0.0473%
Concho Resources Inc	CXO	20,697.29	0.08%	0.40%	11.70%	12.13%	0.0097%
Dominion Energy Inc	D	62,038.81	0.24%	4.73%	4.89%	9.74%	0.0234%
Delta Air Lines Inc	DAL	37,151.18	0.14%	2.60%	12.72%	15.48%	0.0223%
DuPont de Nemours Inc	DD	56,212.11	0.22%	1.36%	65.59%	67.39%	0.1467%
Deere & Co	DE	52,529.33	0.20%	1.83%	9.45%	11.37%	0.0231%
Discover Financial Services	DFS	25,118.12	0.10%	2.12%	7.79%	10.00%	0.0097%
Dollar General Corp	DG	34,914.91	0.14%	0.95%	10.60%	11.59%	0.0157%
Quest Diagnostics Inc	DGX	13,680.73	0.05%	2.06%	7.13%	9.27%	0.0049%
DR Horton Inc	DHI	16,095.12	0.06%	1.39%	12.47%	13.95%	0.0087%
Danaher Corp	DHR	102,321.24	0.40%	0.47%	8.44%	8.93%	0.0354%
Walt Disney Co/The	DIS	251,309.96	0.97%	1.27%	2.08%	3.36%	0.0327%
Discovery Inc	DISCA	21,138.39	0.08%	0.00%	13.35%	13.35%	0.0109%
DISH Network Corp	DISH	18,020.72	0.07%	0.00%	-21.96%	-21.96%	-0.0153%
Digital Realty Trust Inc	DLR	25,649.53	0.10%	3.66%	7.30%	11.09%	0.0110%
Dollar Tree Inc	DLTR	25,513.61	0.10%	0.00%	8.52%	8.52%	0.0084%

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
Dover Corp	DOV	14,562.01	0.06%	1.99%	11.50%	13.60%	0.0077%
Dow Inc	DOW	36,924.52	0.14%	5.68%	7.15%	13.03%	0.0186%
Duke Realty Corp	DRE	11,361.52	0.04%	2.76%	4.62%	7.45%	0.0033%
Darden Restaurants Inc	DRI	14,969.84	0.06%	2.90%	10.75%	13.80%	0.0080%
DTE Energy Co	DTE	23,429.21	0.09%	2.98%	7.43%	10.52%	0.0095%
Duke Energy Corp	DUK	64,238.72	0.25%	4.29%	5.03%	9.43%	0.0235%
DaVita Inc	DVA	9,361.66	0.04%	0.00%	18.83%	18.83%	0.0068%
Devon Energy Corp	DVN	11,841.50	0.05%	1.19%	5.34%	6.56%	0.0030%
DXC Technology Co	DXC	14,813.14	0.06%	1.48%	5.28%	6.80%	0.0039%
Electronic Arts Inc	EA	30,009.29	0.12%	0.00%	13.20%	13.20%	0.0153%
eBay Inc	EBAY	34,425.33	0.13%	1.42%	10.66%	12.15%	0.0162%
Ecolab Inc	ECL	56,910.53	0.22%	0.94%	13.13%	14.13%	0.0312%
Consolidated Edison Inc	ED	29,188.83	0.11%	3.37%	4.18%	7.62%	0.0086%
Equifax Inc	EFX	16,340.24	0.06%	1.16%	11.63%	12.86%	0.0081%
Edison International	EIX	21,962.93	0.09%	3.64%	5.52%	9.26%	0.0079%
Estee Lauder Cos Inc/The	EL	66,262.49	0.26%	0.90%	11.84%	12.80%	0.0328%
Eastman Chemical Co	EMN	10,801.71	0.04%	3.15%	6.50%	9.75%	0.0041%
Emerson Electric Co	EMR	41,034.57	0.16%	2.94%	8.84%	11.91%	0.0189%
EOG Resources Inc	EOG	54,063.04	0.21%	1.02%	7.79%	8.85%	0.0185%
Equinix Inc	EQIX	42,395.68	0.16%	1.95%	18.37%	20.50%	0.0337%
Equity Residential	EQR	28,131.07	0.11%	2.98%	6.73%	9.80%	0.0107%
Eversource Energy	ES	24,503.90	0.09%	2.83%	5.94%	8.85%	0.0084%
Essex Property Trust Inc	ESS	19,184.63	0.07%	2.67%	5.26%	8.00%	0.0059%
E*TRADE Financial Corp	ETFC	10,912.31	0.04%	1.10%	12.73%	13.90%	0.0059%
Eaton Corp PLC	ETN	35,235.77	0.14%	3.42%	8.95%	12.52%	0.0171%
Entergy Corp	ETR	19,549.13	0.08%	3.58%	0.38%	3.96%	0.0030%
Evergy Inc	EVRG	14,682.52	0.06%	3.19%	8.85%	12.18%	0.0069%
Edwards Lifesciences Corp	EW	38,518.59	0.15%	0.00%	14.75%	14.75%	0.0220%
Exelon Corp	EXC	46,499.51	0.18%	3.02%	2.35%	5.41%	0.0097%
Expeditors International of Washington I	EXPD	13,047.61	0.05%	1.27%	9.80%	11.14%	0.0056%
Expedia Group Inc	EXPE	19,808.50	0.08%	0.95%	21.84%	22.90%	0.0176%
Extra Space Storage Inc	EXR	13,522.83	0.05%	3.34%	5.43%	8.86%	0.0046%
Ford Motor Co	F	40,813.05	0.16%	5.87%	-4.77%	0.96%	0.0015%
Diamondback Energy Inc	FANG	17,944.33	0.07%	0.61%	14.55%	15.20%	0.0106%
Fastenal Co	FAST	18,662.00	0.07%	2.94%	7.55%	10.60%	0.0077%
Facebook Inc	FB	550,957.10	2.13%	0.00%	19.22%	19.22%	0.4101%
Fortune Brands Home & Security Inc	FBHS	7,991.39	0.03%	1.53%	9.47%	11.07%	0.0034%
Freeport-McMoRan Inc	FCX	16,841.87	0.07%	1.72%	-7.91%	-6.26%	-0.0041%
FedEx Corp	FDX	42,783.75	0.17%	1.63%	14.40%	16.15%	0.0268%
FirstEnergy Corp	FE	22,751.05	0.09%	3.56%	3.80%	7.42%	0.0065%
F5 Networks Inc	FFIV	8,693.42	0.03%	0.00%	9.95%	9.95%	0.0034%
Fidelity National Information Services I	FIS	39,728.44	0.15%	1.14%	10.92%	12.12%	0.0186%
Fiserv Inc	FISV	35,774.82	0.14%	0.00%	13.00%	13.00%	0.0180%
Fifth Third Bancorp	FITB	20,489.37	0.08%	3.45%	3.95%	7.47%	0.0059%
Foot Locker Inc	FL	4,598.67	0.02%	3.61%	6.55%	10.28%	0.0018%
FLIR Systems Inc	FLIR	7,326.28	N/A	1.26%	N/A	N/A	N/A
Flowserve Corp	FLS	6,909.68	0.03%	1.48%	19.15%	20.77%	0.0056%
FleetCor Technologies Inc	FLT	24,207.42	0.09%	0.00%	19.67%	19.67%	0.0184%
FMC Corp	FMC	10,921.01	0.04%	1.82%	9.33%	11.23%	0.0048%
Fox Corp	FOXA	22,706.76	0.09%	0.22%	1.67%	1.89%	0.0017%
First Republic Bank/CA	FRC	16,273.49	0.06%	0.77%	12.14%	12.95%	0.0082%
Federal Realty Investment Trust	FRT	9,644.90	0.04%	3.23%	5.61%	8.94%	0.0033%
TechnipFMC PLC	FTI	11,622.76	0.05%	2.00%	17.52%	19.69%	0.0089%
Fortinet Inc	FTNT	13,119.54	0.05%	0.00%	24.04%	24.04%	0.0122%
Fortive Corp	FTV	27,317.30	0.11%	0.38%	11.52%	11.92%	0.0126%
General Dynamics Corp	GD	52,522.71	0.20%	2.20%	8.76%	11.05%	0.0225%
General Electric Co	GE	91,568.48	0.35%	0.38%	8.87%	9.26%	0.0329%
Gilead Sciences Inc	GILD	85,906.23	0.33%	3.71%	8.62%	12.49%	0.0416%
General Mills Inc	GIS	31,614.92	0.12%	3.79%	5.53%	9.42%	0.0115%
Corning Inc	GLW	26,077.38	0.10%	2.43%	11.04%	13.60%	0.0137%
General Motors Co	GM	54,650.68	0.21%	3.99%	11.70%	15.92%	0.0337%
Alphabet Inc	GOOGL	751,025.00	2.91%	0.00%	12.45%	12.45%	0.3622%
Genuine Parts Co	GPC	15,129.30	0.06%	2.95%	5.84%	8.87%	0.0052%
Global Payments Inc	GPN	25,090.58	0.10%	0.02%	16.73%	16.76%	0.0163%
Gap Inc/The	GPS	6,792.15	0.03%	5.44%	5.24%	10.82%	0.0028%
Garmin Ltd	GRMN	15,149.80	0.06%	2.91%	7.00%	10.01%	0.0059%
Goldman Sachs Group Inc/The	GS	77,838.06	0.30%	1.67%	1.14%	2.81%	0.0085%
WW Grainger Inc	GWW	14,871.63	0.06%	2.09%	12.47%	14.68%	0.0085%
Halliburton Co	HAL	19,874.27	0.08%	3.20%	8.84%	12.19%	0.0094%
Hasbro Inc	HAS	13,300.26	0.05%	2.57%	9.47%	12.16%	0.0063%
Huntington Bancshares Inc/OH	HBAN	14,461.80	0.06%	4.23%	8.24%	12.64%	0.0071%
Hanesbrands Inc	HBI	6,224.53	0.02%	3.62%	3.25%	6.93%	0.0017%
HCA Healthcare Inc	HCA	46,269.69	0.18%	0.91%	11.62%	12.59%	0.0226%
HCP Inc	HCP	15,285.90	0.06%	4.63%	2.68%	7.37%	0.0044%
Home Depot Inc/The	HD	228,826.50	0.89%	2.60%	9.37%	12.10%	0.1072%
Hess Corp	HES	19,289.60	0.07%	1.66%	-23.46%	-21.99%	-0.0164%
HollyFrontier Corp	HFC	7,903.02	0.03%	2.89%	1.05%	3.96%	0.0012%
Hartford Financial Services Group Inc/Th	HIG	20,142.73	0.08%	2.23%	9.50%	11.83%	0.0092%

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
Huntington Ingalls Industries Inc	HII	9,338.45	0.04%	1.53%	40.00%	41.84%	0.0151%
Hilton Worldwide Holdings Inc	HLT	28,448.46	0.11%	0.62%	13.10%	13.76%	0.0152%
Harley-Davidson Inc	HOG	5,699.58	0.02%	4.31%	8.60%	13.10%	0.0029%
Hologic Inc	HOLX	12,871.77	0.05%	0.00%	8.39%	8.39%	0.0042%
Honeywell International Inc	HON	127,056.48	0.49%	1.90%	8.18%	10.16%	0.0500%
Helmerich & Payne Inc	HP	5,538.57	0.02%	5.63%	25.62%	31.97%	0.0069%
Hewlett Packard Enterprise Co	HPE	20,020.27	0.08%	3.06%	5.79%	8.94%	0.0069%
HP Inc	HPQ	31,315.81	0.12%	3.05%	3.11%	6.21%	0.0075%
H&R Block Inc	HRB	5,917.44	0.02%	3.47%	10.00%	13.64%	0.0031%
Hormel Foods Corp	HRL	21,642.06	0.08%	2.07%	5.70%	7.83%	0.0066%
Harris Corp	HRS	22,341.09	N/A	1.45%	N/A	N/A	N/A
Henry Schein Inc	HSIC	10,420.31	0.04%	0.00%	3.25%	3.25%	0.0013%
Host Hotels & Resorts Inc	HST	13,499.08	0.05%	4.62%	15.05%	20.01%	0.0105%
Hershey Co/The	HSY	27,985.40	0.11%	2.24%	7.07%	9.38%	0.0102%
Humana Inc	HUM	35,824.79	0.14%	0.79%	13.47%	14.31%	0.0199%
International Business Machines Corp	IBM	122,268.05	0.47%	4.69%	1.92%	6.65%	0.0315%
Intercontinental Exchange Inc	ICE	48,458.56	0.19%	1.27%	9.35%	10.68%	0.0200%
IDEXX Laboratories Inc	IDXX	23,680.12	0.09%	0.00%	18.30%	18.30%	0.0168%
International Flavors & Fragrances Inc	IFF	15,479.82	0.06%	1.97%	7.80%	9.85%	0.0059%
Illumina Inc	ILMN	54,118.05	0.21%	0.00%	27.09%	27.09%	0.0568%
Incyte Corp	INCY	18,218.70	0.07%	0.00%	43.10%	43.10%	0.0304%
IHS Markit Ltd	INFO	25,555.18	0.10%	0.00%	11.15%	11.15%	0.0110%
Intel Corp	INTC	214,313.99	0.83%	2.60%	8.88%	11.59%	0.0962%
Intuit Inc	INTU	67,748.07	0.26%	0.71%	16.16%	16.93%	0.0444%
International Paper Co	IP	17,212.51	0.07%	4.65%	4.77%	9.53%	0.0064%
Interpublic Group of Cos Inc/The	IPG	8,743.21	0.03%	4.16%	11.75%	16.15%	0.0055%
IPG Photonics Corp	IPGP	8,197.44	0.03%	0.00%	10.49%	10.49%	0.0033%
IQVIA Holdings Inc	IQV	31,736.03	0.12%	0.00%	15.96%	15.96%	0.0196%
Ingersoll-Rand PLC	IR	30,547.51	0.12%	1.71%	9.16%	10.94%	0.0130%
Iron Mountain Inc	IRM	8,979.36	0.03%	7.84%	7.32%	15.45%	0.0054%
Intuitive Surgical Inc	ISRG	60,558.59	0.23%	0.00%	12.30%	12.30%	0.0289%
Gartner Inc	IT	14,499.15	0.06%	0.00%	14.00%	14.00%	0.0079%
Illinois Tool Works Inc	ITW	49,130.14	0.19%	2.66%	7.27%	10.02%	0.0191%
Invesco Ltd	IVZ	9,750.71	0.04%	6.06%	7.12%	13.40%	0.0051%
JB Hunt Transport Services Inc	JBHT	9,939.82	0.04%	1.12%	13.13%	14.32%	0.0055%
Johnson Controls International plc	JCI	37,099.22	0.14%	2.59%	7.80%	10.49%	0.0151%
Jacobs Engineering Group Inc	JEC	11,528.42	0.04%	0.69%	13.10%	13.84%	0.0062%
Jefferies Financial Group Inc	JEF	5,589.91	N/A	2.60%	N/A	N/A	N/A
Jack Henry & Associates Inc	JKHY	10,339.11	0.04%	1.14%	9.03%	10.22%	0.0041%
Johnson & Johnson	JNJ	369,796.20	1.43%	2.70%	5.98%	8.76%	0.1255%
Juniper Networks Inc	JNPR	9,169.39	0.04%	2.84%	7.92%	10.87%	0.0039%
JPMorgan Chase & Co	JPM	362,676.18	1.40%	3.04%	6.80%	9.95%	0.1398%
Nordstrom Inc	JWN	4,927.21	0.02%	4.78%	5.97%	10.89%	0.0021%
Kellogg Co	K	18,240.42	0.07%	4.25%	2.29%	6.58%	0.0046%
KeyCorp	KEY	17,897.12	0.07%	4.01%	6.26%	10.40%	0.0072%
Keysight Technologies Inc	KEYS	16,899.63	N/A	0.00%	N/A	N/A	N/A
Kraft Heinz Co/The	KHC	37,866.90	0.15%	5.15%	0.45%	5.62%	0.0082%
Kimco Realty Corp	KIM	7,799.31	0.03%	6.13%	3.83%	10.08%	0.0030%
KLA-Tencor Corp	KLAC	19,103.51	0.07%	2.52%	9.44%	12.07%	0.0089%
Kimberly-Clark Corp	KMB	45,821.04	0.18%	3.08%	4.17%	7.31%	0.0130%
Kinder Morgan Inc/DE	KMI	47,266.94	0.18%	4.76%	13.90%	18.99%	0.0348%
CarMax Inc	KMX	14,361.26	0.06%	0.00%	10.61%	10.61%	0.0059%
Coca-Cola Co/The	KO	217,230.58	0.84%	3.11%	6.30%	9.51%	0.0800%
Kroger Co/The	KR	17,341.92	0.07%	2.69%	6.00%	8.77%	0.0059%
Kohl's Corp	KSS	7,704.33	0.03%	5.64%	5.55%	11.34%	0.0034%
Kansas City Southern	KSU	12,253.51	0.05%	1.24%	12.50%	13.82%	0.0066%
Loews Corp	L	16,668.23	N/A	0.46%	N/A	N/A	N/A
L Brands Inc	LB	7,212.49	0.03%	4.65%	9.38%	14.25%	0.0040%
Leggett & Platt Inc	LEG	5,036.78	0.02%	4.07%	10.00%	14.27%	0.0028%
Lennar Corp	LEN	15,285.48	0.06%	0.33%	10.09%	10.43%	0.0062%
Laboratory Corp of America Holdings	LH	17,061.46	0.07%	0.00%	7.28%	7.28%	0.0048%
Linde PLC	LIN	108,987.46	0.42%	1.75%	15.05%	16.93%	0.0715%
LKQ Corp	LKQ	8,355.38	0.03%	0.00%	13.30%	13.30%	0.0043%
L3 Technologies Inc	LLL	19,479.04	0.08%	1.42%	5.00%	6.45%	0.0049%
Eli Lilly & Co	LLY	107,558.35	0.42%	2.24%	9.32%	11.66%	0.0486%
Lockheed Martin Corp	LMT	102,714.16	0.40%	2.46%	7.82%	10.38%	0.0413%
Lincoln National Corp	LNC	13,041.02	0.05%	2.34%	9.00%	11.45%	0.0058%
Alliant Energy Corp	LNT	11,651.32	0.05%	2.90%	5.56%	8.54%	0.0039%
Lowe's Cos Inc	LOW	79,004.10	0.31%	2.09%	14.66%	16.90%	0.0517%
Lam Research Corp	LRCX	28,162.20	0.11%	2.22%	9.10%	11.42%	0.0125%
Southwest Airlines Co	LUV	27,576.83	0.11%	1.39%	5.01%	6.44%	0.0069%
Lamb Weston Holdings Inc	LW	9,267.91	0.04%	1.24%	11.83%	13.14%	0.0047%
LyondellBasell Industries NV	LYB	31,896.28	0.12%	4.94%	6.20%	11.29%	0.0139%
Macy's Inc	M	6,628.38	0.03%	7.03%	1.83%	8.92%	0.0023%
Mastercard Inc	MA	270,196.19	1.05%	0.47%	17.28%	17.78%	0.1861%
Mid-America Apartment Communities Inc	MAA	13,424.12	0.05%	3.28%	7.00%	10.39%	0.0054%
Macerich Co/The	MAC	4,730.08	0.02%	8.98%	0.13%	9.12%	0.0017%
Marriott International Inc/MD	MAR	46,715.00	0.18%	1.29%	8.26%	9.61%	0.0174%

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
Masco Corp	MAS	11,518.86	0.04%	1.21%	11.10%	12.37%	0.0055%
McDonald's Corp	MCD	158,560.12	0.61%	2.26%	8.69%	11.05%	0.0679%
Microchip Technology Inc	MCHP	20,628.23	0.08%	1.69%	10.87%	12.65%	0.0101%
McKesson Corp	MCK	25,047.22	0.10%	1.20%	4.01%	5.23%	0.0051%
Moody's Corp	MCO	37,030.78	0.14%	0.98%	7.05%	8.06%	0.0116%
Mondelez International Inc	MDLZ	77,639.49	0.30%	1.98%	6.94%	8.99%	0.0270%
Medtronic PLC	MDT	130,615.25	0.51%	2.17%	7.34%	9.59%	0.0485%
MetLife Inc	MET	47,204.85	0.18%	3.50%	8.46%	12.11%	0.0221%
MGM Resorts International	MGM	15,347.84	0.06%	1.82%	12.35%	14.28%	0.0085%
Mohawk Industries Inc	MHK	10,679.96	0.04%	0.00%	6.82%	6.82%	0.0028%
McCormick & Co Inc/MD	MKC	20,542.51	0.08%	1.44%	6.20%	7.68%	0.0061%
Martin Marietta Materials Inc	MLM	14,377.15	0.06%	0.86%	13.90%	14.81%	0.0083%
Marsh & McLennan Cos Inc	MMC	51,006.58	0.20%	1.75%	11.73%	13.58%	0.0268%
3M Co	MMM	99,917.81	0.39%	3.27%	7.10%	10.49%	0.0406%
Monster Beverage Corp	MNST	34,696.47	0.13%	0.00%	14.45%	14.45%	0.0194%
Altria Group Inc	MO	88,588.06	0.34%	6.96%	6.53%	13.71%	0.0471%
Mosaic Co/The	MOS	9,656.28	0.04%	0.76%	14.00%	14.82%	0.0055%
Marathon Petroleum Corp	MPC	37,027.09	0.14%	3.83%	9.33%	13.34%	0.0191%
Merck & Co Inc	MRK	215,883.93	0.84%	2.62%	11.17%	13.94%	0.1166%
Marathon Oil Corp	MRO	11,622.59	0.05%	1.41%	-2.65%	-1.26%	-0.0006%
Morgan Stanley	MS	73,698.70	0.29%	2.97%	9.49%	12.60%	0.0360%
MSCI Inc	MSCI	20,220.42	0.08%	0.97%	10.00%	11.02%	0.0086%
Microsoft Corp	MSFT	1,026,511.09	3.98%	1.35%	11.85%	13.28%	0.5282%
Motorola Solutions Inc	MSI	27,474.82	0.11%	1.38%	9.00%	10.44%	0.0111%
M&T Bank Corp	MTB	23,235.33	0.09%	2.52%	7.28%	9.89%	0.0089%
Mettler-Toledo International Inc	MTD	20,834.76	0.08%	0.00%	12.97%	12.97%	0.0105%
Micron Technology Inc	MU	42,595.77	0.16%	0.00%	-1.90%	-1.90%	-0.0031%
Maxim Integrated Products Inc	MXIM	16,296.47	0.06%	3.08%	8.97%	12.18%	0.0077%
Mylan NV	MYL	9,814.51	0.04%	0.00%	4.71%	4.71%	0.0018%
Noble Energy Inc	NBL	10,712.39	0.04%	2.02%	6.31%	8.39%	0.0035%
Norwegian Cruise Line Holdings Ltd	NCLH	11,551.66	0.04%	0.36%	10.18%	10.56%	0.0047%
Nasdaq Inc	NDAQ	15,935.80	0.06%	1.92%	7.09%	9.08%	0.0056%
NextEra Energy Inc	NEE	98,114.69	0.38%	2.43%	5.31%	7.81%	0.0297%
Newmont Goldcorp Corp	NEM	31,531.30	0.12%	1.46%	5.10%	6.60%	0.0081%
Netflix Inc	NFLX	160,599.63	0.62%	0.00%	43.23%	43.23%	0.2689%
NiSource Inc	NI	10,745.37	0.04%	2.79%	5.51%	8.37%	0.0035%
NIKE Inc	NKE	131,948.38	0.51%	1.10%	17.48%	18.67%	0.0954%
Nektar Therapeutics	NKTR	6,201.84	0.02%	0.00%	-2.40%	-2.40%	-0.0006%
Nielsen Holdings PLC	NLSN	8,034.16	0.03%	6.33%	12.00%	18.71%	0.0058%
Northrop Grumman Corp	NOC	54,863.97	0.21%	1.62%	5.95%	7.62%	0.0162%
National Oilwell Varco Inc	NOV	8,579.01	0.03%	0.90%	24.00%	25.01%	0.0083%
NRG Energy Inc	NRG	9,382.42	0.04%	0.34%	32.57%	32.97%	0.0120%
Norfolk Southern Corp	NSC	53,015.21	0.21%	1.73%	13.37%	15.21%	0.0312%
NetApp Inc	NTAP	14,809.37	0.06%	3.11%	9.73%	12.99%	0.0075%
Northern Trust Corp	NTRS	19,590.89	0.08%	2.74%	8.75%	11.62%	0.0088%
Nucor Corp	NUE	16,793.69	0.07%	2.91%	0.65%	3.57%	0.0023%
NVIDIA Corp	NVDA	100,016.07	0.39%	0.39%	9.76%	10.17%	0.0394%
Newell Brands Inc	NWL	6,524.20	0.03%	5.96%	-4.75%	1.07%	0.0003%
News Corp	NWSA	7,987.66	0.03%	1.53%	-10.26%	-8.81%	-0.0027%
Realty Income Corp	O	21,826.72	0.08%	3.95%	4.69%	8.73%	0.0074%
ONEOK Inc	OKE	28,401.76	0.11%	5.16%	11.96%	17.42%	0.0192%
Omnicom Group Inc	OMC	18,042.74	0.07%	3.17%	4.06%	7.29%	0.0051%
Oracle Corp	ORCL	190,041.61	0.74%	1.60%	7.63%	9.30%	0.0684%
O'Reilly Automotive Inc	ORLY	28,909.16	0.11%	0.00%	15.22%	15.22%	0.0170%
Occidental Petroleum Corp	OXY	37,610.46	0.15%	6.21%	12.23%	18.82%	0.0274%
Paychex Inc	PAYX	29,566.80	0.11%	3.01%	7.15%	10.27%	0.0118%
People's United Financial Inc	PBCT	6,684.49	0.03%	4.22%	2.00%	6.26%	0.0016%
PACCAR Inc	PCAR	24,826.13	0.10%	4.67%	5.00%	9.79%	0.0094%
Public Service Enterprise Group Inc	PEG	29,729.42	0.12%	3.20%	6.14%	9.43%	0.0109%
PepsiCo Inc	PEP	183,820.87	0.71%	2.89%	5.45%	8.42%	0.0600%
Pfizer Inc	PFE	240,856.13	0.93%	3.31%	5.09%	8.48%	0.0791%
Principal Financial Group Inc	PFG	16,133.51	0.06%	3.81%	4.60%	8.50%	0.0053%
Procter & Gamble Co/The	PG	275,038.36	1.07%	2.65%	7.15%	9.89%	0.1054%
Progressive Corp/The	PGR	46,687.11	0.18%	3.45%	6.23%	9.79%	0.0177%
Parker-Hannifin Corp	PH	21,809.80	0.08%	1.82%	9.02%	10.91%	0.0092%
PulteGroup Inc	PHM	8,763.08	0.03%	1.39%	8.15%	9.59%	0.0033%
Packaging Corp of America	PKG	9,007.17	0.03%	3.35%	8.33%	11.83%	0.0041%
PerkinElmer Inc	PKI	10,685.89	0.04%	0.29%	16.09%	16.41%	0.0068%
Prologis Inc	PLD	50,519.09	0.20%	2.64%	7.04%	9.77%	0.0191%
Philip Morris International Inc	PM	122,177.19	0.47%	5.99%	6.78%	12.97%	0.0614%
PNC Financial Services Group Inc/The	PNC	61,973.40	0.24%	3.00%	7.48%	10.59%	0.0254%
Pentair PLC	PNR	6,394.38	0.02%	1.99%	7.24%	9.30%	0.0023%
Pinnacle West Capital Corp	PNW	10,564.18	0.04%	3.20%	5.29%	8.58%	0.0035%
PPG Industries Inc	PPG	27,550.56	0.11%	1.68%	8.62%	10.36%	0.0111%
PPL Corp	PPL	22,369.71	N/A	5.35%	N/A	N/A	N/A
Perrigo Co PLC	PRGO	6,475.91	0.03%	1.59%	-0.80%	0.78%	0.0002%
Prudential Financial Inc	PRU	41,006.00	0.16%	3.99%	9.00%	13.16%	0.0209%
Public Storage	PSA	41,565.89	0.16%	3.39%	5.23%	8.71%	0.0140%

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
Phillips 66	PSX	42,425.18	0.16%	3.69%	2.05%	5.78%	0.0095%
PVH Corp	PVH	7,089.78	0.03%	0.16%	8.12%	8.29%	0.0023%
Quanta Services Inc	PWR	5,444.66	0.02%	0.42%	22.00%	22.47%	0.0047%
Pioneer Natural Resources Co	PXD	25,913.68	0.10%	0.51%	24.90%	25.48%	0.0256%
PayPal Holdings Inc	PYPL	134,482.83	0.52%	0.00%	19.06%	19.06%	0.0993%
QUALCOMM Inc	QCOM	92,478.22	0.36%	3.32%	15.42%	18.99%	0.0680%
Qorvo Inc	QRVO	7,863.51	0.03%	0.25%	9.62%	9.88%	0.0030%
Royal Caribbean Cruises Ltd	RCL	25,411.42	0.10%	2.35%	11.71%	14.19%	0.0140%
Everest Re Group Ltd	RE	10,068.54	0.04%	2.28%	10.00%	12.39%	0.0048%
Regency Centers Corp	REG	11,191.26	0.04%	3.47%	4.32%	7.86%	0.0034%
Regeneron Pharmaceuticals Inc	REGN	34,316.94	0.13%	0.00%	11.92%	11.92%	0.0158%
Regions Financial Corp	RF	15,137.58	0.06%	4.05%	9.22%	13.46%	0.0079%
Robert Half International Inc	RHI	6,758.97	0.03%	2.19%	9.05%	11.34%	0.0030%
Red Hat Inc	RHT	33,438.74	0.13%	0.00%	20.30%	20.30%	0.0263%
Raymond James Financial Inc	RJF	11,905.09	0.05%	1.57%	11.10%	12.75%	0.0059%
Ralph Lauren Corp	RL	8,778.26	0.03%	2.42%	7.84%	10.35%	0.0035%
ResMed Inc	RMD	17,498.20	0.07%	1.33%	11.05%	12.45%	0.0084%
Rockwell Automation Inc	ROK	19,391.25	0.08%	2.34%	11.48%	13.96%	0.0105%
Rollins Inc	ROL	11,748.49	0.05%	1.55%	10.00%	11.63%	0.0053%
Roper Technologies Inc	ROP	38,032.81	0.15%	0.53%	12.93%	13.49%	0.0199%
Ross Stores Inc	ROST	36,148.63	0.14%	1.03%	9.40%	10.48%	0.0147%
Republic Services Inc	RSG	27,862.22	0.11%	1.76%	13.26%	15.13%	0.0163%
Raytheon Co	RTN	48,432.73	0.19%	2.16%	9.31%	11.56%	0.0217%
SBA Communications Corp	SBAC	25,463.38	0.10%	0.00%	42.50%	42.50%	0.0419%
Starbucks Corp	SBUX	101,534.90	0.39%	1.78%	12.72%	14.60%	0.0574%
Charles Schwab Corp/The	SCHW	53,654.03	0.21%	1.69%	11.14%	12.93%	0.0269%
Sealed Air Corp	SEE	6,661.00	0.03%	1.54%	5.73%	7.32%	0.0019%
Sherwin-Williams Co/The	SHW	42,307.59	0.16%	0.94%	9.46%	10.44%	0.0171%
SVB Financial Group	SIVB	11,684.79	0.05%	0.00%	11.00%	11.00%	0.0050%
JM Smucker Co/The	SJM	13,136.20	0.05%	3.06%	4.03%	7.15%	0.0036%
Schlumberger Ltd	SLB	55,044.76	0.21%	5.03%	31.36%	37.18%	0.0793%
SL Green Realty Corp	SLG	6,859.57	0.03%	4.25%	-0.84%	3.39%	0.0009%
Snap-on Inc	SNA	9,177.19	0.04%	2.30%	7.35%	9.73%	0.0035%
Synopsys Inc	SNPS	19,290.52	0.07%	0.00%	13.60%	13.60%	0.0102%
Southern Co/The	SO	57,537.25	0.22%	4.46%	3.75%	8.29%	0.0185%
Simon Property Group Inc	SPG	49,364.82	0.19%	5.17%	4.87%	10.17%	0.0194%
S&P Global Inc	SPGI	56,081.90	0.22%	0.99%	9.20%	10.24%	0.0222%
Sempra Energy	SRE	37,715.37	0.15%	2.82%	8.74%	11.69%	0.0171%
SunTrust Banks Inc	STI	27,895.49	0.11%	3.36%	6.22%	9.68%	0.0105%
State Street Corp	STT	20,919.57	0.08%	3.55%	7.27%	10.94%	0.0089%
Seagate Technology PLC	STX	13,044.83	0.05%	5.34%	4.60%	10.07%	0.0051%
Constellation Brands Inc	STZ	37,804.60	0.15%	1.51%	8.09%	9.66%	0.0142%
Stanley Black & Decker Inc	SWK	21,913.10	0.08%	1.86%	9.10%	11.05%	0.0094%
Skyworks Solutions Inc	SWKS	13,344.03	0.05%	2.00%	10.57%	12.67%	0.0065%
Synchrony Financial	SYF	23,898.60	0.09%	2.61%	4.03%	6.69%	0.0062%
Stryker Corp	SYK	76,847.88	0.30%	1.11%	8.10%	9.26%	0.0276%
Symantec Corp	SYMC	13,451.90	0.05%	1.44%	7.26%	8.76%	0.0046%
Sysco Corp	SYY	36,348.34	0.14%	2.17%	12.13%	14.44%	0.0203%
AT&T Inc	T	244,555.98	0.95%	6.11%	5.54%	11.82%	0.1119%
Molson Coors Brewing Co	TAP	12,128.28	0.05%	3.69%	-0.23%	3.45%	0.0016%
TransDigm Group Inc	TDG	25,728.44	0.10%	0.00%	13.09%	13.09%	0.0130%
TE Connectivity Ltd	TEL	32,265.04	0.12%	1.86%	9.93%	11.89%	0.0149%
Teleflex Inc	TFX	15,283.93	0.06%	0.41%	12.97%	13.40%	0.0079%
Target Corp	TGT	44,373.29	0.17%	3.04%	6.75%	9.89%	0.0170%
Tiffany & Co	TIF	11,368.59	0.04%	2.48%	9.25%	11.84%	0.0052%
TJX Cos Inc/The	TJX	64,125.86	0.25%	1.72%	10.05%	11.86%	0.0295%
Torchmark Corp	TMK	9,835.28	0.04%	0.75%	7.91%	8.69%	0.0033%
Thermo Fisher Scientific Inc	TMO	117,466.46	0.46%	0.25%	10.83%	11.09%	0.0505%
Tapestry Inc	TPR	9,206.01	0.04%	4.25%	10.20%	14.67%	0.0052%
TripAdvisor Inc	TRIP	6,435.65	0.02%	0.00%	9.34%	9.34%	0.0023%
T Rowe Price Group Inc	TROW	25,943.72	0.10%	2.72%	7.10%	9.92%	0.0100%
Travelers Cos Inc/The	TRV	39,160.52	0.15%	2.16%	13.06%	15.36%	0.0233%
Tractor Supply Co	TSCO	13,125.83	0.05%	1.23%	11.00%	12.29%	0.0062%
Tyson Foods Inc	TSN	29,455.12	0.11%	1.86%	3.10%	4.98%	0.0057%
Total System Services Inc	TSS	22,699.58	0.09%	0.42%	12.14%	12.58%	0.0111%
Take-Two Interactive Software Inc	TTWO	12,776.84	0.05%	0.00%	8.80%	8.80%	0.0044%
Twitter Inc	TWTR	26,825.23	0.10%	0.00%	31.76%	31.76%	0.0330%
Texas Instruments Inc	TXN	107,668.54	0.42%	2.73%	9.87%	12.73%	0.0531%
Textron Inc	TXT	12,345.71	0.05%	0.15%	12.06%	12.21%	0.0058%
Under Armour Inc	UAA	10,658.97	0.04%	0.00%	31.19%	31.19%	0.0129%
United Continental Holdings Inc	UAL	23,136.94	0.09%	0.00%	13.81%	13.81%	0.0124%
UDR Inc	UDR	12,649.77	0.05%	3.05%	5.49%	8.62%	0.0042%
Universal Health Services Inc	UHS	11,753.36	0.05%	0.31%	9.38%	9.71%	0.0044%
Ulta Beauty Inc	ULTA	20,278.41	0.08%	0.00%	21.00%	21.00%	0.0165%
UnitedHealth Group Inc	UNH	231,893.22	0.90%	1.59%	13.74%	15.44%	0.1387%
Unum Group	UNM	7,108.60	0.03%	3.18%	9.00%	12.33%	0.0034%
Union Pacific Corp	UNP	119,702.51	0.46%	2.12%	13.02%	15.28%	0.0708%
United Parcel Service Inc	UPS	88,890.23	0.34%	3.70%	8.79%	12.65%	0.0436%

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
United Rentals Inc	URI	10,427.91	0.04%	0.00%	12.00%	12.00%	0.0048%
US Bancorp	USB	83,424.07	0.32%	3.02%	6.70%	9.82%	0.0317%
United Technologies Corp	UTX	112,350.33	0.44%	2.28%	8.87%	11.25%	0.0489%
Visa Inc	V	346,417.34	1.34%	0.58%	15.54%	16.17%	0.2169%
Varian Medical Systems Inc	VAR	12,380.44	0.05%	0.00%	8.55%	8.55%	0.0041%
VF Corp	VFC	34,691.72	0.13%	2.22%	-19.07%	-17.05%	-0.0229%
Viacom Inc	VIAB	12,248.94	0.05%	2.70%	3.51%	6.25%	0.0030%
Valero Energy Corp	VLO	35,720.04	0.14%	4.20%	13.02%	17.49%	0.0242%
Vulcan Materials Co	VMC	18,137.57	0.07%	0.88%	16.30%	17.25%	0.0121%
Vornado Realty Trust	VNO	12,231.09	0.05%	4.32%	4.23%	8.63%	0.0041%
Verisk Analytics Inc	VRSK	23,970.47	0.09%	0.51%	9.46%	9.99%	0.0093%
VeriSign Inc	VRSN	24,928.39	0.10%	0.00%	8.80%	8.80%	0.0085%
Vertex Pharmaceuticals Inc	VRTX	46,967.53	0.18%	0.00%	51.00%	51.00%	0.0928%
Ventas Inc	VTR	25,249.30	0.10%	4.65%	4.34%	9.09%	0.0089%
Verizon Communications Inc	VZ	236,272.92	0.92%	4.25%	2.34%	6.64%	0.0608%
Wabtec Corp	WAB	13,499.32	0.05%	0.00%	15.00%	15.00%	0.0078%
Waters Corp	WAT	14,953.85	0.06%	0.00%	9.90%	9.90%	0.0057%
Walgreens Boots Alliance Inc	WBA	49,374.85	0.19%	3.31%	5.36%	8.75%	0.0167%
WellCare Health Plans Inc	WCG	14,342.40	0.06%	0.00%	17.22%	17.22%	0.0096%
Western Digital Corp	WDC	13,932.04	0.05%	4.21%	-5.24%	-1.14%	-0.0006%
WEC Energy Group Inc	WEC	26,298.10	0.10%	2.83%	6.13%	9.05%	0.0092%
Welltower Inc	WELL	33,014.81	0.13%	4.27%	6.11%	10.51%	0.0134%
Wells Fargo & Co	WFC	212,672.31	0.82%	3.91%	10.36%	14.47%	0.1192%
Whirlpool Corp	WHR	9,016.98	0.03%	3.33%	4.97%	8.38%	0.0029%
Willis Towers Watson PLC	WLTW	24,753.90	0.10%	1.32%	13.97%	15.38%	0.0147%
Waste Management Inc	WM	49,004.50	0.19%	1.76%	7.51%	9.34%	0.0177%
Williams Cos Inc/The	WMB	33,978.04	0.13%	5.40%	3.90%	9.40%	0.0124%
Walmart Inc	WMT	315,418.25	1.22%	1.92%	3.56%	5.52%	0.0674%
Westrock Co	WRK	9,374.35	0.04%	4.97%	3.17%	8.21%	0.0030%
Western Union Co/The	WU	8,566.79	0.03%	3.91%	3.36%	7.34%	0.0024%
Weyerhaeuser Co	WY	19,617.67	0.08%	5.17%	5.20%	10.51%	0.0080%
Wynn Resorts Ltd	WYNN	13,348.98	0.05%	2.98%	23.23%	26.56%	0.0137%
Cimarex Energy Co	XEC	6,018.03	0.02%	1.21%	29.26%	30.64%	0.0071%
Xcel Energy Inc	XEL	30,617.91	0.12%	2.71%	5.42%	8.20%	0.0097%
Xilinx Inc	XLNX	29,599.38	0.11%	1.26%	9.60%	10.92%	0.0125%
Exxon Mobil Corp	XOM	324,228.73	1.26%	4.45%	15.93%	20.73%	0.2604%
DENTSPLY SIRONA Inc	XRAY	13,654.93	0.05%	0.59%	12.57%	13.20%	0.0070%
Xerox Corp	XRX	7,954.03	0.03%	2.86%	6.50%	9.45%	0.0029%
Xylem Inc/NY	XYL	15,049.60	0.06%	1.15%	13.97%	15.20%	0.0089%
Yum! Brands Inc	YUM	33,862.27	0.13%	1.52%	12.43%	14.05%	0.0184%
Zimmer Biomet Holdings Inc	ZBH	24,112.95	0.09%	0.84%	5.66%	6.52%	0.0061%
Zions Bancorp NA	ZION	8,394.35	0.03%	2.83%	7.60%	10.54%	0.0034%
Zoetis Inc	ZTS	54,322.69	0.21%	0.55%	10.81%	11.39%	0.0240%
Total Market Capitalization:		25,816,650.84					14.88%

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
14.78%	2.63%	12.15%

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	23,262.68	0.10%	0.90%	9.50%	10.44%	0.0101%
American Airlines Group Inc	AAL	14,281.54	0.06%	1.24%	6.50%	7.78%	0.0046%
Advance Auto Parts Inc	AAP	10,995.13	0.05%	0.16%	14.00%	14.17%	0.0065%
Apple Inc	AAPL	918,968.80	3.81%	1.57%	12.50%	14.17%	0.5396%
AbbVie Inc	ABBV	123,639.20	0.51%	5.46%	12.50%	18.30%	0.0938%
AmerisourceBergen Corp	ABC	17,981.89	0.07%	1.92%	8.00%	10.00%	0.0074%
ABIOMED Inc	ABMD	11,746.87	0.05%	0.00%	24.50%	24.50%	0.0119%
Abbott Laboratories	ABT	149,849.50	0.62%	1.51%	10.00%	11.59%	0.0719%
Accenture PLC	ACN	119,105.00	0.49%	1.64%	9.00%	10.71%	0.0529%
Adobe Inc	ADBE	147,581.90	0.61%	0.00%	19.50%	19.50%	0.1193%
Analog Devices Inc	ADI	41,620.30	0.17%	1.92%	10.00%	12.02%	0.0207%
Archer-Daniels-Midland Co	ADM	23,128.00	0.10%	3.39%	9.50%	13.05%	0.0125%
Automatic Data Processing Inc	ADP	73,865.15	0.31%	2.04%	13.50%	15.68%	0.0480%
Alliance Data Systems Corp	ADS	7,227.34	0.03%	1.82%	12.00%	13.93%	0.0042%
Autodesk Inc	ADSK	37,214.61	N/A	0.00%	N/A	N/A	N/A
Ameren Corp	AEE	18,999.62	0.08%	2.57%	6.50%	9.15%	0.0072%
American Electric Power Co Inc	AEP	44,837.80	0.19%	3.08%	4.00%	7.14%	0.0133%
AES Corp/VA	AES	11,236.36	N/A	3.25%	N/A	N/A	N/A
Aflac Inc	AFL	41,310.59	0.17%	1.97%	7.50%	9.54%	0.0163%
Allergan PLC	AGN	42,882.80	0.18%	2.26%	4.00%	6.31%	0.0112%
American International Group Inc	AIG	47,183.23	N/A	2.36%	N/A	N/A	N/A
Apartment Investment & Management Co	AIV	7,887.84	0.03%	3.02%	-3.00%	-0.03%	0.0000%
Assurant Inc	AIZ	6,643.45	0.03%	2.23%	6.50%	8.80%	0.0024%
Arthur J Gallagher & Co	AJG	16,213.75	0.07%	1.97%	15.50%	17.62%	0.0118%
Akamai Technologies Inc	AKAM	13,060.62	0.05%	0.00%	18.00%	18.00%	0.0097%
Albemarle Corp	ALB	7,362.47	0.03%	2.12%	5.50%	7.68%	0.0023%
Align Technology Inc	ALGN	23,653.60	0.10%	0.00%	27.00%	27.00%	0.0265%
Alaska Air Group Inc	ALK	7,499.16	0.03%	2.31%	5.50%	7.87%	0.0024%
Allstate Corp/The	ALL	34,482.15	0.14%	1.93%	10.50%	12.53%	0.0179%
Allegion PLC	ALLE	10,186.40	0.04%	1.00%	8.50%	9.54%	0.0040%
Alexion Pharmaceuticals Inc	ALXN	28,883.68	0.12%	0.00%	21.00%	21.00%	0.0251%
Applied Materials Inc	AMAT	40,444.56	0.17%	1.97%	8.50%	10.55%	0.0177%
Amcor PLC	AMCR	N/A	N/A	0.00%	N/A	N/A	N/A
Advanced Micro Devices Inc	AMD	32,470.82	0.13%	0.00%	27.50%	27.50%	0.0370%
AMETEK Inc	AME	20,182.16	0.08%	0.63%	10.50%	11.16%	0.0093%
Affiliated Managers Group Inc	AMG	5,183.10	0.02%	1.48%	10.00%	11.55%	0.0025%
Amgen Inc	AMGN	113,098.70	0.47%	3.21%	7.00%	10.32%	0.0484%
Ameriprise Financial Inc	AMP	20,032.33	0.08%	2.60%	13.00%	15.77%	0.0131%
American Tower Corp	AMT	96,136.88	0.40%	1.88%	9.50%	11.47%	0.0457%
Amazon.com Inc	AMZN	943,749.40	3.91%	0.00%	39.00%	39.00%	1.5253%
Arista Networks Inc	ANET	19,016.16	0.08%	0.00%	11.00%	11.00%	0.0087%
ANSYS Inc	ANSS	17,085.95	0.07%	0.00%	11.00%	11.00%	0.0078%
Anthem Inc	ANTM	74,949.20	0.31%	1.10%	19.00%	20.20%	0.0628%
Aon PLC	AON	46,618.96	0.19%	0.91%	10.00%	10.96%	0.0212%
AO Smith Corp	AOS	7,660.92	0.03%	1.92%	9.50%	11.51%	0.0037%
Apache Corp	APA	11,093.10	0.05%	3.39%	50.00%	54.24%	0.0249%
Anadarko Petroleum Corp	APC	34,556.34	N/A	1.70%	N/A	N/A	N/A
Air Products & Chemicals Inc	APD	48,880.53	0.20%	2.09%	9.00%	11.18%	0.0227%
Amphenol Corp	APH	28,572.24	0.12%	0.96%	9.50%	10.51%	0.0124%
Aptiv PLC	APTV	20,232.71	0.08%	1.12%	11.00%	12.18%	0.0102%
Alexandria Real Estate Equities Inc	ARE	16,644.03	N/A	2.67%	N/A	N/A	N/A
Arconic Inc	ARNC	10,834.39	N/A	0.33%	N/A	N/A	N/A
Atmos Energy Corp	ATO	12,388.50	0.05%	2.09%	7.50%	9.67%	0.0050%
Activision Blizzard Inc	ATVI	34,979.75	0.14%	0.81%	9.50%	10.35%	0.0150%
AvalonBay Communities Inc	AVB	29,151.78	0.12%	2.93%	4.00%	6.99%	0.0084%
Broadcom Inc	AVGO	111,340.90	0.46%	3.80%	33.50%	37.94%	0.1750%
Avery Dennison Corp	AVY	9,523.58	0.04%	2.11%	11.00%	13.23%	0.0052%
American Water Works Co Inc	AWK	21,334.83	0.09%	1.69%	9.50%	11.27%	0.0100%
American Express Co	AXP	104,558.00	0.43%	1.37%	10.00%	11.44%	0.0496%
AutoZone Inc	AZO	27,766.13	0.12%	0.00%	13.50%	13.50%	0.0155%
Boeing Co/The	BA	211,211.50	0.88%	2.33%	15.50%	18.01%	0.1576%
Bank of America Corp	BAC	270,498.40	1.12%	2.34%	10.50%	12.96%	0.1453%
Baxter International Inc	BAX	41,844.34	0.17%	1.07%	10.50%	11.63%	0.0202%
BB&T Corp	BBT	37,307.96	0.15%	3.61%	8.00%	11.75%	0.0182%
Best Buy Co Inc	BBY	18,260.13	0.08%	2.92%	10.50%	13.57%	0.0103%
Becton Dickinson and Co	BDX	66,116.70	0.27%	1.27%	10.00%	11.33%	0.0311%
Franklin Resources Inc	BEN	17,536.44	0.07%	3.19%	7.50%	10.81%	0.0079%

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
Brown-Forman Corp	BF/B	26,444.87	0.11%	1.21%	13.50%	14.79%	0.0162%
Baker Hughes a GE Co	BHGE	12,545.40	N/A	2.96%	N/A	N/A	N/A
Biogen Inc	BIIB	45,559.04	0.19%	0.00%	5.50%	5.50%	0.0104%
Bank of New York Mellon Corp/The	BK	41,288.14	0.17%	2.60%	8.50%	11.21%	0.0192%
Booking Holdings Inc	BKNG	82,243.84	0.34%	0.00%	11.50%	11.50%	0.0392%
BlackRock Inc	BLK	71,932.11	0.30%	2.84%	9.50%	12.47%	0.0372%
Ball Corp	BLL	22,493.04	0.09%	0.89%	23.00%	23.99%	0.0224%
Bristol-Myers Squibb Co	BMY	79,969.66	0.33%	3.35%	11.50%	15.04%	0.0499%
Broadridge Financial Solutions Inc	BR	15,117.69	0.06%	1.65%	11.00%	12.74%	0.0080%
Berkshire Hathaway Inc	BRK/B	-	N/A	0.00%	N/A	N/A	N/A
Boston Scientific Corp	BSX	58,209.80	0.24%	0.00%	16.00%	16.00%	0.0386%
BorgWarner Inc	BWA	8,750.77	0.04%	1.61%	7.00%	8.67%	0.0031%
Boston Properties Inc	BXP	21,434.14	0.09%	2.77%	4.50%	7.33%	0.0065%
Citigroup Inc	C	157,479.10	0.65%	2.91%	10.00%	13.06%	0.0852%
Conagra Brands Inc	CAG	14,188.72	0.06%	3.01%	5.50%	8.59%	0.0051%
Cardinal Health Inc	CAH	13,341.46	0.06%	4.29%	17.00%	21.65%	0.0120%
Caterpillar Inc	CAT	76,396.54	0.32%	3.08%	13.00%	16.28%	0.0515%
Chubb Ltd	CB	68,433.61	0.28%	2.01%	10.00%	12.11%	0.0343%
Cboe Global Markets Inc	CBOE	11,953.45	0.05%	1.16%	14.50%	15.74%	0.0078%
CBRE Group Inc	CBRE	16,998.25	0.07%	0.00%	10.50%	10.50%	0.0074%
CBS Corp	CBS	18,987.98	0.08%	1.42%	9.50%	10.99%	0.0086%
Crown Castle International Corp	CCI	56,958.73	0.24%	3.51%	10.50%	14.19%	0.0335%
Carnival Corp	CCL	25,717.60	0.11%	4.10%	10.00%	14.31%	0.0152%
Cadence Design Systems Inc	CDNS	20,422.45	0.08%	0.00%	12.50%	12.50%	0.0106%
Celanese Corp	CE	13,308.19	0.06%	2.36%	11.00%	13.49%	0.0074%
Celgene Corp	CELG	69,162.02	0.29%	0.00%	13.50%	13.50%	0.0387%
Cerner Corp	CERN	23,319.76	0.10%	1.00%	9.00%	10.05%	0.0097%
CF Industries Holdings Inc	CF	10,380.62	N/A	2.60%	N/A	N/A	N/A
Citizens Financial Group Inc	CFG	16,120.65	0.07%	3.72%	12.00%	15.94%	0.0107%
Church & Dwight Co Inc	CHD	18,789.60	0.08%	1.19%	9.00%	10.24%	0.0080%
CH Robinson Worldwide Inc	CHRW	11,498.68	0.05%	2.38%	9.00%	11.49%	0.0055%
Charter Communications Inc	CHTR	89,088.41	0.37%	0.00%	16.00%	16.00%	0.0591%
Cigna Corp	CI	60,618.26	0.25%	0.03%	14.50%	14.53%	0.0365%
Cincinnati Financial Corp	CINF	17,289.41	0.07%	2.11%	8.50%	10.70%	0.0077%
Colgate-Palmolive Co	CL	63,186.71	0.26%	2.34%	6.00%	8.41%	0.0220%
Clorox Co/The	CLX	19,768.93	0.08%	2.74%	6.50%	9.33%	0.0076%
Comerica Inc	CMA	10,882.37	0.05%	3.83%	12.00%	16.06%	0.0072%
Comcast Corp	CMCSA	198,242.30	0.82%	1.92%	13.50%	15.55%	0.1277%
CME Group Inc	CME	70,981.92	0.29%	1.51%	3.00%	4.53%	0.0133%
Chipotle Mexican Grill Inc	CMG	20,481.02	0.08%	0.00%	26.00%	26.00%	0.0221%
Cummins Inc	CMI	27,027.00	0.11%	2.66%	8.00%	10.77%	0.0121%
CMS Energy Corp	CMS	16,766.67	0.07%	2.69%	7.00%	9.78%	0.0068%
Centene Corp	CNC	22,888.83	0.09%	0.00%	15.50%	15.50%	0.0147%
CenterPoint Energy Inc	CNP	15,085.13	0.06%	3.90%	12.50%	16.64%	0.0104%
Capital One Financial Corp	COF	43,029.18	0.18%	1.75%	6.00%	7.80%	0.0139%
Cabot Oil & Gas Corp	COG	9,987.23	0.04%	1.53%	50.00%	51.91%	0.0215%
Cooper Cos Inc/The	COO	16,208.28	0.07%	0.02%	14.50%	14.52%	0.0098%
ConocoPhillips	COP	68,601.68	0.28%	2.01%	37.00%	39.38%	0.1120%
Costco Wholesale Corp	COST	117,583.50	0.49%	0.97%	8.50%	9.51%	0.0463%
Coty Inc	COTY	10,136.39	0.04%	3.71%	9.00%	12.88%	0.0054%
Campbell Soup Co	CPB	12,350.03	0.05%	3.41%	1.00%	4.43%	0.0023%
Capri Holdings Ltd	CPRI	5,275.07	0.02%	0.00%	7.50%	7.50%	0.0016%
Copart Inc	CPRT	17,103.85	0.07%	0.00%	12.50%	12.50%	0.0089%
salesforce.com Inc	CRM	121,987.20	0.51%	0.00%	57.00%	57.00%	0.2881%
Cisco Systems Inc	CSCO	247,609.30	1.03%	2.44%	8.00%	10.54%	0.1081%
CSX Corp	CSX	69,196.73	0.29%	1.21%	14.50%	15.80%	0.0453%
Cintas Corp	CTAS	24,410.33	0.10%	0.97%	16.00%	17.05%	0.0172%
CenturyLink Inc	CTL	12,376.55	0.05%	8.81%	1.00%	9.85%	0.0051%
Cognizant Technology Solutions Corp	CTSH	36,512.73	0.15%	1.25%	5.00%	6.28%	0.0095%
Corteva Inc	CTVA	N/A	N/A	0.00%	N/A	N/A	N/A
Citrix Systems Inc	CTXS	13,108.22	0.05%	1.41%	7.00%	8.46%	0.0046%
CVS Health Corp	CVS	69,923.27	0.29%	3.71%	6.50%	10.33%	0.0299%
Chevron Corp	CVX	236,719.30	0.98%	3.83%	16.50%	20.65%	0.2025%
Concho Resources Inc	CXO	21,056.98	0.09%	0.48%	21.00%	21.53%	0.0188%
Dominion Energy Inc	D	62,082.82	0.26%	4.81%	6.50%	11.47%	0.0295%
Delta Air Lines Inc	DAL	36,660.13	0.15%	2.75%	9.50%	12.38%	0.0188%
DuPont de Nemours Inc	DD	N/A	N/A	0.00%	N/A	N/A	N/A
Deere & Co	DE	51,594.27	0.21%	1.87%	14.00%	16.00%	0.0342%
Discover Financial Services	DFS	25,507.01	0.11%	2.04%	7.50%	9.62%	0.0102%
Dollar General Corp	DG	35,857.82	0.15%	0.92%	12.50%	13.48%	0.0200%
Quest Diagnostics Inc	DGX	13,445.56	0.06%	2.11%	8.50%	10.70%	0.0060%
DR Horton Inc	DHI	17,048.45	0.07%	1.34%	6.50%	7.88%	0.0056%
Danaher Corp	DHR	102,824.70	0.43%	0.47%	12.50%	13.00%	0.0554%
Walt Disney Co/The	DIS	252,653.60	1.05%	1.24%	6.50%	7.78%	0.0815%
Discovery Inc	DISCA	16,235.62	0.07%	0.00%	15.00%	15.00%	0.0101%
DISH Network Corp	DISH	18,297.13	0.08%	0.00%	-2.00%	-2.00%	-0.0015%
Digital Realty Trust Inc	DLR	25,778.48	0.11%	3.46%	5.00%	8.55%	0.0091%
Dollar Tree Inc	DLTR	26,323.70	0.11%	0.00%	15.50%	15.50%	0.0169%

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
Dover Corp	DOV	14,249.51	0.06%	1.96%	11.00%	13.07%	0.0077%
Dow Inc	DOW	36,639.96	N/A	5.83%	N/A	N/A	N/A
Duke Realty Corp	DRE	11,637.54	0.05%	2.74%	7.00%	9.84%	0.0047%
Darden Restaurants Inc	DRI	14,593.56	0.06%	2.97%	12.00%	15.15%	0.0092%
DTE Energy Co	DTE	24,033.75	0.10%	3.02%	5.50%	8.60%	0.0086%
Duke Energy Corp	DUK	64,486.24	0.27%	4.28%	6.00%	10.41%	0.0278%
DaVita Inc	DVA	8,720.82	0.04%	0.00%	11.00%	11.00%	0.0040%
Devon Energy Corp	DVN	11,663.08	0.05%	1.28%	26.50%	27.95%	0.0135%
DXC Technology Co	DXC	14,684.01	0.06%	1.54%	14.50%	16.15%	0.0098%
Electronic Arts Inc	EA	27,780.59	0.12%	0.00%	10.00%	10.00%	0.0115%
eBay Inc	EBAY	34,969.92	0.14%	1.43%	10.00%	11.50%	0.0167%
Ecolab Inc	ECL	55,438.15	0.23%	0.96%	10.00%	11.01%	0.0253%
Consolidated Edison Inc	ED	29,063.76	0.12%	3.39%	3.00%	6.44%	0.0078%
Equifax Inc	EFX	16,305.58	0.07%	1.16%	8.00%	9.21%	0.0062%
Edison International	EIX	20,780.22	0.09%	3.84%	15.00%	19.13%	0.0165%
Estee Lauder Cos Inc/The	EL	66,189.98	0.27%	0.95%	12.50%	13.51%	0.0371%
Eastman Chemical Co	EMN	10,483.80	0.04%	3.28%	8.00%	11.41%	0.0050%
Emerson Electric Co	EMR	41,218.89	0.17%	3.01%	12.00%	15.19%	0.0259%
EOG Resources Inc	EOG	53,069.80	0.22%	1.26%	34.50%	35.98%	0.0791%
Equinix Inc	EQIX	42,738.66	0.18%	1.97%	25.00%	27.22%	0.0482%
Equity Residential	EQR	29,120.20	0.12%	2.91%	-12.00%	-9.26%	-0.0112%
Eversource Energy	ES	24,603.91	0.10%	2.80%	5.50%	8.38%	0.0085%
Essex Property Trust Inc	ESS	19,958.74	0.08%	2.61%	2.00%	4.64%	0.0038%
E*TRADE Financial Corp	ETFC	11,119.21	0.05%	1.23%	17.50%	18.84%	0.0087%
Eaton Corp PLC	ETN	34,964.98	0.14%	3.44%	9.00%	12.59%	0.0182%
Entergy Corp	ETR	19,644.91	0.08%	3.58%	0.50%	4.09%	0.0033%
Evergy Inc	EVRG	15,011.08	N/A	3.28%	N/A	N/A	N/A
Edwards Lifesciences Corp	EW	40,194.11	0.17%	0.00%	15.00%	15.00%	0.0250%
Exelon Corp	EXC	48,783.04	0.20%	2.93%	10.50%	13.58%	0.0275%
Expeditors International of Washington I	EXPD	13,101.89	0.05%	1.31%	7.50%	8.86%	0.0048%
Expedia Group Inc	EXPE	19,276.45	0.08%	0.99%	24.00%	25.11%	0.0201%
Extra Space Storage Inc	EXR	13,864.50	0.06%	3.35%	6.00%	9.45%	0.0054%
Ford Motor Co	F	39,343.69	0.16%	5.98%	3.50%	9.58%	0.0156%
Diamondback Energy Inc	FANG	17,709.28	0.07%	0.70%	17.00%	17.76%	0.0130%
Fastenal Co	FAST	19,030.96	0.08%	2.59%	8.50%	11.20%	0.0088%
Facebook Inc	FB	541,011.10	2.24%	0.00%	16.50%	16.50%	0.3699%
Fortune Brands Home & Security Inc	FBHS	7,788.52	0.03%	1.58%	10.50%	12.16%	0.0039%
Freeport-McMoRan Inc	FCX	16,512.38	0.07%	1.76%	22.50%	24.46%	0.0167%
FedEx Corp	FDX	43,906.89	0.18%	1.69%	7.50%	9.25%	0.0168%
FirstEnergy Corp	FE	23,208.07	0.10%	3.57%	8.00%	11.71%	0.0113%
F5 Networks Inc	FFIV	8,494.00	0.04%	0.00%	12.00%	12.00%	0.0042%
Fidelity National Information Services I	FIS	40,013.24	0.17%	1.13%	18.00%	19.23%	0.0319%
Fiserv Inc	FISV	35,969.99	0.15%	0.00%	10.50%	10.50%	0.0157%
Fifth Third Bancorp	FITB	20,185.78	0.08%	3.52%	7.00%	10.64%	0.0089%
Foot Locker Inc	FL	4,694.41	0.02%	3.64%	12.00%	15.86%	0.0031%
FLIR Systems Inc	FLIR	7,305.11	0.03%	1.30%	12.00%	13.38%	0.0040%
Flowserve Corp	FLS	6,685.11	0.03%	1.49%	13.50%	15.09%	0.0042%
FleetCor Technologies Inc	FLT	23,940.72	0.10%	0.00%	12.50%	12.50%	0.0124%
FMC Corp	FMC	10,803.86	0.04%	2.01%	15.00%	17.16%	0.0077%
Fox Corp	FOXA	N/A	N/A	0.00%	N/A	N/A	N/A
First Republic Bank/CA	FRC	16,063.03	0.07%	0.79%	10.50%	11.33%	0.0075%
Federal Realty Investment Trust	FRT	9,976.97	0.04%	3.07%	4.00%	7.13%	0.0029%
TechnipFMC PLC	FTI	N/A	N/A	0.00%	N/A	N/A	N/A
Fortinet Inc	FTNT	13,133.66	0.05%	0.00%	25.00%	25.00%	0.0136%
Fortive Corp	FTV	27,074.70	N/A	0.35%	N/A	N/A	N/A
General Dynamics Corp	GD	51,407.66	0.21%	2.29%	6.00%	8.36%	0.0178%
General Electric Co	GE	92,702.18	0.38%	0.38%	3.50%	3.89%	0.0149%
Gilead Sciences Inc	GILD	87,358.19	0.36%	3.68%	-5.50%	-1.92%	-0.0070%
General Mills Inc	GIS	32,336.37	0.13%	3.67%	4.00%	7.74%	0.0104%
Corning Inc	GLW	25,899.84	0.11%	2.42%	15.00%	17.60%	0.0189%
General Motors Co	GM	52,423.80	0.22%	4.22%	2.50%	6.77%	0.0147%
Alphabet Inc	GOOGL	N/A	N/A	0.00%	N/A	N/A	N/A
Genuine Parts Co	GPC	15,159.98	0.06%	2.94%	8.50%	11.56%	0.0073%
Global Payments Inc	GPN	25,417.35	0.11%	0.03%	17.50%	17.53%	0.0185%
Gap Inc/The	GPS	6,841.80	0.03%	5.36%	6.00%	11.52%	0.0033%
Garmin Ltd	GRMN	15,518.09	0.06%	2.79%	10.00%	12.93%	0.0083%
Goldman Sachs Group Inc/The	GS	71,777.09	0.30%	1.74%	8.50%	10.31%	0.0307%
WW Grainger Inc	GWW	15,346.90	0.06%	2.08%	8.50%	10.67%	0.0068%
Halliburton Co	HAL	19,951.36	0.08%	3.15%	24.50%	28.04%	0.0232%
Hasbro Inc	HAS	13,580.72	0.06%	2.52%	7.50%	10.11%	0.0057%
Huntington Bancshares Inc/OH	HBAN	13,875.79	0.06%	4.53%	11.50%	16.29%	0.0094%
Hanesbrands Inc	HBI	6,343.82	0.03%	3.42%	4.00%	7.49%	0.0020%
HCA Healthcare Inc	HCA	43,935.41	0.18%	1.25%	12.50%	13.83%	0.0252%
HCP Inc	HCP	15,895.84	0.07%	4.45%	32.50%	37.67%	0.0248%
Home Depot Inc/The	HD	232,586.30	0.96%	2.58%	9.00%	11.70%	0.1127%
Hess Corp	HES	18,658.51	N/A	1.63%	N/A	N/A	N/A
HollyFrontier Corp	HFC	7,453.89	0.03%	3.14%	18.50%	21.93%	0.0068%
Hartford Financial Services Group Inc/Th	HIG	20,074.92	0.08%	2.16%	11.00%	13.28%	0.0110%

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
Huntington Ingalls Industries Inc	HII	9,350.02	0.04%	1.53%	7.00%	8.58%	0.0033%
Hilton Worldwide Holdings Inc	HLT	28,258.91	0.12%	0.62%	17.00%	17.67%	0.0207%
Harley-Davidson Inc	HOG	5,728.22	0.02%	4.17%	8.50%	12.85%	0.0030%
Hologic Inc	HOLX	13,190.10	0.05%	0.00%	18.50%	18.50%	0.0101%
Honeywell International Inc	HON	128,293.60	0.53%	1.86%	8.00%	9.93%	0.0528%
Helmerich & Payne Inc	HP	5,587.67	N/A	5.56%	N/A	N/A	N/A
Hewlett Packard Enterprise Co	HPE	20,193.48	0.08%	3.27%	6.50%	9.88%	0.0083%
HP Inc	HPQ	31,415.16	0.13%	3.21%	8.50%	11.85%	0.0154%
H&R Block Inc	HRB	5,749.35	0.02%	3.71%	7.00%	10.84%	0.0026%
Hormel Foods Corp	HRL	22,280.02	0.09%	2.07%	9.00%	11.16%	0.0103%
Harris Corp	HRS	23,543.56	0.10%	1.39%	12.00%	13.47%	0.0131%
Henry Schein Inc	HSIC	10,569.78	0.04%	0.00%	7.00%	7.00%	0.0031%
Host Hotels & Resorts Inc	HST	13,808.46	0.06%	4.29%	4.00%	8.38%	0.0048%
Hershey Co/The	HSY	28,715.29	0.12%	2.10%	6.00%	8.16%	0.0097%
Humana Inc	HUM	34,951.11	0.14%	0.85%	11.50%	12.40%	0.0180%
International Business Machines Corp	IBM	123,110.40	0.51%	4.69%	2.00%	6.74%	0.0344%
Intercontinental Exchange Inc	ICE	48,832.95	0.20%	1.27%	10.50%	11.84%	0.0240%
IDEXX Laboratories Inc	IDXX	23,482.69	0.10%	0.00%	13.00%	13.00%	0.0127%
International Flavors & Fragrances Inc	IFF	16,073.84	0.07%	2.04%	8.50%	10.63%	0.0071%
Illumina Inc	ILMN	52,709.79	0.22%	0.00%	14.00%	14.00%	0.0306%
Incyte Corp	INCY	18,553.77	N/A	0.00%	N/A	N/A	N/A
IHS Markit Ltd	INFO	23,938.03	0.10%	0.00%	17.00%	17.00%	0.0169%
Intel Corp	INTC	211,269.60	0.88%	2.67%	10.50%	13.31%	0.1165%
Intuit Inc	INTU	69,154.00	0.29%	0.71%	13.00%	13.76%	0.0394%
International Paper Co	IP	17,384.43	0.07%	4.59%	11.50%	16.35%	0.0118%
Interpublic Group of Cos Inc/The	IPG	8,700.64	0.04%	4.32%	11.00%	15.56%	0.0056%
IPG Photonics Corp	IPGP	7,679.95	0.03%	0.00%	10.50%	10.50%	0.0033%
IQVIA Holdings Inc	IQV	30,471.34	0.13%	0.00%	12.50%	12.50%	0.0158%
Ingersoll-Rand PLC	IR	30,412.44	0.13%	1.68%	12.00%	13.78%	0.0174%
Iron Mountain Inc	IRM	9,336.32	0.04%	7.50%	8.50%	16.32%	0.0063%
Intuitive Surgical Inc	ISRG	61,513.98	0.25%	0.00%	14.00%	14.00%	0.0357%
Gartner Inc	IT	14,451.12	0.06%	0.00%	14.00%	14.00%	0.0084%
Illinois Tool Works Inc	ITW	49,580.24	0.21%	2.63%	9.00%	11.75%	0.0241%
Invesco Ltd	IVZ	8,313.80	0.03%	5.98%	7.00%	13.19%	0.0045%
JB Hunt Transport Services Inc	JBHT	9,881.11	0.04%	1.17%	10.00%	11.23%	0.0046%
Johnson Controls International plc	JCI	35,653.34	0.15%	2.62%	2.00%	4.65%	0.0069%
Jacobs Engineering Group Inc	JEC	11,173.78	0.05%	0.83%	12.50%	13.38%	0.0062%
Jefferies Financial Group Inc	JEF	5,491.94	0.02%	2.72%	18.50%	21.47%	0.0049%
Jack Henry & Associates Inc	JKHY	10,676.65	0.04%	1.15%	10.50%	11.71%	0.0052%
Johnson & Johnson	JNJ	377,658.00	1.57%	2.71%	12.00%	14.87%	0.2328%
Juniper Networks Inc	JNPR	9,482.88	0.04%	2.82%	6.00%	8.90%	0.0035%
JPMorgan Chase & Co	JPM	357,453.40	1.48%	2.96%	8.50%	11.59%	0.1716%
Nordstrom Inc	JWN	5,134.27	0.02%	4.46%	6.50%	11.10%	0.0024%
Kellogg Co	K	18,764.60	0.08%	4.13%	4.50%	8.72%	0.0068%
KeyCorp	KEY	17,102.58	0.07%	4.33%	10.50%	15.06%	0.0107%
Keysight Technologies Inc	KEYS	16,583.84	0.07%	0.00%	16.00%	16.00%	0.0110%
Kraft Heinz Co/The	KHC	37,947.47	0.16%	5.20%	3.50%	8.79%	0.0138%
Kimco Realty Corp	KIM	8,061.17	0.03%	5.96%	5.00%	11.11%	0.0037%
KLA-Tencor Corp	KLAC	18,390.74	0.08%	2.64%	11.50%	14.29%	0.0109%
Kimberly-Clark Corp	KMB	46,862.70	0.19%	3.02%	7.00%	10.13%	0.0197%
Kinder Morgan Inc/DE	KMI	47,737.14	0.20%	4.74%	35.50%	41.08%	0.0813%
CarMax Inc	KMX	14,258.16	0.06%	0.00%	11.50%	11.50%	0.0068%
Coca-Cola Co/The	KO	220,484.90	0.91%	3.10%	6.50%	9.70%	0.0886%
Kroger Co/The	KR	18,457.74	0.08%	2.68%	4.50%	7.24%	0.0055%
Kohl's Corp	KSS	7,594.56	0.03%	5.72%	11.00%	17.03%	0.0054%
Kansas City Southern	KSU	11,872.58	0.05%	1.22%	12.00%	13.29%	0.0065%
Loews Corp	L	16,515.60	0.07%	0.46%	12.00%	12.49%	0.0085%
L Brands Inc	LB	6,601.92	0.03%	5.02%	-4.00%	0.92%	0.0003%
Leggett & Platt Inc	LEG	5,031.54	0.02%	4.17%	9.00%	13.36%	0.0028%
Lennar Corp	LEN	17,040.97	0.07%	0.30%	8.50%	8.81%	0.0062%
Laboratory Corp of America Holdings	LH	16,580.61	0.07%	0.00%	8.00%	8.00%	0.0055%
Linde PLC	LIN	110,009.40	N/A	1.85%	N/A	N/A	N/A
LKQ Corp	LKQ	8,373.69	0.03%	0.00%	10.00%	10.00%	0.0035%
L3 Technologies Inc	LLL	20,547.94	0.09%	1.31%	7.00%	8.36%	0.0071%
Eli Lilly & Co	LLY	112,189.20	0.46%	2.23%	11.50%	13.86%	0.0644%
Lockheed Martin Corp	LMT	102,505.10	0.42%	2.54%	11.50%	14.19%	0.0603%
Lincoln National Corp	LNC	12,976.96	0.05%	2.38%	9.00%	11.49%	0.0062%
Alliant Energy Corp	LNT	11,864.95	0.05%	2.84%	6.50%	9.43%	0.0046%
Lowe's Cos Inc	LOW	80,644.80	0.33%	2.17%	11.50%	13.79%	0.0461%
Lam Research Corp	LRCX	27,573.03	0.11%	2.39%	11.00%	13.52%	0.0155%
Southwest Airlines Co	LUV	27,978.71	0.12%	1.40%	11.00%	12.48%	0.0145%
Lamb Weston Holdings Inc	LW	8,979.13	N/A	1.30%	N/A	N/A	N/A
LyondellBasell Industries NV	LYB	32,066.53	0.13%	4.85%	5.50%	10.48%	0.0139%
Macy's Inc	M	6,770.47	0.03%	6.89%	3.50%	10.51%	0.0029%
Mastercard Inc	MA	273,192.90	1.13%	0.50%	16.00%	16.54%	0.1873%
Mid-America Apartment Communities Inc	MAA	13,659.00	0.06%	3.20%	-3.00%	0.15%	0.0001%
Macerich Co/The	MAC	4,815.67	0.02%	8.92%	3.00%	12.05%	0.0024%
Marriott International Inc/MD	MAR	45,682.76	0.19%	1.40%	12.50%	13.99%	0.0265%

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
Masco Corp	MAS	11,348.61	0.05%	1.29%	10.50%	11.86%	0.0056%
McDonald's Corp	MCD	156,620.60	0.65%	2.34%	8.50%	10.94%	0.0710%
Microchip Technology Inc	MCHP	20,332.95	0.08%	1.76%	10.50%	12.35%	0.0104%
McKesson Corp	MCK	25,814.40	0.11%	1.16%	9.00%	10.21%	0.0109%
Moody's Corp	MCO	38,799.60	0.16%	1.01%	11.00%	12.07%	0.0194%
Mondelez International Inc	MDLZ	80,076.86	0.33%	1.98%	8.50%	10.56%	0.0351%
Medtronic PLC	MDT	133,067.30	0.55%	2.11%	7.50%	9.69%	0.0534%
MetLife Inc	MET	46,900.93	0.19%	3.57%	7.50%	11.20%	0.0218%
MGM Resorts International	MGM	15,045.74	0.06%	1.86%	22.50%	24.57%	0.0153%
Mohawk Industries Inc	MHK	10,751.05	0.04%	0.00%	3.50%	3.50%	0.0016%
McCormick & Co Inc/MD	MKC	20,589.29	0.09%	1.48%	8.50%	10.04%	0.0086%
Martin Marietta Materials Inc	MLM	14,021.68	0.06%	0.88%	9.00%	9.92%	0.0058%
Marsh & McLennan Cos Inc	MMC	49,419.05	0.20%	1.87%	9.50%	11.46%	0.0235%
3M Co	MMM	100,263.70	0.42%	3.31%	8.50%	11.95%	0.0497%
Monster Beverage Corp	MNST	34,526.11	0.14%	0.00%	13.50%	13.50%	0.0193%
Altria Group Inc	MO	94,074.36	0.39%	6.37%	8.50%	15.14%	0.0590%
Mosaic Co/The	MOS	9,116.17	0.04%	0.89%	22.00%	22.99%	0.0087%
Marathon Petroleum Corp	MPC	34,650.65	0.14%	4.08%	11.50%	15.81%	0.0227%
Merck & Co Inc	MRK	218,527.80	0.91%	2.60%	8.50%	11.21%	0.1015%
Marathon Oil Corp	MRO	11,570.20	N/A	1.84%	N/A	N/A	N/A
Morgan Stanley	MS	73,273.38	0.30%	2.76%	10.00%	12.90%	0.0392%
MSCI Inc	MSCI	20,105.23	0.08%	1.06%	18.50%	19.66%	0.0164%
Microsoft Corp	MSFT	1,049,859.00	4.35%	1.34%	13.50%	14.93%	0.6496%
Motorola Solutions Inc	MSI	27,498.53	0.11%	1.37%	10.50%	11.94%	0.0136%
M&T Bank Corp	MTB	22,654.86	0.09%	2.41%	9.50%	12.02%	0.0113%
Mettler-Toledo International Inc	MTD	20,372.94	0.08%	0.00%	10.00%	10.00%	0.0084%
Micron Technology Inc	MU	40,228.70	0.17%	0.00%	11.50%	11.50%	0.0192%
Maxim Integrated Products Inc	MXIM	15,893.27	0.07%	3.15%	8.00%	11.28%	0.0074%
Mylan NV	MYL	9,404.59	0.04%	0.00%	6.50%	6.50%	0.0025%
Noble Energy Inc	NBL	10,505.25	N/A	2.21%	N/A	N/A	N/A
Norwegian Cruise Line Holdings Ltd	NCLH	11,320.69	0.05%	0.00%	16.00%	16.00%	0.0075%
Nasdaq Inc	NDAQ	16,195.62	0.07%	1.92%	8.00%	10.00%	0.0067%
NextEra Energy Inc	NEE	98,856.02	0.41%	2.50%	10.00%	12.63%	0.0517%
Newmont Goldcorp Corp	NEM	20,180.46	0.08%	1.49%	2.50%	4.01%	0.0034%
Netflix Inc	NFLX	159,666.90	0.66%	0.00%	32.00%	32.00%	0.2117%
NiSource Inc	NI	10,973.75	0.05%	2.72%	12.50%	15.39%	0.0070%
NIKE Inc	NKE	134,082.50	0.56%	1.03%	14.50%	15.60%	0.0867%
Nektar Therapeutics	NKTR	6,165.93	N/A	0.00%	N/A	N/A	N/A
Nielsen Holdings PLC	NLSN	8,336.34	0.03%	5.97%	45.50%	52.83%	0.0183%
Northrop Grumman Corp	NOC	55,008.60	0.23%	1.63%	9.50%	11.21%	0.0255%
National Oilwell Varco Inc	NOV	8,382.44	N/A	0.92%	N/A	N/A	N/A
NRG Energy Inc	NRG	9,374.53	N/A	0.34%	N/A	N/A	N/A
Norfolk Southern Corp	NSC	52,211.98	0.22%	1.75%	15.00%	16.88%	0.0365%
NetApp Inc	NTAP	15,479.49	0.06%	3.06%	18.50%	21.84%	0.0140%
Northern Trust Corp	NTRS	18,663.63	0.08%	2.80%	8.50%	11.42%	0.0088%
Nucor Corp	NUE	16,400.53	0.07%	2.97%	13.00%	16.16%	0.0110%
NVIDIA Corp	NVDA	93,846.91	0.39%	0.42%	11.50%	11.94%	0.0465%
Newell Brands Inc	NWL	6,376.12	0.03%	6.11%	4.50%	10.75%	0.0028%
News Corp	NWSA	7,933.62	N/A	1.48%	N/A	N/A	N/A
Realty Income Corp	O	22,261.25	0.09%	3.75%	4.50%	8.33%	0.0077%
ONEOK Inc	OKE	27,968.14	0.12%	5.42%	16.00%	21.85%	0.0253%
Omnicom Group Inc	OMC	17,774.16	0.07%	3.28%	6.50%	9.89%	0.0073%
Oracle Corp	ORCL	196,216.60	0.81%	1.69%	10.00%	11.77%	0.0957%
O'Reilly Automotive Inc	ORLY	29,416.34	0.12%	0.00%	12.00%	12.00%	0.0146%
Occidental Petroleum Corp	OXY	38,366.14	0.16%	6.14%	27.50%	34.48%	0.0548%
Paychex Inc	PAYX	31,469.06	0.13%	2.83%	10.50%	13.48%	0.0176%
People's United Financial Inc	PBCT	6,525.14	0.03%	4.34%	9.00%	13.54%	0.0037%
PACCAR Inc	PCAR	25,027.69	0.10%	4.57%	7.50%	12.24%	0.0127%
Public Service Enterprise Group Inc	PEG	30,809.52	0.13%	3.11%	6.00%	9.20%	0.0118%
PepsiCo Inc	PEP	188,068.30	0.78%	2.85%	6.50%	9.44%	0.0736%
Pfizer Inc	PFE	242,285.20	1.00%	3.30%	11.00%	14.48%	0.1454%
Principal Financial Group Inc	PFG	16,057.70	0.07%	3.74%	5.50%	9.34%	0.0062%
Procter & Gamble Co/The	PG	280,280.80	1.16%	2.67%	8.50%	11.28%	0.1311%
Progressive Corp/The	PGR	47,812.08	0.20%	0.49%	15.50%	16.03%	0.0318%
Parker-Hannifin Corp	PH	22,075.28	0.09%	2.05%	11.50%	13.67%	0.0125%
PulteGroup Inc	PHM	9,074.59	0.04%	1.38%	8.00%	9.44%	0.0035%
Packaging Corp of America	PKG	8,939.70	0.04%	3.34%	6.00%	9.44%	0.0035%
PerkinElmer Inc	PKI	10,652.19	0.04%	0.29%	11.00%	11.31%	0.0050%
Prologis Inc	PLD	51,930.72	0.22%	2.62%	6.50%	9.21%	0.0198%
Philip Morris International Inc	PM	120,153.50	0.50%	5.91%	7.00%	13.12%	0.0653%
PNC Financial Services Group Inc/The	PNC	60,070.80	0.25%	2.86%	8.00%	10.97%	0.0273%
Pentair PLC	PNR	6,390.95	0.03%	1.94%	6.50%	8.50%	0.0023%
Pinnacle West Capital Corp	PNW	11,066.02	0.05%	3.08%	5.00%	8.16%	0.0037%
PPG Industries Inc	PPG	27,191.75	0.11%	1.67%	7.50%	9.23%	0.0104%
PPL Corp	PPL	22,752.04	0.09%	5.23%	1.50%	6.77%	0.0064%
Perrigo Co PLC	PRGO	5,913.28	0.02%	1.93%	2.50%	4.45%	0.0011%
Prudential Financial Inc	PRU	40,787.96	0.17%	4.00%	7.00%	11.14%	0.0188%
Public Storage	PSA	42,223.29	0.17%	3.46%	5.50%	9.06%	0.0158%

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
Phillips 66	PSX	41,196.04	0.17%	4.07%	10.00%	14.27%	0.0244%
PVH Corp	PVH	6,792.65	0.03%	0.17%	9.50%	9.68%	0.0027%
Quanta Services Inc	PWR	5,578.10	0.02%	0.41%	15.50%	15.94%	0.0037%
Pioneer Natural Resources Co	PXD	25,994.25	0.11%	0.42%	37.50%	38.00%	0.0409%
PayPal Holdings Inc	PYPL	139,221.90	0.58%	0.00%	19.00%	19.00%	0.1096%
QUALCOMM Inc	QCOM	88,306.37	0.37%	3.41%	10.50%	14.09%	0.0516%
Qorvo Inc	QRVO	7,975.38	N/A	0.00%	N/A	N/A	N/A
Royal Caribbean Cruises Ltd	RCL	24,881.97	0.10%	2.36%	12.50%	15.01%	0.0155%
Everest Re Group Ltd	RE	10,297.12	0.04%	2.30%	9.00%	11.40%	0.0049%
Regency Centers Corp	REG	11,736.56	0.05%	3.35%	16.00%	19.62%	0.0095%
Regeneron Pharmaceuticals Inc	REGN	34,506.72	0.14%	0.00%	10.00%	10.00%	0.0143%
Regions Financial Corp	RF	14,788.84	0.06%	3.97%	10.50%	14.68%	0.0090%
Robert Half International Inc	RHI	6,782.16	0.03%	2.20%	9.50%	11.80%	0.0033%
Red Hat Inc	RHT	33,282.79	0.14%	0.00%	15.50%	15.50%	0.0214%
Raymond James Financial Inc	RJF	11,332.02	0.05%	1.74%	10.00%	11.83%	0.0056%
Ralph Lauren Corp	RL	8,974.47	0.04%	2.39%	7.50%	9.98%	0.0037%
ResMed Inc	RMD	17,670.26	0.07%	1.20%	14.50%	15.79%	0.0116%
Rockwell Automation Inc	ROK	19,298.92	0.08%	2.40%	9.50%	12.01%	0.0096%
Rollins Inc	ROL	12,436.31	0.05%	1.11%	13.00%	14.18%	0.0073%
Roper Technologies Inc	ROP	38,172.99	0.16%	0.50%	11.50%	12.03%	0.0190%
Ross Stores Inc	ROST	38,195.24	0.16%	1.00%	11.00%	12.06%	0.0191%
Republic Services Inc	RSG	30,799.44	0.13%	1.81%	11.50%	13.41%	0.0171%
Raytheon Co	RTN	50,999.20	0.21%	2.07%	10.00%	12.17%	0.0257%
SBA Communications Corp	SBAC	26,453.74	0.11%	0.00%	28.50%	28.50%	0.0312%
Starbucks Corp	SBUX	102,474.90	0.42%	1.89%	13.50%	15.52%	0.0659%
Charles Schwab Corp/The	SCHW	53,416.07	0.22%	1.70%	12.00%	13.80%	0.0306%
Sealed Air Corp	SEE	6,801.73	0.03%	1.47%	22.50%	24.14%	0.0068%
Sherwin-Williams Co/The	SHW	43,541.76	0.18%	0.96%	10.50%	11.51%	0.0208%
SVB Financial Group	SIVB	11,214.70	0.05%	0.00%	19.50%	19.50%	0.0091%
JM Smucker Co/The	SJM	13,781.18	0.06%	2.86%	5.50%	8.44%	0.0048%
Schlumberger Ltd	SLB	52,980.92	0.22%	5.23%	24.00%	29.86%	0.0656%
SL Green Realty Corp	SLG	7,292.64	0.03%	4.04%	4.00%	8.12%	0.0025%
Snap-on Inc	SNA	9,307.15	0.04%	2.34%	7.00%	9.42%	0.0036%
Synopsys Inc	SNPS	18,552.95	0.08%	0.00%	10.00%	10.00%	0.0077%
Southern Co/The	SO	58,277.38	0.24%	4.46%	3.50%	8.04%	0.0194%
Simon Property Group Inc	SPG	50,940.13	0.21%	5.28%	5.50%	10.93%	0.0231%
S&P Global Inc	SPGI	56,918.01	0.24%	0.99%	13.00%	14.05%	0.0332%
Sempra Energy	SRE	38,447.68	0.16%	2.82%	11.00%	13.98%	0.0223%
SunTrust Banks Inc	STI	27,763.12	0.12%	3.20%	10.00%	13.36%	0.0154%
State Street Corp	STT	20,874.11	0.09%	3.50%	6.00%	9.61%	0.0083%
Seagate Technology PLC	STX	12,794.63	0.05%	5.46%	6.00%	11.62%	0.0062%
Constellation Brands Inc	STZ	35,264.59	0.15%	1.64%	9.50%	11.22%	0.0164%
Stanley Black & Decker Inc	SWK	22,178.22	0.09%	1.85%	9.50%	11.44%	0.0105%
Skyworks Solutions Inc	SWKS	13,097.57	0.05%	2.00%	7.50%	9.58%	0.0052%
Synchrony Financial	SYF	23,585.81	0.10%	2.57%	10.00%	12.70%	0.0124%
Stryker Corp	SYK	75,988.09	0.31%	1.02%	15.00%	16.10%	0.0507%
Symantec Corp	SYMC	13,137.84	0.05%	1.46%	9.00%	10.53%	0.0057%
Sysco Corp	SYY	36,086.83	0.15%	2.20%	12.00%	14.33%	0.0214%
AT&T Inc	T	237,451.70	0.98%	6.33%	5.50%	12.00%	0.1181%
Molson Coors Brewing Co	TAP	11,897.67	0.05%	3.18%	5.50%	8.77%	0.0043%
TransDigm Group Inc	TDG	26,396.66	0.11%	0.00%	11.00%	11.00%	0.0120%
TE Connectivity Ltd	TEL	32,361.33	0.13%	1.92%	8.50%	10.50%	0.0141%
Teleflex Inc	TFX	15,845.63	0.07%	0.41%	15.00%	15.44%	0.0101%
Target Corp	TGT	44,166.42	0.18%	3.06%	8.00%	11.18%	0.0205%
Tiffany & Co	TIF	11,668.97	0.05%	2.50%	10.50%	13.13%	0.0063%
TJX Cos Inc/The	TJX	65,277.92	0.27%	1.71%	13.50%	15.33%	0.0415%
Torchmark Corp	TMK	9,824.09	0.04%	0.77%	10.00%	10.81%	0.0044%
Thermo Fisher Scientific Inc	TMO	117,330.40	0.49%	0.26%	10.00%	10.27%	0.0499%
Tapestry Inc	TPR	8,958.29	0.04%	4.37%	12.00%	16.63%	0.0062%
TripAdvisor Inc	TRIP	6,498.25	0.03%	0.00%	18.00%	18.00%	0.0048%
T Rowe Price Group Inc	TROW	25,910.58	0.11%	2.81%	10.00%	12.95%	0.0139%
Travelers Cos Inc/The	TRV	39,858.56	0.17%	2.16%	9.00%	11.26%	0.0186%
Tractor Supply Co	TSCO	12,884.36	0.05%	1.31%	11.50%	12.89%	0.0069%
Tyson Foods Inc	TSN	28,699.95	0.12%	1.97%	6.50%	8.53%	0.0101%
Total System Services Inc	TSS	22,951.28	0.10%	0.40%	10.00%	10.42%	0.0099%
Take-Two Interactive Software Inc	TTWO	12,512.67	0.05%	0.00%	28.00%	28.00%	0.0145%
Twitter Inc	TWTR	27,214.84	N/A	0.00%	N/A	N/A	N/A
Texas Instruments Inc	TXN	105,812.00	0.44%	2.73%	6.00%	8.81%	0.0386%
Textron Inc	TXT	12,213.02	0.05%	0.15%	13.00%	13.16%	0.0067%
Under Armour Inc	UAA	11,985.43	0.05%	0.00%	12.00%	12.00%	0.0060%
United Continental Holdings Inc	UAL	23,028.57	0.10%	0.00%	8.50%	8.50%	0.0081%
UDR Inc	UDR	12,829.42	0.05%	2.94%	1.50%	4.46%	0.0024%
Universal Health Services Inc	UHS	11,209.81	0.05%	0.32%	11.00%	11.34%	0.0053%
Ulta Beauty Inc	ULTA	20,994.07	0.09%	0.00%	19.00%	19.00%	0.0165%
UnitedHealth Group Inc	UNH	236,115.30	0.98%	1.74%	13.50%	15.36%	0.1503%
Unum Group	UNM	6,960.99	0.03%	3.48%	9.00%	12.64%	0.0036%
Union Pacific Corp	UNP	118,616.80	0.49%	2.10%	14.50%	16.75%	0.0823%
United Parcel Service Inc	UPS	89,027.40	0.37%	3.71%	8.50%	12.37%	0.0456%

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
United Rentals Inc	URI	10,304.80	0.04%	0.00%	14.50%	14.50%	0.0062%
US Bancorp	USB	83,405.77	0.35%	3.01%	6.00%	9.10%	0.0315%
United Technologies Corp	UTX	112,123.70	0.46%	2.26%	9.00%	11.36%	0.0528%
Visa Inc	V	347,132.50	1.44%	0.62%	15.00%	15.67%	0.2254%
Varian Medical Systems Inc	VAR	12,436.03	0.05%	0.00%	10.00%	10.00%	0.0052%
VF Corp	VFC	35,042.77	0.15%	2.30%	10.00%	12.42%	0.0180%
Viacom Inc	VIAB	12,385.34	0.05%	2.61%	6.00%	8.69%	0.0045%
Valero Energy Corp	VLO	33,273.93	0.14%	4.51%	11.50%	16.27%	0.0224%
Vulcan Materials Co	VMC	17,658.95	0.07%	0.93%	14.00%	15.00%	0.0110%
Vornado Realty Trust	VNO	12,880.18	0.05%	3.91%	-3.50%	0.34%	0.0002%
Verisk Analytics Inc	VRSK	23,894.98	0.10%	0.69%	9.50%	10.22%	0.0101%
VeriSign Inc	VRSN	25,193.89	0.10%	0.00%	10.50%	10.50%	0.0110%
Vertex Pharmaceuticals Inc	VRTX	46,699.46	0.19%	0.00%	50.00%	50.00%	0.0968%
Ventas Inc	VTR	25,587.61	0.11%	4.50%	3.00%	7.57%	0.0080%
Verizon Communications Inc	VZ	237,141.40	0.98%	4.27%	4.00%	8.36%	0.0821%
Wabtec Corp	WAB	11,770.11	0.05%	0.66%	13.50%	14.20%	0.0069%
Waters Corp	WAT	14,856.91	0.06%	0.00%	10.50%	10.50%	0.0065%
Walgreens Boots Alliance Inc	WBA	52,439.30	0.22%	3.33%	9.50%	12.99%	0.0282%
WellCare Health Plans Inc	WCG	14,852.17	0.06%	0.00%	21.50%	21.50%	0.0132%
Western Digital Corp	WDC	11,614.52	0.05%	5.05%	0.50%	5.56%	0.0027%
WEC Energy Group Inc	WEC	26,935.25	0.11%	2.85%	6.00%	8.94%	0.0100%
Welltower Inc	WELL	30,687.01	0.13%	4.15%	8.00%	12.32%	0.0157%
Wells Fargo & Co	WFC	206,917.90	0.86%	4.01%	5.00%	9.11%	0.0781%
Whirlpool Corp	WHR	8,898.12	0.04%	3.40%	6.50%	10.01%	0.0037%
Willis Towers Watson PLC	WLTW	24,759.41	0.10%	1.36%	16.50%	17.97%	0.0184%
Waste Management Inc	WM	49,293.82	0.20%	1.77%	8.00%	9.84%	0.0201%
Williams Cos Inc/The	WMB	34,053.18	0.14%	5.56%	20.00%	26.12%	0.0369%
Walmart Inc	WMT	315,735.90	1.31%	1.94%	7.00%	9.01%	0.1179%
Westrock Co	WRK	9,376.85	0.04%	4.99%	9.50%	14.73%	0.0057%
Western Union Co/The	WU	8,610.38	0.04%	4.02%	6.00%	10.14%	0.0036%
Weyerhaeuser Co	WY	19,781.01	0.08%	5.12%	17.50%	23.07%	0.0189%
Wynn Resorts Ltd	WYNN	13,182.97	0.05%	3.27%	18.00%	21.56%	0.0118%
Cimarex Energy Co	XEC	5,770.12	0.02%	1.41%	18.00%	19.54%	0.0047%
Xcel Energy Inc	XEL	31,554.29	0.13%	2.69%	5.50%	8.26%	0.0108%
Xilinx Inc	XLNX	29,053.10	0.12%	1.29%	11.50%	12.86%	0.0155%
Exxon Mobil Corp	XOM	324,144.10	1.34%	4.54%	14.50%	19.37%	0.2602%
DENTSPLY SIRONA Inc	XRAY	12,852.83	0.05%	0.61%	3.00%	3.62%	0.0019%
Xerox Corp	XRX	8,026.27	0.03%	2.82%	10.50%	13.47%	0.0045%
Xylem Inc/NY	XYL	14,985.67	0.06%	1.15%	14.00%	15.23%	0.0095%
Yum! Brands Inc	YUM	33,849.72	0.14%	1.57%	12.00%	13.66%	0.0192%
Zimmer Biomet Holdings Inc	ZBH	24,516.61	0.10%	0.82%	4.50%	5.34%	0.0054%
Zions Bancorp NA	ZION	8,103.58	0.03%	2.84%	10.00%	12.98%	0.0044%
Zoetis Inc	ZTS	54,115.57	0.22%	0.58%	13.00%	13.62%	0.0305%
Total Market Capitalization:		24,130,896.91					14.78%

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 and Value Line Beta Coefficients

Company	Ticker	[1] Bloomberg	[2] Value Line
Atmos Energy Corporation	ATO	0.501	0.650
New Jersey Resources Corporation	NJR	0.624	0.700
Northwest Natural Holding Company	NWN	0.558	0.600
ONE Gas, Inc.	OGS	0.535	0.650
South Jersey Industries, Inc.	SJI	0.708	0.800
Spire Inc.	SR	0.479	0.650
Mean		0.568	0.675

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line

Capital Asset Pricing Model Results
Bloomberg and Value Line Derived Market Risk Premium

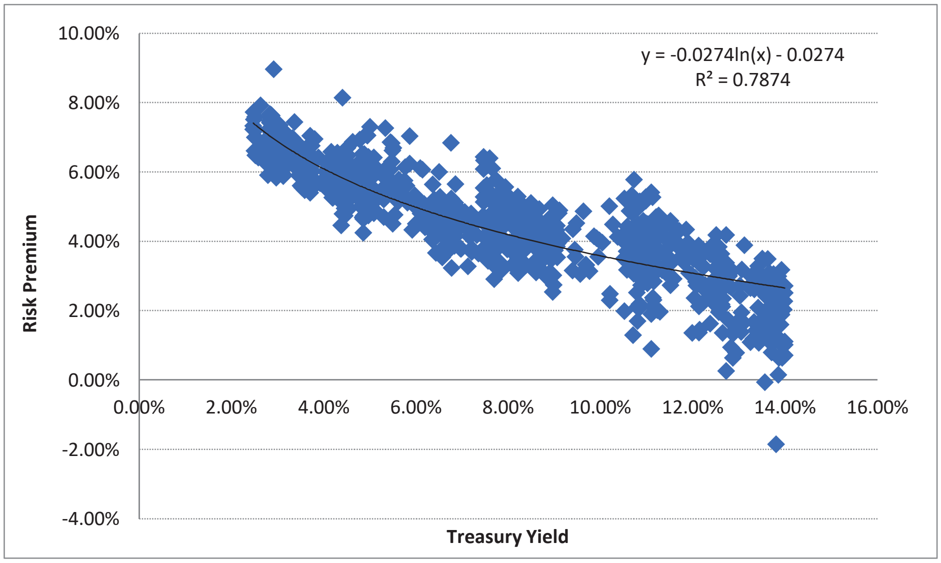
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
			Ex-Ante Market Risk Premium		CAPM Result		ECAPM Result	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP AVERAGE BLOOMBERG BETA COEFFICIENT								
Current 30-Year Treasury [9]	2.63%	0.568	12.25%	12.15%	9.58%	9.53%	10.91%	10.84%
Near Term Projected 30-Year Treasury [10]	2.70%	0.568	12.25%	12.15%	9.65%	9.60%	10.98%	10.91%
Mean					9.62%	9.56%	10.94%	10.88%

			Ex-Ante Market Risk Premium		CAPM Result		ECAPM 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	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP AVERAGE VALUE LINE AVERAGE BETA COEFFICIENT								
Current 30-Year Treasury [9]	2.63%	0.675	12.25%	12.15%	10.90%	10.83%	11.89%	11.82%
Near Term Projected 30-Year Treasury [10]	2.70%	0.675	12.25%	12.15%	10.97%	10.90%	11.96%	11.89%
Mean					10.93%	10.87%	11.93%	11.86%

Notes:
[1] *See Notes [9] and [10]*
[2] Source: Exhibit No.___(RBH-4)
[3] Source: Exhibit No.___(RBH-3)
[4] Source: Exhibit No.___(RBH-3)
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Equals Col. [1] + (0.75 x Col. [2] x Col. [3]) + (0.25 x Col. [3])
[8] Equals Col. [1] + (0.75 x Col. [2] x Col. [4]) + (0.25 x Col. [4])
[9] Source: Bloomberg Professional
[10] Source: Blue Chip Financial Forecasts, Vol. 38, No. 7, July 1, 2019, at 2.

Bond Yield Plus Risk Premium

	[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
	-2.74%	-2.74%			
Current 30-Year Treasury			2.63%	7.24%	9.87%
Near Term Projected 30-Year Treasury			2.70%	7.17%	9.87%
Long Term Projected 30-Year Treasury			3.70%	6.31%	10.01%



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. 7, July 1, 2019, at 2.
Long Term Projected = Blue Chip Financial Forecasts, Vol. 38, No. 6, June 1 2019, 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 186-trading day average (i.e. lag period)
[9] Equals [7] - [8]

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	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	14.20%	11.15%	3.05%
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
12/18/1980	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	13.60%	12.15%	1.45%
4/30/1981	15.00%	12.15%	2.85%
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	13.50%	12.87%	0.63%
7/31/1981	14.20%	12.87%	1.33%
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%
11/6/1981	15.17%	13.64%	1.53%
11/12/1981	15.00%	13.65%	1.35%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/25/1981	15.25%	13.66%	1.59%
11/25/1981	16.10%	13.66%	2.44%
11/25/1981	16.10%	13.66%	2.44%
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	15.70%	13.72%	1.98%
12/22/1981	16.00%	13.72%	2.28%
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	15.55%	13.79%	1.76%
7/1/1982	16.00%	13.79%	2.21%
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%
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%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	14.74%	13.42%	1.32%
9/30/1982	15.50%	13.42%	2.08%
9/30/1982	16.50%	13.42%	3.08%
9/30/1982	16.70%	13.42%	3.28%
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	14.50%	12.77%	1.73%
11/24/1982	16.02%	12.77%	3.25%
11/30/1982	12.98%	12.72%	0.26%
11/30/1982	15.50%	12.72%	2.78%
11/30/1982	15.50%	12.72%	2.78%
11/30/1982	15.65%	12.72%	2.93%
11/30/1982	16.00%	12.72%	3.28%
11/30/1982	16.10%	12.72%	3.38%
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	15.50%	12.13%	3.37%
1/24/1983	16.00%	12.13%	3.87%
1/28/1983	14.90%	12.07%	2.83%
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%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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	15.00%	10.70%	4.30%
7/19/1983	15.10%	10.70%	4.40%
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	14.75%	10.87%	3.88%
8/31/1983	15.25%	10.87%	4.38%
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	14.88%	11.07%	3.81%
10/27/1983	15.33%	11.07%	4.26%
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%
12/12/1983	14.50%	11.22%	3.28%
12/12/1983	15.50%	11.22%	4.28%
12/20/1983	15.40%	11.26%	4.14%
12/20/1983	16.00%	11.26%	4.74%
12/22/1983	15.75%	11.27%	4.48%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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	15.60%	12.60%	3.00%
9/12/1984	15.90%	12.60%	3.30%
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%
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%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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	14.88%	10.58%	4.30%
12/20/1985	15.00%	10.58%	4.42%
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%
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%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	12.85%	8.95%	3.90%
12/31/1987	13.25%	8.95%	4.30%
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%
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]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
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	12.10%	8.70%	3.40%
11/21/1990	12.50%	8.70%	3.80%
11/28/1990	12.75%	8.70%	4.05%
11/29/1990	12.75%	8.70%	4.05%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/18/1990	13.10%	8.68%	4.42%
12/20/1990	12.50%	8.67%	3.83%
12/21/1990	12.50%	8.67%	3.83%
12/21/1990	13.00%	8.67%	4.33%
12/21/1990	13.60%	8.67%	4.93%
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	11.60%	8.18%	3.42%
11/26/1991	12.00%	8.18%	3.82%
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%
6/24/1992	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%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	11.00%	7.67%	3.33%
11/25/1992	12.00%	7.67%	4.33%
12/3/1992	11.85%	7.66%	4.19%
12/16/1992	11.90%	7.63%	4.27%
12/22/1992	12.30%	7.62%	4.68%
12/22/1992	12.40%	7.62%	4.78%
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	11.50%	7.25%	4.25%
5/3/1993	11.75%	7.25%	4.50%
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	10.10%	6.57%	3.53%
10/29/1993	10.20%	6.57%	3.63%
10/29/1993	11.25%	6.57%	4.68%
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	10.60%	6.45%	4.15%
12/16/1993	11.20%	6.45%	4.75%
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%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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	10.90%	7.21%	3.69%
9/29/1994	11.00%	7.21%	3.79%
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	11.50%	7.59%	3.91%
12/8/1994	11.70%	7.59%	4.11%
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	11.10%	6.85%	4.25%
11/8/1995	11.30%	6.85%	4.45%
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%
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%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
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	10.30%	5.54%	4.76%
10/24/2001	11.00%	5.54%	5.46%
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%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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%
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%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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	10.40%	4.52%	5.88%
12/21/2005	11.00%	4.52%	6.48%
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%
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%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	9.53%	4.84%	4.69%
6/29/2007	10.10%	4.84%	5.26%
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%
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%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
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	10.40%	4.27%	6.13%
12/18/2009	10.50%	4.27%	6.23%
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	10.23%	4.37%	5.86%
1/21/2010	10.33%	4.37%	5.96%
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%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	9.19%	4.46%	4.73%
4/29/2010	9.40%	4.46%	4.94%
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	9.60%	4.31%	5.29%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.30%	4.31%	5.99%
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%
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	9.50%	3.15%	6.35%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/24/2012	9.75%	3.15%	6.60%
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	9.30%	2.91%	6.39%
10/31/2012	9.90%	2.91%	6.99%
10/31/2012	10.00%	2.91%	7.09%
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	10.00%	2.87%	7.13%
12/4/2012	10.50%	2.87%	7.63%
12/20/2012	9.50%	2.84%	6.66%
12/20/2012	10.10%	2.84%	7.26%
12/20/2012	10.25%	2.84%	7.41%
12/20/2012	10.30%	2.84%	7.46%
12/20/2012	10.40%	2.84%	7.56%
12/20/2012	10.50%	2.84%	7.66%
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%
6/13/2013	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%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	9.10%	3.71%	5.39%
5/8/2014	9.59%	3.71%	5.88%
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%
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%

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	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%
3/27/2019	9.70%	3.12%	6.58%
4/30/2019	9.73%	3.11%	6.62%
5/7/2019	9.65%	3.10%	6.55%
5/21/2019	9.80%	3.10%	6.70%
		Average:	4.70%
		Count:	1,121

Expected Earnings Analysis

Company	Ticker	[1] Expected ROE 2022-24	[2] Shares Outstanding 2019	[3] Shares Outstanding 2022-24	[4] Shares Outstanding % Increase	[5] Adjustment Factor	[6] Adjusted ROE
Atmos Energy Corporation	ATO	10.0%	120.00	145.00	3.86%	1.019	10.19%
New Jersey Resources Corporation	NJR	11.5%	88.00	89.00	0.23%	1.001	11.51%
Northwest Natural Holding Company	NWN	12.0%	30.00	32.00	1.30%	1.006	12.08%
ONE Gas, Inc.	OGS	10.0%	53.00	55.00	0.74%	1.004	10.04%
South Jersey Industries, Inc.	SJI	12.0%	94.00	100.00	1.25%	1.006	12.07%
Spire Inc. [7]	SR	9.0%	51.00	55.00	1.52%	1.008	9.07%
						Median	10.85%
						Average	10.83%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals = ([3] / [2])^(1/5)-1
[5] Equals (2 x (1 + [4])) / (2 + [4])
[6] Equals [1] x [5]
[7] Reflects Value Line August 30, 2019 Report due to typographical error in May 31, 2019 Report

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	$86.79	NA	NA	NA	$8,692,258	$403,692,258	$395,000,000	2.153%
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.	4/18/2018	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.	5/12/2016	8,050,000	$26.25	$0.9188	$330,000	$25.29	$7,725,938	$211,312,500	$203,586,563	3.656%
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.	5/12/2016	2,185,000	$63.05	$2.0491	$300,000	$60.86	$4,777,284	$137,764,250	$132,986,967	3.468%
Mean							$6,831,775	$255,453,014		
									WEIGHTED AVERAGE FLOTATION COSTS:	2.674%

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	$103.85	2.02%	2.10%	2.16%	6.50%	6.45%	7.50%	10.20%	7.66%	9.76%	9.82%
New Jersey Resources Corporation	NJR	$1.17	$49.18	2.38%	2.45%	2.51%	7.00%	6.00%	3.50%	5.84%	5.59%	8.03%	8.10%
Northwest Natural Holding Company	NWN	$1.90	$68.91	2.76%	2.90%	2.98%	4.50%	4.00%	27.00%	6.66%	10.54%	13.44%	13.52%
ONE Gas, Inc.	OGS	$2.00	$89.61	2.23%	2.30%	2.36%	5.90%	5.00%	8.00%	5.32%	6.06%	8.36%	8.42%
South Jersey Industries, Inc.	SJI	$1.15	$32.77	3.51%	3.64%	3.74%	7.20%	5.50%	10.50%	6.12%	7.33%	10.97%	11.07%
Spire Inc.	SR	$2.37	$84.59	2.80%	2.87%	2.95%	4.90%	3.43%	5.50%	5.18%	4.75%	7.62%	7.70%
PROXY GROUP MEAN												9.70%	9.77%

DCF Result Adjusted For Flotation Costs:	9.77%
DCF Result Unadjusted For Flotation Costs:	9.70%
Difference (Flotation Cost Adjustment):	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 - 2.674%)
[6] Source: Zacks
[7] Source: Yahoo! Finance
[8] Source: Value Line
[9] Source: Exhibit No.___(RBH-2), Value Line
[10] Equals Average([6], [7], [8], [9])
[11] Equals [4] + [10]
[12] Equals [5] + [10]
[13] Equals average [12] - average [11]

Percentage SB 901 of Common Equity

Present Value - SB 901

	9.00%	9.34%	9.68%	10.02%	10.36%	10.70%
4.00%	$ 17,117,064	$ 15,977,376	$ 14,974,420	$ 14,085,026	$ 13,290,979	$ 12,577,762
4.20%	$ 17,864,564	$ 16,630,985	$ 15,550,779	$ 14,597,065	$ 13,748,894	$ 12,989,702
4.40%	$ 18,677,064	$ 17,337,518	$ 16,170,803	$ 15,145,548	$ 14,237,541	$ 13,427,797
4.60%	$ 19,563,428	$ 18,103,674	$ 16,839,647	$ 15,734,509	$ 14,760,122	$ 13,894,620
4.80%	$ 20,534,207	$ 18,937,332	$ 17,563,314	$ 16,368,602	$ 15,320,299	$ 14,393,092
5.00%	$ 21,602,064	$ 19,847,826	$ 18,348,833	$ 17,053,220	$ 15,922,280	$ 14,926,544

Present Value - Common Equity

	9.00%	9.34%	9.68%	10.02%	10.36%	10.70%
4.00%	$ 4,606,640,749	$ 4,299,921,435	$ 4,030,000,218	$ 3,790,641,520	$ 3,576,943,166	$ 3,384,998,056
4.20%	$ 4,807,812,160	$ 4,475,824,387	$ 4,185,113,366	$ 3,928,444,316	$ 3,700,179,757	$ 3,495,861,750
4.40%	$ 5,026,476,737	$ 4,665,970,493	$ 4,351,977,509	$ 4,076,055,139	$ 3,831,687,260	$ 3,613,764,408
4.60%	$ 5,265,019,912	$ 4,872,162,684	$ 4,531,980,561	$ 4,234,559,751	$ 3,972,327,228	$ 3,739,398,388
4.80%	$ 5,526,281,484	$ 5,096,521,588	$ 4,726,737,961	$ 4,405,210,309	$ 4,123,085,180	$ 3,873,549,927
5.00%	$ 5,813,669,214	$ 5,341,558,731	$ 4,938,141,293	$ 4,589,458,522	$ 4,285,093,725	$ 4,017,115,608

Percentage Present Value SB 901 of Present Value Common Equity

	9.00%	9.34%	9.68%	10.02%	10.36%	10.70%
4.00%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
4.20%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
4.40%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
4.60%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
4.80%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
5.00%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%

Sources:
Company Provided Data
Ch 6. Sh. 1 for Northern and Southern California, and South Lake Tahoe Filings

Proxy Group Capital Structure

		% Common Equity								
Company	Ticker	2019Q1	2018Q4	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	Average
Atmos Energy Corporation	ATO	60.12%	59.37%	60.85%	60.80%	60.61%	59.80%	55.97%	55.99%	59.19%
New Jersey Resources Corporation	NJR	54.61%	53.34%	52.11%	53.49%	55.77%	53.59%	51.55%	54.23%	53.59%
Northwest Natural Holding Company	NWN	51.67%	50.88%	47.67%	50.03%	50.45%	48.78%	52.07%	54.58%	50.77%
ONE Gas, Inc.	OGS	61.38%	61.38%	62.81%	62.88%	62.87%	62.16%	61.82%	61.84%	62.14%
South Jersey Industries, Inc.	SJI	38.16%	30.84%	30.88%	31.98%	50.85%	50.12%	50.62%	54.16%	42.20%
Spire Inc.	SR	51.60%	51.32%	52.08%	51.42%	49.70%	49.33%	48.73%	51.30%	50.69%
Mean		52.92%	51.19%	51.07%	51.77%	55.04%	53.96%	53.46%	55.35%	53.10%

		% Long-Term Debt								
Company	Ticker	2019Q1	2018Q4	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	Average
Atmos Energy Corporation	ATO	39.88%	40.63%	39.15%	39.20%	39.39%	40.20%	44.03%	44.01%	40.81%
New Jersey Resources Corporation	NJR	45.39%	46.66%	47.89%	46.51%	44.23%	46.41%	48.45%	45.77%	46.41%
Northwest Natural Holding Company	NWN	48.33%	49.12%	52.33%	49.97%	49.55%	51.22%	47.93%	45.42%	49.23%
ONE Gas, Inc.	OGS	38.62%	38.62%	37.19%	37.12%	37.13%	37.84%	38.18%	38.16%	37.86%
South Jersey Industries, Inc.	SJI	61.84%	69.16%	69.12%	68.02%	49.15%	49.88%	49.38%	45.84%	57.80%
Spire Inc.	SR	48.40%	48.68%	47.92%	48.58%	50.30%	50.67%	51.27%	48.70%	49.31%
Mean		47.08%	48.81%	48.93%	48.23%	44.96%	46.04%	46.54%	44.65%	46.90%

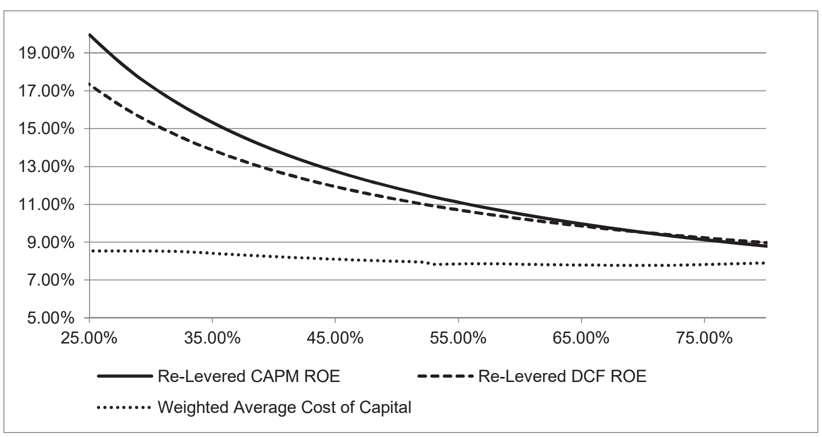
Source: S&P Global Market Intelligence

Effects of Leverage on the Company's Return on Equity

CAPM Adjustment	
Proxy Average Value LIne Equity Ratio	57.08%
Proxy Average Value Line D/E Ratio	75.18%
Proxy Average Tax Rate	21.00%
Proxy Average Value Line Beta	0.68
Proxy Average Value Line Asset Beta	0.42
Check: Re-Levered Beta	0.68
Value Line Risk Premium	12.15%
Risk Free Rate	2.63%
Moody's A Utility Index	3.86%
Moody's Baa Utility Index	4.36%
Spread	0.50%

DCF Adjustment	
Levered ROE	10.50%
Cost of Debt	4.36%
Debt/Total Capital Ratio	42.92%
Debt/Equity Ratio	75.18%
Combined Tax Rate	21.00%
Calculated Unlevered ROE	8.21%
Check: Re-Levered ROE	10.50%

Equity Ratio	D/E Ratio	Re-Levered Beta	Re-Levered CAPM ROE	Re-Levered DCF ROE	Cost of Debt	Weighted Average Cost of Capital
17.08%	4.85	2.05	27.51%	22.99%	5.61%	8.58%
22.08%	3.53	1.60	22.12%	18.95%	5.61%	8.55%
27.08%	2.69	1.32	18.72%	16.41%	5.61%	8.53%
32.08%	2.12	1.13	16.38%	14.66%	5.61%	8.51%
37.08%	1.70	0.99	14.67%	13.38%	5.36%	8.33%
42.08%	1.38	0.88	13.37%	12.40%	5.11%	8.18%
47.08%	1.12	0.80	12.35%	11.63%	4.86%	8.05%
52.08%	0.92	0.73	11.52%	11.01%	4.61%	7.94%
53.00%	0.89	0.72	11.38%	10.91%	4.36%	7.83%
57.08%	0.75	0.68	10.83%	10.50%	4.36%	7.86%
62.08%	0.61	0.63	10.26%	10.07%	4.11%	7.81%
67.08%	0.49	0.59	9.77%	9.70%	3.86%	7.78%
72.08%	0.39	0.55	9.35%	9.39%	3.61%	7.78%
77.08%	0.30	0.52	8.99%	9.12%	3.61%	7.85%
82.08%	0.22	0.50	8.66%	8.88%	3.61%	7.93%
87.08%	0.15	0.47	8.38%	8.66%	3.61%	8.01%
92.08%	0.09	0.45	8.13%	8.47%	3.61%	8.09%
97.08%	0.03	0.43	7.90%	8.30%	3.61%	8.17%
102.08%	-0.02	0.42	7.69%	8.15%	3.61%	8.24%
107.08%	-0.07	0.40	7.51%	8.01%	3.61%	8.32%



Effects of Leverage on the Company's Return on Equity

Notes:

Hamada's Equation:

$$B_a = \frac{B_e}{(1 + (1 - \mathrm{T}) \text{ x } \frac{D}{E})}$$

or, rearranged:

$$B_e = B_a \text{ x } (1 + (1 - \mathrm{T}) \text{ x DE})$$

Where:

B_a	= Asset Beta
B_e	= Equity Beta
T	= Tax Rate
D/E	= Debt/Equity Ratio

Under Modigliani-Miller Proposition:

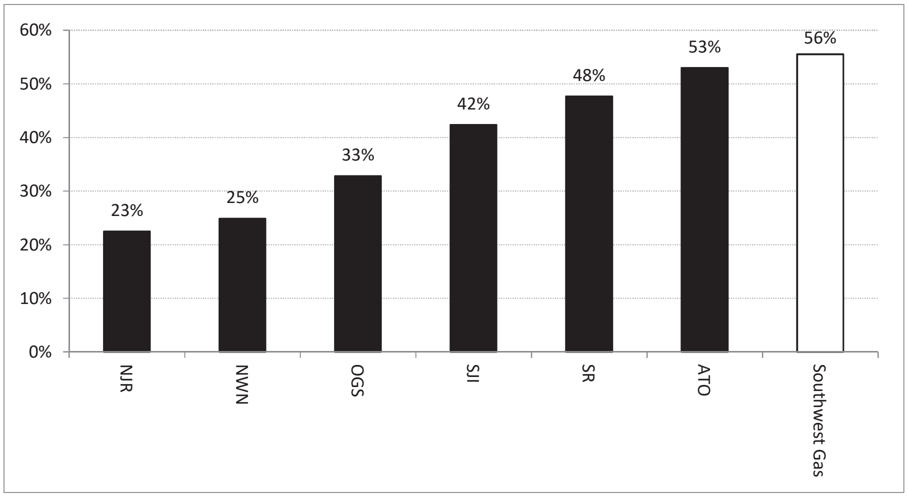
$$R_e = R_a + \frac{D}{E} (R_a - R_d) \text{ X } (1 - \mathrm{T})$$

or, rearranged:

$$R_a = \frac{(Re + \frac{D}{E} \text{ x } R_d \text{ x } (1 - \mathrm{T}))}{(1 + \frac{D}{E} \text{ x } (1 - \mathrm{T}))}$$

R_a	= Unlevered Return on Equity
R_e	= Levered Return on Equity
R_d	= Cost of Debt
T	= Tax Rate
D/E	= Debt/Equity Ratio

Capital Expenditures Relative to Net Plant



Company	Ticker	2-Year CAPEX / 2018 Net Plant [1]
Atmos Energy Corporation	ATO	53.02%
New Jersey Resources Corporation	NJR	22.51%
Northwest Natural Holding Company	NWN	24.88%
ONE Gas, Inc.	OGS	32.81%
South Jersey Industries, Inc.	SJI	42.38%
Spire Inc.	SR	47.67%
Median		37.59%
Southwest Gas [2]		55.53%

Notes:

[1] Source: Value Line; Value Line estimates 2019 and 2020 CAPEX
[2] Ch. 17, Sh. 4, 12, 13, 14 for Southern and Northern California, and South Lake Tahoe Filings

Company Witness:
Celine Louise R. Apo

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

APPLICATION 19-08___

PREPARED DIRECT TESTIMONY

OF

CELINE LOUISE R. APO

ON BEHALF OF

SOUTHWEST GAS CORPORATION

AUGUST 30, 2019

Table of Contents
Prepared Direct Testimony
of
CELINE LOUISE R. APO

BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

Prepared Direct Testimony
Of
CELINE LOUISE R. APO

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Celine Louise R. Apo. 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 Supervisor.

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 provided testimony to the California Public Utilities Commission (Commission) and the Public Utilities Commission of Nevada.

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 sponsor Southwest Gas' Conservation and Energy Efficiency (CEE) Plan, which is detailed herein and in Exhibit No.__(CLA-1) and Exhibit No.__(CLA-2).

Q. 6 Please summarize your prepared direct testimony.

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

- An overview of Southwest Gas' existing CEE Plan for 2014-2020
- An overview of the Company's proposed CEE Plan for 2021-2025
- An explanation of the purpose and process for minor program modifications
- Proposed CEE Plan cost recovery

II. OVERVIEW OF SOUTHWEST GAS' EXISTING CEE PLAN FOR YEARS 2014-2020

Q. 7 Did Southwest Gas receive approval of its existing CEE Plan in its last general rate case proceeding?

A. 7 Yes. Southwest Gas received approval for a 5-year CEE Plan June 12, 2014, as part of its last general rate case filing (Decision (D.) 14-06-028). The Company launched the approved CEE Plan in July 2014. Subsequently, Southwest Gas received approval to extend its existing CEE Plan through December 31, 2020 (D.17-06-006).

Q. 8 What programs are included in Southwest Gas' existing CEE Plan?

A. 8 Southwest Gas currently offers the *Smarter Greener Better*® Residential Rebates program and the *Smarter Greener Better* Commercial Rebates program, which are designed to reduce residential and commercial customers' energy consumption and utility bills. Rebates are offered for energy efficient water heating and space heating equipment, as well as for commercial foodservice equipment. A list of all measures in Southwest Gas' existing CEE Plan, including expenditures, therm savings and participation levels for program years 2014-2018 is provided in Exhibit No.___(CLA-1).

Q. 9 Has Southwest Gas expended its annual CEE Plan budget of $1 million?

A. 9 No. The Company developed its initial CEE Plan using measures it anticipated customers would be most interested in and participation and budget levels estimated to be sufficient for market demand. Due to the limited participation and expenditures experienced under Southwest Gas' CEE Plan during 2014-2018, the Company has adjusted its program and measure offerings in its proposed CEE Plan in an effort to increase program participation and expenditures, as discussed in more detail below.

III. OVERVIEW OF THE COMPANY'S PROPOSED CEE PLAN FOR YEARS 2021-2025

Q. 10 What programs are included in the Company's proposed CEE Plan for years 2021-2025?

A. 10 Southwest Gas is proposing the following programs to customers in the Company's California service territories:

- **Residential Equipment Direct-Install (RED)** – The RED program is a no cost to the customer energy assistance program, which will offer the direct-installation of water heating and space heating equipment to residential customers. This program, which will include single family, multifamily, and mobile homes, will offer a limited number of measures, and is specifically targeted for residential customers that do not qualify for Southwest Gas' Energy Savings Assistance program for low income households. The measures offered to residential customers under the RED program include:
    - Faucet Aerator – Kitchen
    - Faucet Aerator – Lavatory/Bathroom

    - Low-Flow Showerhead
    - Smart Low-Flow Showerhead
    - Duct Sealing – This measure would only be offered to single family and mobile home customers since it did not pass cost-effectiveness using the total resource cost (TRC) test for multifamily customers.
- **Residential Equipment Rebates** – The Residential Equipment Rebates program will offer rebates for qualifying energy efficient water heating and space heating equipment to residential customers in single family, multifamily, and mobile homes. Customers who receive direct-install measures under the RED program may also take advantage of the rebates available under this program. In addition to the measures provided under the RED program, residential customers may also obtain rebates for the following measures:
    - Natural Gas Tankless Water Heater
    - Natural Gas Gravity Wall Furnace
    - Natural Gas Fireplace
    - Smart Thermostat – This measure would only be offered to customers in climate zone 16 since it did not pass cost-effectiveness using the TRC test for climate zone 14.
- **New Home Rebates** – The New Home Rebates program will offer rebates to homebuilders for single family homes built to the State of California Title 24 Energy Efficiency Standards and equipped with energy efficient

natural gas appliances. Homebuilders will be offered rebates for homes built with the following measures under the New Home Rebates Program:

  - Natural Gas Tankless Water Heater
  - Natural Gas Furnace

- **Commercial Equipment Rebates** – The Commercial Equipment Rebates program will offer energy audits, direct-install measures, and rebates for qualifying energy-efficient water heating, space heating, and commercial food service equipment to commercial customers. The Commercial Equipment Rebates Program will offer the direct-installation of or rebates for the following measures:
  - Energy Audit
  - Faucet
  - Low-Flow Showerhead
  - Pre-Rinse Spray Valve
  - Natural Gas Storage Water Heater
  - Natural Gas Tankless Water Heater
  - Natural Gas Condensing Furnace
  - Natural Gas Condensing HVAC Boiler
  - Combination Oven
  - Convection Oven
  - Conveyor Broiler
  - Underfired Broiler
  - Conveyor Oven
  - Fryer

- Griddle
- Rack Oven
- Steam Cooker

- **Solar Thermal Rebates** – The Solar Thermal Rebates program will offer rebates to residential and commercial customers for the following types of solar thermal systems:
  - Commercial Pools
  - Commercial and Multifamily
  - Single Family Residential

These programs include some of the measures in Southwest Gas' existing CEE Plan as well as additional offerings to expand customers' opportunities to reduce their energy consumption and utility bills. Two tiers of some measures may be offered to incentivize the installation of high-efficiency equipment and offset the higher incremental cost. A complete list of all measures, including requirements, rebate amounts, estimated annual energy therm savings by climate zone, and TRC ratios by climate zone, under each program in the Company's proposed CEE Plan is detailed in Exhibit No.__(CLA-2).

Q. 11 Was a cost-effectiveness evaluation performed for the Company's proposed CEE Plan for years 2021-2025?

A. 11 Yes. A cost-effectiveness evaluation was performed utilizing the following five types of tests: TRC test, utility cost test (UCT), ratepayer impact measure (RIM) test, participant cost test (PCT), and societal cost test (SCT). Excluding renewables (solar thermal systems), only cost-effective measures, identified as those with a TRC ratio of 1.0 or above, have been included in Southwest Gas' proposed CEE Plan for years 2021-2025.

Q. 12 What is the budget for the Company's proposed CEE Plan for years 2021-2025?

A. 12 The Company is proposing to maintain its current annual CEE Plan budget of $1 million. The $1 million annual budget, which includes all programs mentioned above, will be utilized for program administration, program outreach, and customer rebates, including the costs of direct-install measures. The Company anticipates that its proposal to offer additional programs and measures for years 2021-2025 will result in additional customer participation and program expenditures.

IV. PURPOSE & PROCESS FOR MINOR PROGRAM MODIFICATIONS

Q. 13 Does Southwest Gas see a need to make minor program modifications in between plan filings?

A. 13 Yes. Since Southwest Gas files for approval of its CEE Plan as part of its general rate case applications, the Company believes minor program modifications may be needed in between general rate case filings to adjust the approved CEE programs to market and customer demands. Having the flexibility to timely respond to market needs and industry and technology changes will help Southwest Gas maintain up-to-date program offerings and maximize program participation.

Q. 14 What process will the Company follow to request minor program modifications?

A. 14 The Company proposes to submit an advice letter to request minor program modifications as needed for its approved CEE Plan in between general rate case applications.

<u>V. PROPOSED CEE PLAN COST RECOVERY</u>

Q. 15 How does Southwest Gas currently recover its CEE Plan costs?

A. 15 Southwest Gas currently recovers its CEE Plan costs under the CEE rate component of the Company's Public Purpose Program (PPP) surcharge as approved in D.14-06-028.

Q. 16 Does the Company propose any changes to the existing cost recovery method?

A. 16 No. The Company seeks to continue utilizing its current methodology.

Q. 17 Is the Company proposing to update the CEE rate as part of this general rate case?

A. 17 No. Southwest Gas is only requesting approval of the CEE Plan budget in this general rate case. To develop the CEE rate, Southwest Gas will use the approved CEE Plan budget and the appropriate month-ending Conservation and Energy Efficiency Balancing Account (CEEBA) balance in year 2020. Because the Company does not know what the 2020 CEEBA balance will be at this time, the Company proposes to update the CEE rate component when it updates its PPP surcharges through the Commission's Advice Letter process.

Q. 18 Does this conclude your prepared direct testimony in this matter?

A. 18 Yes.

SUMMARY OF QUALIFICATIONS
CELINE LOUISE R. APO

I graduated from the University of Nevada Las Vegas with a Bachelor of Science in Business Administration; Accounting in 2009.

From 2010 to present, I have been employed by Southwest Gas Corporation (Company), initially as an Analyst I in the State Regulatory Affairs department. I was subsequently promoted to Analyst II/Energy Efficiency in 2012, Senior Analyst/Energy Efficiency in 2015, and Administrator/Energy Efficiency in 2017. My responsibilities included supporting the development, implementation, promotion, and reporting of the Company's conservation and energy efficiency (CEE) and low-income programs in Arizona, California, and Nevada.

In May 2018, I transitioned to my current position as Supervisor in the Regulation and Energy Efficiency department. My responsibilities continue to include overseeing the development, implementation, promotion, and reporting of the Company's CEE and low-income programs. I am also responsible for assisting and reviewing various regulatory filings and projects for the Company's Arizona, California, and Nevada rate jurisdictions.

CA CEE PLAN - ANNUAL EXPENDITURES, SAVINGS, AND PARTICIPATION FOR YEARS 2014-2018 [1]

Program and Measures	2014			2015			2016		
	Expenditures	Savings (therms)	Participation	Expenditures	Savings (therms)	Participation	Expenditures	Savings (therms)	Participation
CEE Plan Administration [2]									
CEE Plan Administration Total	**$0.00**	**N/A**	**N/A**	**$0.00**	**N/A**	**N/A**	**$0.00**	**N/A**	**N/A**
SGB Residential Rebates									
Administration	$28,122.45	N/A	N/A	$21,495.64	N/A	N/A	$23,898.01	N/A	N/A
Natural Gas Tankless Water Heater	$2,000.00	660	10	$11,000.00	3,630	55	$7,800.00	2,574	39
Smart Low-flow Showerhead	$0.00	0	0	$45.00	63	3	$60.00	84	4
Natural Gas Furnace	$1,400.00	819	7	$4,800.00	2,808	24	$4,200.00	2,457	21
SGB Residential Rebates Total	**$31,522.45**	**1,479**	**17**	**$37,340.64**	**6,501**	**82**	**$35,958.01**	**5,115**	**64**
SGB Commercial Rebates									
Administration	$17,130.43	N/A	N/A	$20,211.42	N/A	N/A	$17,834.94	N/A	N/A
Natural Gas Tankless Water Heater	$0.00	0	0	$200.00	66	1	$0.00	0	0
Smart Low-flow Showerhead	$0.00	0	0	$0.00	0	0	$0.00	0	0
Natural Gas Furnace	$0.00	0	0	$0.00	0	0	$2,800.00	1,638	14
Non-condensing Boiler	$0.00	0	0	$0.00	0	0	$0.00	0	0
Condensing Boiler	$0.00	0	0	$0.00	0	0	$11,250.00	17,835	3
Boiler - Modulating Burner Control	$0.00	0	0	$0.00	0	0	$0.00	0	0
Boiler - O2 Trim Control Pad	$0.00	0	0	$0.00	0	0	$0.00	0	0
Boiler - Steam Trap	$0.00	0	0	$0.00	0	0	$0.00	0	0
Griddle	$250.00	298	2	$0.00	0	0	$0.00	0	0
Fryer	$5,000.00	5,050	10	$5,000.00	5,050	10	$5,500.00	5,555	11
Convection Oven	$0.00	0	0	$0.00	0	0	$0.00	0	0
Combination Oven	$0.00	0	0	$0.00	0	0	$0.00	0	0
Conveyor Oven	$0.00	0	0	$0.00	0	0	$0.00	0	0
SGB Commercial Rebates Total	**$22,380.43**	**5,348**	**12**	**$25,411.42**	**5,116**	**11**	**$37,384.94**	**25,028**	**28**
CEE Plan Grand Total	**$53,902.88**	**6,827**	**29**	**$62,752.06**	**11,617**	**93**	**$73,342.95**	**30,143**	**92**

[1] CEE Plan as approved in Decision 14-06-028.

[2] These expenditures are for costs that are not program specific.

CA CEE PLAN - ANNUAL EXPENDITURES, SAVINGS, AND PARTICIPATION FOR YEARS 2014-2018 [1]

Program and Measures	2017			2018		
	Expenditures	Savings (therms)	Participation	Expenditures	Savings (therms)	Participation
CEE Plan Administration [2]						
CEE Plan Administration Total	**$0.00**	**N/A**	**N/A**	**$5,603.40**	**N/A**	**N/A**
SGB Residential Rebates						
Administration	$37,368.99	N/A	N/A	$20,371.36	N/A	N/A
Natural Gas Tankless Water Heater	$10,800.00	3,564	54	$10,600.00	3,498	53
Smart Low-flow Showerhead	$45.00	63	3	$0.00	0	0
Natural Gas Furnace	$4,400.00	2,574	22	$6,200.00	3,627	31
SGB Residential Rebates Total	**$52,613.99**	**6,201**	**79**	**$37,171.36**	**7,125**	**84**
SGB Commercial Rebates						
Administration	$31,763.23	N/A	N/A	$14,652.32	N/A	N/A
Natural Gas Tankless Water Heater	$800.00	264	4	$400.00	132	2
Smart Low-flow Showerhead	0	0	0	$0.00	0	0
Natural Gas Furnace	0	0	0	$0.00	0	0
Non-condensing Boiler	0	0	0	$9,000.00	1,826	1
Condensing Boiler	0	0	0	$0.00	0	0
Boiler - Modulating Burner Control	0	0	0	$0.00	0	0
Boiler - O2 Trim Control Pad	0	0	0	$0.00	0	0
Boiler - Steam Trap	0	0	0	$0.00	0	0
Griddle	0	0	0	$0.00	0	0
Fryer	$2,000.00	2,020	4	$1,500.00	1,515	3
Convection Oven	0	0	0	$0.00	0	0
Combination Oven	0	0	0	$1,500.00	806	2
Conveyor Oven	0	0	0	$0.00	0	0
SGB Commercial Rebates Total	**$34,563.23**	**2,284**	**8**	**$27,052.32**	**4,279**	**8**
CEE Plan Grand Total	**$87,177.22**	**8,485**	**87**	**$69,827.08**	**11,404**	**92**

[1] CEE Plan as approved in Decision 14-06-028.

[2] These expenditures are for costs that are not program specific.

CA CEE PLAN - PROPOSED PROGRAMS AND MEASURES FOR YEARS 2021-2025

Program and Measures	Measure Requirement [1]	Rebate Amount	Estimated Annual Savings (therms) [2]		TRC Ratio [3]	
			Climate Zone (CZ) 14 [4]	CZ 16 [5]	CZ 14 [4]	CZ 16 [5]
Residential Equipment Direct-Install (RED) - available for single family, multifamily*, and mobile homes					**1.52**	
Faucet Aerator - Kitchen	Gallons per minute (GPM) rating ≤ 1.5	$5.80 / unit	6.69	8.37	6.33	7.92
Faucet Aerator - Lavatory/Bathroom	GPM rating ≤ 1.0	$5.62 / unit	3.26	4.08	3.18	3.98
Low-Flow Showerhead	GPM rating ≤ 1.5	$30 / unit	8.42	10.54	1.81	2.27
Smart Low-Flow Showerhead	GPM rating ≤ 1.5	$55.42 / unit	10.28	12.41	1.20	1.45
*Duct Sealing (excludes multifamily)	Post-sealing leakage ≤ 15%	$252.69 / home	26.94	60.72	1.05	2.46
Residential Equipment Rebates - available for single family, multifamily, and mobile homes					**1.30**	
Natural Gas Tankless Water Heater (TWH)	Uniform Energy Factor (UEF) ≥ 0.81	$300 / unit	39.50		1.08	
Natural Gas Gravity Wall Furnace	Annual Fuel Utilization Efficiency AFUE ≥ 70%	$25 / unit	14.99	21.18	4.09	5.78
Natural Gas Fireplace - Tier 1	70% - 74.9% efficient with intermittent pilot light	$50 / unit	16.00	27.00	2.06	3.48
Natural Gas Fireplace - Tier 2	Efficiency ≥ 75% with intermittent pilot light	$100 / unit	28.00	47.00	1.86	3.12
Smart Thermostat (excludes CZ 14)	ENERGY STAR qualified	$100 / unit	N/A	48.23	N/A	1.94
New Home Rebates - available for single family homes only					**1.50**	
Title 24 Home - Single Story Tier 1	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 92%	$400 / home	68.15	85.52	1.62	2.04
Title 24 Home - Two Story Tier 1	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 92%	$650 / home	105.34	122.36	1.24	1.44
Title 24 Home - Single Story Tier 2	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 96%	$500 / home	75.49	97.59	1.64	2.13
Title 24 Home - Two Story Tier 2	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 96%	$750 / home	118.69	140.59	1.34	1.59
Commercial Equipment Rebates					**1.65**	
Commercial Energy Audit	American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Level II	$5,000 / facility	N/A	N/A	N/A	N/A
Faucet - Tier 1	GPM rating ≤ 1.0	$5.13 / unit	3.58	4.69	4.05	5.31
Faucet - Tier 2	GPM rating ≤ 0.5	$5.13 / unit	6.25	8.19	7.08	9.27
Low-Flow Showerhead - Tier 1	GPM rating ≤ 1.8	$14.90 /unit	6.87	8.60	2.68	3.35
Low-Flow Showerhead - Tier 2	GPM rating ≤ 1.5	$14.90 /unit	11.45	14.33	4.46	5.59
Pre-Rinse Spray Valve - Tier 1	GPM rating ≤ 1.07	$49 / unit	16.04	19.44	2.17	1.30
Pre-Rinse Spray Valve - Tier 2	GPM rating ≤ 0.75	$49 / unit	55.52	67.29	3.73	4.52
Natural Gas Storage Water Heater (≤ 75,000 Btu/hr) - Tier 1	Thermal Efficiency ≥ 83%	$1.50 / MBtuh	0.65	0.76	1.90	2.19
Natural Gas Storage Water Heater (≤ 75,000 Btu/hr) - Tier 2	Thermal Efficiency ≥ 90%	$5.00 / MBtuh	2.01	2.32	1.75	2.02
Natural Gas Storage Water Heater (> 75,000 Btu/hr) - Tier 1	Thermal Efficiency ≥ 83%	$1.50 / MBtuh	0.59	0.75	2.02	2.57
Natural Gas Storage Water Heater (> 75,000 Btu/hr) - Tier 2	Thermal Efficiency ≥ 90%	$5.00 / MBtuh	1.80	2.31	1.89	2.43
Natural Gas Tankless Water Heater (≤ 200,000 Btu/hr)	UEF ≥ 0.81	$10.00 / MBtuh	2.28	2.61	1.09	1.25
Natural Gas Condensing Furnace	AFUE ≥ 95%	$2.50 / MBtuh	1.26	1.57	2.99	3.72
Natural Gas Condensing HVAC Boiler (≥ 300,000 Btu/hr)	Thermal Efficiency ≥ 94%	$2.50 / MBtuh	0.93	1.16	2.07	2.58
Combination Oven	Fisher-Nickel qualified	$1,500 / unit	1,163.67		1.96	
Convection Oven (full sized)	Fisher-Nickel qualified	$500 / oven chamber	250.00		1.57	
Convection Oven (half sized)	Fisher-Nickel qualified	$250 / oven chamber	162.00		2.56	
Conveyor Broiler	Fisher-Nickel qualified	$1,000 / unit	2,079.00		5.79	
Underfired Broiler	Fisher-Nickel qualified	$1,000 / unit	653.33		2.40	
Conveyor Oven (≥ 25" wide)	Fisher-Nickel qualified	$750 / unit	884.00		3.27	
Fryer	Fisher-Nickel qualified	$500 / vat	548.00		4.21	
Griddle	Fisher-Nickel qualified	$125 / 3 feet	126.00		3.50	
Rack Oven	Fisher-Nickel qualified	$1,000 / oven chamber	2,104.00		4.35	
Steam Cooker	Fisher-Nickel qualified	$1,000 / unit	2,595.00		7.35	
Solar Thermal Rebates					**0.40**	
Solar Thermal Commercial Pools	Collector must be OG-100 certified	$7.00 / therm	1,997.00	1,720.00	1.71	1.92
Solar Thermal Commercial and Multifamily	Collector must be OG-100 certified	$20.19 / therm	2,021.00	1,668.00	0.42	0.32
Solar Thermal Single Family Residential	System must be OG-300 certified	$29.85 / therm	136.00	120.00	0.17	0.16
CEE Plan					**1.31**	

[1] Equipment must use natural gas directly or utilize the appropriate natural gas fueled water or space heating source

[2] Average therm savings for all property/facility types

[3] Workpapers CLA-2

[4] Southwest Gas' service areas in CZ 14 include: Adelanto, Apple Valley, Barstow, Lenwood, North Barstow, Daggett, Helendale, Hesperia, Oak Hills, Hinkley, Lucerne Valley, Oro Grande, Victorville, and Yermo. The Company also serves a small area in CZ 15 (Needles), which has been included in the savings and cost-effectiveness analysis for CZ 14.

[5] Southwest Gas' service areas in CZ 16 include: Big Bear City, Big Bear Lake, Fawnskin, Sugarloaf, Carnelian Bay, Homewood, Tahoma, Kings Beach, Tahoe City, Tahoe Vista, South Lake Tahoe, Northstar, and Truckee.