



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)

VOLUME III

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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Prepared Direct Testimony
of
BRANDY LITTLE

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Appendix A – Summary of Qualifications of Brandy Little

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
BRANDY LITTLE

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

1 therms for calendar year 2018; and (3) the forecasted number of bills and therms
2 for 2019, 2020, and for test year 2021.

3 **Q. 6 Please summarize your prepared direct testimony.**

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

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

10 **II. REGRESSION ANALYSIS**

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

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

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

5 **III. FORECASTED SALES VOLUME PROJECTIONS**

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

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

13 **IV. FORECASTED METHODOLOGY**

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

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

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

22 A. 10 Yes. Southwest Gas has consistently utilized the same forecasting methodology
23 to develop the billing determinants. The California Public Utilities Commission
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1 (Commission) has accepted Southwest Gas' methodological approach for
2 forecasting therm sales volumes and number of bills since at least 1985.

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

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

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

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

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

15 A. 13 Yes.

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**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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Prepared Direct Testimony
of
VALERIE J. ONTIVEROZ

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Appendix A – Summary of Qualifications 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.

1 **Q. 6 Please summarize your prepared direct testimony.**

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

- 3 • The Company's compliance with Decision (D.) 14-06-028, as modified by
- 4 D.17-06-006, issued in the its last general rate case, A.12-12-024
- 5 • Overview of the Company's application for rate relief.
- 6 • The Company's incorporation of a risk-based decision-making¹ framework
- 7 into its general rate case in response to Commission Decisions (D.) 14-12-
- 8 025 and 19-04-020, including the proposal to implement three risk-based
- 9 infrastructure projects.
- 10 • The Company's proposal to incorporate a third residential baseline season
- 11 responsive to Senate Bill (SB) 711, enacted in 2017, to minimize bill volatility
- 12 for residential customers.
- 13 • The Company's adjustment to base year expenses to exclude certain officer
- 14 compensation from rates in accordance with SB 901, enacted in 2018.
- 15 • Revisions to the Company's California Gas Tariff to reflect proposals
- 16 addressed in this application, Pipeline and Hazardous Materials Safety
- 17 Administration (PHMSA) rule changes, as well as to incorporate revisions to
- 18 correct minor inconsistencies and other ministerial updates.

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

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

22 A. 7 D.14-06-028 was issued in the Company's last general rate case, A.12-12-024,
23 and authorized rate increases for test year 2014, as well as Post-Test Year
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25 ¹ The "risk-based decision-making" is also referred to as "risk-informed decision-making".

1 Margin (PTYM) adjustments of 2.75% for years 2015 through 2018 for the
2 Company's three rate jurisdictions: Southern California, Northern California and
3 South Lake Tahoe.² D.14-06-028 also directed Southwest Gas to file its next
4 general rate case by September 1, 2017 with a 2019 test year.³ In 2017, the
5 Commission issued D.17-06-006 granting the Company's petition to modify
6 D.14-06-028 to file its next general rate by September 1, 2019, with a 2021 test
7 year.⁴ D.17-06-006 authorized Southwest Gas to maintain its existing rate
8 structure through 2020, as authorized in D.14-06-028, including the 2.75%
9 PTYM adjustments for years 2019 and 2020.⁵

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

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

16 **Q. 9 Please describe the TMA and OCMA.**

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

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23 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.

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

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

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

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

14 **Q. 11 Were there other compliance directives in either D.14-06-028 or D.17-06-
15 006.**

16 A. 11 No.

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

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

19 A. 12 In this application, Southwest Gas is requesting a five-year general rate case
20 cycle, with a 2021 test year for the projected 12-month period ending December
21 31, 2021, and four attrition years from 2022 through 2025. The Company is
22 requesting test year 2021 base rate increases of \$6.8 million for Southern
23 California, \$1.5 million for Northern California, and \$4.5 million for South Lake
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25 ⁸ Cal. PU Code § 706(a)(2).

1 Tahoe. The Company is also requesting to maintain its PTYM adjustments of
2 2.75% in each of its three rate jurisdictions.

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

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

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

19 A. 14 When the Company acquired its South Lake Tahoe facilities from its previous
20 operator in 2005, there had not been a rate increase in South Lake Tahoe in
21 approximately twenty years and the system was comprised largely of aging pipe
22 and infrastructure that needed to be rebuilt. For example, in the Company's first
23 rate case following the acquisition,⁹ the average South Lake Tahoe rate base
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25 ⁹ Decision 08-11-048 in Application 07-12-022, effective January 1, 2009.

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

12 **IV. COMPLIANCE WITH COMMISSION DECISIONS AND STATE LEGISLATION**

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

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

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

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

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

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

16 A. 17 Yes. As discussed more fully in the prepared direct testimony of Company
17 witness Kevin M. Lang from an operations perspective, the Company is
18 proposing three new programs derived from this risk assessment process: 1)
19 Meter Protection Program; 2) COYL Program¹¹; and 3) Targeted Pipe
20 Replacement Program for Driscopipe™ 7000 plastic pipe (M7000) and select
21 distribution and high-pressure steel pipe (Southern California only). Company
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24 ¹⁰ Bear Valley Electric Service, Liberty Utilities, and PacifiCorp (dba, Pacific Power).

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

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

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

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

9 **Q. 19 What is SB 711?**

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

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

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

21 **Q. 21 What was the result of the communication?**

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

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

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

11 **Q. 23 What is SB 901?**

12 A. 23 SB 901, enacted in September 2018, primarily related to wildfire-related items,
13 repeals California Public Utilities (PU) Code § 706 (enacted by Assembly Bill
14 1266, 2015) and adds new language prohibiting an electrical or gas corporation
15 from recovering from ratepayers any annual salary, bonus, benefits, or other
16 consideration of any value paid to an officer of the electrical corporation or gas
17 corporation, and requires that compensation instead be funded solely by
18 shareholders of the utility.

19 **Q. 24 Did the Commission define the term officer?**

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

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

5 Q. 25 Yes. The Company established the Officer Compensation Memorandum
6 Account-2019 (OCMA-2019), effective January 1, 2019, to track the difference
7 between compensation for officers of the utility that is authorized in general rate
8 cases or resolutions and all compensation as defined by PU Code 706.¹³

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

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

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

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

23 _____
24 ¹² Resolution E-4963 – Commission Resolution to establish memorandum accounts to track
25 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.

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

3 Q. 28 Yes. As discussed in the prepared direct testimony of Timothy S. Lyons, an
4 adjustment has been made to base year 2018 expenses to project for test year
5 2021 rates.

6 **V. PROPOSED TARIFF REVISIONS**

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

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

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

20 A. 30 The Company proposes the following revisions to its Preliminary Statement:
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25 ¹⁵ Rule No. 3-Application for Service; Rule No. 6-Establishment and Reestablishment of Credit; Rule No. 7-Deposits; and Rule No. 8-Notices.

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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.

14 **Q. 31 Please describe the Company’s proposed revisions to the Schedules section**
15 **of its California Gas tariff.**

16 Q. 31 Consistent with the Company’s proposal to incorporate a third residential baseline
17 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

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

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

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

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

9 Q. 33 On October 21, 2016, PHMSA issued its Final Rule amending 49 CFR 192.381,
10 192.383 and 192.385 to expand the existing requirements for the installation of
11 EFVs on new or replaced service lines to single-family residences. This expansion
12 includes: 1) new or replaced branched service lines to single-family residences; 2)
13 new or replaced service lines to multi-family residences; 3) small commercial entities
14 consuming gas volumes not exceeding 1,000 standard cubic feet per hour (SCFH);
15 and 4) the installation of EFVs or service line shut-off valves (e.g., curb valves) on
16 service lines with meter capabilities exceeding 1,000 SCFH. Further, the
17 amendments to 49 CFR 192.383 allow customers to request that the utility install an
18 EFV on an existing service line (i.e., a retrofit installation), and requires utilities to
19 notify customers of their right to request a retrofit EFV installation. The CFR
20 amendments went into effect April 14, 2017 and while the Company is operationally
21 compliant, it must revise its tariff to correspond with these pipeline safety changes.

21 **Q. 34 Does this conclude your prepared direct testimony?**

22 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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Prepared Direct Testimony
of
TIMOTHY S. LYONS

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Appendix A – Summary of Qualifications 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.

1 **II. DEVELOPMENT OF TEST YEAR 2021 REVENUE REQUIREMENT**

2 **Q. 6 When were current base rates established?**

3 A. 6 The current base rates were authorized in Decision (D.) 14-06-028 issued in the
4 Company's last general rate case, A.12-12-024. D.14-06-028 also authorized
5 PTYM adjustments for years 2015 through 2018.¹

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

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

14 The Company also requests PTYM adjustments of 2.75 percent for years
15 2022 through 2025.

16 Chapter 6 also includes a gross revenue conversion factor (GRCF) for
17 each rate jurisdiction. The GRCF is the ratio of the gross revenue required to
18 produce a one-dollar change in net operating income for the 2021 test year. The
19 GRCF is 1.41069 for Southern California, 1.41793 for Northern California and
20 1.41793 for South Lake Tahoe.

21
22
23
24
25

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

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

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

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

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

11 **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%

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

21 For Southern California, the Company plans to increase net plant from
22 \$180.0 million in 2014 to \$337.7 million in 2021, or a CAGR of 9.4 percent.

23 For Northern California, the Company plans to increase net plant from
24 \$85.1 million in 2014 to \$124.9 million in 2021, or a CAGR of 5.6 percent.

1 For South Lake Tahoe, the Company plans to increase net plant from
2 \$27.2 million in 2014 to \$72.0 million in 2021, or a CAGR of 14.9 percent.

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

6 **III. DEVELOPMENT OF TEST YEAR RATE BASE**

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

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

15 **Q. 11 What is System Allocable plant?**

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

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

21 A. 12 The development of System Allocable test year rate base is included in Chapter
22 8B. The Chapter calculates System Allocable plant, annual depreciation and
23 amortization expenses, and accumulated provision for depreciation and
24 amortization. Chapter 8B includes GPIS and Accumulated Depreciation
25 balances for each jurisdiction that are adjusted for: (1) projected plant additions;

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

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

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

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

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

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

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

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

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

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

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

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

24 A. 18 Test year 2021 depreciation and amortization expense is based on an annual
25 depreciation provision, with a half-year convention being applied to plant added

1 during the year. The depreciation rates used for System Allocable GPIS in the
2 test year are based on the depreciation rates approved in the most recent
3 Nevada rate case.² This is the same approach adopted in the Company's most
4 recent rate case, A.12-12-024.

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

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

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

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

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

18 A. 21 The development of jurisdictional rate base is included in Chapter 17. Chapter
19 17 provides the calculation of jurisdictional plant investment, annual depreciation
20 and amortization expenses, and accumulated provision for depreciation and
21 amortization. Jurisdictional rate base includes plant investment and costs
22

23 _____
24 ² In the Matter of the Application of Southwest Gas Corporation for Authority to Increase its Retail Natural
25 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

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

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

8 Test year depreciation and amortization expense is based on an annual
9 depreciation provision, with a half-year convention being applied to plant added
10 during the year. The depreciation rates used in the 2021 test year are based on
11 the depreciation study submitted to the Public Advocates Office on August 28,
12 2019. Working capital consists of materials and supplies, customer advances
13 and cash working capital, which is based on the lead-lag study performed for
14 this application. The working capital calculation is described below.

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

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

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

21 A. 23 Customer growth plant additions include investments in mains, services and
22 meters to extend service to new customers. Customer growth plant additions
23 are based on a projected increase in the number of customers.
24
25

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

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

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

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

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

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

23 **Q. 27 Please describe the development of overheads.**

24 A. 27 Plant additions are adjusted for overheads, which reflect the indirect costs
25 associated with the plant additions, including supervision and engineering,

1 administrative and general, property taxes, and Allowance for Funds Used
2 During Construction (AFUDC). The overhead rate was based on the seven-year
3 average of overhead rates for the historical period 2012 through 2018.

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

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

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

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

18 **Q. 30 Please explain how CARB was projected.**

19 A. 30 The CARB payments expected to be deferred through 2020 were considered in
20 making this projection. To date, payments have been made through 2018 and
21 the 2019 invoice has been received. The projected total of \$968,178 is
22 requested to be recovered as a regulatory amortization over the requested five-
23 year rate case cycle. Each California jurisdiction is allocated a portion of this
24 amount based on its weighted 4-Factor relative to the Total California 4-Factor.
25

1 **Q. 31 What is the TMA?**

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

11 **Q. 32 Please explain how the GHGMA was projected.**

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

20 **Q. 33 What is the MHPCBA?**

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

1 actual, prudently incurred program costs shall be entered in a
2 balancing account for recovery in the first year following cut over of
3 service; “to the meter” construction costs must be capitalized based
4 on actual (not forecast) expenditures at the utility’s then-current
5 authorized return on rate base; “beyond the meter” construction
6 costs must be capitalized based on actual (not forecast)
7 expenditures and consistent with their status as a regulatory asset,
8 these costs must be amortized over ten years at a rate equivalent to
9 the utility’s then-current authorized return on rate base.³

10 In accordance with D.14-03-021, the MHPCBA TTM revenue requirement is
11 projected for each rate jurisdiction through December 31, 2020. The projected
12 totals of \$1,551,684 for Southern California, \$36,095 for Northern California and
13 \$73,718 for South Lake Tahoe are requested to be amortized over the five-year
14 rate case cycle.

15 The MHPCBA BTM revenue requirement is also projected for each rate
16 jurisdiction through December 31, 2020. The projected totals of \$1,240,852 for
17 Southern California, \$21,096 for Northern California and \$20,404 for South Lake
18 Tahoe are requested to be amortized over 10 years per D.14-03-021. The
19 MHPCBA BTM also includes a line item for the annual amortization of the BTM
20 investment since the revenue requirement deferrals on these assets cease at
21 December 31, 2020, and these investments are not included in the Company’s
22 GPIS balances. The amounts requested are \$279,779 for Southern California,
23 \$3,593 for Northern California and \$4,141 for South Lake Tahoe.

24 **Q. 34 What is the PBA?**

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

³ D.14-03-021, OP 8, at pg. 77.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

25

1 **IV. DEVELOPMENT OF TEST YEAR 2021 EXPENSES**

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

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

9 **Q. 42 What are System Allocable expenses?**

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

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

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

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

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

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

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

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

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

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

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

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

- 24 • Chapter 11B (Gas Supply and Distribution expenses)

25

- 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

1 31, 2018 and escalated based on historical labor escalation factors. Labor
2 loading expenses are based on the labor loading factor described below. Test
3 year Distribution materials and expenses are based on the recorded expenses
4 as of December 31, 2018 and escalated based on the CPI forecast.

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

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

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

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

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

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

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

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

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

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

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

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

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

24 | A. 54 Yes. For Northern California and South Lake Tahoe jurisdictions, adjustments
25 | were made to 2018 recorded O&M expenses that reflect expense amounts

1 inadvertently charged to Northern Nevada District 22. This resulted in an
2 increase in 2018 recorded O&M expenses by \$0.5 million for Northern California,
3 and \$0.3 million for Salt Lake Tahoe.

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

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

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

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

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

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

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

22 A. 57 Test year escalation factors for labor and materials and expenses are described
23 in Chapter 7. The labor escalation factors for 2019 were based on approved
24 wage increases; labor escalation factor for 2020 and 2021 were based on a
25 seven-year average of historical wage increases. Escalated labor loading

1 escalation costs were based on applying the labor loading percentage to
2 escalated labor costs. Materials and expenses escalation factors for 2019-2021
3 were based on the CPI Forecast.

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

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

7 **Q. 59 Please describe SB 901.**

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

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

16 A. 60 Yes. In compliance with Commission Resolution E-4963, OP 1, on December
17 20, 2018, the Company filed a Tier 1 advice letter with the Commission
18 establishing an Officer Compensation Memorandum Account (OCMA-2019).

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

20 A. 61 The current balances are as follows:

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

24

25

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

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

6 A. 62 The Company made an adjustment to 2018 base year expenses to remove
7 \$6,637,775 of labor and certain benefits from Account 920 before allocation,
8 \$376,158 of benefits before allocation, and \$28,891 and \$14,981 of direct labor
9 from Northern California and South Lake Tahoe respectively. This results in a
10 reduction of expenses of approximately \$533,473 in Southern California,
11 \$133,255 in Northern California and \$98,028 in South Lake Tahoe in
12 accordance with SB 901.

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

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

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

21 A. 64 As referenced in the prepared direct testimony of Company witness Byron C.
22 Williams, the Company proposes an annual adjustment to reflect the actual
23 Average Rate Assumption Method (ARAM). As part of its annual Post Test Year
24 Margin (PTYM) Adjustment, the Company will include an adjustment for EADIT
25 amortization. The EADIT amortization included in the PTYM Adjustment will lag

1 by a year due to the timing of the Company's calendar year federal income tax
2 return. For example, the EADIT amortization amount calculated using the ARAM
3 method for the calendar year 2018 is not finalized until October 2019. The
4 difference between the EADIT amount included in base rates and actual EADIT
5 would flow back to customers as an offset to the PTYM Adjustment.

6 **V. DEVELOPMENT OF TEST YEAR MARGIN REVENUES**

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

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

9 **VI. PTYM ADJUSTMENT**

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

11 A. 66 The Commission approved the PTYM annual adjustment of 2.75 percent for the
12 years 2015 through 2018 in Decision 14-06-028.⁶ The Commission found that
13 this level of adjustment would likely mitigate the rate impacts on its customers,
14 and also promote productivity and efficiency increases.⁷ The 2.75 percent PTYM
15 adjustment was extended for 2019 and 2020 in D.17-06-006.⁸

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

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

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

24 ⁶ D.14-06-028, at pg. 24-25.

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.

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

4 A. 70 The Company anticipates that the entire cost of service for the project will be
5 included in rates by the 2024 PTYM adjustment. The project is expected to take
6 three years to complete with annual investments of approximately \$20 million
7 beginning in 2020 and extending through 2022. As discussed above,
8 approximately \$30 million of the project costs will be included in the Company's
9 2021 test year rates. The balance of actual costs recorded to plant in service
10 through September 2021 (the Company uses September ending balances to
11 calculate rates effective January 1 of the following year) will be included in the
12 Company's 2022 PTY adjustment as described above. The cost of service for
13 the Company's actual costs recorded to plant in service through September
14 2022 will be included in the 2023 PTYM adjustment, and the cost of service for
15 remaining costs recorded to plant in service through September 2023 would be
16 recovered in the 2024 PTYM adjustment.

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

18 A. 71 Yes.

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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 Unutil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unutil	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

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Appendix A – Summary of Qualifications of Timothy S. Lyons

Exhibit No.__(TSL-1)

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)

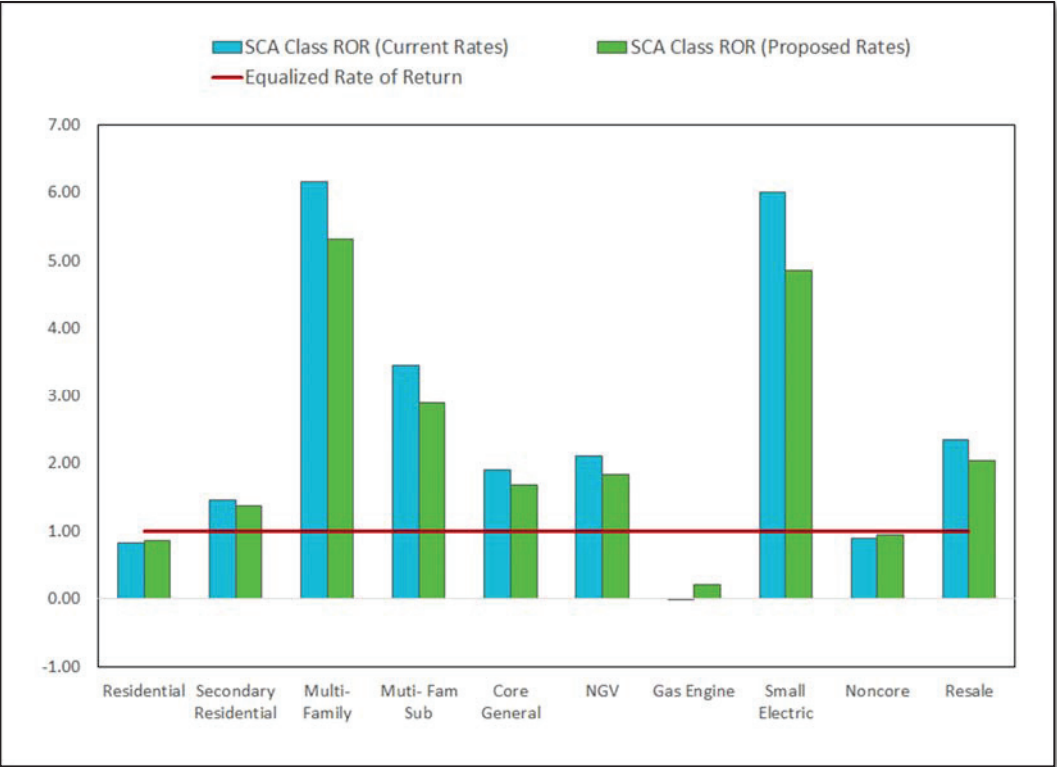


Figure 1 (for Southern California) shows that the Residential, Gas Engine and Noncore rate classes produce RORs at current rates that are less than the system ROR (i.e., unit ROR is less than 1.00 percent), indicating the rates recover less than their cost of service. The remaining rate classes produce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

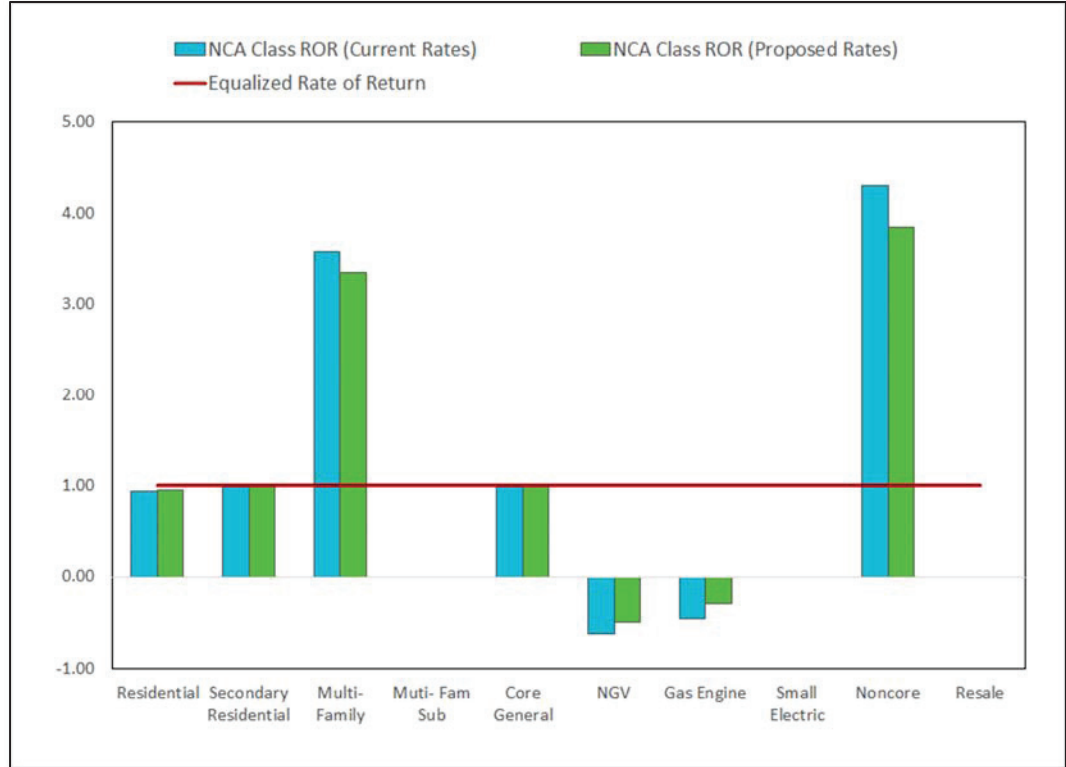


Figure 2 (for Northern California) shows that the Residential, Natural Gas Vehicle (“NGV”) and Gas Engine rate classes produce RORs at current rates that are less than the system ROR (i.e., unit ROR is less than 1.00 percent), indicating the rates recover less than their cost of service. The remaining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

1 methodologies filed in the Company's most recent general rate case filing,
2 Application (A.) 12-12-024.

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

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

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

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

24 The Company prepared a bill impact analysis to evaluate the impact of
25 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%
Winter 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%

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

5 **II. DEVELOPMENT OF THE CCOSS**

6 **Q. 7 Please describe the purpose of a CCOSS.**

7 A. 7 The purpose of a CCOSS is to allocate a utility's overall cost of service to each
8 rate class in a manner that reflects its underlying cost of service. The CCOSS
9 sponsored in this testimony was developed by identifying the relationship
10 between the service requirements for each rate class and their respective cost
11 drivers. This approach is well established in industry literature¹ and is consistent
12 with the Company's approach adopted by the Commission in A.12-12-024.

13 **Q. 8 How was the CCOSS developed?**

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

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

20 A. 9 The approach used to develop the CCOSS consisted of a three step process:
21 (1) functionalization, or cost assignment into functional categories, largely
22 related to production, storage, transmission and distribution; (2) classification,
23 or cost assignment according to whether costs are related to serving peak
24

25 ¹ See "Principles of Public Utility Rates" by James C. Bonbright.

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

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

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

17 **Q. 11 What is Functionalization?**

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

1 **Q. 12 What is Classification?**

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

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

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

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

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

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1 **Q. 14 Please discuss the classification of distribution mains.**

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

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

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

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

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

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

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

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1 **Q. 17 What is Allocation?**

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

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

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

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

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

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

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

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

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

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

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

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

21 In general, the allocation of rate base followed the Company's
22 methodologies adopted by the Commission in A.12-12-024. Plant investment
23 designed to meet customer peak demands was allocated to each rate class
24 based on the demand allocator. Plant investment designed to connect
25

1 customers to the distribution system and meet their service requirements was
2 allocated to each rate class based on number of customers and/or one of the
3 special studies described above.

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

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

8 **Q. 23 Please describe the overall results of the Company's CCROSS.**

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

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

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

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

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

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

10 **IV. DEVELOPMENT OF THE RATE DESIGN**

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

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

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

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

20 A. 27 First, rates were designed to recover the overall cost of service. This was done
21 by developing customer and consumption charges based on test year bills and
22 usage. In addition, rates were designed to be fair and equitable. This was done
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25 ² See Bonbright, James, Danielsen, Albert, and Kamerschen, David. "Principles of Public Utility Rates."
Public Utilities Reports, Inc. pp. 377-407 (2nd Ed. 1988).

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

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

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

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

17 A. 29 Since each customer rate class presently produces a ROR that is different than
18 the system ROR, as shown in Figures 1, 2 and 3, the starting point for setting
19 the revenue targets for each customer rate class was based on the relationship
20 between the current revenues and revenues at equalized rates of return.
21 Specifically, the proposed revenue targets for each customer rate class were
22 based on the Company's PCRM that moves each customer rate class close to
23 the system ROR subject to limitations to address customer bill impact
24 considerations. The PCRM approach adjusts the percentage increase for each
25 customer rate class by multiplying the system percentage increase by the ratio

1 of the margin at the system ROR to the margin at the current ROR for each
2 customer rate class. The PCRM contains rate caps to limit the rate increase for
3 individual customer rate classes. Specifically, the Company proposes that no
4 customer rate class receive a rate increase more than twice the overall rate
5 increase. The proposed rate caps would apply to each of the Company's three
6 rate jurisdictions.

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

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

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

13 Residential

14 Basic Service Charge

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

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

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1 Commodity Charges

2 The Company is proposing to continue its currently approved “two-part”
3 residential commodity charge. The commodity charge is consistent with Section
4 739.7 which states that the commodity charge must be a two-part rate with a
5 baseline rate for an initial block of usage followed by a higher rate for any
6 consumption above the baseline quantity. Only primary residential customers
7 are eligible for the lower, Tier I rate while secondary residential customers pay
8 a single rate.

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

11 Other Rate Classes

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

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

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

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

1 **V. PROPOSED CHANGES TO RESIDENTIAL BASELINE SEASONS**

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

4 A. 32 The Company proposed changes to the Residential baseline seasons in
5 response to Senate Bill (SB) 711, which was approved by Governor Brown in
6 2017 in response to winter season bill volatility. SB 711 directed the Commission
7 to make efforts to minimize bill volatility for residential customers: “Those
8 methods may include modifying the length of the baseline seasons or defining
9 additional baseline seasons.”³

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

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

13 Presently, the Company has two seasons: Winter Season and Summer
14 Season. The Winter Season includes six months (November through April) for
15 the three “Warmer” climate zones (Barstow, Needles and Victorville)⁴ and eight
16 months (October through May) for the four “Colder” climate zones (Big Bear,
17 North Lake Tahoe, South Lake Tahoe and Truckee).⁵ The Summer Season
18 includes six months (May through October) for the three “Warmer” climate zones
19 and four months (June through September) for the four “Colder” climate zones.

20 The Company’s proposal would create three seasons for the Company’s
21 seven climate zones.

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

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

25 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.

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- 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%
Winter 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%
Winter 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 CCROSS 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

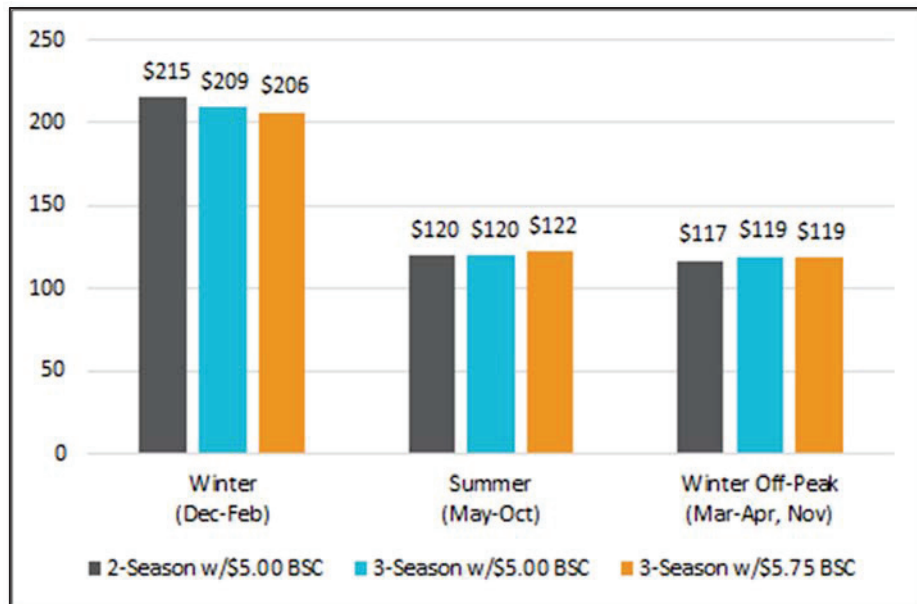
1 costs. This is important since customer-related costs not recovered through the
2 customer charge are recovered through consumption charges, which are
3 disproportionately recovered from high-use customers. Second, the proposed
4 customer charge of \$5.75 helps reduce winter bills.

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

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

17 The bill impact comparison in Figures 7, 8 and 9 is presented under the
18 following three scenarios: 1) the Company's existing two baseline seasons and
19 \$5.00 basic service charge; 2) the Company's proposed three baseline seasons
20 and the existing \$5.00 basic service charge; and 3) the Company's proposed
21 three baseline seasons and increase in basic service charge to \$5.75.

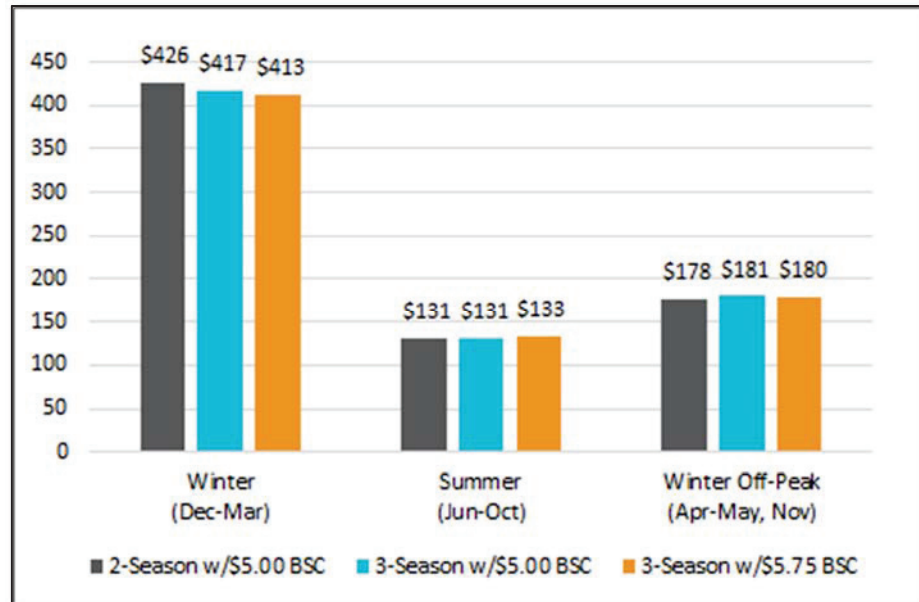
Figure 7: Seasonal Bill Impact Analysis (Victorville)⁶



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).

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

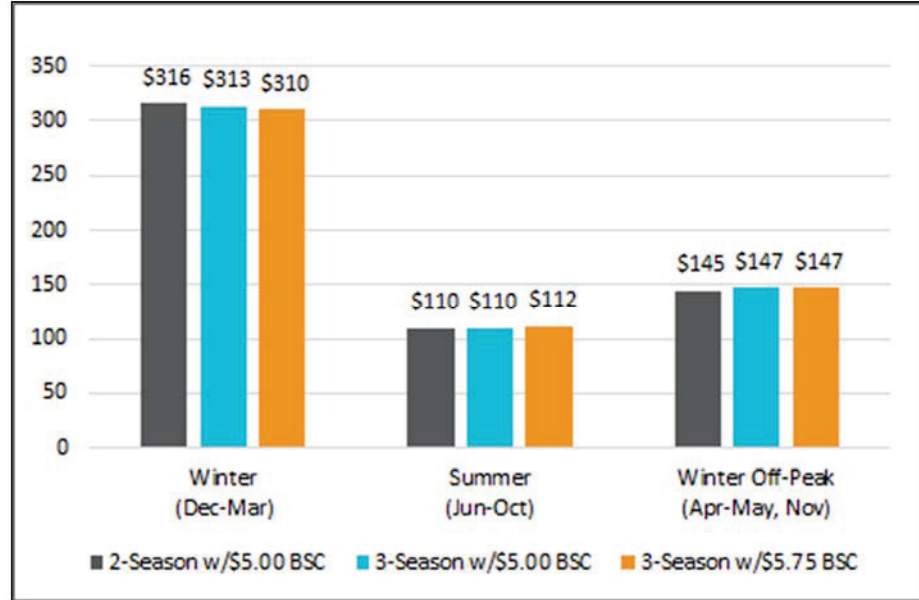
Figure 8: Seasonal Bill Impact Analysis (Truckee)⁷



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.

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

1 **VI. INFRASTRUCTURE RELIABILITY AND REPLACEMENT ADJUSTMENT**

2 **MECHANISM (IRRAM)**

3 **Q. 40 What is the IRRAM?**

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

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

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

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

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

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

22 Q. 43 The Company is proposing to use the current IRRAM balance to offset the
23 program costs for the new School COYL program proposed in this application.
24

25 ⁹ Advice Letter No. 1021, effective January 1, 2017.

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

3 A. 44 As discussed in the prepared direct testimony of Company witness Kevin M.
4 Lang, the Company is proposing three infrastructure programs: 1) Meter
5 Protection Program; 2) COYL Program;¹⁰ and 3) Targeted Pipe Replacement
6 Program for Driscopipe™ 7000 plastic pipe (M7000) and select distribution and
7 high-pressure steel pipe (Southern California only). The total program budgets
8 for each program by jurisdiction for this general rate case cycle are provided in
9 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 <i>(Southern California Rate Jurisdiction only)</i>	
	Annual Budget
M7000 pipe	\$ 17,740,800
Distribution Steel	\$ 4,435,200
High Pressure Distribution Steel	\$ 2,400,000

24 _____
25 ¹⁰ The COYL program consists of the Residential/Commercial COYL program and the School COYL program.

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

3 A. 45 The Company proposes the following 2021 IRRAM surcharge rates of \$0.02206
4 per therm for the Southern California rate jurisdiction, \$0.01249 per therm for
5 the Northern California rate jurisdiction, and \$0.02206 per therm for the South
6 Lake Tahoe rate jurisdiction. The calculations are shown in Chapter 20. The
7 Company proposes to implement the IRRAM surcharge rates on January 1,
8 2021 and the surcharges will be updated annually in its annual balancing
9 account Advice Letter submission.

10 **Q. 46 Does this conclude your prepared direct testimony?**

11 A. 46 Yes.

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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 Unutil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unutil	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)

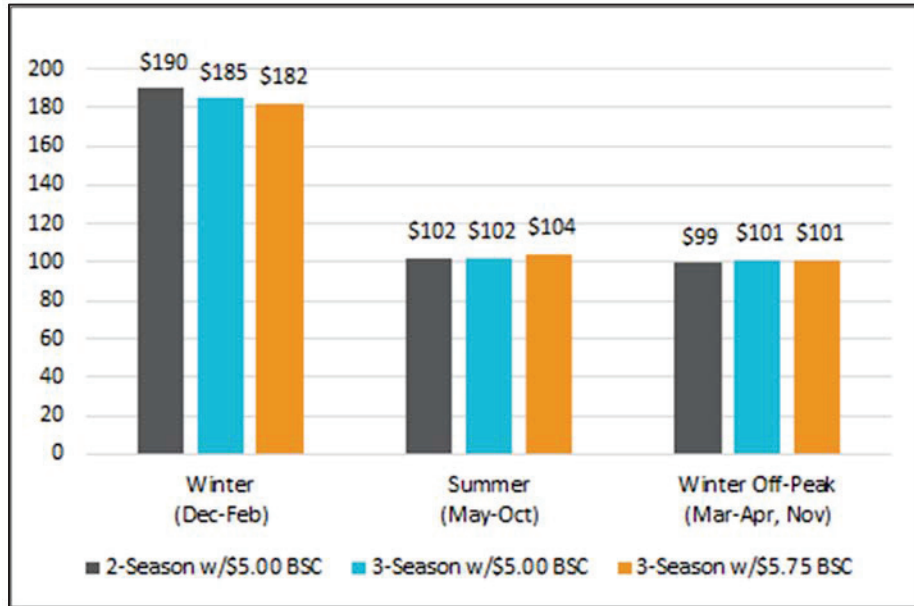


Figure 2: Seasonal Bill Impact Analysis (Victorville)

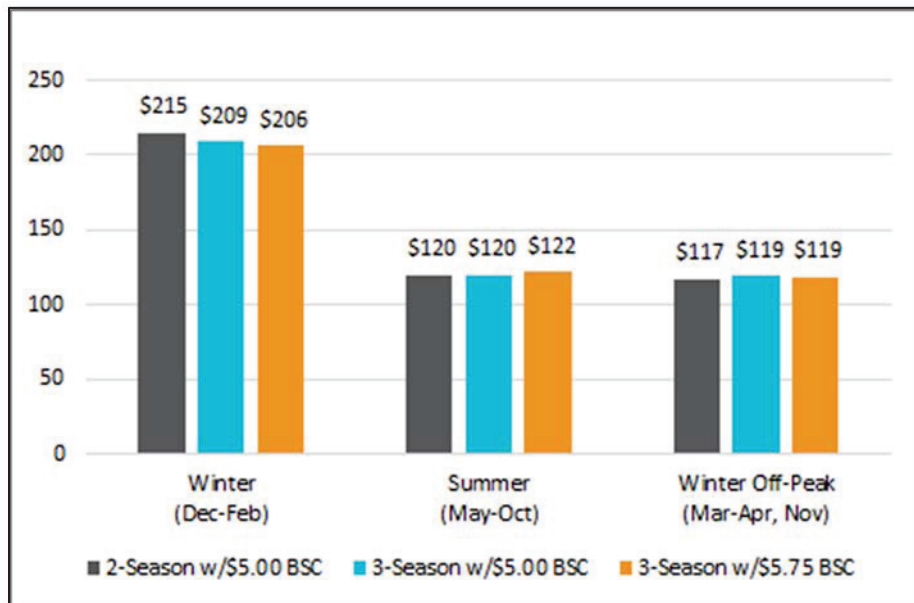


Figure 3: Seasonal Bill Impact Analysis (Big Bear)

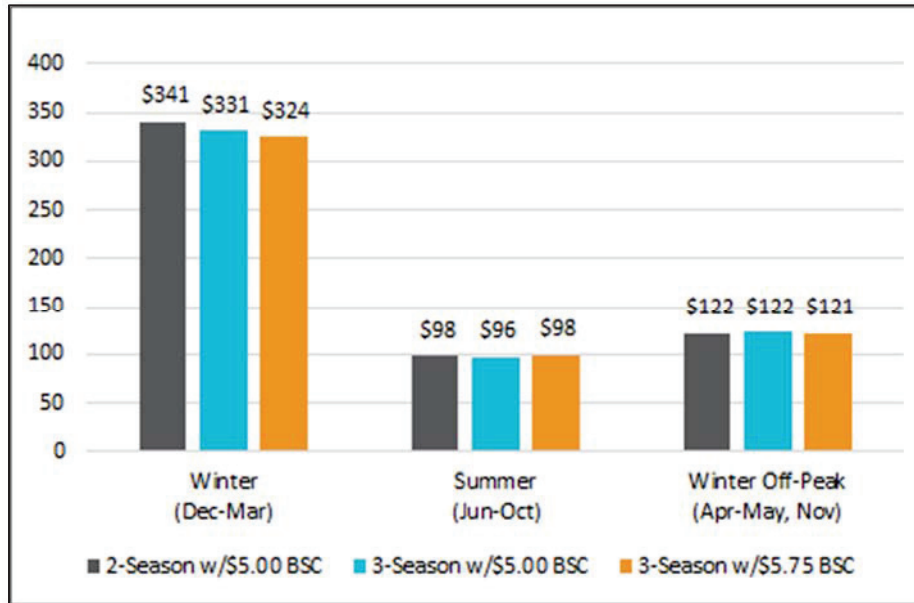


Figure 4: Seasonal Bill Impact Analysis (Needles)

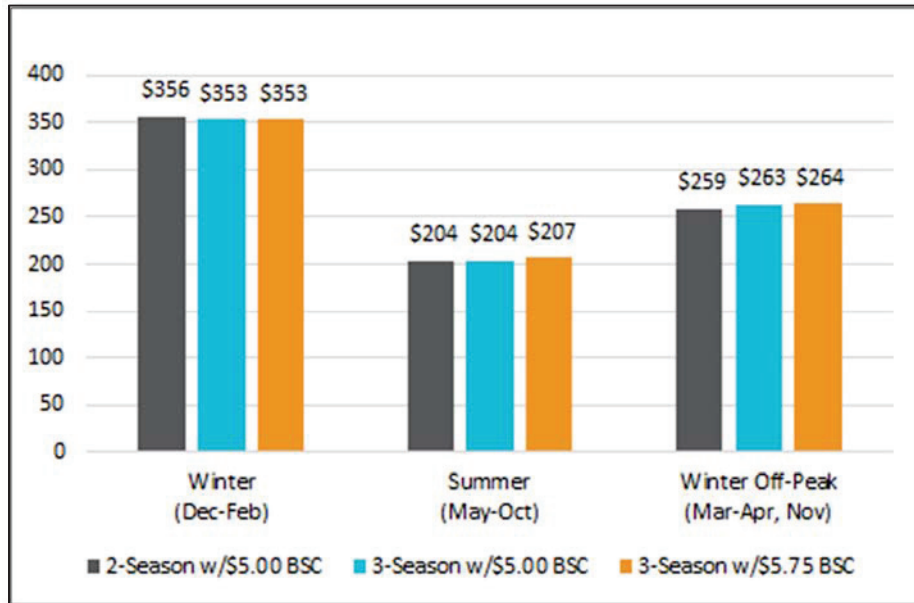


Figure 5: Seasonal Bill Impact Analysis (North Lake Tahoe)

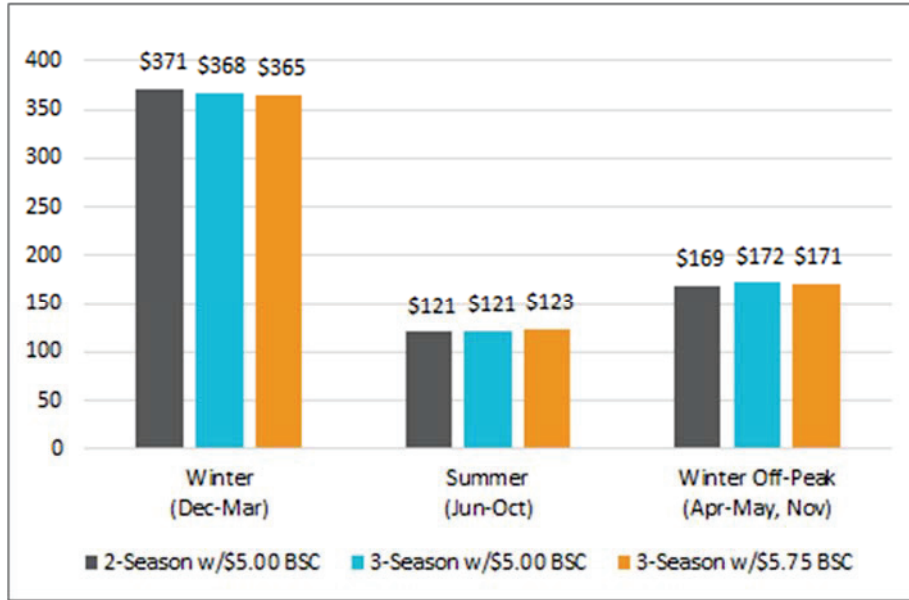


Figure 6: Seasonal Bill Impact Analysis (Truckee)

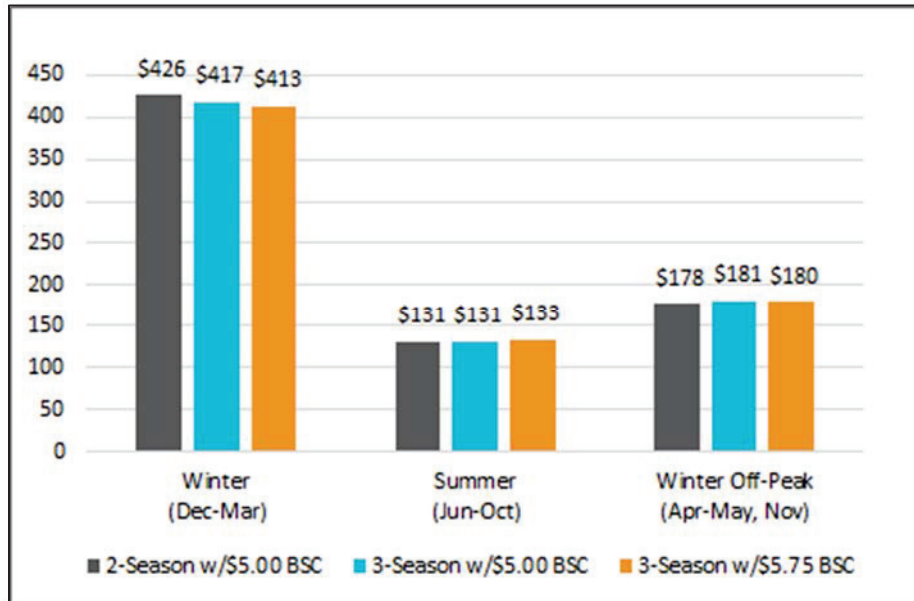
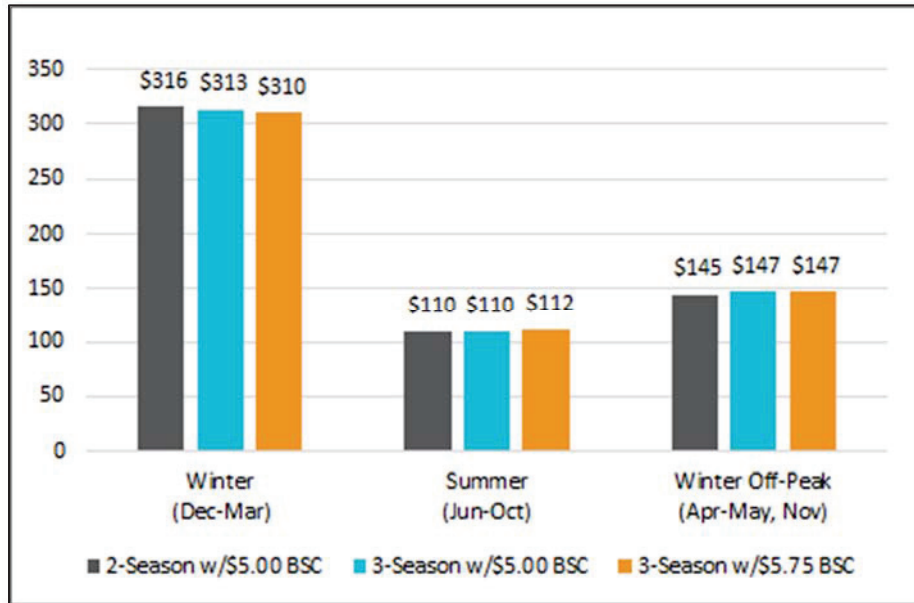


Figure 7: Seasonal Bill Impact Analysis (South Lake Tahoe)



**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, 2019

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Prepared Direct Testimony
of
BRADLEY C. ANDERSON

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Appendix A – Summary of Qualifications of Bradley C. Anderson

Exhibit No. ___(BCA-1)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
Bradley C. Anderson

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.

1 and Enforcement Division and the Small Multi-Jurisdictional Utilities (“Voluntary
2 Agreement”), which was approved by the Commission in D.19-04-020, issued
3 May 6, 2019.²

4 **Q. 6 Please summarize your prepared direct testimony.**

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

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

9 **II. SOUTHWEST GAS’ EXISTING RISK MANAGEMENT PROGRAM**

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

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

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

25 ² Application 15-05-002.

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

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

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

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

17 **III. THE RISK-BASED DECISION-MAKING PROCESS**

18 **Q. 9 Please provide an overview of the Commission’s risk-based decision-**
19 **making process.**

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

24 _____
25 ³ Enterprise Risk Management – Integrating with Strategy and Performance p. 10.

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

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

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

24 _____
25 ⁴ D.19-04-020, at p.3.

⁵ Id. at Attachment 3.

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

3 A. 11 The Company retained the services of Accenture Consulting (Accenture) to
4 assist with the development of its risk-based decision-making framework.
5 Accenture reviewed the Company's existing ERM program and leveraged it to
6 develop and implement a risk-informed decision-making framework for the
7 Company's California operations in compliance with D.14-12-025 and the
8 Voluntary Agreement. Accenture also worked with the Company's project team⁶
9 to brainstorm additional risks, including those specific to the Company's
10 California operations. Each risk was then assessed utilizing a bowtie analysis,
11 scored, and documented with existing controls and proposed mitigation plans.
12 A copy of Accenture's Report on Southwest Gas' Risk-Informed Decision-
13 Making Framework ("Report") is attached as Exhibit No. __ (BCA-1) to my
14 testimony. The Report describes Accenture's engagement and the process
15 used to develop the risk-based framework in greater detail. With the exception
16 of witness qualifications and the purpose of testimony, which I address herein,
17 the Report also addresses the items listed in the Voluntary Agreement's
18 template for GRC testimony.

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

21
22

23 ⁶ The Company's project team consisted of subject matter experts from Risk Management, Engineering
24 Staff, Gas Operations Support Staff (GOSS), and Division Operations for the Company's California
25 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.

- 1 A. 12 Yes. The Voluntary Agreement identifies the following general principles:
- 2 1. Identify top risks
 - 3 2. Describe the controls or mitigation currently in place
 - 4 3. Present a plan for improving the mitigation of each risk
 - 5 4. Present two alternative mitigation plans that were considered
 - 6 5. Present an estimate of “risk mitigated to cost ratio” or related “risk reduction
 - 7 per dollar spent”
 - 8 6. Identify lessons learned to apply in future filings
 - 9 7. Move toward probabilistic calculations as much as possible
 - 10 8. For those business areas with less data, improve the collection of data and
 - 11 provide a timeframe for improvement
 - 12 9. Describe the company’s safety culture, executive engagement, and
 - 13 compensation policies
 - 14 10. Respond to immediate or short-term crises outside of the RAMP and GRC
 - 15 process

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

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

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

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

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

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

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

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

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

23 The Company's commitment to safety is established and modeled through its
24 executive engagement. This "tone at the top" is demonstrated by recent changes
25 that incorporated safety metrics into the Company's management compensation

1 plan.⁷ It is also reflected in the Company's Pipeline Safety Committee – a group
2 of Vice Presidents and Senior Vice Presidents that meet regularly to discuss
3 emerging issues within the industry, as well as best practices and lessons
4 learned from the Company's own operations.

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

18 Southwest Gas also recognizes the importance of educating its customers
19 and the general public about natural gas safety. The Company consistently
20 provides safety messaging in its customer bills and on its website, as well as
21 through broader outreach mediums such as radio spots and social media.
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23

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

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

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

13 **IV. REQUESTED FUNDING OF MITIGATION MEASURES**

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

16 A. 17 As discussed in the Report, Southwest Gas is proposing several mitigations that
17 address various risks identified through the risk-based decision-making process.
18 Southwest Gas also evaluated certain controls that it has in place (for example,
19 controls related to dig-ins), which are extremely effective. In most cases,
20 Southwest Gas believes that the funding included in its requested revenue
21 requirement increase⁸ is sufficient to continue the identified controls and
22 implement the proposed mitigations. However, the Company is requesting
23 specific funding for three (3) of its proposed mitigations – the Targeted Pipe

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

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

6 **Q. 18 Does this conclude your prepared direct testimony?**

7 **A. 18 Yes.**

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**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

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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.

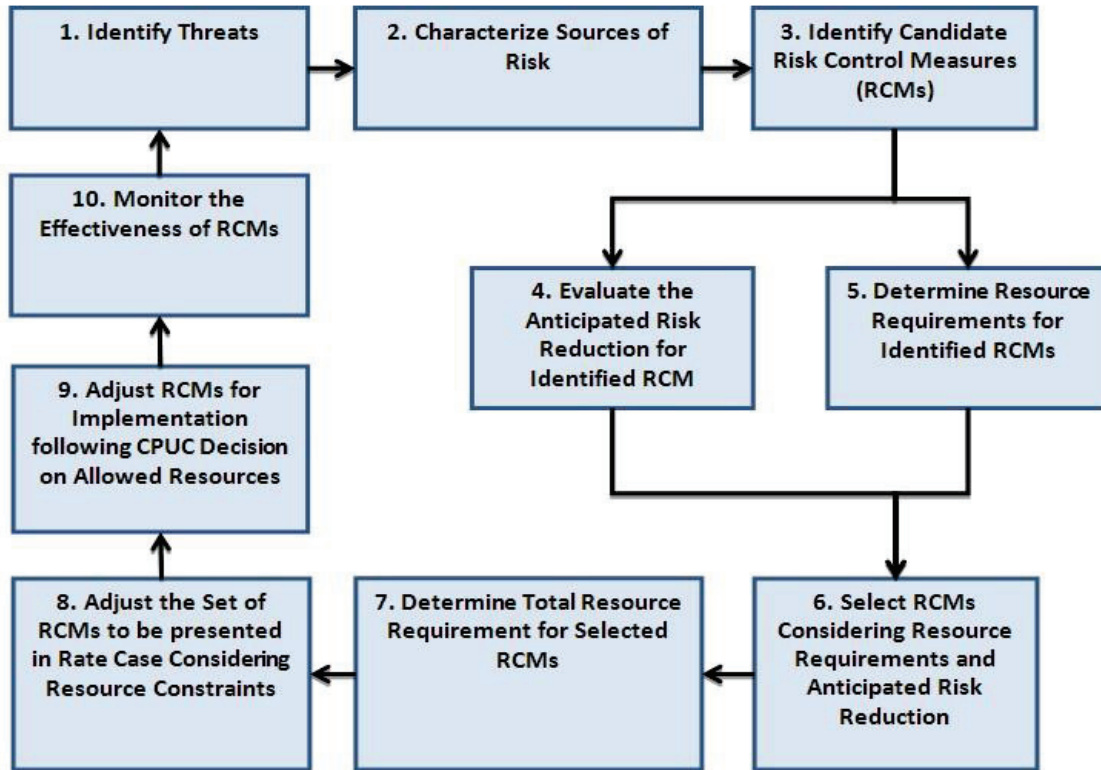
Description of the SWG Risk Management Process

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

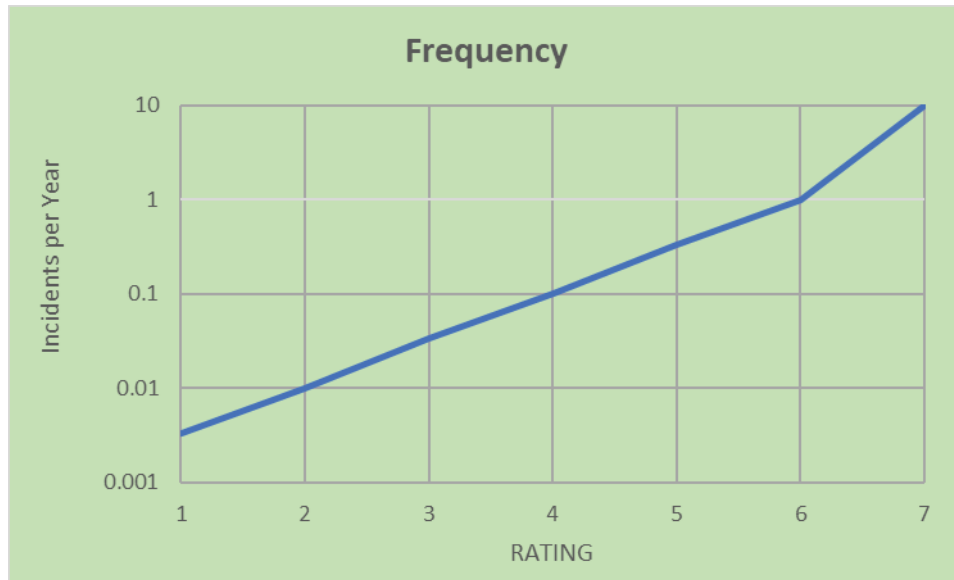
the risk event, the magnitude of likelihood and consequences for each risk event, the risk mitigations that affect the risk events and the risk reduction information resulting from the mitigations. The risk team compiles and enters the following data about each risk into the risk registry:

- 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:	> 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
Likelihood of an occurrence							
<i>Min Rate</i>	10.0000	1.0000	0.3333	0.1000	0.0333	0.0100	0.0033
<i>Max Rate</i>	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.



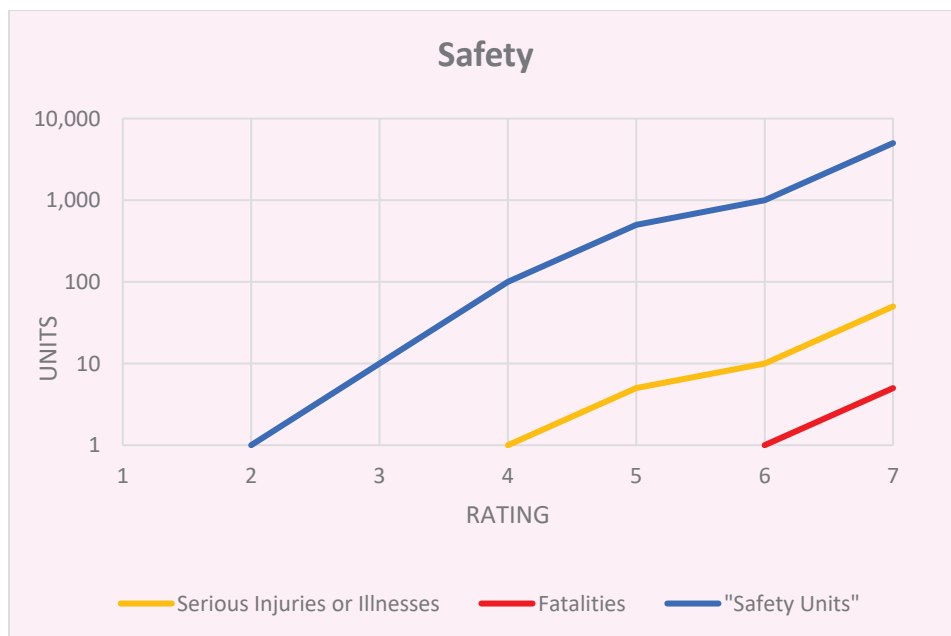
To assess consequence, SWG relied on subject matter expert knowledge to define three Impact Categories: Safety; Operational and Financial, using a pairwise comparison to determine the weights to be attributed to each of the categories. A pairwise comparison is a facilitated exercise where the risk project 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
<i>Minor Injuries or Illnesses</i>		5,000	1,000	500	100	10	1	0
<i>Serious Injuries or Illnesses</i>		50	10	5	1	0	0	0
<i>Fatalities</i>		5	1	0	0	0	0	0
<i>"Safety Units"</i>		5,000	1,000	500	100	10	1	0

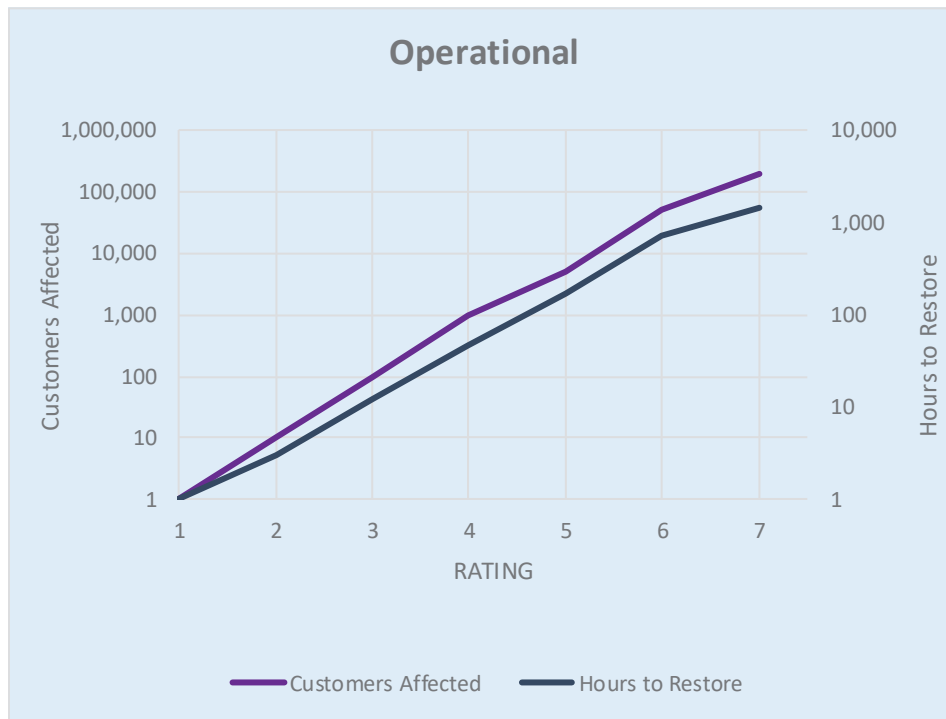
The Safety Impact Category rating was applied on a continuous scale from 1 to 7. The figure below identifies the relationship between Safety Units and the impact rating values as whole numbers.



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	Customers affected: 50k - 200k	Customers affected: 5k - 50k	Customers affected: 1k - 5k	Customers affected: 100 - 1k	Customers affected: 10 - 100	Customers affected: <10
		Time to restore: 60 days	Time to restore: 30 days	Time to restore: 1 week	Time to restore: 2 days	Time to restore: 12 hours	Time to restore: 3 hours	Time to restore: <1 hour
<i>Customers Affected</i>		200,000	50,000	5,000	1,000	100	10	1
<i>Hours to Restore</i>		1,440	720	168	48	12	3	1

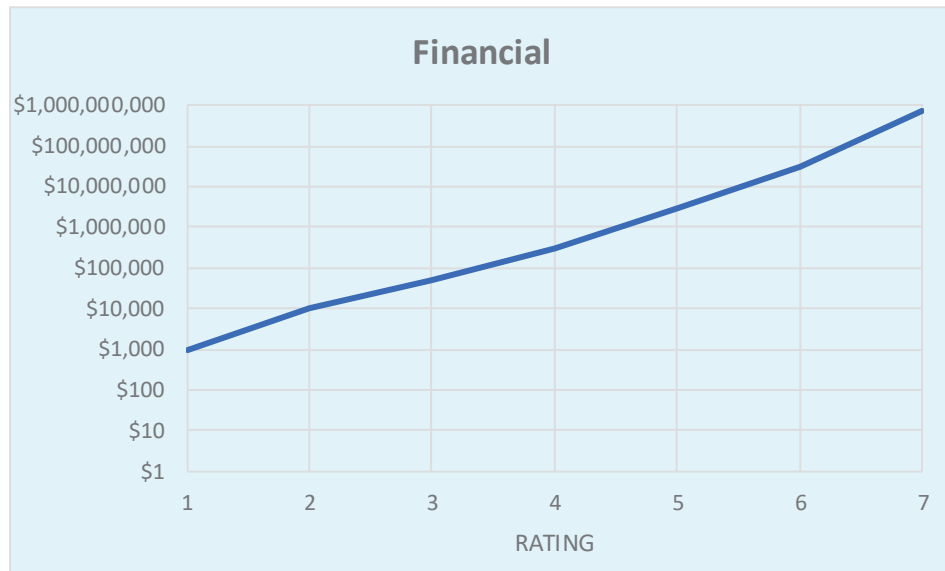
The Operational Impact Category rating was applied on a continuous scale from 1 to 7. The figure below identifies the relationship between the Customers Affected, Hours to Restore and the impact rating values as whole numbers.



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
	<i>Financial loss</i>	\$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 it 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

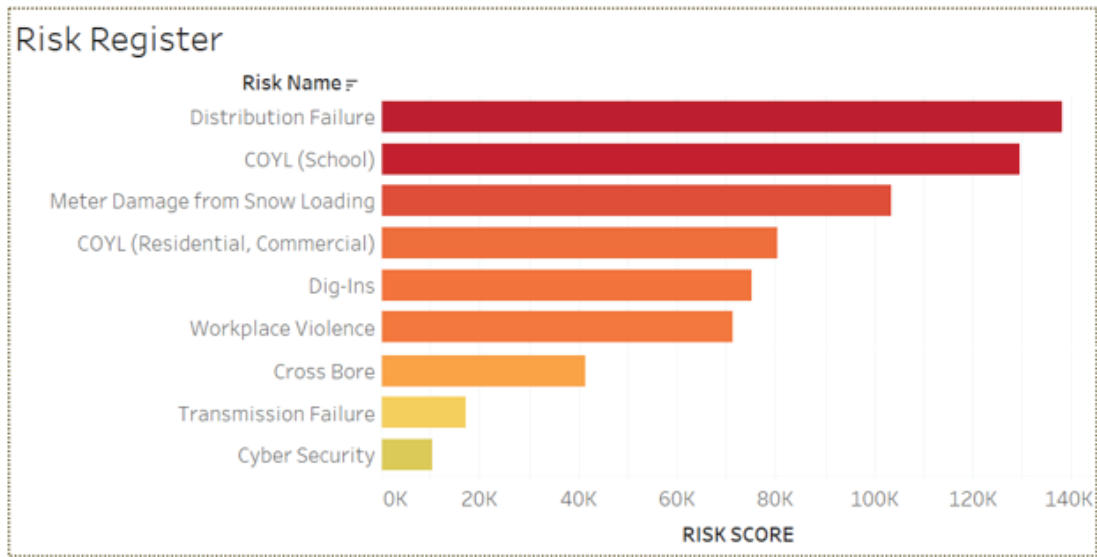
The table below identifies the SWG Top Risks based on risk scores and the judgement of the Risk Team.

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.

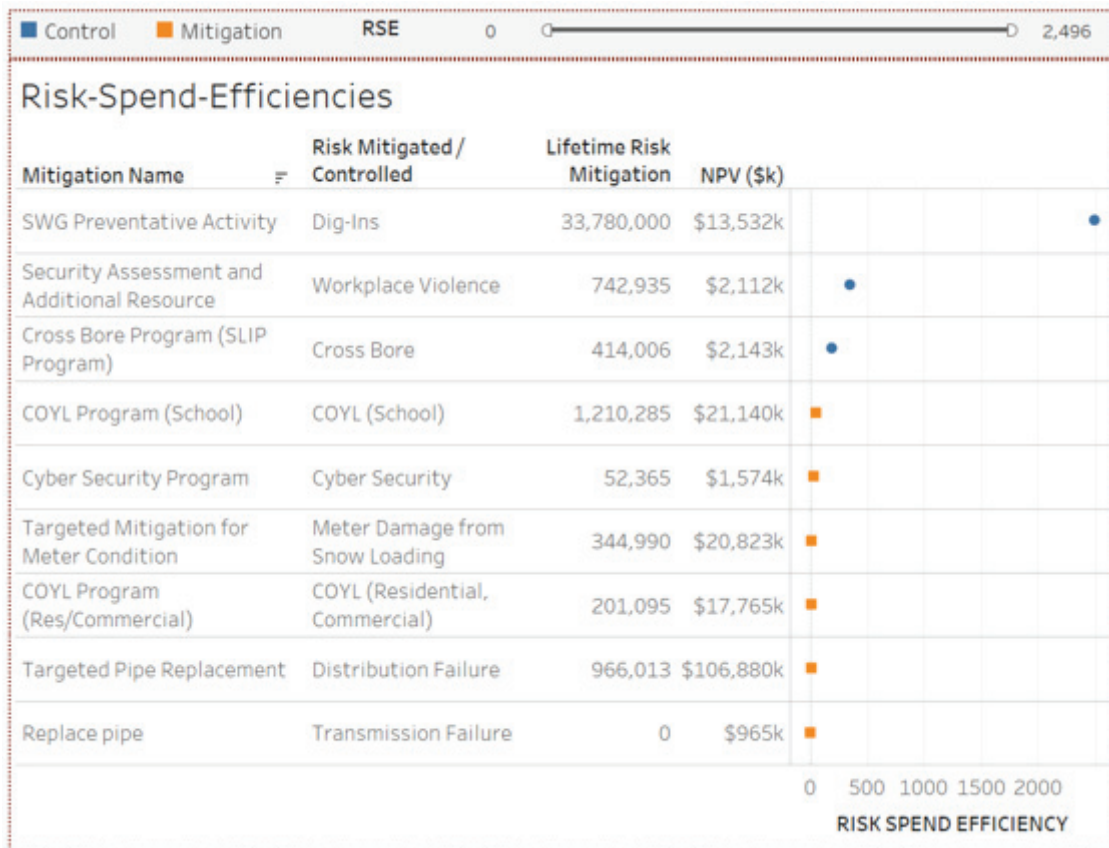


Risk Controls and Mitigations

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 Programs 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.



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 damage
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 damage
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 infiltrates SWG's digital environment causing a data breach resulting in loss of customer information.							
Safety	<i>Minor Injuries or Illnesses</i>	<i>Serious Injuries or Illnesses</i>	<i>Fatalities</i>	<i>Value (Safety Units)</i>	<i>7x7 Rating</i>	<i>Impact Score</i>	<i>Rationale</i>
	0	0	0	0	1.0	6	One SCADA control point in California
Operational	<i>Customers Affected</i>	<i>Hours to Restore</i>		<i>7x7 Rating (Customers)</i>	<i>7x7 Rating (Hours)</i>	<i>Impact Score</i>	<i>Rationale</i>
	0	0		0.0	0.0	0	
Financial	<i>Financial Loss</i>				<i>7x7 Rating</i>	<i>Impact Score</i>	<i>Rationale</i>
	\$32,000,000				6.0	157,087	Figure derived from Ponnemen's recent report
Frequency	<i># Events</i>	<i>Time Period (Years)</i>		<i>7x7 Rating</i>	<i>Frequency (Incidents/Yr)</i>	<i>Frequency Value</i>	<i>Rationale</i>
	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 frequent 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 into	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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Prepared Direct Testimony
of
KEVIN M. LANG

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Appendix A – Summary of Qualifications of Kevin M. Lang

Exhibit No.__(KML-01)

Exhibit No.__(KML-02)

Exhibit No.__(KML-03)

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.

1 **Q. 6 Please summarize your prepared direct testimony.**

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

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

10 **II. RISK-INFORMED DECISION-MAKING PROCESS**

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

12 A. 7 As discussed more fully in the prepared direct testimony of Company witness of
13 Bradley C. Anderson, Southwest Gas, along with the other small and multi-
14 jurisdictional utilities in California were directed to transition to including a risk-
15 informed decision-making process into their general rate case applications
16 beginning in 2017.¹ Through this process, the Company identified and evaluated
17 several risks and controls and mitigations to address the identified risks.

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

20 A. 8 Yes. The Company's proposals for a Targeted Pipe Replacement Program, a
21 Meter Protection Program, and a COYL Program all were derived as a result of
22 the risk-informed decision-making process. Additional specific details on the
23 scoring and ranking of these three identified items is located in the Prepared
24

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

1 Direct Testimony of Bradley C. Anderson.

2 **III. TARGETED PIPE REPLACEMENT PROGRAM**

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

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

- 7 • Pre-1961 vintage distribution steel pipelines
- 8 • Pre-1961 vintage distribution high-pressure steel pipelines
- 9 • Driscopipe™ 7000 distribution plastic pipelines

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

11 A. 10 Although no immediate safety concern exists on vintage pipelines such as the
12 ones the Company has identified for its Targeted Pipe Replacement Program,
13 Southwest Gas realizes it has aging infrastructure. It is prudent to proactively
14 replace aging infrastructure before the pipe leaks, resulting in a safety concern.
15 Safety and reliability are Southwest Gas' top priorities and the Company
16 consistently strives to be a leader in the natural gas industry by being a proactive
17 and prudent operator.

18 **Q. 11 What is the Company proposing with regards to select distribution and**
19 **high-pressure steel pipe replacement?**

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

25

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

3 California has had some form of state pipeline safety code as early as
4 1961.² In contrast, the federal pipeline safety code requirements were not
5 formally established until 1970. Prior to 1961, there was no formal state pipeline
6 safety code for pipeline construction practices, material selection, material and
7 pipeline testing, cathodic protection requirement, recordkeeping requirements,
8 and other key elements of modern pipeline construction requirements. Older
9 pipelines do not have all of the safety features associated with modern pipelines
10 such as improved coatings, enhancements to steel pipe quality and performance
11 standards, more comprehensive welding procedures, and enhanced testing
12 requirements. Prior to the promulgation of state and federal pipeline safety
13 regulations, operators utilized industry consensus standards and other industry
14 practices of the time to govern pipeline construction practices, material
15 selection, and material and pipeline testing. These consensus standards were
16 voluntary and not as comprehensive as the mandatory pipeline safety standards
17 in place today.

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

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

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

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

9 **Q. 12 What is Driscopipe™ 7000 pipe?**

10 A. 12 Driscopipe is the brand name for Phillips Driscopipe, Inc. and its predecessor
11 company Phillips Products Company. The brand name Driscopipe is still in use
12 today. Driscopipe is a polyethylene (PE) plastic pipe type that has been installed
13 in natural gas systems since the 1960s. Driscopipe model 7000 pipe was
14 installed for use for distribution pressure mains and services, typically between
15 one-half inch and four inches in diameter and was installed between 1974 and
16 1980. The Company has approximately 360 miles of 7000 pipe in its Southern
17 California Districts 11 and 12 as of March 1, 2019.

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

20 A. 13 The Company is proposing to proactively replace approximately 40 miles per
21 year of 7000 pipe in its Southern California service territory. This plastic
22 distribution pipe is at least 40 years old and is showing signs that it is no longer
23 performing as expected. Similar to the Company's proposal for pre-1961 vintage
24 steel, Southwest Gas has already replaced all of its known early vintage plastic
25 pipe types (PVC, Aldyl-HD, Tenite) in its California distribution system and 7000

1 pipe is the next oldest plastic pipe type. The Company approach to proactively
2 replacing aging infrastructure before it becomes a safety concern has yielded a
3 distribution system with very low leak rates.

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

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

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

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

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

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

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

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

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

24 A. 18 As mentioned previously, Southwest Gas has approximately 159 miles of pre-
25 1961 steel pipe and approximately 360 miles of 7000 pipe in its Southern

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

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

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

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

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

1 **IV. METER PROTECTION PROGRAM**

2 **Q. 21 Please describe the Company’s proposed Meter Protection Program.**

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

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

20 The Company’s proposed Meter Protection Program would include a suite
21 of safety options that are aimed at enhancing the protection of existing meters
22 in heavy snow load areas that currently do not have an adequate form of meter
23 protection against snow load. These four options would include retrofitting meter
24 sheds for current customers without such protection; upgrading certain meter
25 sets acquired by Southwest Gas with more robust piping; evaluating and

1 installing an Excess Flow Valve (EFV) on certain service lines; and upgrading
2 the meter encoder receiver transmitter (ERT) device to allow for daily meter
3 usage monitoring. This suite of protection options will provide both a proactive
4 as well as reactive level of protection against damage from snow and ice loading.

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

6 A. 22 The Company considers its California service territories located in Big Bear
7 Lake, North Lake Tahoe, South Lake Tahoe and Truckee to be heavy snow load
8 areas. These areas commonly receive five (5) feet or 60 inches of snowfall or
9 more annually. For example, the United States Climate Data website
10 (www.usclimatedata.com) reports average annual snowfall totals based upon
11 data collected from 1981 through 2010. The average annual snowfall reported
12 for the City of Big Bear Lake is approximately 67 inches; the North Lake Tahoe
13 area including Tahoe City is approximately 184 inches; the City of Truckee is
14 approximately 202 inches; and the City of South Lake Tahoe is approximately
15 408 inches.

16 **Q. 23 What is a meter shed?**

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

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

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

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

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

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

20 A. 26 No. The Company’s proposed Meter Protection Program would focus on meter
21 shed installations on those existing unprotected customer meters where the
22

23 _____
24 ³ The MHP Program is a voluntary program offered to eligible master-metered submetered MHPs or
25 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.

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

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

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

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

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

25

1 **Q. 29 What is an Excess Flow Valve?**

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

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

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

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

19 A. 31 Yes. The Company currently installs EFVs on all new service lines meeting
20 certain sizing parameters,⁴ fully replaced service lines, and anytime the
21 Company exposes the main-to-service connection for maintenance. The
22 installation of an EFV on these types of situations is mandated by federal
23

24 ⁴ In situations such as commercial installation or extremely large residential installations where the natural
25 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.

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

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

13 **Q. 32 What is enhanced metering?**

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

21 The early versions of these ERT devices only collected composite usage
22 data and would relay it to a hand-held device for meter reading and billing
23 purposes. The latest technology in ERTs capture hourly data and are capable
24 of data logging in up to 1-minute increments. The ability to remotely capture
25 hourly or more frequent usage data in heavy snow load areas following an

1 extreme snow fall event would provide the Company with the ability to target
2 certain neighborhoods and evaluate the customer usage data. A targeted data
3 analysis would look for unusual increases in natural gas usage through the
4 meter or other anomalies that could be indicative of a damage to the Company's
5 meter set assembly or the customer-owned piping downstream of the
6 Company's meter.

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

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

16 **A. 33** Southwest Gas is currently installing the most up-to-date technology of ERT
17 devices for all new meter set installations and any time a meter is removed from
18 the field and replaced. The Company's proposal, as part of its Meter Protection
19 Program, would identify those meters in heavy snow load areas that do not have
20 the most current type of ERT device installed and target those for replacement.
21 This meter reading technology upgrade would work in concert with the
22 application of a meter shed, meter set piping material upgrade, and an EFV to
23 provide maximum protection from the threat of snow and ice loading.
24
25

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

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

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

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

22 **V. CUSTOMER-OWNED YARD LINE (COYL) PROGRAM**

23 Q. 36 What is a COYL?

24 A. 36 A COYL is the primary customer gas piping that begins from the service point of
25 delivery at the outlet of the Company's meter located at the property line or public

1 right-of-way, and extends underground from the meter to the house, building, or
2 gas utilization equipment where gas is consumed. By definition, a COYL is pipe
3 downstream from the Company's meter, and is not owned by Southwest Gas.
4 The customer is solely responsible for inspecting and maintaining a COYL.
5 Exhibit No.__(KML-03) provides a schematic of a typical COYL. For the purpose
6 of the COYL Program, a COYL does not include other secondary COYLs that
7 may branch off the primary COYL or that may exist further downstream on the
8 customer's houseline pipe facilities.

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

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

- 15 • Southwest Gas does not maintain the customer's buried piping;
- 16 • If the customer's piping is not maintained, it may be subject to the potential
17 hazards of corrosion and leakage;
- 18 • Buried gas piping should be:
 - 19 ○ Periodically inspected for leaks;
 - 20 ○ Periodically inspected for corrosion if the piping is metallic; and
 - 21 ○ Repaired if any unsafe condition is discovered.
- 22 • When excavating near buried gas piping, the piping should be located in
23 advance, and the excavation done by hand; and
- 24
- 25

- 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

1 leak found would result in the full shut-down of the natural gas supply to the
2 school pending repair or replacement by the school of the leaking COYL.

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

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

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

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

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

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

- 20 1) Conduct a verification survey to confirm the inventory of school and
21 non-school COYLs;
- 22 2) Prioritize school COYLs by contacting each school COYL owner
23 and verify interest in a school COYL Program;
- 24 3) Prioritize non-school COYLs by contacting each non-school COYL
25 owner and verify interest in a non-school COYL Program;

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

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

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

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

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

23 A. 45 The potential impact of a leaking COYL located at a school is significantly higher
24 than that of a leaking residential or commercial COYL. In addition, some large
25 commercial or industrial customers may already perform some level of general

1 maintenance including leak detection surveys of their COYL. Southwest Gas
2 has identified 2 instances in 2019 where a leak on a school COYL has resulted
3 in a shutdown of natural gas service to a school due to a leaking COYL. The
4 Company proposes to complete replacement of identified school COYLs over
5 the next five years.

6 **Q. 46 Please describe the non-school program.**

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

17 **Q. 47 Please describe the school COYL program.**

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

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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.

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.



METER WITH SNOW SHELTER



METER WITHOUT SNOW SHELTER



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:

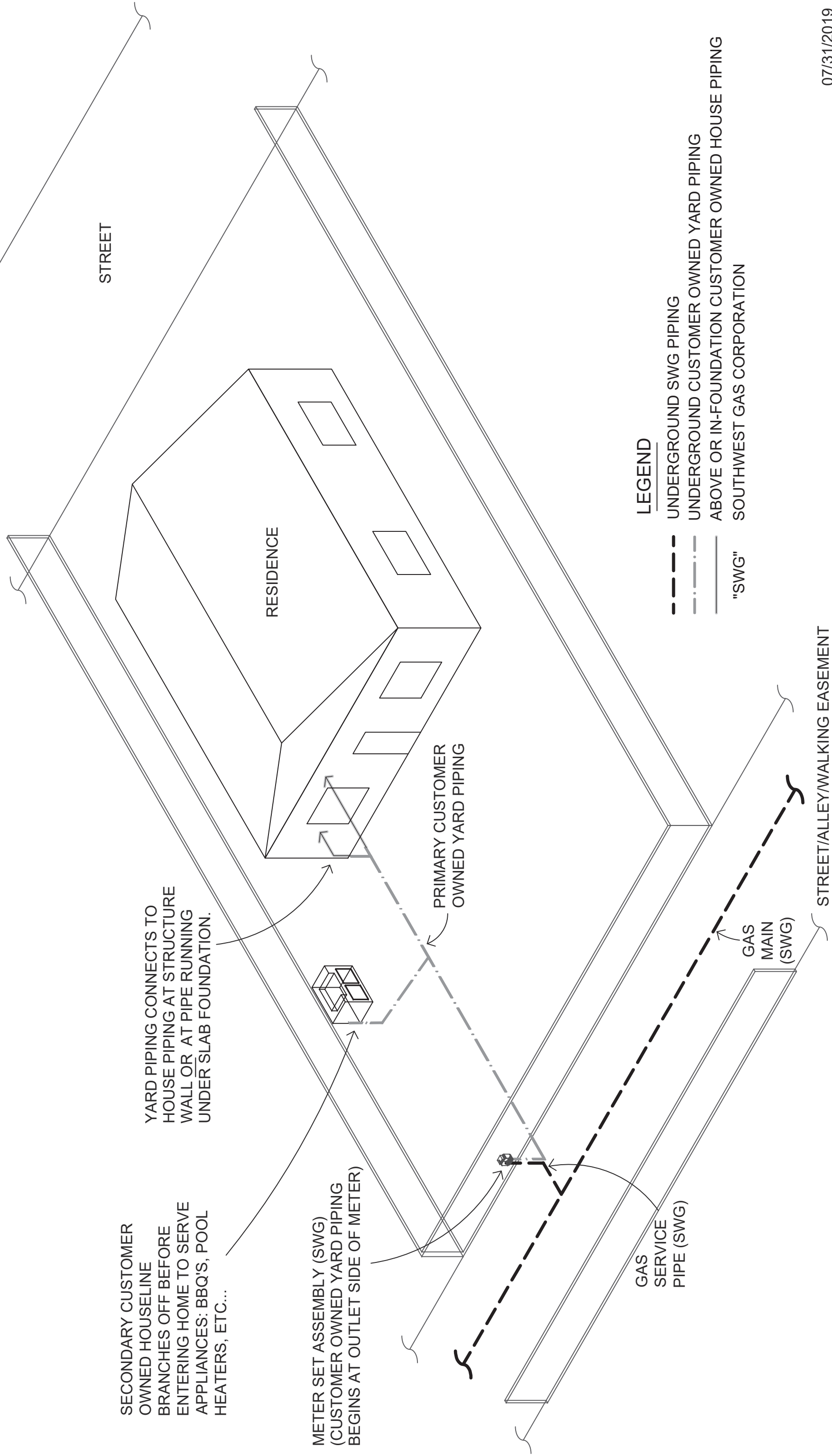
- **SMELL** - an odor similar to rotten eggs, even if it's faint or momentary.
- **HEAR** - a hissing or roaring coming from the ground, above-ground piping, or a natural gas appliance.
- **SEE** - dirt or water blowing into the air, unexplained dead or dying vegetation or grass, or standing water continuously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



STREET

RESIDENCE

PRIMARY CUSTOMER OWNED YARD PIPING

YARD PIPING CONNECTS TO HOUSE PIPING AT STRUCTURE WALL OR AT PIPE RUNNING UNDER SLAB FOUNDATION.

SECONDARY CUSTOMER OWNED HOUSELINE BRANCHES OFF BEFORE ENTERING HOME TO SERVE APPLIANCES: BBQ'S, POOL HEATERS, ETC...

METER SET ASSEMBLY (SWG) (CUSTOMER OWNED YARD PIPING BEGINS AT OUTLET SIDE OF METER)

GAS SERVICE PIPE (SWG)

GAS MAIN (SWG)

STREET/ALLEY/WALKING EASEMENT

LEGEND

- UNDERGROUND SWG PIPING
- · - · - UNDERGROUND CUSTOMER OWNED YARD PIPING
- ABOVE OR IN-FOUNDATION CUSTOMER OWNED HOUSE PIPING
- "SWG" SOUTHWEST GAS CORPORATION

**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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Prepared Direct Testimony
of
BYRON C. WILLIAMS

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Appendix A – Summary of Qualifications 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.

1 **Q. 6 Please summarize your prepared direct testimony.**

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

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

10 **II. OVERVIEW OF TAX INFORMATION AND RELATED SCHEDULES**

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

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

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

18 A. 8 Chapter 16 (Sheets 1 and 2) provides a summary of significant tax accounting
19 methods including (as applicable) use of full normalization accounting,
20 contributions and advances, and the methods of projecting property taxes.
21 Chapter 16 also provides the calculation of net federal and California income
22 taxes on operations, as well as taxes other than income taxes. In addition,
23 Chapter 16 provides the computations of the balance of deferred income taxes
24 projected for the end of the test period and shown elsewhere in the filing as an
25

1 adjustment to rate base, as well as the amortization of Excess Accumulated
2 Deferred Income Taxes.

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

4 A. 9 The calculation of federal and California income taxes on operations is shown
5 on Sheet 7 of Chapter 16. In this filing Southwest Gas uses the statutory
6 21 percent federal income and 8.84 percent California corporate franchise tax
7 rates.

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

10 A. 10 Chapter 16 provides the calculation of deferred federal and state income tax
11 liabilities. The calculation is performed by adding the deferred tax adjustments
12 resulting from the projection of Schedule M differences to the December 31,
13 2018 deferred income tax balances in the general ledger. Chapter 16 also
14 shows the calculation of deferred income taxes and provides the calculation and
15 allocation of System Allocable taxes to the applicable rate jurisdiction.

16 **III. INCOME TAXES AND THE TCJA**

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

18 A. 11 As part of the TCJA, the corporate federal income tax rate was reduced from 35
19 percent to 21 percent, effective January 1, 2018. The reduced federal income
20 tax rate of 21 percent was applied to both current and deferred federal income
21 taxes for the test period.

22 **Q. 12 What other significant changes resulted from the TCJA?**

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

1 utility property not eligible for bonus depreciation. Where bonus depreciation
2 was not calculated for depreciable property, Modified Accelerated Cost
3 Recovery System (MACRS) tax depreciation rates were used.

4 **IV. EXCESS ACCUMULATED DEFERRED INCOME TAXES**

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

6 A. 13 EADIT is the portion of deferred tax liability that existed at the end of 2017
7 (calculated at the 35 percent federal income tax rate) that will never be paid to
8 the federal government because the tax rate was reduced to 21 percent. At the
9 end of 2017, the income tax deferred liability accounts were revalued assuming
10 a 21 percent federal tax rate. The EADIT was reclassified from the deferred
11 income tax liability account to a regulatory liability account, to be refunded to
12 customers.

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

14 A. 14 Plant-related EADIT is the portion of the total EADIT that is associated with the
15 cumulative book/tax differences of depreciable property. The Company treats
16 all plant-related EADIT as protected, and therefore subject to the Internal
17 Revenue Service (IRS) normalization rules and related penalties in the event of
18 their violation. Non-plant EADIT is total EADIT less plant-related EADIT and is
19 not subject to the IRS normalization rules and violation penalties.

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

21 A. 15 The California plant-related EADIT balances are approximately \$19 million,
22 \$10 million, and \$5 million for the Southern California, Northern California, and
23 South Lake Tahoe rate jurisdictions, respectively. The California non-plant
24 EADIT balances are approximately \$900,000, (\$1 million), and \$400,000 for the
25

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

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

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

13 **Q. 17 What is the ARAM?**

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

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

20 A. 18 The ARAM calculation consists of two parts: (1) the entity calculates the ratio of
21 aggregate deferred taxes for the property to the aggregate timing differences for
22 the property; and (2) the resulting percentage ratio calculated is multiplied by the
23 amount of timing differences turning around during the year.
24
25

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

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

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

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

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

20 A. 21 No. Southwest Gas has not recorded any amortization of its EADIT for California
21 in the Company's financial statements. The Company proposes to begin
22 amortizing its California EADIT in 2021, the test year contemplated in this
23 application.
24
25

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

3 A. 22 The Company's proposed methodology ensures that all eligible EADIT is
4 returned to customers. It also ensures that the amortization of the EADIT for
5 financial statement purposes matches the period in which the EADIT is returned
6 to customers. The Company will reduce the EADIT regulatory liability recorded
7 in its financial statements as the EADIT is returned to customers. The proposed
8 approach and use of the ARAM methodology also mitigates any potential
9 normalization violations as defined by the Internal Revenue Code and
10 associated Treasury Regulations.

11 **Q. 23 Have any of the Company's other rate jurisdictions agreed with this**
12 **proposed methodology for the amortization of EADIT?**

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

17 **V. OTHER TAXES**

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

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

25

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

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

4 **Q. 26 How is the MBT calculated?**

5 A. 26 The MBT is based on total gross wages, less employee health care benefits paid
6 by the employer, less a statutory deduction amount. This amount is then
7 multiplied by a tax rate of 1.475%. The Company calculates this amount
8 separately for employees who work at the corporate headquarters in Las Vegas,
9 Nevada, and perform job functions that benefit the Company in all its
10 jurisdictional service territories. This calculation is similar to the calculation for
11 the Company's other system allocable expenses.

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

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

17 **Q. 28 Does this conclude your prepared direct testimony?**

18 A. 28 Yes.

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20
21
22
23
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25

**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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Prepared Direct Testimony
of
THEODORE K. WOOD

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Appendix A – Summary of Qualifications of Theodore K. Wood

Exhibit No.__(TKW-1)

Exhibit No.__(TKW-2)

Exhibit No.__(TKW-3)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
THEODORE K. WOOD

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Theodore K. Wood. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

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

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

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

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

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

A. 4 Yes. I have previously provided testimony to the Arizona Corporation Commission (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

1 the Company's three California rate jurisdictions: Southern California; Northern
2 California; and South Lake Tahoe. Specifically, my prepared direct testimony
3 supports:

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

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

13 **Q. 6 Please summarize your prepared direct testimony.**

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

- 15 • The development of the overall requested RORs for the Company's three rate
16 jurisdictions, based on a 2021 test period. The Company is requesting overall
17 rates of return of 7.44 percent and 7.76 percent, for its Southern California rate
18 jurisdiction and for both the Northern California and South Lake Tahoe rate
19 jurisdictions, respectively.
- 20 • A review of the Company's financial profile, addressing the Company's credit
21 ratings and the importance of these ratings in accessing the capital markets,
22 and, additionally the need for Southwest Gas to offer a competitive rate of
23 return to continue to attract capital. I also discuss how Southwest Gas' overall
24 RORs are necessary to support and sustain the Company's financial profile
25 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.

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

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

20 **II. SOUTHWEST GAS' REQUESTED OVERALL RATES OF RETURN**

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

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

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

5 SOUTHERN CALIFORNIA RATE JURISDICTION

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

9
10 NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTIONS

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

14
15 **Q. 9 Why are the overall requested RORs appropriate and necessary for**
16 **Southwest Gas?**

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

21 Moreover, the overall requested RORs meet the standard of
22 reasonableness set forth by the United States Supreme Court in Bluefield Water
23 Works & Improvement Co. v. Public Service Commission of West Virginia, 262
24 U.S. 679 (1923) (Bluefield):

1 The return should be reasonably sufficient to assure confidence in
2 the financial soundness of the utility, and should be adequate,
3 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.

4 The overall requested RORs also meet the comparability standard set
5 forth by the court in Federal Power Commission v. Hope Natural Gas Company,
6 320 U.S. 591 (1944) (Hope):

7 . . . the return to the equity owner should be commensurate with
8 returns on investments in other enterprises having corresponding
risks.

9 An explanation regarding the practical application of these two court rulings to a
10 diversified utility such as Southwest Gas is appropriate.

11 The Company has, since the late 1950s, filed rate cases as a “diversified”
12 utility. The multi-jurisdictional rate case filings are based on the fact that
13 Southwest Gas, as a natural gas utility, serves three states with several different
14 ratemaking jurisdictions. The Company requests only gas distribution utility
15 required rates of return in all jurisdictional filings within each state. The capital
16 costs requested in this filing are utility-only costs. Southwest Gas’ practices
17 assure that the costs of utility operations attributable to each of its jurisdictions are
18 properly insulated from the impact of any non-utility activities.

19 In summary, Southwest Gas’ requested overall RORs in this proceeding
20 are fair to both customers and shareholders and properly reflects the risks and
21 returns appropriate for its gas distribution properties.

22 **III. SOUTHWEST GAS’ FINANCIAL PROFILE**

23 **A. Credit Ratings**

24 **Q. 10 What is a credit rating?**

25 **A. 10** A credit rating reflects a rating agency’s opinion of the creditworthiness of a

1 particular company, security, or obligation. Credit ratings play an important role in
2 capital markets by providing an effective and objective tool for market participants
3 to evaluate and assess credit risk. In a report on the role and function of credit
4 rating agencies the Securities and Exchange Commission (SEC) concluded:

5 The importance of credit ratings to investors and other market
6 participants had increased significantly, impacting an issuer's
7 access to and cost of capital, the structure of financial transactions,
and the ability of fiduciaries and others to make particular
investments.¹

8 As a result, the Company's credit ratings are a key factor in determining the
9 required yield on the Company's debt securities and bank facilities, and the
10 amount and terms of available unsecured trade credit. Credit rating agencies use
11 both quantitative and qualitative information in the process of developing a credit
12 rating.

13 **Q. 11 Is a credit rating the equivalent of an equity rating?**

14 A. 11 No. While both credit and equity analysts use similar analytical tools, a credit
15 rating is quite different from an equity rating as it reflects default risk, which
16 focuses on downside risk. An equity rating looks at both upside and downside risk
17 and is focused on stock price and return performance. The risks faced by debt
18 holders and shareholders are not the same, due to the priority of debt holders on
19 the operating cash flows of a company. Due to differences in risk, debt holders
20 and shareholders have different required rates of return.

21 **Q. 12 How important is the regulatory environment in the determination of a credit
22 rating for a public utility?**

23 A. 12 For a public utility, credit rating agencies regard regulation as a significant factor
24

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

1 in determining financial performance, as regulation defines the environment in
2 which the utility operates. The importance of regulation on the credit rating for a
3 utility is reflected in the following statement from Standard & Poor's (S&P):

4 Based on Standard & Poor's Ratings Services' experience in rating
5 U.S. investor-owned utilities, we believe that the fundamental
6 regulatory environment can be one of the most important factors
7 we analyze when assigning utility credit ratings.²

8 Similarly, Moody's Investors Service (Moody's) states:

9 For rate-regulated utilities, which typically operate as a monopoly,
10 the regulatory environment and how the utility adapts to that
11 environment are the most important credit considerations.³

12 The importance of regulation in the ratings process for utilities is further
13 evidenced by Moody's assigning a 50% weighting to the following two key
14 factors: (1) regulatory framework; and (2) the ability to recover costs and earn
15 returns.

16 **Q. 13 What are the Company's current long-term unsecured debt credit ratings?**

17 **A. 13** Currently, Southwest Gas' long-term unsecured debt credit ratings are "A" from
18 Fitch, Inc. (Fitch), "A3" from Moody's, and "BBB+" from S&P.

19 **Q. 14 What is the Company's current credit rating outlook?**

20 **A. 14** Credit rating agencies also provide a credit rating outlook, which is an
21 assessment of the direction of the credit rating over the intermediate to longer
22 term. The current credit rating outlooks for Southwest Gas provided by Moody's
23 and Fitch are "stable", while the ratings outlook from S&P is "negative".

24 ² Standard & Poor's Ratings Direct, *Credit FAQ: Standard & Poor's Assessments Of Regulatory Climates*
25 *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.

1 **Q. 15 How do the Company's credit ratings compare to the credit ratings of the**
2 **proxy group of companies that were used to estimate the cost of common**
3 **equity?**

4 A. 15 The proxy group consisting of six natural gas local distribution companies used in
5 the prepared direct testimony of Company witness Robert B. Hevert have an
6 average Moody's rating of A2 and an average S&P rating of A-. Relative to
7 Southwest Gas, the proxy group has an average rating from Moody's that is one
8 notch higher (A2 versus A3). Compared to the Company's S&P rating, the proxy
9 group has an average rating that is one notch higher (A- versus BBB+).⁴

10 **Q. 16 What is the Company's target credit rating?**

11 A. 16 The Company's long-run goal is to achieve an "A" credit rating on average from
12 the ratings agencies. The short-run goal, at a minimum, is to maintain its
13 current strong investment grade credit ratings. The Company believes that an
14 "A" credit rating provides the Company with a greater amount of financial
15 flexibility. The Company would be able to attract capital at reasonable prices
16 during both normal and turbulent market conditions. In addition, an "A" credit
17 rating would be in a range that has been generally found to minimize the long-
18 run average pre-tax cost of capital paid by customers.⁵

19 **B. Holding Company Reorganization**

20 **Q. 17 Please discuss the Company's reorganization into a holding company**
21 **structure.**

22 A. 17 On January 1, 2017, Southwest Gas reorganized and implemented a holding
23

24 ⁴ Exhibit No.__(TKW-1).

25 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.

1 company structure to provide further separation between its regulated and
2 unregulated lines of business, as well as to provide additional financing flexibility.
3 This reorganization was approved by the Commission in D.16-01-037 (Application
4 (A.) 15-10-004). As part of the holding company reorganization, Centuri Group,
5 Inc. (Centuri) and Southwest Gas each became subsidiaries of the new publicly
6 traded parent holding company, Southwest Gas Holdings, Inc.; whereas,
7 historically, Centuri had been a direct subsidiary of Southwest Gas. All of the
8 Company's outstanding debt securities (not associated with Centuri) at the time of
9 the reorganization remained at the Southwest Gas utility entity. Each outstanding
10 share of Southwest Gas common stock automatically converted into a share of
11 stock in Southwest Gas Holdings, Inc., on a one-for-one basis, and the ticker
12 symbol of the stock, "SWX," remains unchanged.

13 **Q. 18 How have the rating agencies viewed the reorganization?**

14 A. 18 The rating agencies have viewed this as beneficial to the credit rating, with
15 Moody's stating:

16 We view this change in organizational structure as credit positive
17 because it provides additional separation between Southwest Gas
18 and Centuri, reducing the likelihood of credit contagion from the
unregulated businesses.⁶

19 **C. Tax Reform**

20 **Q. 19 What impact does tax reform have on the Company's credit rating?**

21 A. 19 The Tax Cuts and Jobs Act (Tax Act), which was signed into law December 22,
22 2017, and became effective January 1, 2018, decreased the corporate income tax
23 rate from 35 percent to 21 percent. Given that income taxes are a material portion
24

25 ⁶ Moody's Investors Service, *Credit Opinion: Southwest Gas Corporation*, January 5, 2018, p.3-4.

1 of the utility's revenue requirement, the reduction in the tax rate has a positive
2 impact on customer rates. However, rating agencies have viewed the Tax Act to
3 be credit negative, as it reduces a utility's cash flow. Moody's stated the following:

4 Within the investor-owned utilities sector, the just-passed tax
5 legislation will have an overall negative credit impact on regulated
6 operating companies and their holding companies. Although the
7 regulated utility sector is carved out in terms of the treatment of
8 interest deductibility and expensing of capital expenditures, from
9 an earnings perspective, the effect on regulated entities is neutral
10 because savings on the lower tax expense are passed on to their
11 customers as required by regulation. However, from a cash flow
12 perspective, the legislation is credit negative.⁷

9 Correspondingly, Fitch stated:

10 The Tax Cuts and Jobs Act has negative credit implications for the
11 regulated utilities and several utility holding companies over the
12 short to medium term. A reduction in customer bills to reflect lower
13 federal income taxes and return of excess ADIT (Accumulated
14 Deferred Income Taxes) to customers is expected to lower
15 revenues and FFO (Funds from Operations) across the sector.
16 Absent mitigating strategies on the regulatory front, this is
17 expected to lead to weaker credit metrics and negative rating
18 actions for those issuers that have limited headroom to absorb the
19 leverage creep. The end of bonus depreciation or the "interest-free
20 loan" from the federal government and reduced FFO at a time
21 when capex budgets are elevated will necessitate greater reliance
22 on equity and debt funding for the utility subsidiaries. This could
23 lead to higher costs of capital for the sector, especially if regulators
24 require an immediate reduction in customer bills to reflect the tax
25 law changes.⁸

19 In response to the negative cash flow impacts on projected financial metrics,
20 Moody's lowered the ratings outlook on 25 regulated utilities and utility holding
21 companies (24 from stable to negative and one from positive to stable).⁹ Neither
22

23 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.

24 ⁸ Fitch Ratings, *Special Report: Tax Reform Impact on the U.S. Utilities, Power & Gas Sector*, January 24, 2018, p.2.

25 ⁹ Moody's Investors Services, *Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform*, January 19, 2018.

1 Southwest Gas or Southwest Gas Holdings, Inc. were among the companies cited
2 in the ratings action by Moody's. However, in June 2018, Moody's announced
3 they changed their outlook for the entire regulated utility sector to negative.¹⁰ As
4 cited by Moody's, the Tax Act has increased the financial risk for utilities. With the
5 Tax Act, the loss of bonus depreciation for utilities beginning in 2018 coupled with
6 a lower tax rate reduces the cash flow contribution from deferred taxes associated
7 with capital investment. Bonus depreciation had generally been available since
8 September 11, 2001 and ranged from 30% to 100%.¹¹ Moody's also discusses
9 the refunding of excess deferred taxes over the long-term, which will also have a
10 negative cash flow impact. The negative cash flow impacts from the Tax Act will
11 create a more challenging financial environment going forward, which may
12 negatively impact the Company's ability to maintain its current credit ratings.

13 **Q. 20 What can be done to mitigate the negative credit rating impact resulting from**
14 **the Tax Act?**

15 A. 20 Both regulatory responses and financial policy changes by utilities can help offset
16 the impact to credit metrics. Some of the potential regulatory actions cited by
17 Moody's include:

18 Potential regulatory offsets to tax-related cash leakage could
19 include: accelerated cost recovery of certain regulatory assets or
20 future investment; changes to the equity layer or allowed ROEs in
21 rates, and other actions.¹²

22 From a financial policy perspective, some utilities are increasing the amount of
23 common equity in their capital structures to help improve their credit metrics. For

24 ¹⁰ Moody's Investors Service, *Regulated utilities – US, 2019 outlook shifts to negative due to weaker cash flows, continued high leverage*, June 18, 2018.

25 ¹¹ Bonus depreciation provision was not in place during the period January 1, 2005 – December 31, 2007.

¹² Id. at p.1.

1 example, due to the Tax Act, several large utilities, including Duke Energy
2 Corporation, Southern Company and Dominion Energy Inc. issued or set-up
3 programs to issue additional equity during the first quarter of 2018 to improve their
4 financial profile.

5 **Q. 21 Has the Company or its parent company, Southwest Gas Holdings, Inc.,**
6 **issued additional common equity to maintain the Company’s strong**
7 **investment grade credit ratings?**

8 A. 21 Yes. Southwest Gas is committed to maintaining an appropriate capital structure
9 to support its strong investment grade credit ratings. This commitment has been
10 demonstrated by the parent company’s willingness to continue to issue new equity
11 to finance the Company’s investment in utility plant and maintain its capital
12 structure. New equity issuances to support the Southwest Gas capital structure
13 have come primarily from the prior establishment of a \$150 million Equity Shelf
14 Program (ESP) in March 2017 and a new \$300 million ESP in May 2019.¹³ From
15 January 2017 through June 2019, the Company issued 2,802,602 shares of
16 common stock under this program, raising net proceeds of approximately \$222.8
17 million. The net proceeds during this period were contributed to, and reflected in
18 the records of, Southwest Gas as a capital contribution from the parent holding
19 company. At June 30, 2019, the Company had approximately \$225 million of
20

21 ¹³ On May 8, 2019, Southwest Gas Holdings, Inc. filed with the Securities and Exchange Commission
22 (“SEC”) an automatic shelf registration statement on Form S-3 (File No. 333-231297), which became
23 effective upon filing, for the offer and sale of up to \$300 million of common stock from time to time in
24 at-the-market offerings under the prospectus included therein and in accordance with the Sales Agency
25 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.

1 remaining ESP capacity.

2 In addition, approximately \$34.2 million of capital contributions from the
3 parent holding company were made over the same period, using proceeds of
4 common stock issuances from the parent company's other common stock
5 programs and a secondary common stock issuance.

6 **D. Infrastructure Replacement Programs**

7 **Q. 22 Please briefly describe the Company's approved Infrastructure Reliability
8 and Replacement Adjustment Mechanism (IRRAM) and Customer Owned
9 Yard Line (COYL) program.**

10 A. 22 In D.14-06-028, issued in the Company's last general rate case (A.12-12-024),
11 the Commission approved the IRRAM and a limited COYL program. The
12 Company requested the IRRAM in the Company's last general rate case to
13 address the Company's investment in certain non-revenue producing gas
14 infrastructure and pipeline replacement programs, and the funding of unfunded
15 government mandates between general rate cases. The specific details of the
16 Company's three proposed programs under the IRRAM are described in the
17 prepared direct testimony of Company witness Kevin M. Lang.

18 **Q. 23 How will the Company's IRRAM help sustain the Company's improved
19 financial profile?**

20 A. 23 The proposed capital investments under the IRRAM would improve
21 Southwest Gas' ability to recover costs associated with its non-revenue
22 producing infrastructure investments on a more-timely basis, which would over
23 time help maintain Southwest Gas' financial metrics, including its ability to earn
24 its authorized RORs, and increase the opportunity for Southwest Gas to
25 improve its credit ratings. From a capital attraction standpoint, the IRRAM

1 would continue to make Southwest Gas more comparable to other natural gas
2 utilities that have similar mechanisms or other mechanisms that allow for timely
3 recovery of replacement costs.

4 **Q. 24 How do rating agencies view capital tracking mechanisms such as**
5 **IRRAM as a factor for the Company's credit rating?**

6 A. 24 Rating agencies view the Commission approval of such mechanisms as a
7 positive regulatory support factor. Specifically, rating agencies recognize the
8 benefit from such mechanisms, with S&P stating:

9 A utility's credit quality during construction projects will depend
10 on credit-supportive regulation. We believe supportive and
11 timely cost recovery that helps avoid large rate increases will
12 become more critical to utilities' ability to maintain cash flow,
13 earnings power, and, ultimately, credit quality. Cost recovery
14 options generally include base-rate increases when projects are
15 complete, along with rate surcharges and riders during
16 construction.¹⁴

17 Similarly, Moody's states:

18 An increasing array of accelerated cost recovery mechanisms in
19 various state jurisdictions is helping to support the credit
20 qualities of gas utilities.¹⁵

21 In addition, Moody's has specifically cited the approval of such infrastructure
22 recovery mechanisms for Southwest Gas as reflecting constructive regulatory
23 treatment and being credit positive, stating:

24 In recent years, there have been meaningful improvements in
25 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

24 ¹⁴ Standard & Poor's RatingsDirect, U.S. Utilities' Capital Spending Is Rising, And Cost Recovery Is
Vital, May 14, 2012.

25 ¹⁵ Moody's Investors Service, Special Comment, *Pipeline Safety Costs Rising As Alternative Rate
Designs Sought*, April 25, 2012, p. 1.

1 recovery of qualifying non-revenue producing capital
2 expenditures associated with the enhancement and
3 replacement of gas infrastructure. A gas infrastructure recovery
4 (GIR) mechanism has been implemented in Nevada with the
5 2014 GIR advance application authorizing \$14.4 million of
6 replacement work for 2015. Also, all three jurisdictions
7 implemented decoupling mechanisms albeit the actual
8 mechanism varies state by state. Constructive regulatory
9 framework developments and signs of an improving regulatory
10 environment are credit positive.¹⁶

11 **Q. 25 Please summarize the importance of the potential credit rating impacts**
12 **resulting from this proceeding to Southwest Gas.**

13 A. 25 The importance to the Company's credit rating is due to the capital-intensive
14 nature of the natural gas distribution business. Southwest Gas needs to make
15 continuing and substantial investments to provide reliable and safe service to
16 customers. On a total company basis, Southwest Gas anticipates capital
17 expenditures over the next three-year period ending December 31, 2021, to be
18 approximately \$2.1 billion. Accordingly, Southwest Gas needs to have
19 continuing access to capital and credit capacity at reasonable costs.
20 Commission approval of the Company's proposed spending under the IRRAM
21 and approval of these requested RORs will give the Company the opportunity
22 to sustain, and the ability to improve, its credit ratings, which benefits both its
23 customers and its investors.

24 **E. Capital Attraction**

25 **Q. 26 Please describe the importance of the capital-attraction function of utility**
26 **ratemaking.**

27 A. 26 The Company must compete with other utilities and other investment
28 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

1 Southwest Gas to successfully attract capital, it must demonstrate an ability to
2 achieve an adequate return on that capital. The importance of the
3 capital-attraction standard of utility ratemaking was described by Professor James
4 C. Bonbright, a recognized expert on the principles of utility ratemaking, as
5 follows:

6 This is one of the most prominent and most widely recognized
7 functions of public utility rates. Public utility companies are
8 permitted to impose charges for their services largely in order to
9 induce and enable them to supply these services and to make
10 provision for their continuation and for their required expansion. If
11 denied the opportunity to levy compensatory charges, they could
12 not long continue operation in the absence of tax-financed
13 subsidies.

14 This production-motivation function of prices gives rise to the
15 capital attraction standard of reasonable public utility rates. By this
16 standard, reasonable rates are rates adequate to yield revenues
17 that will cover all legitimate operating expenses plus a return on
18 investment sufficient to maintain sound corporate credit and to
19 attract required amounts of new capital. Rates below this level are
20 deemed deficient because, at least in the long run, they will not
21 enable the company to live up to its obligations to serve the
22 community.¹⁷

23 For Southwest Gas to successfully attract equity capital, it must demonstrate an
24 ability to achieve a competitive return on that equity capital. The ongoing and
25 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

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.

1 common equity for proxy groups of similar natural gas utilities.

2 **Q. 27 What is the amount of external capital Southwest Gas has acquired over the**
3 **past two years?**

4 A. 27 Over the past two-year period ended June 30, 2019, Southwest Gas has had to
5 access the capital markets to fund utility capital expenditures. In addition to the
6 \$257 million of equity capital received from common stock issuances by its parent
7 company, Southwest Gas also completed two public debt issuances totaling \$600
8 million in gross proceeds.¹⁸ This demonstrates the Company's actual experience
9 and the significance of the need to have access to the capital markets.

10 **Q. 28 How does the overall ROR balance the interests of both customers and**
11 **investors of the Company?**

12 A. 28 The Company's financial health is, over time, important in determining the rates it
13 must charge its customers. The Company's credit ratings are significantly
14 influenced by its financial strength. The Company's cost of debt is in large part
15 determined by the Company's credit ratings. All other things being equal, with
16 higher credit ratings, the Company's cost of capital and the rates it charges its
17 customers would be lower.

18 It is also important that investors be given the opportunity to earn an ROR
19 commensurate with the level of risk associated with their investment. Investor
20 confidence in Southwest Gas, which is the primary subsidiary of Southwest Gas
21 Holdings, Inc., is important for the parent company's existing shareholders and for
22 its future ability to issue additional common equity. If the overall authorized ROR
23

24 ¹⁸ On March 15, 2018, Southwest Gas completed a public offering of \$300 million aggregate principal
25 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.

1 is set below the Company's actual cost of capital, the Company may be unable to
 2 attract sufficient financing at reasonable rates to continue to fund required capital
 3 expenditures and maintain its quality of customer service. The Company's
 4 requested overall RORs will help sustain the Company's financial condition,
 5 including its credit ratings. In the long-run, this will benefit both the Company's
 6 customers and investors.

7 With the regulatory support of the Commission in approving the
 8 Company's proposed overall RORs, Southwest Gas can maintain, with the
 9 opportunity to improve, its financial profile and credit ratings. Such improvement
 10 benefits Southwest Gas' customers by reducing the long-run average capital costs
 11 embedded in customer rates.

12 **IV. RECOMMENDED CAPITAL STRUCTURE**

13 **Q. 29 What is Southwest Gas' current Commission-authorized ratemaking capital**
 14 **structure and overall RORs?**

15 A. 29 The Company's authorized RORs were established in D.14-06-028, based on a
 16 2014 test year. The capital structure and weighted cost of capital last authorized
 17 for the Company's California three rate jurisdictions are as follows:

18 **SOUTHERN CALIFORNIA RATE JURISDICTION**

<u>Component</u>	<u>Ratio</u>	<u>Cost</u>	<u>Weighted Cost</u>
Long-Term Debt	45.00%	2.83%	1.27%
Common Equity	<u>55.00%</u>	10.10%	<u>5.56%</u>
Total	<u>100.00%</u>		<u>6.83%</u>

23 **NORTHERN CALIFORNIA/SOUTH LAKE TAHOE RATE JURISDICTIONS**

<u>Component</u>	<u>Ratio</u>	<u>Cost</u>	<u>Weighted Cost</u>
Long-Term Debt	45.00%	5.84%	2.63%

1	Common Equity	<u>55.00%</u>	10.10%	<u>5.56%</u>
2	Total	<u>100.00%</u>		<u>8.13%</u>

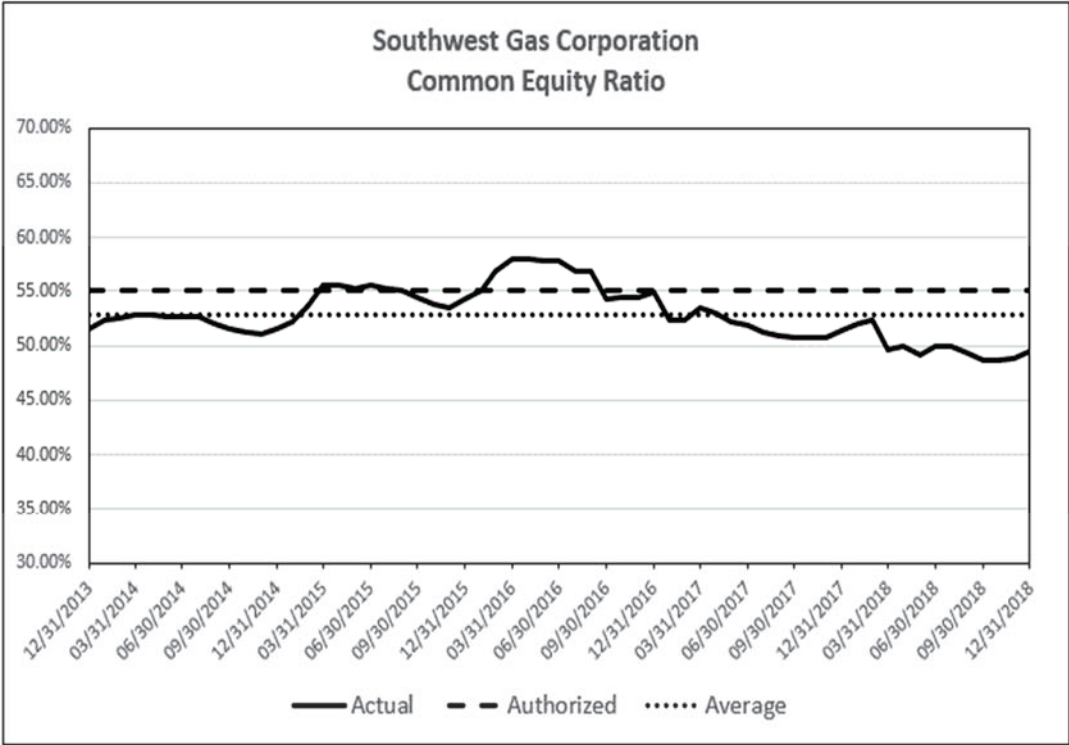
3
4 **Q. 30 Was the capital structure authorized by the Commission in Southwest Gas'**
5 **last general rate case the Company's actual capital structure?**

6 A. 30 No. The Company proposed a target capital structure the Company expected to
7 achieve during the 2014-2018 period, which would have been the time that new
8 rates would be in place. The Company proposed a capital structure with a 57%
9 common equity ratio. The Commission approved a target capital structure with a
10 55% common equity ratio for ratemaking purposes.

11 **Q. 31 Please discuss the actual common equity ratio achieved during the 2014-**
12 **2018 period.**

13 A. 31 During this period, the Company had a monthly average of common equity ratio
14 52.9%, achieving a maximum common equity ratio of 58 percent. The following
15 graph displays the common equity ratio during the period 2014-2018.

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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.

1 **Q. 32 Please discuss the recommended capital structure used to develop the**
2 **overall proposed RORs in this proceeding.**

3 A. 32 The recommended capital structure used to determine the RORs consists of 47.0
4 percent long-term debt and 53.0 percent common equity. The recommended
5 capital structure is the target capital structure the Company reasonably expects to
6 achieve on average during the 2021-2025 period when new rates will be in effect
7 as authorized through this application.

8 **Q. 33 How does the recommended equity component of the target capital**
9 **structure compare to the average and median projected common equity**
10 **ratios for the proxy group companies?**

11 A. 33 The *Value Line Investment Survey* average and median projected common equity
12 ratios for the proxy group companies for 2019, 2020, and 2022-2024 periods are
13 displayed in the following table:

14
15 **PROXY GROUP OF SIX VALUE LINE GAS DISTRIBUTION COMPANIES**
16 **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%

17
18
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20
21 The projected average and median common equity ratios for the proxy
22 group indicates an increasing common equity ratio over the period 2019-2024 and
23 the Company's target common equity ratio of 53 percent is lower relative to the
24 proxy group. The Company's lower common equity ratio indicates higher financial
25 risk relative to the proxy group. Exhibit No.__(TKW-2) displays the projected

1 common equity ratios for the individual proxy group companies.

2 **Q. 34 How does the Company’s requested target common equity ratio of 53**
3 **percent compare to the requested common equity ratios of the four**
4 **California major energy utilities?**

5 **A. 34** From the consolidated proceeding for the cost of capital applications (test year
6 2020) of the four California major energy utilities (A.19-04-014, et al.), also known
7 as the “generic cost of capital proceeding”, the requested common equity ratios
8 are as follows:

9 **CALIFORNIA 2020 GENERIC COST OF CAPITAL PROCEEDING**

10

11 <u>Company</u>	11 <u>Common Equity Ratio %</u>
12 Southern California Gas Company	56.00%
13 San Diego Gas & Electric Company	56.00%
14 Southern California Edison Company	52.00%
15 Pacific Gas and Electric Company	52.00%
16 Average	54.00%

17

18 The Company’s requested capital structure, with a common equity ratio of 53
19 percent, is in alignment with the range of the common equity ratios requested in
20 the generic cost of capital proceeding by the four major California energy utilities.
21 Such alignment was cited as an important factor in the Company’s last general
22 rate in approving a target capital structure for ratemaking.¹⁹ Exhibit No. __ (TKW-
23 3) displays the capital structures, capital costs by type of capital, and the overall
24 weighted costs of capital requested by the four California major energy utilities in

25 ¹⁹ D.14-06-028, pp. 32-33.

1 the A.19-04-014, et al.

2 **Q. 35 Please summarize the support factors for the Company's proposed target**
3 **capital structure in this proceeding.**

4 A. 35 The Company's proposed target capital structure, with a 53 percent common
5 equity ratio, is the expected average capital structure that will be in place during
6 the 2021-2025 period and is in alignment with the Company's actual 2014-2018
7 average capital structure (52.9 percent common equity ratio). This capital
8 structure for ratemaking purposes is also consistent in supporting the Company's
9 strong investment grade credit ratings. In addition, the requested target capital
10 structure, while having a lower relative common equity ratio, is reasonable in
11 comparison to both: (1) the projected capital structures for the proxy group
12 companies used to estimate the cost of common equity in this proceeding
13 (average common equity of 57.1 percent for 2022-24); and (2) the average
14 common equity requested by the four California major energy utilities in A.19-04-
15 014, et al. (average common equity ratio of 54 percent).

16 **V. EMBEDDED COST OF LONG-TERM DEBT**

17 **Q. 36 Have you determined the appropriate cost rate for long-term debt capital**
18 **based on the 2021 test year?**

19 A. 36 Yes. For the Southern California rate jurisdiction, the appropriate cost of long-
20 term debt is 3.99 percent, which includes the cost of the jurisdiction-specific Big
21 Bear Industrial Development Revenue Bonds (IDRBs). For both the Northern
22 California and South Lake Tahoe rate jurisdictions, the appropriate cost rate for
23 long-term debt is 4.67 percent. The cost of long-term debt is comprised of the
24 cost of fixed-rate debentures, fixed-rate medium-term notes, and a variable-rate
25 term facility, with the Southern California rate jurisdiction also including the Big

1 Bear IDRBs. For the Southern California rate jurisdiction, the components of the
2 embedded cost of long-term debt for the 2021 test year are displayed in Tab A,
3 Schedule 5, Sheet 2 of 4, of Chapter 24. For the Northern California and South
4 Lake Tahoe rate jurisdictions, the components of the embedded cost of long-term
5 debt for the 2021 test year are displayed in Tab A Schedule 5, Sheet 1 of 3, of
6 Chapter 24.

7 **Q. 37 Please describe the development of the cost rates of the debentures and**
8 **notes.**

9 A. 37 The Company anticipates having ten outstanding debentures and notes issues
10 totaling approximately \$2.2 billion of gross principal, during the 2021 test year. The
11 debentures and notes have a weighted average cost of 4.64 percent.

12 **Q. 38 Please describe the cost rate of the medium-term notes.**

13 A. 38 The Company established a \$150 million medium-term note program in November
14 1997. The name is somewhat of a misnomer as medium-term notes can be issued
15 with maturities ranging from nine months to 30 years. The Company issued all of
16 its medium-term note program and will have outstanding three remaining medium-
17 term note issues for the 2021 test year totaling approximately \$57.4 million of
18 gross principal. For the 2021 test year, the medium-term notes have a weighted
19 average cost of 7.78 percent.

20 **Q. 39 How are the effective cost rates of debentures, notes, and medium-term**
21 **notes calculated?**

22 A. 39 The effective cost rates of debentures, notes, and medium-term notes are
23 calculated through the use of the yield-to-maturity (YTM) or effective interest rate
24 method.

25

1 **Q. 40 Please describe and discuss the development of the cost rate for the**
2 **variable-rate term facility debt.**

3 A. 40 The Company has a \$400 million revolving credit facility. In addition, the Company
4 has a \$50 million uncommitted F-2 commercial paper program, supported by the
5 revolving credit facility. The Company continues to view \$150 million of the facility
6 as a permanent intermediate-term component of its debt portfolio. Accordingly, the
7 Company classifies it as long-term debt. Southwest Gas uses the remaining \$250
8 million of the facility to fund recurring, seasonal working capital needs.

9 For the 2021 test year, the Company anticipates having approximately
10 \$141.4 million outstanding on average as part of the long-term debt portion of the
11 facility. Of this amount, all of the \$141.4 million will be outstanding as London
12 Interbank Offered Rate (LIBOR) loans. For the LIBOR loans, an average
13 one-month LIBOR rate of 2.50 percent was used for 2021, which was obtained
14 from the IHS Markit July 2019 key interest rate forecast for 2021. The all-in
15 effective rate of the long-term debt portion of the facility for the 2021 test year is
16 3.61 percent. This all-in rate includes the interest on the loans, an annual fee, any
17 unused commitment fees and amortization of debt expenses incurred to establish
18 the facility.

19 **Q. 41 Why are the Clark County IDRBs excluded from the Southern California,**
20 **Northern California, and South Lake Tahoe rate jurisdictions, and the Big**
21 **Bear IDRBs excluded from the Northern California and South Lake Tahoe**
22 **rate jurisdictions in calculating the cost of debt?**

23 A. 41 Southwest Gas issued IDRBs in two of its rate jurisdictions. The IDRB issues and
24 applicable rate jurisdictions are as follows: (1) the Clark County, Nevada IDRBs
25 (2003 Series A, 2008 Series A and 2009 Series A) for its Southern Nevada rate

1 jurisdiction, and (2) the City of Big Bear, California IDRBs (1993 Series A) for its
2 Southern California rate jurisdiction. As reflected in the IDRB indentures and
3 financing agreements, the proceeds from the issuance of this type of debt are
4 restricted to funding qualified construction expenditures for additions and
5 improvements in the specific distribution systems to which the IDRBs relate. In
6 addition, there are strict Internal Revenue Service (IRS) rules which mandate that
7 the benefits of the tax-exempt, lower cost IDRBs must accrue to customers in the
8 specific jurisdiction to which the IDRBs apply. Deviation from the requirements of
9 the IRS rules could result in the loss of the IDRB tax-exempt status, which would,
10 in turn, require the Company to refinance its debt at a much higher cost.

11 **Q. 42 How have regulatory jurisdictions treated the cost of Southwest Gas' IDRBs**
12 **in past regulatory proceedings?**

13 A. 42 Southwest Gas has historically excluded the IDRBs from the cost of debt
14 calculation in all regulatory jurisdictions, except for the specific jurisdictions
15 (Southern Nevada for Clark County IDRBs and Southern California for City of Big
16 Bear IDRBs), to which the relevant IDRBs apply. This Commission, the PUCN,
17 the ACC, and the FERC have accepted this treatment for IDRBs in past regulatory
18 proceedings.

19 **Q. 43 Please describe and discuss the development of the cost of IDRBs for the**
20 **Southern California rate jurisdiction.**

21 A. 43 For the 2021 test year, the anticipated effective cost of the \$50 million variable
22 rate Big Bear IDRBs is 2.77 percent. The interest rate on the IDRBs is set weekly
23 by a remarketing agent. The weekly rates are set close to the Securities Industry
24
25

1 and Financial Markets Association (SIFMA) Municipal Swap Index rate²⁰, also
2 known by market participants simply as the SIFMA rate. The actual Big Bear rate
3 spread above SIFMA has been approximately 4 basis points. The projected rate
4 for 2021 is based on a regression analysis of the historical average monthly
5 SIFMA rates as a function of the 1-month LIBOR rates, plus the 4 basis points
6 spread. The regression equation is then used to forecast SIFMA rates for 2021,
7 using the IHS Markit forecast of the average 1-month LIBOR rate for 2021. In
8 addition, the Big Bear IDRBS are credit-enhanced with a back-up line of credit.
9 The annual credit facility fees are included to determine the effective cost.

10 **Q. 44 Please explain how the embedded cost of debt for the Southern California**
11 **rate jurisdiction is calculated.**

12 A. 44 Due to the \$50 million in gross principal of the Big Bear IDRBS, which are specific
13 to the Southern California rate jurisdiction, the embedded debt cost is the weighted
14 cost of the Big Bear IDRBS, combined with the Company's other long-term debt.
15 To determine the embedded debt cost, the implicit amount of debt required to
16 finance the Southern California jurisdictional rate base was determined by
17 multiplying the percent of total debt in the capital structure by the amount of rate
18 base. The implicit amount of debt is calculated as follows:

$$\begin{aligned} \text{Implicit Debt} &= \text{Debt to Capital Ratio} \times \text{Southern California Rate Base} \\ &= 47 \text{ Percent} \times \$295,188,996 \end{aligned}$$

22 20 The SIFMA Municipal Swap index is a 7-day high-grade market index comprised of tax-exempt Variable Rate
23 Demand Obligations reset rates that are reported to the Municipal Securities Rule Making Board's (MSRB's)
24 SHORT reporting system. The index is calculated on an actual/actual basis and is published every Wednesday by
25 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.

1 = \$138,738,828

2
3 Next, the Big Bear IDRBs are allocated first to the total amount of implicit
4 debt. The remaining portion of other debt is calculated as the difference between
5 the implicit amount of debt and the jurisdiction-specific Big Bear IDRBs. The other
6 debt is comprised of the Company's non-jurisdictional specific debt, applied on a
7 pro rata basis. For the Southern California rate jurisdiction, the amount of other
8 debt is calculated as follows:

9	Implicit Amount of Debt	\$138,738,828
10	Less Net Proceeds Big Bear IDRBs	<u>49,769,498</u>
11	= Other Debt	<u>\$ 88,969,330</u>

12
13 The embedded debt cost is then calculated using the components of debt
14 identified in the previous calculation to calculate the weighted cost of debt for the
15 Southern California rate jurisdiction. The allocation process and the calculation of
16 the weighted embedded cost of debt for the Southern California rate jurisdiction
17 are displayed in Chapter 24, Tab A, Schedule 5, Sheet 1 of 4.

18 **VI. CONTINUATION OF THE ATM MECHANISM**

19 **Q. 45 Is Southwest Gas making an ATM proposal in this proceeding?**

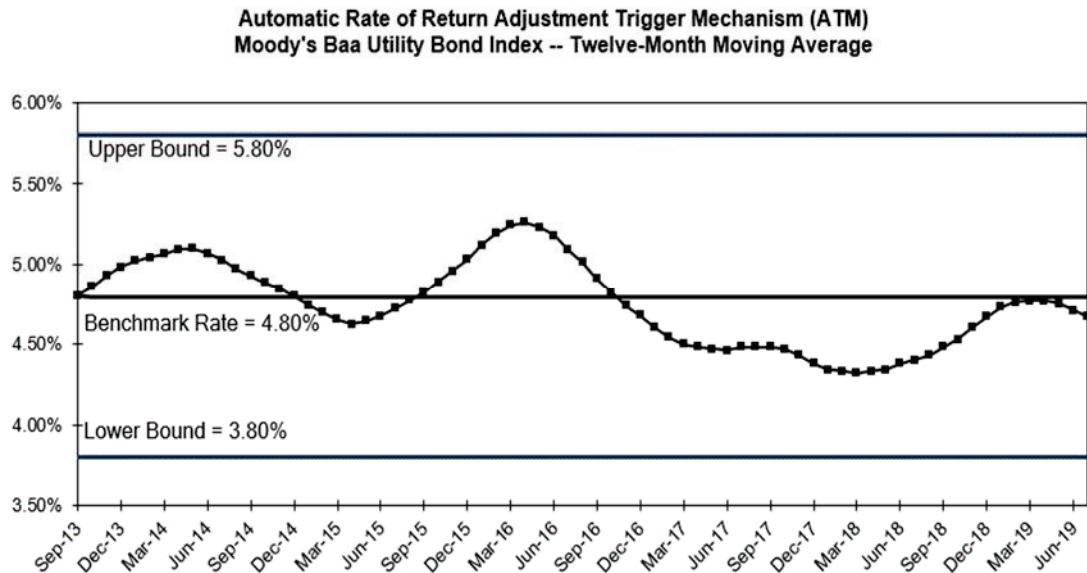
20 A. 45 Yes. The Company is requesting the continuation of the ATM approved in D.14-
21 06-028.²¹ The ATM adjusts the authorized ROR between general rate cases as
22 a result of changes in utility bond yields. The need for an ROR adjustment is
23 triggered when the average benchmark yield, measured by the Moody's Baa Utility
24 Bond yield, changes by more than 100 basis points.

25

²¹ D.14-06-028, p. 70.

1 **Q. 46 Has the ATM been triggered since the authorized RORs were established in**
2 **D.14-06-028?**

3 A. 46 No. The current ATM benchmark rate is 4.80 percent, which was established for
4 the twelve-month period of October 2012 to September 2013. Since that time, in
5 no year has the twelve-month average rate for the measurement period (April to
6 September of the same year) exceeded the benchmark rate of 4.80 percent by
7 more than 100 basis points. The following graph displays the twelve-month rolling
8 average of the Moody's Baa Utility Bond Index.



20 **Q. 47 Please discuss the features of the Company's requested ATM.**

21 A. 47 The ATM would have the following features:

- 22
- 23 • The initial benchmark for the ATM would be the twelve-month average yield
 - 24 of Baa utility bonds as reported by Moody's for the period October 2019
 - 25 through September 2020. The annual measurement period is the twelve-
 - month period ended September. Should the ATM be triggered, the Company

1 will file an advice letter detailing the results of the trigger mechanism, which
2 includes any required change in rates and revenue requirements based on the
3 trigger mechanism.

- 4 • If, in any year, the difference between the current twelve-month average and
5 the benchmark, exceeds 100 basis points, then an automatic adjustment in
6 the Company's authorized ROR will result. The Company will update its cost
7 of capital and compute a new ROR as follows:

- 8 1. The authorized ROE in effect at the time of adjustment is adjusted by
9 one-half of the change in the average utility bond yields that triggered
10 the adjustment.

- 11 2. The embedded costs of long-term debt and preferred equity are updated
12 to reflect actual September month-end embedded costs in that year.

- 13 3. The capital structure authorized in this application will be used to
14 compute the updated ROR.

- 15 • In any year that the twelve-month average triggers an automatic adjustment,
16 that average becomes the new benchmark until another automatic adjustment
17 is triggered.

- 18 • There would be no off-ramp provision, as Southwest Gas would have the right
19 to file a cost of capital application outside of the ATM upon an extraordinary
20 or catastrophic event that materially impacts its cost of capital and/or capital
21 structure.

22 **Q. 48 What are the benefits of continuing the Company's ATM for ROR**
23 **adjustments?**

24 **A. 48** The continuation of the ATM would facilitate the Company's five-year rate case
25 cycle, as it would not require separate cost of capital reviews or participation in the

1 four major utilities' generic cost of capital proceeding outside of a general rate
2 case. As a result, the continuation of the ATM will allow the Company and the
3 Commission to better utilize staff resources and avoid the litigation costs of
4 participating in a separate cost of capital proceeding. The ATM will streamline the
5 regulatory process and adjust the Company's authorized ROR based on changes
6 in actual observed capital market conditions. Such a mechanism is fair and
7 reasonable to both the Company's investors and customers. In addition, the ATM
8 would provide Southwest Gas with a comparable cost of capital mechanism
9 approved and utilized by the other California major energy utilities.

10 **Q. 49 Does this conclude your prepared direct testimony?**

11 **A. 49 Yes.**

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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 (CRRRA), 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

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**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**

<u>Moody's Bond Rating</u>	<u>S&P Bond Rating</u>	<u>Numerical Weight</u>
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**

Line No.	Company (a)	Symbol (b)	Projected Common Equity Ratio					Line No.
			2019 (b)	2020 (c)	2022-2024 (d)	Average (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)

<u>Capital</u>	<u>Ratio</u>	<u>Cost</u>	<u>Weighted Cost</u>
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	<u>100.00%</u>		<u>7.85%</u>

SAN DIEGO GAS & ELECTRIC (A. 19-04-017)

<u>Capital</u>	<u>Ratio</u>	<u>Cost</u>	<u>Weighted Cost</u>
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	<u>100.00%</u>		<u>8.95%</u>

SOUTHERN CALIFORNIA EDISON (A. 19-04-014)

<u>Capital</u>	<u>Ratio</u>	<u>Cost</u>	<u>Weighted Cost</u>
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	<u>100.00%</u>		<u>8.28%</u>

PACIFIC GAS & ELECTRIC (A. 19-04-015)

<u>Capital</u>	<u>Ratio</u>	<u>Cost</u>	<u>Weighted Cost</u>
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	<u>100.00%</u>		<u>8.72%</u>

**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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 of
ROBERT B. HEVERT

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Appendix B – Summary of Qualifications of Robert B. Hevert

Exhibit No.__(RBH- 1) Constant Growth DCF Results

Exhibit No.__(RBH- 2) Retention Growth Estimate

Exhibit No.__(RBH- 3) Market Risk Premium Calculations

Exhibit No.__(RBH- 4) Beta Coefficients

- 1 Exhibit No.__(RBH- 5) CAPM Results
- 2 Exhibit No.__(RBH- 6) Bond Yield Plus Risk Premium Analysis
- 3 Exhibit No.__(RBH- 7) Expected Earnings Analysis
- 4 Exhibit No.__(RBH- 8) Flotation Cost Analysis
- 5 Exhibit No.__(RBH- 9) Senate Bill 901
- 6 Exhibit No.__(RBH- 10) Capital Structure
- 7 Exhibit No.__(RBH- 11) Effect of Leverage on Return on Equity
- 8 Exhibit No.__(RBH- 12) Capital Expenditures

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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

1 and asset-based transactions, asset and enterprise valuation, transaction due
2 diligence, and strategic matters. A summary of my professional and educational
3 background, including a list of my testimony in prior proceedings, is included in
4 Appendix B to this testimony.

5 **Q. 5 Have you previously testified before any regulatory commission?**

6 A. 5 Yes. As an expert witness, I have provided testimony in more than 250
7 proceedings regarding various financial and regulatory matters before numerous
8 state utility regulatory agencies, the Federal Energy Regulatory Commission,
9 Federal District Court, and the Alberta Utilities Commission.

10 **Q. 6 What is the purpose of your prepared direct testimony in this proceeding?**

11 A. 6 The purpose of my prepared direct testimony is to present evidence and provide
12 a recommendation regarding the Company's return on equity ("ROE").¹ My
13 analysis and conclusions are supported by the data presented in Exhibit
14 No.__(RBH-1) through Exhibit No.__(RBH-12), which have been prepared by
15 me or under my direction.

16 **Q. 7 Please summarize your prepared direct testimony.**

17 A. 7 My prepared direct testimony addresses the following topics:

- 18 • Overview of analyses and key analytical issues considered;
- 19 • Regulatory guidelines and financial considerations;
- 20 • The analytical bases for my ROE recommendation;
- 21 • Business risks and other considerations that have a direct bearing on the
22 Company's Cost of Equity;

23
24
25

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

1 expenditures relative to the proxy group; assessed evolving capital market and
2 business conditions, including changes in Federal monetary policy; and
3 calculated the cost of issuing additional shares of common stock. Although I did
4 not make explicit adjustments to my ROE estimates for those factors, I did
5 consider them in determining where the Company's Cost of Equity falls within
6 the range of analytical results.

7 My analyses recognize that estimating the Cost of Equity is an empirical,
8 but not an entirely mathematical exercise; it relies on both quantitative and
9 qualitative data and analyses, all of which are used to inform the judgment that
10 inevitably must be applied. I therefore considered my analytical results in the
11 context of such Company-specific and general capital market factors as those
12 summarized above. Based on the quantitative and qualitative analyses
13 discussed throughout my prepared direct testimony, I find 10.50 percent to be a
14 reasonable and appropriate estimate of the Company's Cost of Equity.

15 Lastly, it is important to keep in mind that no single model is more reliable
16 than all others at all times and under all market conditions; all require reasoned
17 judgment in their application, and in interpreting their results. Therefore, the
18 results of each ROE model must be assessed in the context of current and
19 expected capital market conditions, and relative to other appropriate
20 benchmarks. In developing my recommendation, I recognized that the low and
21 high ends of the range of results (set by the low end of the range of Constant
22 Growth DCF model results, and the high end of the range of Empirical CAPM
23 results, respectively) are not likely to be reasonable estimates of the Company's
24 Cost of Equity.

25

1 **Q. 10 Are there other factors that should be considered in determining the**
2 **weight given to the methods and results summarized above?**

3 A. 10 Yes. All models used to estimate the Cost of Equity are subject to certain
4 assumptions, which may become more, or less, relevant as market conditions
5 and market data change. An important consideration is the consistency of each
6 model's underlying assumptions with current and expected market conditions,
7 and the reasonableness of its results relative to observable benchmarks. For
8 example, the Constant Growth DCF model assumes the estimated Cost of
9 Equity will remain constant in perpetuity. Because that model effectively
10 assumes the market conditions supporting current utility valuations will remain
11 in place in perpetuity, its results should be viewed with caution.

12 Risk Premium-based methods (such as the CAPM), on the other hand,
13 provide a measure of risk and have the benefit of directly considering investors'
14 expectations regarding future market returns. Other Risk Premium approaches
15 (e.g., the Bond Yield Plus Risk Premium approach) reflect the well-documented
16 finding that the Cost of Equity does not move in lockstep with interest rates. For
17 example, at times interest rates fall because investors are so risk averse they
18 would rather accept a very modest return on Treasury securities than take on
19 the risk of equity ownership. In such circumstances, low interest rates suggest
20 an increasing, not a decreasing, Cost of Equity.

21 The Expected Earnings analysis calculates the Cost of Equity based on
22 the opportunity cost of the return of an alternative investment in an enterprise
23 with similar risk, and corroborates the findings from the DCF, CAPM and Bond
24 Yield Plus Risk Premium approaches. Because those methods provide different
25

1 perspectives on investor return requirements, their use in combination enables
2 a more comprehensive assessment of the Cost of Equity.

3 In summary, each model has strengths and weaknesses and it is important
4 to recognize those differences in estimating the Cost of Equity. In my view, the
5 Constant Growth DCF model, which requires constant assumptions, inputs, and
6 results in perpetuity, should be considered with some caution.² Risk Premium-
7 based methods, which provide the ability to reflect investors' views of risk, future
8 market returns, and the relationship between interest rates and the Cost of
9 Equity, should be given somewhat more consideration. Additionally, as noted
10 earlier, the Expected Earnings method provides a method of corroborating other
11 model results. With those considerations in mind, my recommendation
12 reasonably reflects investors' return requirements in the current market
13 environment.

20 ² Other jurisdictions have noted similar conclusions. See, for example, *Martha Coakley v. Bangor Hydro*
21 *Electric Company*, Opinion No. 531, 147 FERC ¶ 61,234 (2014), *Order On Paper Hearing* Opinion No.
22 531-A, 149 FERC ¶ 61,032 (2014), and *Order On Rehearing* Opinion No. 531-B, 150 FERC ¶ 61,165
23 (2015); Massachusetts Department of Public Utilities, D.P.U. 13-90, *Petition of Fitchburg Gas and Electric*
24 *Light Company (Electric Division) d/b/a Unitil*, May 30, 2014, at 219; *Formal Case No. 1093, In the Matter*
25 *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>

1 **III. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS**

2 **Q. 11 Before addressing the specific aspects of this proceeding, please provide**
3 **an overview of the issues surrounding the Cost of Equity in regulatory**
4 **proceedings, generally.**

5 **A. 11** In general terms, the Cost of Equity is the return investors require to make an
6 equity investment in a firm. That is, investors will provide funds to a firm only if
7 the return they expect is equal to, or greater than, the return they require to
8 accept the risk of providing funds to the firm. From the firm’s perspective, that
9 required return, whether it is provided to debt or equity investors, has a cost.
10 Individually, we speak of the “Cost of Debt” and the “Cost of Equity” as measures
11 of those costs; together, they are referred to as the “Cost of Capital.”

12 The Cost of Capital (including the costs of both debt and equity) is based
13 on the economic principle of “opportunity costs.” Investing in any asset, whether
14 debt or equity securities, implies a forgone opportunity to invest in alternative
15 assets. For any investment to be sensible, its expected return must be at least
16 equal to the return expected on alternative, comparable risk investment
17 opportunities. Because investments with like risks should offer similar returns,
18 the opportunity cost of an investment should equal the return available on an
19 investment of comparable risk. In that important respect, the returns required by
20 debt and equity investors represent a cost to the Company.

21 Although both debt and equity have required costs, they differ in certain
22 fundamental ways. Most noticeably, the Cost of Debt is contractually defined
23 and can be directly observed as the interest rate or yield on debt securities. The
24 Cost of Equity, on the other hand, is neither directly observable nor a contractual
25 obligation. Rather, equity investors have a claim on cash flows only after debt

1 holders are paid; the uncertainty (or risk) associated with those residual cash
2 flows determines the Cost of Equity. Because equity investors bear the “residual
3 risk,” they take greater risks and require higher returns than debt holders. In that
4 basic sense, equity and debt investors differ: they invest in different securities,³
5 face different risks, and require different returns.

6 Whereas the Cost of Debt may be directly observed, the Cost of Equity
7 must be estimated based on market data and various financial models. As
8 discussed throughout my prepared direct testimony, each model is subject to
9 specific assumptions, which may become more, or less, applicable as market
10 conditions change. In addition, because the Cost of Equity is premised on
11 opportunity costs, the models typically are applied to a group of “comparable” or
12 “proxy” companies. The choice of models (including their inputs), the selection
13 of proxy companies, and the interpretation of the model results all require the
14 application of reasoned judgment. That judgment should consider data and
15 information that is not necessarily included in the models themselves. In the
16 end, the estimated Cost of Equity should reflect the return that investors require
17 in light of the subject company’s risks, and the returns available on comparable
18 investments.

19 **Q. 12 Please provide a brief summary of the guidelines established by the United**
20 **States Supreme Court (the “Court”) for the purpose of determining the**
21 **Return on Equity.**

22 **A. 12** The Court established the guiding principles for establishing a fair return for
23 capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public*

24
25 ³ The observed interest rate may be adjusted to reflect issuance costs.

1 *Service Comm'n of West Virginia* (“*Bluefield*”);⁴ and (2) *Federal Power Comm'n*
2 *v. Hope Natural Gas Co.* (“*Hope*”).⁵ In those cases, the Court recognized that
3 the fair rate of return on equity should be: (1) comparable to returns investors
4 expect to earn on other investments of similar risk; (2) sufficient to assure
5 confidence in the company’s financial integrity; and (3) adequate to maintain and
6 support the company’s credit and to attract capital.

7 **Q. 13 Has the Commission provided similar guidance in establishing the**
8 **appropriate Return on Equity?**

9 A. 13 The Commission has relied upon the *Hope* and *Bluefield* standards in
10 determining the appropriate ROE for utilities.⁶ Specifically, the Commission has
11 added:

12 We attempt to set the ROE at a level of return commensurate with
13 market returns on investments having corresponding risks, and
14 adequate to enable a utility to attract investors to finance the
15 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

16 **Q. 14 Aside from those long-held standards, why is it important for a utility to be**
17 **allowed the opportunity to earn a return adequate to attract equity capital**
18 **at reasonable terms?**

19 A. 14 A return adequate to attract capital at reasonable terms enables the utility to
20 provide safe and reliable service while maintaining its financial integrity. In
21 keeping with the *Hope* and *Bluefield* standards, that return should be

22 _____
23 ⁴ See, *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S.
679, 692-93 (1923).

24 ⁵ See, *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

25 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.

1 commensurate with the returns expected elsewhere in the market for
2 investments of equivalent risk. The consequence of the Commission's order in
3 this case, therefore, should be to provide Southwest Gas the opportunity to earn
4 a Return on Equity that is: (1) adequate to attract capital at reasonable terms;
5 (2) sufficient to ensure its financial integrity; and (3) commensurate with returns
6 on investments in enterprises having corresponding risks. To the extent
7 Southwest Gas is provided a reasonable opportunity to earn its market-based
8 Cost of Equity, neither customers nor shareholders should be disadvantaged. In
9 fact, a return adequate to attract capital at reasonable terms enables the
10 Company to provide safe, and reliable natural gas utility service while
11 maintaining its financial integrity.

12 **Q. 15 How is the Cost of Equity estimated in regulatory proceedings?**

13 A. 15 As noted earlier (and as discussed in more detail later in my prepared direct
14 testimony), the Cost of Equity is estimated by the use of various financial models.
15 By their nature, those models produce a range of results from which the ROE is
16 determined. That determination must be based on a comprehensive review of
17 relevant data and information; it does not necessarily lend itself to a strict
18 mathematical solution. The key consideration in determining the ROE is to
19 ensure the overall analysis reasonably reflects investors' view of the financial
20 markets in general, and the subject company (in the context of the proxy
21 companies), in particular.

22 The use of multiple methods, and the consideration given to them, recently
23 was addressed by the Federal Energy Regulatory Commission ("FERC"). In its
24 November 15, 2018 *Order Directing Briefs*, FERC found that "in light of current
25 investor behavior and capital market conditions, relying on the DCF methodology

1 alone will not produce a just and reasonable ROE”.⁸ In its October 16, 2018
2 *Order Directing Briefs*, FERC found that although it “previously relied solely on
3 the DCF model to produce the evidentiary zone of reasonableness...”, it is
4 “...concerned that relying on that methodology alone will not produce just and
5 reasonable results.”⁹ As FERC explained, because the Cost of Equity depends
6 on what the market expects, it is important to understand “how investors analyze
7 and compare their investment opportunities.”¹⁰ FERC also explained that,
8 although certain investors may give some weight to the DCF approach, other
9 investors “place greater weight on one or more of the other methods...”¹¹ Those
10 methods include the CAPM, the Risk Premium method, and the Expected
11 Earnings method, all of which I have applied in this proceeding.

12 In summary, practitioners, academics, and regulatory commissions
13 recognize that financial models are tools to be used in estimating the Cost of
14 Equity, and the strict adherence to any single approach, or to the specific results
15 of any single approach, may lead to flawed or misleading conclusions. That
16 position is consistent with the *Hope* and *Bluefield* principle that it is the analytical
17 result, as opposed to the method employed, that is controlling in arriving at ROE
18 determinations. A reasonable ROE estimate therefore considers multiple
19 methods, and the reasonableness of their individual and collective results in the
20 context of observable, relevant market information.

21 _____
22 ⁸ Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15,
2018) at para. 34.

23 ⁹ Docket No. EL11-66-001, et al., *Order Directing Briefs*, 165 FERC ¶ 61,030 (October 16, 2018) at para.
30.

24 ¹⁰ *Id.*, at para. 33.

25 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.

1 **IV. COST OF EQUITY ESTIMATION**

2 **Q. 16 Please briefly discuss the ROE in the context of the regulated rate of**
3 **return.**

4 A. 16 Regulated utilities primarily use common stock and long-term debt to finance
5 their capital investments. The overall rate of return (“ROR”) weighs the costs of
6 the individual sources of capital by their respective book values. While the cost
7 of debt can be directly observed, the Cost of Equity is market-based and,
8 therefore, must be estimated based on observable market information.

9 **Summary of Business Risks**

10 **Q. 17 Before summarizing your Cost of Equity analysis, please explain why**
11 **mean and median model results for the proxy group do not provide an**
12 **appropriate estimate for the Cost of Equity for Southwest Gas?**

13 A. 17 In my view, there are additional factors that must be taken into consideration
14 when determining where Southwest Gas’ Cost of Equity falls within the range of
15 results. Those factors include: (1) the risks associated with California’s
16 regulatory and political climate; (2) the effect of Senate Bill (“SB”) 901 on the
17 Company’s cost recovery; (3) the Company’s equity ratio relative to the proxy
18 group; and (4) the Company’s significant capital expenditures for the period
19 2019-2021. Those factors, which are discussed below, should be considered in
20 terms of their overall effect on the Company’s Cost of Equity.

21 **Q. 18 Please briefly summarize the regulatory and political risks facing**
22 **Southwest Gas.**

23 A. 18 Southwest Gas faces several risks due to the regulatory and political climate in
24 California. In part due to the wildfires, California utilities and regulators find
25 themselves in an increasingly uncertain environment. As the regulatory

1 environment in California shifts, the possibility of adverse effects on Southwest
2 Gas becomes increasingly relevant to investors. Southwest Gas also may find
3 itself at risk due to California’s legal doctrine of “Inverse Condemnation”, that
4 may hold a utility at fault for damages despite no fault of the utility.¹² Lastly,
5 legislators and regulators in California have begun to initiate efforts aimed at
6 decarbonization, including efforts enabling builders to more easily develop all-
7 electric buildings.¹³

8 **Q. 19 What is the effect of SB 901 on Southwest Gas?**

9 A. 19 As discussed in Section V below, SB 901 excludes certain executive
10 compensation from ratepayer recovery,¹⁴ effectively representing a 37 basis
11 point reduction in the Company’s *pro forma* common equity that must be
12 absorbed by shareholders. Because the Company must compete with other
13 utilities for the long-term capital needed to fund its utility operations, that reduced
14 expected return places Southwest Gas at a competitive disadvantage.

15 **Q. 20 Please summarize the Company’s proposed capital structure.**

16 A. 20 As discussed by Company Witness Theodore K. Wood, Southwest Gas
17 proposes a capital structure of 53.00 percent common equity and 47.00 percent
18 long-term debt.¹⁵

19 **Q. 21 Please summarize Company’s planned capital expenditures.**

20 A. 21 As discussed in Section V below, the Company plans to invest approximately
21 \$211 million dollars for the period 2019-2021. As shown in Chart 4 (see, Section

22 _____
23 ¹² See, Section V, below; See, also, *Barham v. Southern California Edison Co.*, 74 Cal, App. 4th 744, 752,
(1999).

24 ¹³ California Public Utilities Commission, Order Instituting Rulemaking Regarding Building
Decarbonization, Rulemaking 19-01-011, at 6-7.

25 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.

1 V below), that amount is the highest among the proxy group and over 47.00
2 percent higher than the proxy group median.

3 **Proxy Group Selection**

4 **Q. 22 As a preliminary matter, why is it necessary to select a group of proxy**
5 **companies to determine the Cost of Equity for Southwest Gas?**

6 A. 22 First, it is important to bear in mind that the Cost of Equity for a given enterprise
7 depends on the risks attendant to the business in which the company is
8 engaged. According to financial theory, the value of a given company is equal
9 to the aggregate market value of its constituent business units. The value of the
10 individual business units reflects the risks and opportunities inherent in the
11 business sectors in which those units operate. In this proceeding, we are
12 focused on estimating the Cost of Equity for the Company's California
13 operations. Because the ROE is a market-based concept and given the fact that
14 the Company's jurisdictional operations within California are not a separate
15 entity with its own stock price, it is necessary to establish a group of companies
16 that are both publicly traded and comparable to the Company to serve as its
17 "proxy" for purposes of the ROE estimation process.

18 Even if the Company's California jurisdictional assets did constitute the
19 entirety of the parent company's operations, it is possible that transitory events
20 could bias its market value in one way or another over a given period. A
21 significant benefit of using a proxy group is that it serves to moderate the effects
22 of anomalous, temporary events associated with any one company.

1 **Q. 23 Does the selection of a proxy group suggest that analytical results will be**
2 **tightly clustered around average (i.e., mean) results?**

3 A. 23 No. For example, the DCF approach calculates the Cost of Equity using the
4 expected dividend yield and projected growth. Despite the care taken to ensure
5 risk comparability, market expectations with respect to future risks and growth
6 opportunities will vary from company to company. Therefore, even within a
7 group of similarly situated companies, it is common for analytical results to reflect
8 a seemingly wide range.¹⁶ An ongoing issue is how to best estimate the market-
9 required ROE from within that range. That determination necessarily must
10 consider a wide range of both empirical and qualitative information.

11 **Q. 24 Please now provide a summary profile of Southwest Gas.**

12 A. 24 Southwest Gas provides natural gas distribution service to approximately
13 2,047,000 customers in Nevada, Arizona, and California. Of those customers,
14 approximately 196,000 are located in California.¹⁷ Southwest Gas' operations
15 in California comprise three jurisdictions; Northern California, Southern
16 California and South Lake Tahoe. Net income from gas distribution operations
17 accounted for 76.17 percent of Southwest Gas' total net income in 2018.¹⁸ In
18 addition, 11.00 percent of the Company's operating margin was earned by its
19 California operations.¹⁹ Southwest Gas currently has senior unsecured ratings
20 of A3 (outlook: Stable), BBB+ (outlook: Negative) and A (outlook: Stable) from
21
22

23 ¹⁶ In Appendix A, I provide more substantive descriptions of the models used to estimate the ROE.

24 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.

25 ¹⁹ *Ibid.*, at 3.

1 Moody's Investor Service ("Moody's"), Standard & Poor's Rating Services
2 ("S&P") and Fitch Ratings, respectively.²⁰

3 **Q. 25 How did you select the companies included in your proxy group?**

4 A. 25 I began with the universe of companies that Value Line classifies as Natural Gas
5 Utilities, which includes a group of ten domestic U.S. utilities, and applied the
6 following screening criteria:

- 7 • Because utilities generally are considered dividend-paying entities, I
8 excluded companies that do not consistently pay quarterly cash dividends;
- 9 • All the companies in my proxy group are covered by at least two utility
10 industry equity analysts;
- 11 • All the companies in my proxy group have investment grade senior
12 unsecured bond and/or corporate credit ratings from S&P;
- 13 • To incorporate companies that are primarily regulated gas distribution
14 utilities, I included companies with at least 60.00 percent of net operating
15 income from regulated natural gas utility operations; and
- 16 • I eliminated companies that are currently known to be party to a merger,
17 or other significant transaction.

18 **Q. 26 Did you include Southwest Gas in your analysis?**

19 A. 26 No. To avoid the circular logic that otherwise would occur, it has been my
20 consistent practice to exclude the subject company (or its parent) from the proxy
21 group.

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²⁰ Source: Bloomberg Professional.

1 **Q. 27 What companies met those screening criteria?**

2 A. 27 The criteria discussed above resulted in a proxy group of the following six
3 companies:

4 **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

10
11 **Q. 28 Do you believe that a proxy group of six companies is sufficiently large?**

12 A. 28 Yes. The analyses performed in estimating the ROE are more likely to be
13 representative of the subject utility's Cost of Equity to the extent that the chosen
14 proxy companies are fundamentally comparable to the subject utility. Because
15 all analysts use some form of screening process to arrive at a proxy group, the
16 group, by definition, is not randomly drawn from a larger population.
17 Consequently, there is no reason to place more reliance on the quantitative
18 results of a larger proxy group simply by virtue of the resulting larger number of
19 observations.

20 Moreover, because I am using market-based data, my analytical results
21 will not necessarily be tightly clustered around a central point. Results that may
22 be somewhat dispersed, however, do not suggest that the screening approach
23 is inappropriate or the results less meaningful. In my view, including companies
24 whose fundamental comparability is tenuous at best simply for the purpose of
25

1 expanding the number of observations does not add relevant information to the
2 analysis.

3 **Q. 29 How does the proxy group credit rating compare to that of Southwest Gas?**

4 A. 29 As discussed by Company Witness Theodore K. Wood, the proxy group has a
5 credit rating of A2 and A- from Moody's and S&P, respectively.²¹ Compared to
6 the proxy group, the Company's S&P rating is one notch lower. Although credit
7 ratings may be directionally related to the Cost of Equity over the long-term, a
8 change in one is not a direct measure of a change in the other. As discussed
9 below, the Company faces several unique business risks, and given the
10 additional strain on the Company's financial metrics that can arise from those
11 risks, the Company's credit rating relative to the proxy group indicates greater
12 risk as seen by creditors.

13 **Cost of Equity Estimation**

14 **Q. 30 How is the required ROE determined?**

15 A. 30 Because the Cost of Equity is not directly observable, it must be estimated based
16 on both quantitative and qualitative information. Although several models have
17 been developed for that purpose, all are subject to limiting assumptions or other
18 constraints. Consequently, many finance texts recommend using multiple
19 approaches to estimate the Cost of Equity.²² When faced with the task of
20 estimating the Cost of Equity, analysts and investors are inclined to gather and
21 evaluate as much relevant data as reasonably can be analyzed and, therefore,
22 rely on multiple analytical approaches.

23 _____
24 ²¹ Prepared Direct Testimony of Theodore K. Wood, at 8; Exhibit No.____(TWK-1).

25 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.

1 As discussed earlier, because no individual model is more reliable than all
2 others under all market conditions, it is both prudent and appropriate to use
3 multiple methods. I therefore applied the Constant Growth DCF model, the
4 CAPM, the Bond Yield Plus Risk Premium, and the Expected Earnings
5 approach.

6 **Q. 31 Please briefly describe the Constant Growth DCF model.**

7 A. 31 The Constant Growth DCF approach defines the Cost of Equity as the sum of
8 (1) the expected dividend yield, and (2) expected long-term growth. As
9 explained in Appendix A, the model often is expressed in the familiar form $k =$
10 $\frac{D(1+g)}{P_0} + g$, where the expected dividend yield generally equals the expected
11 annual dividend divided by the current stock price, and the growth rate is based
12 on analysts' expectations of earnings growth. The Constant Growth DCF
13 formula, which falls from the longer "present value" structure,²³ requires several
14 simplifying assumptions, including the constancy of inputs in perpetuity.

15 Under the model's strict assumptions, the growth rate equals the rate of
16 capital appreciation (that is, the growth in the stock price).²⁴ Given that
17 assumption, it does not matter whether the investor holds the stock in perpetuity,
18 or whether they hold the stock for some period of time, collect the dividends,
19 then sell at the prevailing market price. That result also assumes the ROE result
20 reached today will remain unchanged in perpetuity. So, if market conditions are
21 such that the model produces an unreasonably low (or high) ROE estimate
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23 ²³ Appendix A, part A.

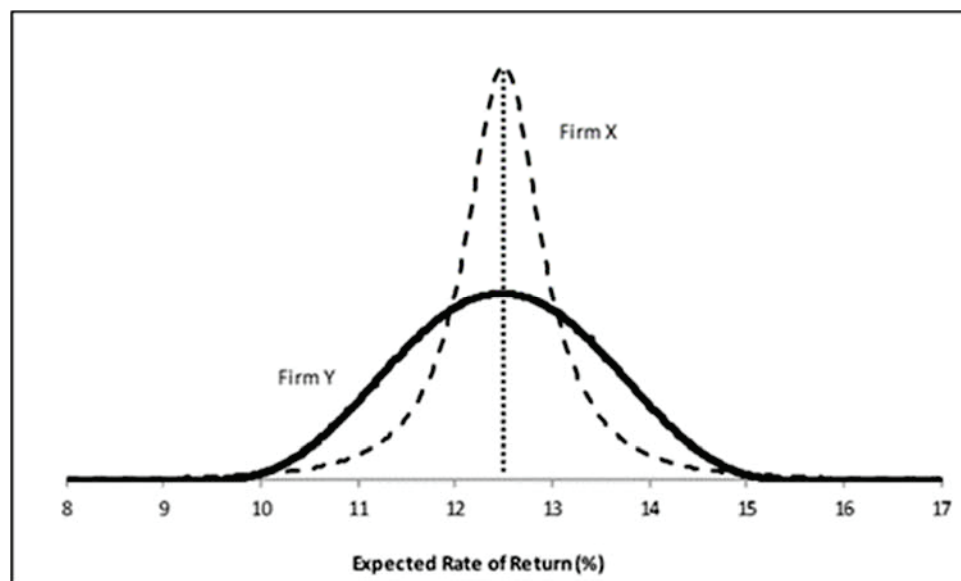
24 ²⁴ As discussed in Appendix A, part A, the model assumes that earnings, dividends, book value, and the
25 stock price all grow at the same constant rate in perpetuity. Additionally, academic research has indicated
that analysts forecasts of growth are superior to other measures of growth (see, Appendix A, part A).

1 today, it assumes that estimate will be the same ROE investors require every
2 day in the future, regardless of whether or how market conditions change.

3 **Q. 32 Please briefly describe the Capital Asset Pricing Model.**

4 A. 32 Whereas DCF models focus on expected cash flows, Risk Premium-based
5 models such as the CAPM focus on the additional return that investors require
6 for taking on additional risk. In finance, “risk” generally refers to the variation in
7 expected returns, rather than the expected return, itself. Consider two firms, X
8 and Y, with expected returns, and the expected variation in returns noted in
9 Chart 1, below. Although the two have the same expected return (12.50
10 percent), Firm Y’s are far more variable. From that perspective, Firm Y would
11 be considered the riskier investment.

12 **Chart 1: Expected Return and Risk**

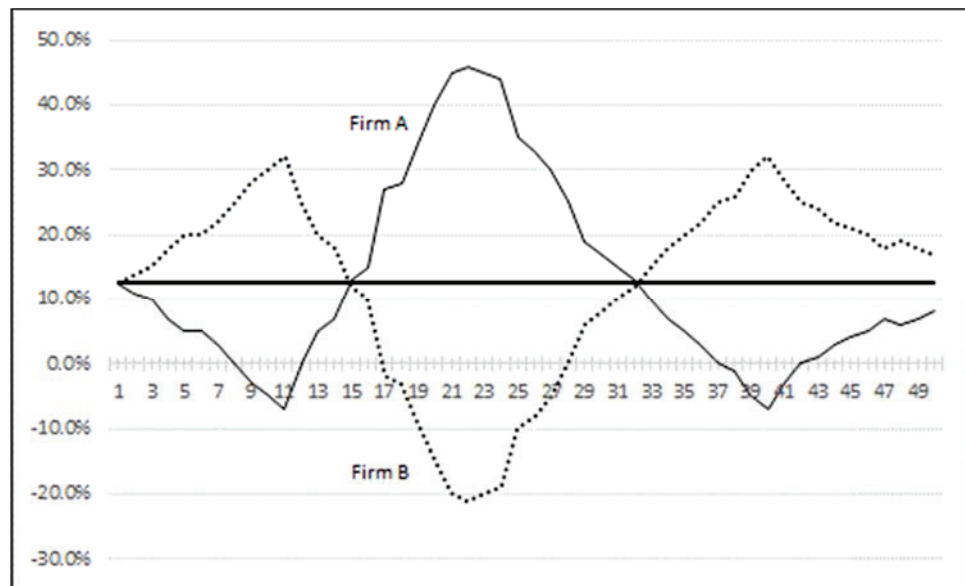


22 Now consider two other firms, Firm A and Firm B. Both have expected
23 returns of 12.50 percent, and both are equally risky as measured by their
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25

1 volatility. But as Firm A's returns go up, Firm B's returns go down. That is, the
2 returns are negatively correlated.

3 **Chart 2: Relative Risk**



13 If we were to combine Firms A and B into a portfolio, we would expect a
14 12.50 percent return with no uncertainty because of the opposing symmetry of
15 their risk profiles. That is, we can diversify away the risk. As long as two stocks
16 are not perfectly correlated, we can achieve diversification benefits by combining
17 them into a portfolio. That is the essence of the Capital Asset Pricing Model -
18 because we can combine firms into a portfolio, the only risk that matters is the
19 risk that remains after diversification, *i.e.*, the “non-diversifiable” risk.

20 The CAPM defines the Cost of Equity as the sum of the “risk-free” rate,
21 and a premium to reflect the additional risk associated with equity investments.
22 The “risk-free” rate is the yield on a security viewed as having no default risk,
23 such as long-term Treasury bonds, and essentially sets the baseline of the
24 CAPM. That is, an investor would expect a higher return than the risk-free rate

1 to purchase an asset that carries risk. The difference between that higher return
2 (*i.e.*, the required return) and the risk-free rate is the risk premium.

$$3 \quad \text{Risk} - \text{Free Rate} + \text{Risk Premium} = \text{Required Return} \quad [1]$$

4 The Risk Premium is defined as a security's Beta coefficient multiplied by
5 the risk premium of the overall market (the "Market Risk Premium" or "MRP").
6 The Beta coefficient is a measure of the subject company's risk relative to the
7 overall market, *i.e.*, the "non-diversifiable" risk. A Beta coefficient of 1.00 means
8 the security is equally risky as the overall market; a value below 1.00 represents
9 a security with less risk than the overall market, and a value over 1.00 represents
10 a security with more risk than the overall market. Equation [2] provides the
11 general format of the CAPM formula:

$$12 \quad \text{Risk} - \text{Free Rate} + (\text{Beta Coefficient} \times \text{Market Risk Premium}) = \text{Required Return} \quad [2]$$

13 **Q. 33 Please briefly describe the Bond Yield Plus Risk Premium approach.**

14 **A. 33** This approach is based on the basic financial principle that equity investors bear
15 the risk associated with ownership and therefore require a premium over the
16 return they would have earned as a bondholder. That is, because returns to
17 equity holders are riskier than returns to bondholders, equity investors must be
18 compensated for bearing that additional risk (that difference often is referred to
19 as the "Equity Risk Premium"). Bond Yield Plus Risk Premium approaches
20 estimate the Cost of Equity as the sum of the Equity Risk Premium and the yield
21 on a particular class of bonds.

$$22 \quad \text{Bond Yield} + \text{Equity Risk Premium} = \text{Required Return} \quad [3]$$

23 **Q. 34 Please briefly describe the Expected Earnings approach.**

24 **A. 34** The Expected Earnings analysis is based on the principle of opportunity costs.
25 Because investors may invest in, and earn returns on alternative investments of

1 similar risk, those rates of return can provide a useful benchmark in determining
2 the appropriate rate of return for a firm. Further, because those results are based
3 solely on the returns expected by investors, exclusive of market-data or models,
4 the Expected Earnings approach provides a direct comparison.

5 **Q. 35 What are the results of your Constant Growth DCF?**

6 A. 35 The results of the Constant Growth DCF are provided in Table 2, below.²⁵

7 **Table 2: Summary of DCF Results²⁶**

	Median	Median High
30-Day Average	9.06%	11.32%
90-Day Average	9.10%	11.36%
180-Day Average	9.17%	11.44%

11 **Q. 36 Please now summarize your remaining analytical results.**

12 A. 36 The Risk Premium-based results, including the CAPM and ECAPM, Bond Yield
13 Plus Risk Premium, and Expected Earnings methods, explained in detail in
14 Appendix A, parts B, C and D, respectively, are provided below.

22 _____
23 ²⁵ See, Appendix A for a more detailed description of the models, assumptions, and inputs described in Section IV.

24 ²⁶ For the purposes of my testimony, I have put more emphasis on the median results of my Constant
25 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.

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Table 3a: Summary of CAPM Results

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
<i>Average Bloomberg Beta Coefficient</i>		
Current 30-Year Treasury (2.63%)	9.58%	9.53%
Near Term Projected 30-Year Treasury (2.70%)	9.65%	9.60%
<i>Average Value Line Beta Coefficient</i>		
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
<i>Average Bloomberg Beta Coefficient</i>		
Current 30-Year Treasury (2.63%)	10.91%	10.84%
Near Term Projected 30-Year Treasury (2.70%)	10.98%	10.91%
<i>Average Value Line Beta Coefficient</i>		
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

1 even if no new issuances are planned in the near future; failure to do so may
2 deny Southwest Gas the opportunity to earn its required rate of return in the
3 future.

4 **Q. 40 Is the need to consider flotation costs eliminated because Southwest Gas**
5 **is a wholly owned subsidiary?**

6 A. 40 No. Like the Company's California operations, wholly owned subsidiaries
7 receive equity from their parent, who compete with other issuers in capital
8 markets. The ability to efficiently raise capital depends on the subsidiaries'
9 ability to earn reasonable returns on the equity invested by the parent. To deny
10 the recovery of the issuance costs required to raise that capital ultimately would
11 penalize the investors that fund the utility operations and would inhibit the
12 company's ability to efficiently raise new equity capital. This is important for
13 companies such as Southwest Gas that are planning continued investments in
14 the near term, and for which access to capital (at reasonable cost rates) to fund
15 those investments will be crucial.

16 **Q. 41 Do the DCF and CAPM models already incorporate investor expectations**
17 **of a return to compensate for flotation costs?**

18 A. 41 No. The models used to estimate the appropriate ROE assume no "friction" or
19 transaction costs, as these costs are not reflected in the market price (in the
20 case of the DCF model) or risk premium (in the case of the CAPM and the Bond
21 Yield Plus Risk Premium model). Therefore, it is appropriate to consider flotation
22 costs when determining where within the range of reasonable results Southwest
23 Gas' return should fall.

1 **Q. 42 Is the need to consider flotation costs recognized by the academic and**
2 **financial communities?**

3 A. 42 Yes. The need to reimburse investors for equity issuance costs is recognized
4 by the academic and financial communities in the same spirit that investors are
5 reimbursed for the costs of issuing debt. For example, Dr. Roger Morin notes
6 that “[t]he costs of issuing [common stock] are just as real as operating and
7 maintenance expenses or costs incurred to build utility plants, and fair regulatory
8 treatment must permit the recovery of these costs.”²⁷ Dr. Morin further notes
9 that “equity capital raised in a given stock issue remains on the utility’s common
10 equity account and continues to provide benefits to ratepayers indefinitely.”²⁸
11 This treatment is consistent with the philosophy of a fair rate of return. As
12 explained by Dr. Shannon Pratt:

13 Flotation costs occur when a company issues new stock. The
14 business usually incurs several kinds of flotation or transaction
15 costs, which reduce the actual proceeds received by the business.
16 Some of these are direct out-of-pocket outlays, such as fees paid
17 to underwriters, legal expenses, and prospectus preparation
18 costs. Because of this reduction in proceeds, the business’s
19 required returns must be greater to compensate for the additional
20 costs. Flotation costs can be accounted for either by amortizing
21 the cost, thus reducing the net cash flow to discount, or by
22 incorporating the cost into the cost of equity capital. Since flotation
23 costs typically are not applied to operating cash flow, they must be
24 incorporated into the cost of equity capital.²⁹

25 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

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.

1 that must be paid to underwriters by the issuer to attract and retain
2 capital).³⁰

3 **Q. 43 Has Southwest Gas recently participated in a common equity offering**
4 **agreement?**

5 A. 43 Yes. As explained by Company Witness Theodore K. Wood, Southwest Gas'
6 parent company recently entered into a \$300 million Equity Shelf Program in
7 May of 2019.³¹ As discussed by Company Witness Theodore K. Wood, the
8 proceeds from this offering, and a previous offering of \$150 million, are reflected
9 in the Company's records as a capital contribution from the parent holding
10 company.³² In addition to anticipated expenses of \$507,860, the Company will
11 incur a commission expense equal to 1.00 percent all shares sold (\$3 million
12 upon completion).³³

13 **Q. 44 Have you calculated the effect of flotation costs on the return on equity?**

14 A. 44 Yes. I modified the DCF calculation to derive the dividend yield that would
15 reimburse investors for direct issuance costs. Based on the weighted average
16 issuance costs shown in Exhibit No.__(RBH-8), a reasonable estimate of
17 flotation costs is approximately 0.07 percent (7 basis points). Although I have
18 calculated the effect of flotation costs, I did not make any explicit adjustments to
19 my ROE estimates to account for flotation costs. Rather, I took it into
20 consideration in determining where the Company's Cost of Equity falls within the
21 range of analytical results.

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23 ³⁰ Morningstar, Inc. Ibbotson SBBI 2013 Valuation Yearbook, at 25.

24 ³¹ Prepared Direct Testimony of Theodore K. Wood, at 12.

25 ³² *Ibid.*

³³ $\$3,000,000 = 1.00\% \times \$300,000,000$. Source: Southwest Gas Holdings, Inc. SEC Form S-3 Registration Statement, May 8, 2019.

1 **V. BUSINESS RISKS AND OTHER CONSIDERATIONS**

2 **Q. 45 Please describe the additional factors you considered in determining the**
3 **appropriate Cost of Equity for Southwest Gas.**

4 A. 45 As discussed earlier, it is important to assess the factors below to determine
5 their effect on the Company, and subsequently, to determine where within my
6 recommended range, the Cost of Equity for Southwest Gas appropriately lies.
7 Those factors include: (1) the regulatory and political risks the Company faces
8 within the state of California, including the effect of SB 901; (2) the Company's
9 proposed capitalization; and (3) the Company's significant capital expenditure
10 plan. Those factors, which are discussed below, should be considered in terms
11 of their overall effect on the Company's Cost of Equity.

12 **Regulatory and Political Risks**

13 **Q. 46 Please describe the concept of Inverse Condemnation.**

14 A. 46 As the California Court of Appeals has explained, the "fundamental policy
15 underlying the concept of inverse condemnation is to spread among the
16 benefiting community any burden disproportionately borne by a member of that
17 community, to establish a public undertaking for the benefit of all."³⁴ Although I
18 am not an attorney, my plain reading of that language suggests utilities could be
19 found liable for damages to private property, despite no indication of wrongdoing
20 or negligence.

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³⁴ *Barham v. Southern California Edison Co.*, 74 Cal, App. 4th 744, 752, (1999).

1 **Q. 47 Have the wildfires in California increased investor awareness of Inverse**
2 **Condemnation?**

3 A. 47 Yes. Although Southwest Gas currently does not face liabilities as a result of
4 the wildfires in California, it is not unreasonable to expect investors would
5 consider the uncertainty associated with Inverse Condemnation, and the
6 regulatory climate in California.

7 **Q. 48 Are there specific examples of negative reactions from the investment**
8 **community in response to Inverse Condemnation?**

9 A. 48 Yes. On January 23, 2019, Regulatory Research Associates (“RRA”) reduced
10 California’s rating to Average/1 from Above Average/3, stating that the “lack of
11 regulatory or legislative protections against wildfire liabilities caused by the
12 application of inverse condemnation...prompted RRA...to reduce its regulatory
13 rating.”³⁵ On August 12, 2019, RRA further reduced the rating to Average/2,
14 citing the effects of Inverse Condemnation remaining a significant issue.³⁶

15 **Q. 49 Are there other political or regulatory risks that Southwest Gas faces in**
16 **California?**

17 A. 49 Yes. Recent legislation has reflected increased focus on decarbonization,
18 including specifically, building decarbonization. As the Commission noted, the
19 California Energy Commission recently instituted a means by which builders of
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22 ³⁵ Source: Regulatory Research Associates. As RRA explains: “RRA maintains three principal rating
23 categories for regulatory climates: Above Average, Average, and Below Average. Within the principal
24 rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger
25 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.

1 all-electric buildings can more easily comply with building codes.³⁷ The
2 Commission further observed “[t]he costs and benefits of building standards that
3 support decarbonization are interdependent with many policies that fall under
4 Commission jurisdiction”³⁸ As these policies advance, their effects could reduce
5 the demand for natural gas, leaving natural gas utilities at risk of holding
6 stranded assets.

7 Although they are difficult to quantify, we reasonably can conclude
8 investors will require higher returns to accept the increased uncertainty
9 surrounding the regulatory and political risks in California.

10 **Senate Bill 901**

11 **Q. 50 Please summarize Senate Bill 901.**

12 A. 50 SB 901 requires certain officer compensation to be borne solely by the
13 shareholders:

14 This bill would repeal the above provisions relating to excess
15 annual compensation of utility officers. The bill would prohibit an
16 electrical corporation or gas corporation from recovering from
17 ratepayers any annual salary, bonus, benefits, or other
18 consideration of any value, paid to an officer of the electrical
19 corporation or gas corporation, and would require that
20 compensation to instead be funded solely by shareholders of the
21 electrical corporation or gas corporation.³⁹

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24 ³⁷ California Public Utilities Commission, *Order Instituting Rulemaking Regarding Building
Decarbonization*, Rulemaking 19-01-011, at 6-7.

³⁸ *Id.*, at 7.

25 ³⁹ California Senate Bill No. 901, Chapter 626, September 21, 2018, at 7-8.

1 **Q. 51 What is the current California portion of executive compensation that will**
2 **be excluded from recovery for Southwest Gas?**

3 A. 51 The 2018 California portion of executive compensation that would be excluded
4 from recovery is approximately \$897,000.⁴⁰

5 **Q. 52 Is \$897,000 the correct amount to use in determining the additional risk SB**
6 **901 places on shareholders?**

7 A. 52 No. \$897,000 is the amount for 2018 that will be funded by shareholders. Under
8 SB 901, however, shareholders will bear that cost in perpetuity.

9 **Q. 53 Have you calculated the effect of SB 901 in perpetuity?**

10 A. 53 Yes. I first calculated the present value of the \$897,000 based on the Gordon
11 Model,⁴¹ which defines value as the expected cash-flow divided by the difference
12 between the Cost of Equity (*i.e.*, the discount rate) and the long-term expected
13 growth rate. I then calculated the present value of the Company's common
14 equity, which is based on the Company's proposed test year rate base.

15 As shown in Exhibit No.__(RBH-9), the present value of the \$897,000
16 excluded under SB 901 divided by the present value of the Company's test year
17 common equity is approximately 0.37 percent (37 basis points).⁴²

23 ⁴⁰ Source: Company-provided information.

24 ⁴¹ See, Morningstar, Inc., *2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook*, at 48-52.

25 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.

1 **Capital Structure and Financial Leverage**

2 **Q. 54 What is Southwest Gas' recommended capital structure?**

3 A. 54 As described in more detail in Company witness Theodore K. Wood's testimony,
4 Southwest Gas' recommended capital structure consists of 53.00 percent
5 common equity and 47.00 percent long-term debt.⁴³

6 **Q. 55 Did you assess the reasonableness of Southwest Gas' proposed capital
7 structure relative to the proxy group?**

8 A. 55 Yes. The proxy group has been selected to reflect comparable companies in
9 terms of financial, business, and regulatory risks. Therefore, it is appropriate to
10 compare the capital structures of the proxy group companies to that of the
11 subject company in order to assess whether the proposed capital structure is
12 consistent with industry standards for companies with commensurate risk
13 profiles.

14 **Q. 56 Please describe your analysis of Southwest Gas' capital structure relative
15 to industry practice.**

16 A. 56 As a measure of industry practice, I calculated the average capital structure for
17 each of the proxy companies over the last eight fiscal quarters. As shown in
18 Exhibit No.__(RBH-10), the proxy group average capital structure over that
19 period includes 53.10 percent common equity and 46.90 percent long-term debt;
20 the average common equity ratios (on a company-specific basis) range from
21 42.20 percent to 62.14 percent. Based on that review, it is apparent that
22 Southwest Gas' proposed capital structure of 53.00 percent common equity is
23 consistent with the proxy group average.

24
25 ⁴³ Prepared Direct Testimony of Theodore K. Wood, at 3.

1 **Q. 57 What is the basis for using average capital components rather than a point-**
2 **in-time measurement?**

3 A. 57 Measuring the capital components at a particular point in time can skew the
4 capital structure by the specific circumstances of a particular period. Therefore,
5 it is more appropriate to normalize the relative relationship between the
6 components over a period of time.

7 **Q. 58 Have you conducted any analyses between the Company's proposed**
8 **common equity ratio and the Company's required ROE?**

9 A. 58 Yes. I estimated the adjustment required for both the CAPM and DCF analyses
10 to account for 5.00 percentage point changes in the equity ratio both above and
11 below the proxy group projected average equity ratio of 57.08 percent (based
12 on Value Line's projected Common Equity for the period 2022-2024.)⁴⁴ I based
13 my adjustment to the CAPM results on the Hamada Equation,⁴⁵ which adjusts
14 the average Beta coefficient for the level of leverage held by the underlying
15 companies on which that measurement is made. In this case, the proxy group
16 projected average equity ratio of 57.08 percent and the average Value Line Beta
17 coefficient of 0.68 translate to an unlevered (or "asset") Beta coefficient of 0.42,
18 when the tax effect of the debt portion of the capital structure is removed from
19 the calculation. The unlevered Beta coefficient can then be re-levered to
20 approximate the additional risk assumed by decreasing the equity ratio to any
21 level specified.

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24 ⁴⁴ The Company is using a Forward Test Year in their accompanying filing.

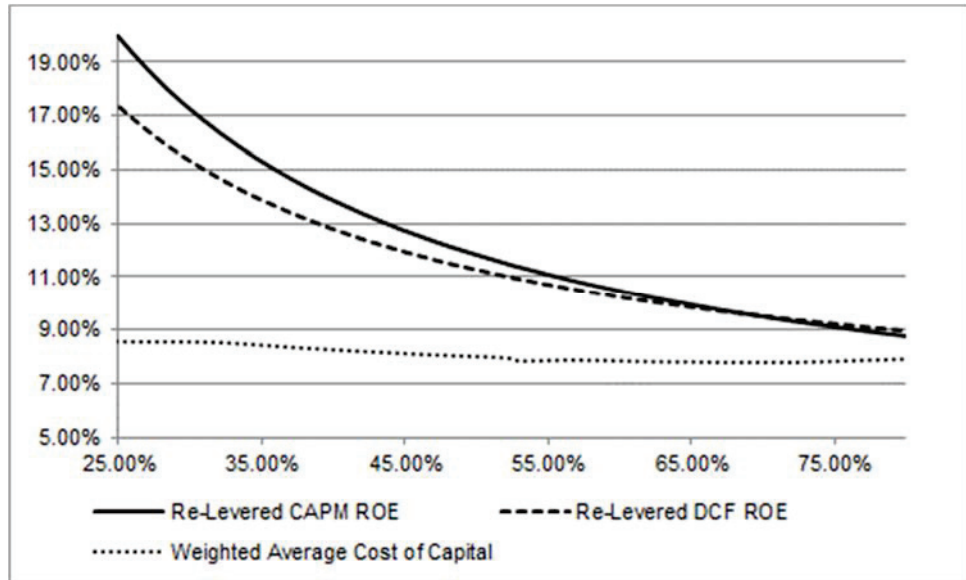
25 ⁴⁵ Shannon P. Pratt, Robert F. Reilly, and Robert P. Schweihs, Valuing a Business, Fourth Edition, at 169.

1 I performed a similar adjustment to the DCF analysis based on the
2 Modigliani-Miller Approach,⁴⁶ using the proxy group average equity and debt
3 ratios and an assumed effective tax rate of 21.00 percent. I then adjusted the
4 unlevered ROE to approximate the added risk assumed by changing the equity
5 ratio in 5.00 percent increments.

6 As shown in Chart 3 (below) and Exhibit No.__(RBH-11), based on the
7 CAPM and DCF analyses, an equity ratio of approximately 53.00 percent
8 indicates a required ROE of approximately 10.91 percent to 11.38 percent.
9 Moreover, as shown in Chart 3 (below), based on several factors, including
10 currently observed credit spreads for utility bonds, Moody's guidelines for
11 Debt/Total Capital, and the average capital structure of the proxy group, the
12 optimal equity ratio with respect to overall weighted cost of capital is well above
13 the Company's requested 53.00 percent equity ratio (*i.e.*, the point at which the
14 WACC is minimized.)

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25 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.

1 **Q. 59 What are your conclusions regarding the Company's proposed common**
2 **equity ratio?**

3 A. 59 Although the Company's proposed common equity ratio of 53.00 percent is
4 consistent with the proxy group average of 53.10 percent, it falls below the 57.08
5 percent proxy group average projected by Value Line. Given the Company is
6 applying a Forward Test Year, I find its proposed common equity ratio of 53.00
7 percent generally to be in alignment with my ROE recommendation.

8 **Capital Expenditures and Credit Metrics**

9 **Q. 60 Please summarize Southwest Gas' capital expenditure plans.**

10 A. 60 Southwest Gas currently plans to invest approximately \$211 million dollars over
11 the period 2019-2021.⁴⁷ That amount includes investments to maintain and
12 improve distribution and general facilities.

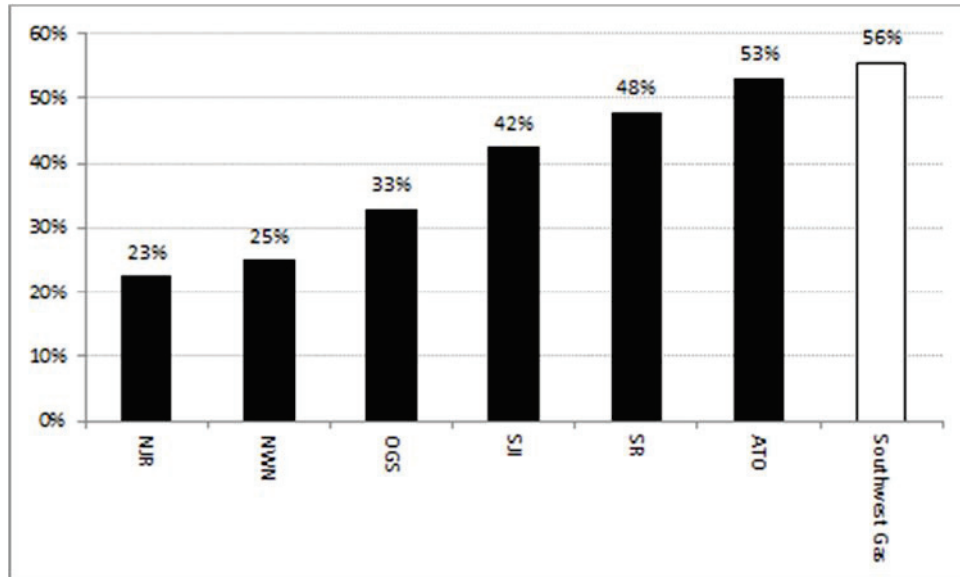
13 **Q. 61 How do Southwest Gas' expected capital expenditures compare to the**
14 **proxy group?**

15 A. 61 To reasonably make that comparison, I calculated the ratio of expected capital
16 expenditures to net plant for each company in the proxy group (see, Exhibit
17 No.__(RBH-12)). For the projected period 2019-2021, I performed that
18 calculation using Southwest Gas' projected capital expenditures relative to its
19 2018 net plant. As shown in Chart 4, relative to the proxy group, Southwest Gas
20 has the highest ratio of projected capital expenditures to net plant, and its
21 projected capital expenditures relative to net plant are 47.71 percent higher than
22 the proxy group median.

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⁴⁷ Source: Company-provided data.

Chart 4: Comparison of Projected Capital Expenditures Relative to Net Plant⁴⁸



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11 **Q. 62 Why is it important for a utility to be allowed the opportunity to earn a**
12 **return that is adequate to attract capital at reasonable terms?**

13 **A. 62** The allowed ROE should enable the subject utility to finance capital expenditures
14 and working capital requirements at reasonable rates, and to maintain its
15 financial integrity in a variety of economic and capital market conditions. As
16 discussed earlier in my prepared direct testimony, a return that is adequate to
17 attract capital at reasonable terms enables the utility to provide safe, reliable
18 service while maintaining its financial soundness. To the extent a utility is
19 provided the opportunity to earn its market-based cost of capital, neither
20 customers nor shareholders should be disadvantaged.

21 The ratemaking process is based on the principle that, for investors and
22 companies to commit the capital needed to provide safe and reliable utility
23 services, the utility must have the opportunity to recover the return of, and the
24

25 ⁴⁸ Sources: Value Line Investment Survey; and Company-provided data.

1 market-required return on, invested capital. Regulatory commissions recognize
2 that because utility operations are capital intensive, their decisions should
3 enable the utility to attract capital at reasonable terms; doing so balances the
4 long-term interests of the utility and its ratepayers.

5 Further, the financial community carefully monitors the current and
6 expected financial condition of utility companies, as well as the regulatory
7 environment in which those companies operate. In that respect, the regulatory
8 environment is one of the most important factors considered in both debt and
9 equity investors' assessments of risk. That is especially important during periods
10 in which the utility expects to make significant capital investments and, therefore,
11 may require access to capital markets.

12 **Q. 63 How do those considerations apply to Southwest Gas and its capital**
13 **spending plans?**

14 **A. 63** It is clear Southwest Gas' capital expenditure program is significant. It also is
15 clear that the financial community recognizes the need for timely cost recovery
16 for those capital expenditures. From a credit perspective, the additional
17 pressure on cash flows associated with high levels of capital expenditures exerts
18 corresponding pressure on credit metrics and, therefore, credit ratings. S&P has
19 noted several long-term challenges for utilities' financial health including: heavy
20 construction programs to address demand growth; declining capacity margins;
21 and aging infrastructure and regulatory responsiveness to mounting requests for
22 rate increases.⁴⁹ More recently, S&P noted that:

24 ⁴⁹ See, Standard & Poor's, *Industry Report Card: Utility Sectors in the Americas Remain Stable, While*
25 *Challenges Beset European, Australian, and New Zealand Counterparts*, RatingsDirect, June 27, 2008,
at 4.

1 We assume that capital spending will remain a focus of most utility
2 managements and strain credit metrics. It provides growth when
3 sales are diminished by ongoing demanded efficiency from
4 regulators and other trends, and it is welcomed by policymakers
5 that appreciate the economic stimulus and the benefits of safer,
6 more reliable service. The speed with which the regulatory
7 process turns the new spending into higher rates to begin to pay
8 for it is an important factor in our assumptions and the forecast.
9 Any extended lag between spending and recovery can exacerbate
10 the negative effect on credit metrics and therefore ratings.⁵⁰

11 **Q. 64 Have the major rating agencies raised concern as they consider the**
12 **implications of the Tax Cuts and Jobs Act (“TCJA”) for utilities’ cash flow**
13 **and credit statistics?**

14 **A. 64** The major rating agencies have observed that a reduction in utilities’ revenue
15 associated with lower income taxes and the potential return of excess
16 accumulated deferred income taxes may reduce utilities’ cash flow.⁵¹ As Fitch
17 pointed out “[a]bsent mitigating strategies on the regulatory front, this is expected
18 to lead to weaker credit metrics and negative rating actions for issuers with
19 limited headroom to absorb the leverage creep.”⁵² In a similar vein, S&P
20 observed that the TCJA is “...negative for credit quality because the combination
21 of a lower tax rate and the loss of stimulus provisions related to bonus
22 depreciation or full expensing of capital spending will create headwinds in
23 operating cash-flow generation capabilities as customer rates are lowered in
24 response to the new tax code.”⁵³ Moody’s stated the following:

25 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.

1 Tax reform is credit negative for US regulated utilities because the
2 lower 21% statutory tax rate reduces cash collected from
3 customers, while the loss of bonus depreciation reduces tax
4 deferrals, all else being equal. Moody's calculates that the recent
5 changes in tax laws will dilute a utility's ratio of cash flow before
6 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

7 All three rating agencies, therefore, have observed the negative effects of the
8 TCJA on utilities' cash flow, and the potential consequences for their credit
9 profiles

10 **Q. 65 Did Moody's update its review of the utility sector?**

11 A. 65 Yes. On June 18, 2018 Moody's changed its outlook on the U.S. regulated utility
12 sector to "negative" from "stable". Moody's explained that its change in outlook
13 "...primarily reflects a degradation in key financial credit ratios, specifically the
14 ratio of cash flow from operations to debt, funds from operations (FFO) to debt
15 and retained cash flow to debt, as well as certain book leverage ratios."⁵⁵ The
16 sector's outlook could remain "negative" if cash flow-based metrics continue to
17 decline, or if there emerge signs of a more "contentious" regulatory environment
18 (which, Moody's notes, is not fully reflected in lower authorized returns).
19 Moody's also noted that "[m]anagement teams' defensive efforts and a few initial
20 signs of supportive regulatory responses to tax reform are important first steps
21 in addressing the sector's increased financial risk," and explained that in its view,

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24 ⁵⁴ Moody's Investors' Service, *Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform*, January 19, 2018.

25 ⁵⁵ See, Moody's Investors Service, *Announcement: Moody's changes the US regulated utility sector outlook to negative from stable*, June 18, 2018.

1 “it will take longer than 12-18 months for the sector to exhibit a material financial
2 improvement from these actions.”⁵⁶

3 **Q. 66 What conclusions do you draw regarding the effects of the Company’s**
4 **capital expenditure plan and the TCJA?**

5 A. 66 There is little question the TCJA has increased cash flow-related risks, and the
6 potentially dilutive effects of additional equity issuances, for utilities. Those risks
7 are manifested in the comments of financial participants such as Moody’s, S&P,
8 and Fitch. Further, because non-regulated companies may benefit from the
9 TCJA in ways utilities cannot, it is reasonable to conclude investors have begun
10 to see utilities as less attractive relative to other industry sectors. Lastly, the
11 dilution in cash flow may increase short-term borrowing requirements to fund
12 day-to-day utility operations. When paired with the Company’s significant capital
13 expenditure program relative to the proxy group, which in itself represents
14 additional pressure on the Company’s credit metrics, the effects of the TCJA
15 should not be overlooked.

16 **VI. CAPITAL MARKET ENVIRONMENT**

17 **Q. 67 Do economic conditions influence the required Cost of Capital and**
18 **required return on common equity?**

19 A. 67 Yes. As discussed in Section IV and in Appendix A, the models used to estimate
20 the Cost of Equity are meant to reflect, and therefore are influenced by, current
21 and expected capital market conditions. Therefore, it is important to assess the
22 reasonableness of any financial model’s results in the context of observable
23 market data. To the extent a given model’s assumptions are misaligned with
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25 ⁵⁶ *Id.*

1 such data, or its results are inconsistent with basic financial principles, it is
2 important to consider whether alternative estimation techniques are likely to
3 provide more meaningful and reliable results.

4 **Q. 68 Does your recommendation consider the current capital market
5 environment?**

6 A. 68 Yes. From an analytical perspective, it is important that the inputs and
7 assumptions used to arrive at an ROE recommendation, including assessments
8 of capital market conditions, are consistent with the recommendation itself.
9 Although all analyses require an element of judgment, the application of that
10 judgment must be made in the context of the quantitative and qualitative
11 information available to the analyst and the capital market environment in which
12 the analyses were undertaken.

13 **Q. 69 Has market volatility changed with the Federal Reserve's move toward
14 monetary policy normalization?**

15 A. 69 Yes. A visible and widely reported measure of expected volatility is the Chicago
16 Board Options Exchange ("Cboe") Volatility Index, often referred to as the VIX.
17 As Cboe explains, the VIX "is a calculation designed to produce a measure of
18 constant, 30-day expected volatility of the U.S. stock market, derived from real-
19 time, mid-quote prices of S&P 500® Index (SPXSM) call and put options."⁵⁷
20 Simply, the VIX is a market-based measure of expected volatility. Because
21 volatility is a measure of risk, increases in the VIX, or in its volatility, are a broad
22 indicator of expected increases in market risk. Although the VIX is not expressed
23 as a percentage, it should be understood as such. That is, if the VIX stood at
24

25 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 Volatility⁵⁹

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?

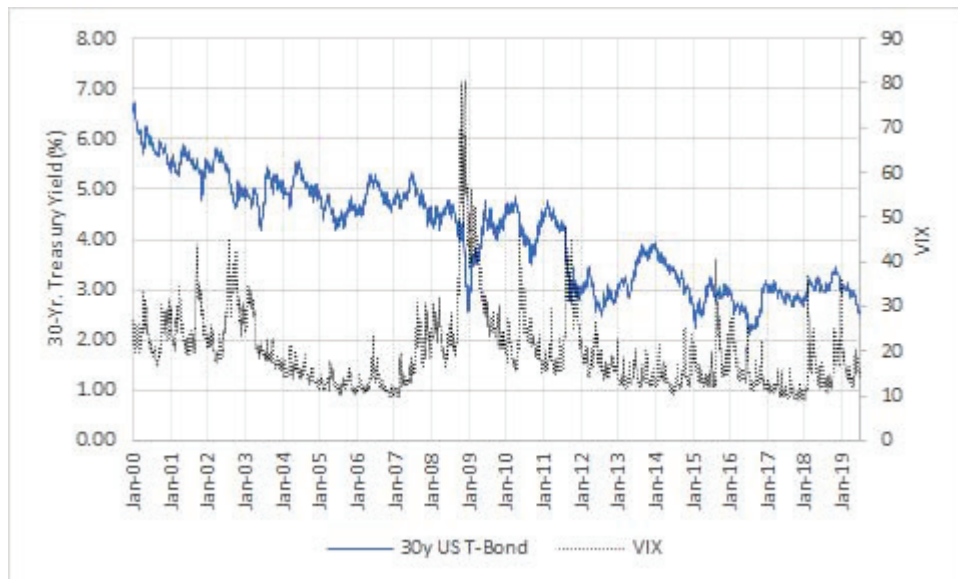
A. 70 Yes. Significant and abrupt increases in volatility tend to be associated with declines in Treasury yields. That relationship makes intuitive sense; as investors

⁵⁸ Source: Duff & Phelps, 2019 SBBI Yearbook, at 6-17.

⁵⁹ Source: Bloomberg Professional.

1 see increasing risk, their objectives may shift principally to capital preservation
2 (that is, avoiding a capital loss). A means of doing so is to allocate capital to the
3 relative safety of Treasury securities, in a “flight to safety”. Because Treasury
4 yields are inversely related to Treasury bond prices, as investors bid up the
5 prices of bonds, they bid down the yields. As Chart 5, below, demonstrates,
6 decreases in the 30-year Treasury yield are coincident with significant increases
7 in the VIX.

8 **Chart 5: 30-Year Treasury Yields vs. VIX (1/2000 – 6/2019)⁶⁰**



18 In those instances, the fall in yields does not reflect a reduction in required
19 returns, it reflects an increase in risk aversion and, therefore, an increase in
20 required equity returns.

21 **Q. 71 Is market volatility expected to increase from its current levels?**

22 **A. 71** Yes. One means of assessing market expectations regarding the future level of
23 volatility is to review Cboe’s “Term Structure of Volatility.” As Cboe points out:

24

25 ⁶⁰ Sources: S&P Global Market Intelligence; and Yahoo! Finance.

1 The implied volatility term structure observed in SPX options
2 markets is analogous to the term structure of interest rates
3 observed in fixed income markets. Similar to the calculation of
4 forward rates of interest, it is possible to observe the option
5 market's expectation of future market volatility through use of the
6 SPX implied volatility term structure.⁶¹

7 Cboe's term structure data is upward sloping, indicating market expectations of
8 increasing volatility. The expected VIX value in June 2020 is about 17.71,
9 suggesting investors see a reversion to long-term average volatility over the
10 coming months.⁶²

11 **Q. 72 Have recent declines in Treasury yields been associated with increases in
12 market volatility?**

13 **A. 72** Yes. Since November 2018, the periods during which Treasury yields fell
14 coincided with increases in the VIX (see, Chart 6, below).

15 **Chart 6: 30-Year Treasury Yields vs. VIX (11/2018 – 6/2019)⁶³**



23 ⁶¹ Source: <http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data>.

24 ⁶² Source: <http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data>, accessed June 28, 2019.

25 ⁶³ Sources: S&P Global Market Intelligence; and Yahoo! Finance.

1 **Q. 73 What conclusions do you draw from those analyses?**

2 A. 73 It is important to consider whether changes in long-term interest rates reflect
3 fundamental changes in investor sentiment, or whether they reflect potentially
4 transitory factors. The recent, sudden decline in interest appears to be related
5 to the increase in equity market volatility, which may be event-driven rather than
6 a fundamental change. Because the methods used to estimate the Cost of
7 Equity are forward-looking it is important to consider those distinctions in
8 assessing model results.

9 **Q. 74 Have natural gas utility dividend yields closely followed long-term**
10 **Treasury yields?**

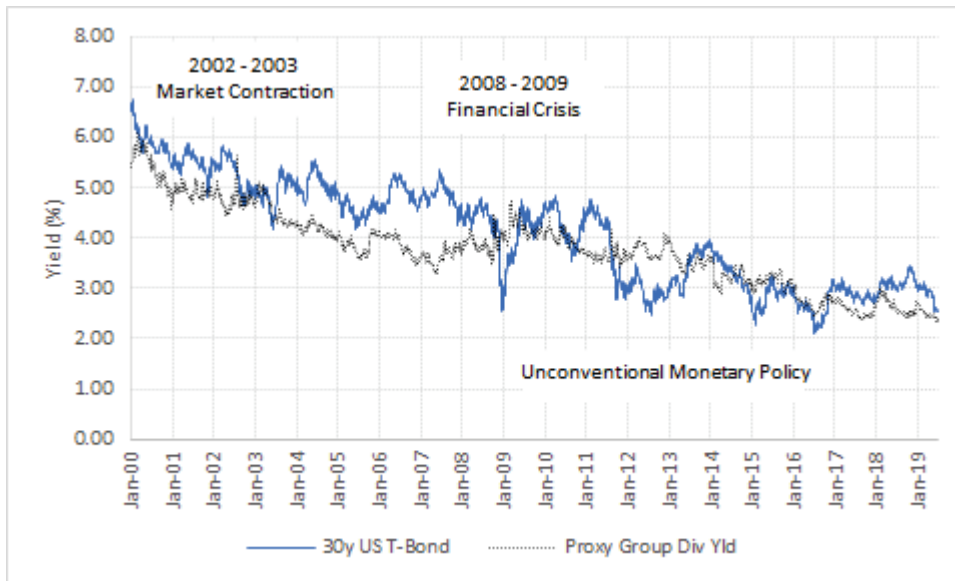
11 A. 74 Although they have been directionally related over time, the fundamental
12 relationship between Treasury yields and natural gas utility⁶⁴ dividend yields
13 changed after the 2008/2009 financial crisis. From 2000 through 2008, Treasury
14 yields generally exceeded natural gas utility dividend yields; the exception was
15 the 2002-2003 market contraction. Then, in 2008-2009, investors sought the
16 safety of Treasury securities, accepting lower Treasury yields in exchange for a
17 greater likelihood of capital preservation. Once the contraction ended (in the
18 latter half of 2009), the relationship fluctuated as the Federal Reserve
19 implemented and maintained “unconventional” monetary policies in reaction to
20 the financial crisis (*i.e.*, Quantitative Easing) with the intended consequence of
21 lowering long-term interest rates (*see*, Chart 7, below). As the Federal Reserve
22 began to “normalize” its monetary policy, the relationship was restored.

23

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25 ⁶⁴ Defined as the proxy group calculated as an index.

Chart 7: Utility Dividend Yields and 30-Year Treasury Yields⁶⁵



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.

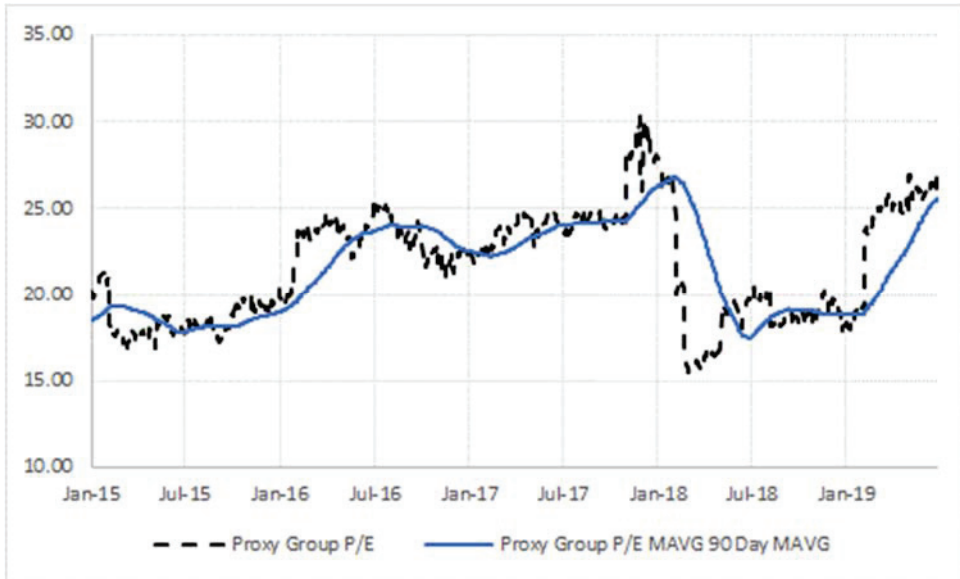
Q. 75 Is that relationship also seen in utility price/earnings ratios?

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.

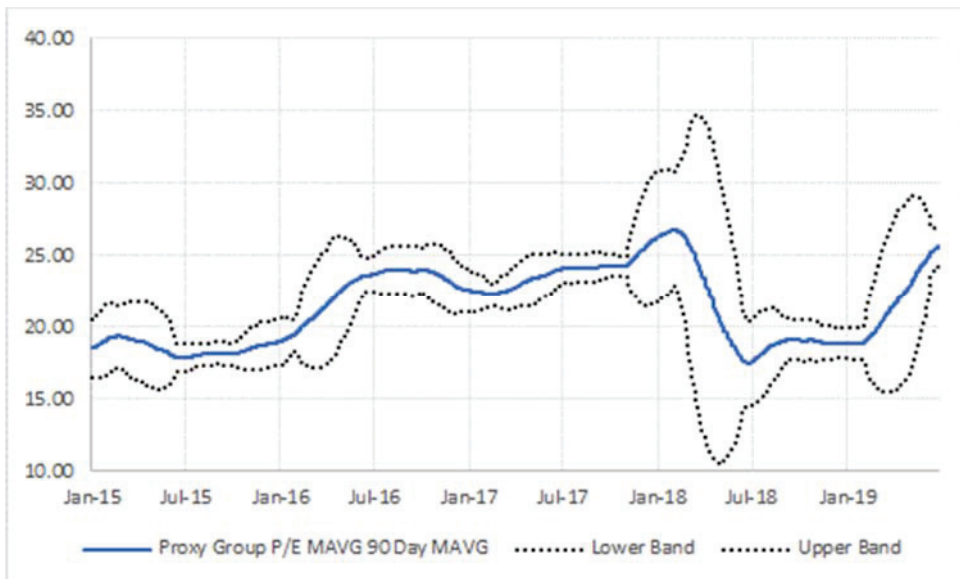
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Chart 8: Proxy Group Average Price/Earnings Ratio⁶⁶



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 Bands⁶⁷



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.

1 That data supports the conclusion discussed earlier, that utility stock prices are
2 sensitive to changes in interest rates, to a degree. The “reach for yield” that
3 sometimes occurs when interest rates fall has a limit; investors will not accept
4 the incremental risk of capital losses when utility valuation levels become
5 “stretched”. That also may be the case when investors see interest rates
6 reacting to market volatility that is event-driven, rather than a fundamental
7 change in the capital market environment or investor risk tolerances. The
8 increasing variability can be seen in Chart 9 (above), when the bands around
9 the 90-day moving average P/E ratios widen. During those periods, the risk of
10 capital loss increases, implying a further limit on valuation levels.

11 **Q 76 What conclusions do you draw from your analyses of the current capital**
12 **market environment, and how do those conclusions affect your ROE**
13 **recommendation?**

14 **A. 76** Because certain models used to estimate the Cost of Equity require long-term
15 assumptions, it is important to understand whether those assumptions hold. The
16 current market environment is one in which changes in interest rates may be
17 associated with events, more than they are a function of fundamental economic
18 conditions. Further, utility valuations have a limit, even when investors look to
19 them for an alternate source of income as interest rates fall.

20 On balance, it remains important to consider changes in market conditions,
21 the likely causes of those changes, and how model results are affected by them.
22 Those assessments necessarily involve the application of reasoned and
23 experienced judgment. As discussed throughout my testimony, that judgment
24 supports my recommended range of 10.00 percent to 10.70 percent.
25

1 **VII. CONCLUSIONS AND RECOMMENDATION**

2 **Q. 77 What is your conclusion regarding the Company's Cost of Equity?**

3 A. 77 As discussed throughout my prepared direct testimony, it is prudent and
4 appropriate to consider multiple methods to arrive at an ROE recommendation.
5 As discussed in Appendix A and as shown in Exhibit No.__(RBH-1) through
6 Exhibit No.__(RBH-12), I have performed several analyses to estimate
7 Southwest Gas' Cost of Equity. Considering those results and other relevant,
8 observable market data, I believe an ROE in the range of 10.00 percent to 10.70
9 percent represents the range of returns required by equity investors under
10 current and expected market conditions. Within that range, I conclude an ROE
11 of 10.50 percent represents a reasonable estimate of the Cost of Equity for
12 Southwest Gas. My recommendation reflects analytical results based on a proxy
13 group of natural gas utilities, and takes into consideration: (1) the regulatory and
14 political risks facing the Company; (2) the effect of Senate Bill 901 on the
15 Company's cost recovery; (3) the Company's equity ratio relative to the proxy
16 group; and (4) the Company's capital expenditures. In addition, I calculated the
17 costs of issuing common stock (that is, "flotation" costs) and considered evolving
18 capital market and business conditions.

19 **Q. 78 Have you reviewed the authorized ROEs in place at the proxy group**
20 **operating companies?**

21 A. 78 Yes. I found the authorized ROEs in place at the proxy group operating
22 companies to have a mean and median authorized ROE of 10.12 percent and
23 9.78 percent, respectively.
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1 | **Q. 79 Does this conclude your prepared direct testimony?**

2 | A. 79 Yes.

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1 **VIII. APPENDIX A**

2 **A. Constant Growth Discounted Cash Flow**

3 **Q. 80 Please more fully describe the Constant Growth DCF approach.**

4 A. 80 The Constant Growth DCF approach is based on the theory that a stock's current
5 price represents the present value of all expected future cash flows. In its
6 simplest form, the Constant Growth DCF model expresses the Cost of Equity as
7 the discount rate that sets the current price equal to expected cash flows:

8
$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_\infty}{(1+k)^\infty} \quad [4]$$

9
10 where P represents the current stock price, $D_1 \dots D_\infty$ represent expected future
11 dividends, and k is the discount rate, or required ROE. Equation [4] is a standard
12 present value calculation that can be simplified and rearranged into the familiar
13 form:

14
15
$$k = \frac{D_0(1+g)}{P} + g \quad [5]$$

16
17 Equation [5] often is referred to as the "Constant Growth DCF" model, in which
18 the first term is the expected dividend yield and the second term is the expected
19 long-term annual growth rate.

20 **Q. 81 What assumptions are inherent in the Constant Growth DCF model?**

21 A. 81 The Constant Growth DCF model assumes: (1) earnings, book value, and
22 dividends all grow at the same, constant rate in perpetuity; (2) a constant
23 dividend payout ratio in perpetuity; (3) the observed P/E ratio will remain
24 constant in perpetuity; and (4) estimated Cost of Equity will remain constant, also
25 in perpetuity.

1 **Q. 82 What market data did you use to calculate the dividend yield in your**
2 **Constant Growth DCF model?**

3 A. 82 The dividend yield is based on each proxy company's current annualized
4 dividend and average closing stock price over the 30-, 90-, and 180-trading day
5 periods as of June 28, 2019, as explained more fully below.

6 **Q. 83 Why did you use three averaging periods to calculate an average stock**
7 **price?**

8 A. 83 I did so to ensure the model's results are not skewed by anomalous events that
9 may affect stock prices on any given trading day. At the same time, the
10 averaging period should be reasonably representative of expected capital
11 market conditions over the long term. In my view, using 30-, 90-, and 180-day
12 averaging periods reasonably balances those concerns.

13 **Q. 84 Did you make any adjustments to the dividend yield to account for periodic**
14 **growth in dividends?**

15 A. 84 Yes. Because utility companies tend to increase their quarterly dividends at
16 different times throughout the year, it is reasonable to assume that dividend
17 increases will be evenly distributed over calendar quarters. Given that
18 assumption, it is appropriate to calculate the expected dividend yield by applying
19 one-half of the long-term growth rate to the current dividend yield. That
20 adjustment ensures that the expected dividend yield is, on average,
21 representative of the coming twelve-month period, and does not overstate the
22 dividends to be paid during that time.

23
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25

1 **Q. 85 Is it important to select appropriate measures of long-term growth in**
2 **applying the DCF model?**

3 A. 85 Yes. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation
4 [5] above) assumes a single growth estimate in perpetuity. Accordingly, to
5 reduce the long-term growth rate to a single measure, one must assume a fixed
6 payout ratio, and the same constant growth rate for earnings per share (“EPS”),
7 dividends per share, and book value per share. Since dividend growth can only
8 be sustained by earnings growth, the model should incorporate a variety of
9 measures of long-term earnings growth. This can be accomplished by averaging
10 those measures of long-term growth that tend to be least influenced by capital
11 allocation decisions that companies may make in response to near-term
12 changes in the business environment. Because such decisions may directly
13 affect near-term dividend payout ratios, estimates of earnings growth are more
14 indicative of long-term investor expectations than are dividend growth estimates.
15 Therefore, for the purposes of the Constant Growth DCF model, growth in EPS
16 represents the appropriate measure of long-term growth.

17 **Q. 86 Please summarize the findings of academic research on the appropriate**
18 **measure for estimating equity returns using the DCF model.**

19 A. 86 The relationship between various growth rates and stock valuation metrics has
20 been the subject of much academic research.⁶⁸ As noted over 40 years ago by
21 Charles Phillips in The Economics of Regulation:

22 For many years, it was thought that investors bought utility stocks
23 largely on the basis of dividends. More recently, however, studies
24 indicate that the market is valuing utility stocks with reference to

25 ⁶⁸ See, for example, Robert S. Harris, Using Analysts’ Growth Forecasts to Estimate Shareholder
Required Rate of Return, Financial Management, Spring 1986.

1 total per share earnings, so that the earnings-price ratio has
2 assumed increased emphasis in rate cases.⁶⁹

3 Phillips' conclusion continues to hold true. Subsequent academic research has
4 clearly and consistently indicated that measures of earnings and cash flow are
5 strongly related to returns, and that analysts' forecasts of growth are superior to
6 other measures of growth in predicting stock prices.⁷⁰ For example, Vander
7 Weide and Carleton state that, "[our] results...are consistent with the hypothesis
8 that investors use analysts' forecasts, rather than historically oriented growth
9 calculations, in making stock buy-and-sell decisions."⁷¹ Other research
10 specifically has noted the importance of analysts' growth estimates in
11 determining the Cost of Equity, and in the valuation of equity securities. Dr.
12 Robert Harris noted that "a growing body of knowledge shows that analysts'
13 earnings forecasts are indeed reflected in stock prices."⁷² Citing Cragg and
14 Malkiel, Dr. Harris notes that those authors "found that the evaluations of
15 companies that analysts make are the sorts of ones on which market valuation
16 is based."⁷³ As Brigham, Shome and Vinson noted, "evidence in the current
17
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20 ⁶⁹ Charles F. Phillips, Jr., The Economics of Regulation, Revised Edition, 1969, Richard D. Irwin, Inc.,
21 at 285.

22 ⁷⁰ See, for example, Christofi, Christofi, Lori and Moliver, *Evaluating Common Stocks Using Value Line's*
23 *Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston,
24 *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21
25 (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.*

1 literature indicates that (i) analysts' forecasts are superior to forecasts based
2 solely on time series data; and (ii) investors do rely on analysts' forecasts."⁷⁴

3 To that point, the research of Carleton and Vander Weide found earnings
4 growth projections had a statistically significant relationship to stock valuation
5 levels, whereas dividend growth rates did not.⁷⁵ Those findings suggest that
6 investors form their investment decisions based on expectations of growth in
7 earnings, not dividends. Consequently, earnings growth not dividend growth, is
8 the appropriate estimate in the Constant Growth DCF model.

9 **Q. 87 Please summarize your inputs to the Constant Growth DCF model.**

10 A. 87 I applied the DCF model to the proxy group of natural gas utility companies using
11 the following inputs for the price and dividend terms:

- 12 • The average daily closing prices for the 30-trading days, 90-trading days,
13 and 180-trading days ended June 28, 2019, for the term P_0 ; and
- 14 • The annualized dividend per share as of June 28, 2019, for the term D_0 .

15 I then calculated my DCF results using each of the following growth terms:

- 16 • The Zacks consensus long-term earnings growth estimates;
- 17 • The First Call consensus long-term earnings growth estimates;
- 18 • The Value Line long-term earnings growth estimates; and
- 19 • An estimate of retention growth.

20 As explained below, I calculated a median low, median, and median high DCF
21 result for each proxy company (see, Exhibit No. ____(RBH-1)).

23 _____
24 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.

25 ⁷⁵ Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

1 Q. 88 What are the results of your Constant Growth DCF analysis?

2 A. 88 My Constant Growth DCF results are summarized in Table 7, below (see, also,
3 Exhibit No.__(RBH-1)).

4 Table 7: Median Constant Growth DCF Results⁷⁶

5

	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%

6
7

8

9 **B. Capital Asset Pricing Model and Empirical Capital Asset Pricing Model**

10 Q. 89 Please briefly describe the general form of the CAPM analysis.

11 A. 89 The CAPM analysis is a risk premium method that estimates the Cost of Equity
12 for a given security as a function of a risk-free return plus a risk premium (to
13 compensate investors for the non-diversifiable or “systematic” risk of that
14 security). As shown in Equation [6], the CAPM is defined by four components,
15 each of which theoretically must be a forward-looking estimate:

16
$$K_e = r_f + \beta(r_m - r_f) \quad [6]$$

17 where:

18 K_e = the required market ROE for a security;

19 β = the Beta coefficient of that security;

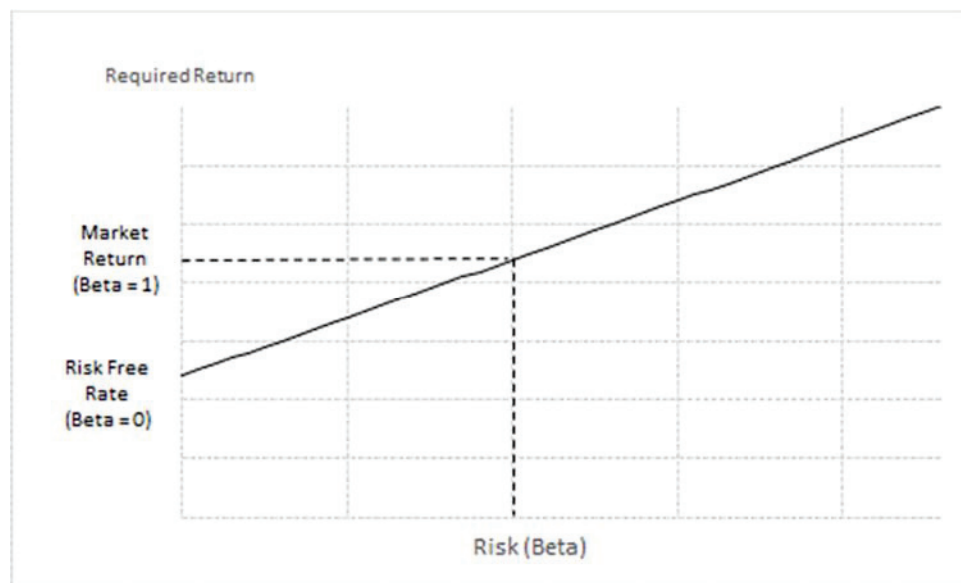
20 r_f = the risk-free rate of return; and

21 r_m = the required return on the market as a whole.

22
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24
25 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.

1
$$\beta_j = \frac{\sigma_j}{\sigma_m} \times \rho_{j,m} \quad [7]$$

2
3 where σ_j is the standard deviation of returns for company “j,” σ_m is the standard
4 deviation of returns for the broad market (as measured, for example, by the S&P
5 500 Index), and $\rho_{j,m}$ is the correlation of returns in between company j and the
6 broad market. The Beta coefficient therefore represents both relative volatility
7 (*i.e.*, the standard deviation) of returns, and the correlation in returns between
8 the subject company and the overall market.

9 Intuitively, companies with higher Beta coefficients have had more volatile
10 returns, and have moved more closely with the overall market. The implication
11 is that a company with a Beta coefficient of 1.00 is as risky as the overall market;
12 companies with Beta coefficients less than 1.00 are less risky, and those whose
13 Beta coefficients are greater than 1.00 have greater risk than the overall market.

14 **Q. 90 What assumptions regarding the risk-free rate did you include in your**
15 **CAPM analysis?**

16 A. 90 Because utility assets represent long duration investments, I used two different
17 measures of the risk-free rate: (1) the current 30-day average yield on 30-year
18 Treasury bonds (2.63 percent);⁷⁸ and (2) the near-term projected 30-year
19 Treasury yield (2.70 percent).⁷⁹

20 **Q. 91 Why have you relied on the 30-year Treasury yield for your CAPM**
21 **analysis?**

22 A. 91 In determining the risk-free rate, it is important to select the term (or maturity)
23 that best matches the life of the underlying investment. Natural gas utilities

24

⁷⁸ Bloomberg Professional.

25 ⁷⁹ Blue Chip Financial Forecast, Vol. 38, No. 7, July 1, 2019, at 2.

1 typically are long-duration investments and as such, the 30-year Treasury yield
2 is most suitable for the purpose of calculating the Cost of Equity.

3 **Q. 92 Please describe your *ex-ante* (i.e., forward-looking) approach to estimating**
4 **the Market Risk Premium.**

5 A. 92 The approach is based on the market required return, less the current 30-year
6 Treasury yield. To estimate the market required return, I calculated the market
7 capitalization weighted average ROE based on the Constant Growth DCF
8 model. To do so, I relied on data from two sources: (1) Bloomberg and (2) Value
9 Line. With respect to Bloomberg-derived growth estimates, I calculated the
10 expected dividend yield (using the same one-half growth rate assumption
11 described earlier), and combined that amount with the projected earnings growth
12 rate to arrive at the market capitalization weighted average DCF result. I
13 performed that calculation for each of the S&P 500 companies for which
14 Bloomberg provided consensus growth rates. I then subtracted the current 30-
15 year Treasury yield from that amount to arrive at the market DCF-derived *ex-*
16 *ante* market risk premium estimate. In the case of Value Line, I performed the
17 same calculation, again using all companies for which five-year earnings growth
18 rates were available. The results of those calculations are provided in Exhibit
19 No.__(RBH-3).

20 **Q. 93 How did you apply your expected Market Risk Premium and risk-free rate**
21 **estimates?**

22 A. 93 I relied on the *ex-ante* Market Risk Premia discussed above, together with the
23 current and near-term projected 30-year Treasury yields as inputs to my CAPM
24 analyses.

25

1 **Q. 94 What Beta coefficient did you use in your CAPM model?**

2 A. 94 As shown in Exhibit No.__(RBH-5), I considered Beta coefficients reported by
3 two sources, Bloomberg and Value Line. Although both services adjust their
4 calculated (or “raw”) Beta coefficients to reflect the tendency to regress to the
5 market mean of 1.00, Value Line calculates the Beta coefficient over a five-year
6 period, whereas Bloomberg’s calculation is based on two years of data.

7 **Q. 95 What are the results of your CAPM analysis?**

8 A. 95 As shown in Table 8, below, the CAPM analyses suggest an ROE range of 9.53
9 percent to 10.97 percent (see, *a/so*, Exhibit No.__(RBH-5)).

10 **Table 8: Summary of CAPM Results⁸⁰**

11

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
<i>Average Bloomberg Beta Coefficient</i>		
Current 30-Year Treasury (2.63%)	9.58%	9.53%
Near Term Projected 30-Year Treasury (2.70%)	9.65%	9.60%
<i>Average Value Line Beta Coefficient</i>		
Current 30-Year Treasury (2.63%)	10.90%	10.83%
Near Term Projected 30-Year Treasury (2.70%)	10.97%	10.90%

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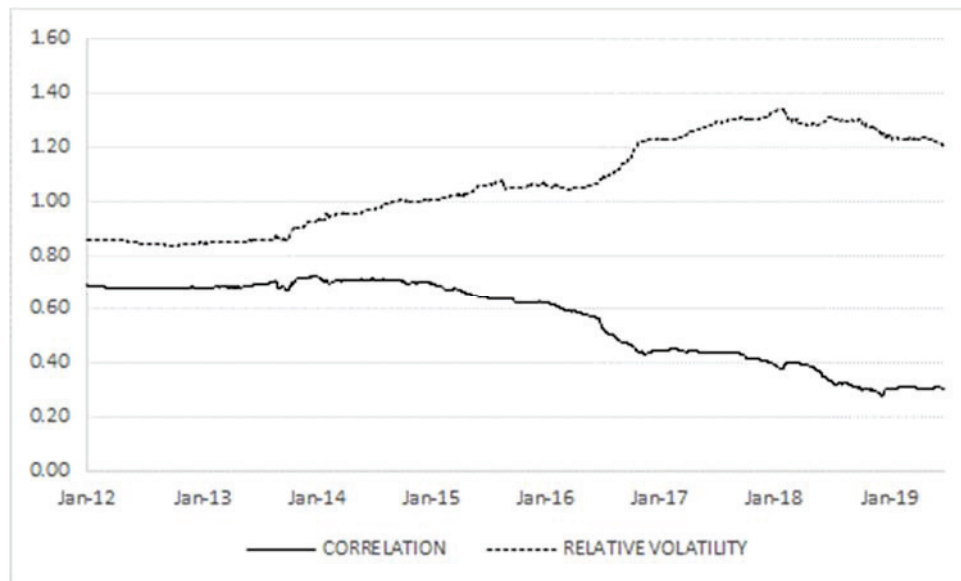
18 **Q. 96 Does the recent decline in the proxy group average Beta coefficient imply
19 a decrease in risk relative to the market?**

20 A. 96 Not necessarily. Although the proxy group average Beta coefficient reported by
21 Bloomberg has fallen from approximately 0.71 in 2014 to 0.57 in June 2019, as
22 Chart 11, below, demonstrates, when the Beta coefficient is deconstructed into
23

24
25 ⁸⁰ Exhibit No.__(RBH-5).

1 its components shown in Equation [7] above, we see that the correlation
 2 between the proxy group companies and the S&P 500 has declined, while the
 3 relative risk has increased. Given that the correlation between the proxy group
 4 companies and the S&P 500 has declined since 2014, while the relative risk has
 5 increased, the CAPM in the form presented here may not adequately reflect the
 6 expected systematic risk, and therefore, the returns required by investors for
 7 low-Beta companies such as utilities.

8 **Chart 11: Components of Beta Coefficients Over Time⁸¹**



18 **Q. 97 Did you consider another form of the CAPM in your analysis?**

19 **A. 97** Yes. I also included the ECAPM approach, which calculates the product of the
 20 adjusted Beta coefficient and the Market Risk Premium, and applies a weight of
 21 75.00 percent to that result. The model then applies a 25.00 percent weight to
 22 the Market Risk Premium, without any effect from the Beta coefficient.⁸² The

23
24 ⁸¹ Calculated as an index. Source: S&P Global Market Intelligence.

25 ⁸² See, e.g., Roger A. Morin, Ph.D., *New Regulatory Finance* 189-90 (2006).

1 results of the two calculations are summed, along with the risk-free rate, to
2 produce the ECAPM result, as noted in Equation [8] below:

$$3 \quad K_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [8]$$

4
5 where:

6 K_e = the required market ROE;

7 β = Adjusted Beta coefficient of an individual security;

8 r_f = the risk-free rate of return; and

9 r_m = the required return on the market as a whole.

10 **Q. 98 What is the benefit of the ECAPM approach?**

11 A. 98 The ECAPM addresses the tendency of the CAPM to under-estimate the Cost
12 of Equity for companies, such as regulated utilities, with low Beta coefficients.
13 As discussed below, the ECAPM recognizes the results of academic research
14 indicating that the risk-return relationship is different (in essence, flatter) than
15 estimated by the CAPM, and that the CAPM under-estimates the alpha, or the
16 constant return term.⁸³

17 Numerous tests of the CAPM have measured the extent to which security
18 returns and Beta coefficients are related as predicted by the CAPM. The
19 ECAPM method reflects the finding that the actual Security Market Line (“SML”)
20 described by the CAPM formula is not as steeply sloped as the predicted SML.⁸⁴
21 Fama and French state that “[t]he returns on the low beta portfolios are too high,

22
23 ⁸³ *Ibid.* at 191 (“The ECAPM and the use of adjusted betas comprised two separate features of asset
24 pricing. Even if a company’s beta is estimated accurately, the CAPM still understates the return for low-
beta stocks.”).

25 ⁸⁴ *Ibid.* at 175. The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on
the X-axis.

1 and the returns on the high beta portfolios are too low.”⁸⁵ Similarly, Dr. Roger
2 Morin states:

3 With few exceptions, the empirical studies agree that . . . low-beta
4 securities earn returns somewhat higher than the CAPM would
predict, and high-beta securities earn less than predicted.⁸⁶

5 ***

6 Therefore, the empirical evidence suggests that the expected
7 return on a security is related to its risk by the following
approximation:

$$8 \quad K = R_F + x(R_M - R_F) + (1-x) \beta(R_M - R_F)$$

9 where x is a fraction to be determined empirically. The value of x
10 that best explains the observed relationship $\text{Return} = 0.0829 +$
0.0520 β is between 0.25 and 0.30. If $x = 0.25$, the equation
11 becomes:

$$12 \quad K = R_F + 0.25(R_M - R_F) + 0.75 \beta(R_M - R_F)^{87}$$

13 Some analysts claim that using adjusted Beta coefficients addresses the
14 empirical issues with the CAPM by increasing the expected returns for low Beta
15 stocks and decreasing the returns for high Beta stocks, concluding that there is
16 no need for the ECAPM approach. I disagree with that conclusion. Beta
17 coefficients are adjusted because of their general regression tendency to
18 converge toward 1.00 over time, *i.e.*, over successive calculations. As also
19 noted earlier, numerous studies have determined that at any given point in time,
20 the SML described by the CAPM formula is not as steeply sloped as the
21 predicted SML. To that point, Dr. Roger Morin states:

22 Some have argued that the use of the ECAPM is inconsistent with
the use of adjusted betas, such as those supplied by Value Line

23 ⁸⁵ Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal
24 of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

⁸⁶ Roger A. Morin, Ph.D., *New Regulatory Finance*, at 175.

25 ⁸⁷ *Ibid.*, at 190, footnote 12 (2006).

1 and Bloomberg. This is because the reason for using the ECAPM
2 is to allow for the tendency of betas to regress toward the mean
3 value of 1.00 over time, and, since Value Line betas are already
4 adjusted for such trend, an ECAPM analysis results in double-
5 counting. This argument is erroneous. Fundamentally, the
6 ECAPM is not an adjustment, increase or decrease, in beta. This
7 is obvious from the fact that the expected return on high beta
8 securities is actually lower than that produced by the CAPM
9 estimate. The ECAPM is a formal recognition that the observed
10 risk-return tradeoff is flatter than predicted by the CAPM based on
11 myriad empirical evidence. The ECAPM and the use of adjusted
12 betas comprised two separate features of asset pricing. Even if a
13 company's beta is estimated accurately, the CAPM still
14 understates the return for low-beta stocks. Even if the ECAPM is
15 used, the return for low-beta securities is understated if the betas
16 are understated. Referring back to Figure 6-1, the ECAPM is a
17 return (vertical axis) adjustment and not a beta (horizontal axis)
18 adjustment. Both adjustments are necessary.⁸⁸

19 Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM
20 and ECAPM. As with the CAPM, my application of the ECAPM uses the Market
21 DCF-derived *ex-ante* Market Risk Premium estimate, the current yield on 30-
22 year Treasury securities as the risk-free rate, and two estimates of the Beta
23 coefficient. The results of my ECAPM analyses shown on Exhibit No.__(RBH-
24 5) and summarized in Table 9, below.

25 ⁸⁸ *Ibid.* at 191.

Table 9: Summary of ECAPM Results⁸⁹

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
<i>Average Bloomberg Beta Coefficient</i>		
Current 30-Year Treasury (2.63%)	10.91%	10.84%
Near Term Projected 30-Year Treasury (2.70%)	10.98%	10.91%
<i>Average Value Line Beta Coefficient</i>		
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).

1 **Q. 100 Please explain how you performed your Bond Yield Plus Risk Premium**
2 **analysis.**

3 A. 100 As suggested above, I first defined the Risk Premium as the difference between
4 the authorized ROE and the then-prevailing level of the long-term (*i.e.*, 30-year)
5 Treasury yield. I then gathered data for 1,121 natural gas utility rate proceedings
6 between January 1980 and June 28, 2019. In addition to the authorized ROE, I
7 also calculated the average period between the filing of the case and the date of
8 the final order (the “lag period”). To reflect the prevailing level of interest rates
9 during the pendency of the proceedings, I calculated the average 30-year
10 Treasury yield over the average lag period (approximately 186 days).

11 Because the data cover multiple economic cycles, the analysis also may
12 be used to assess the stability of the Equity Risk Premium. Prior research, for
13 example, has shown that the Equity Risk Premium is inversely related to the
14 level of interest rates. That analysis is particularly relevant given the relatively
15 low, but increasing level of current Treasury yields.

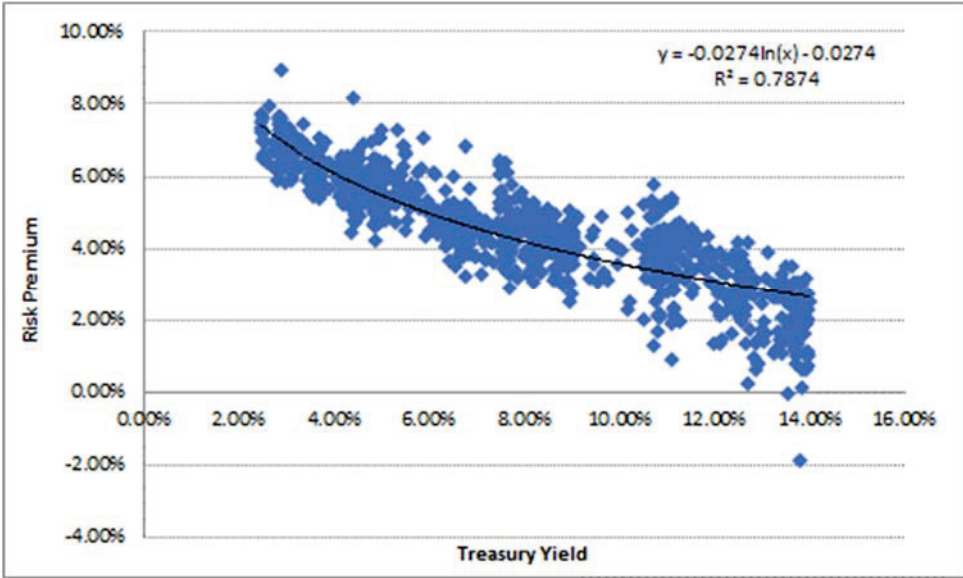
16 **Q. 101 How did you model the relationship between interest rates and the Equity**
17 **Risk Premium?**

18 Q. 101 The basic method used was regression analysis, in which the observed Equity
19 Risk Premium is the dependent variable, and the average 30-year Treasury yield
20 is the independent variable. Relative to the long-term historical average, the
21 analytical period includes interest rates and authorized ROEs that are quite high
22 during one period (*i.e.*, the 1980s) and that are quite low during another (*i.e.*, the
23 post-Lehman bankruptcy period). To account for that variability, I used the semi-
24 log regression, in which the Equity Risk Premium is expressed as a function of
25 the natural log of the 30-year Treasury yield:

1
$$RP = \alpha + \beta(LN(T_{30})) \quad [9]$$

2
3 As shown on Chart 12, below, the semi-log form is useful when measuring an
4 absolute change in the dependent variable (in this case, the Risk Premium)
5 relative to a proportional change in the independent variable (the 30-year
6 Treasury yield).

7 **Chart 12: Equity Risk Premium⁹⁰**



16 As Chart 12 illustrates, the Equity Risk Premium increases as interest rates fall.
17 That finding, that there is an inverse relationship between interest rates and the
18 Equity Risk Premium is supported by published research. For example, Dr.
19 Roger Morin notes that: "... [p]ublished studies by Brigham, Shome, and Vinson
20 (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers,
21 and Lakonishok (1983), Morin (2005), and McShane (2005), and others
22 demonstrate that, beginning in 1980, risk premiums varied inversely with the
23 level of interest rates - rising when interest rates fell and declining when interest
24

25 ⁹⁰ Exhibit No. ___(RBH-6).

1 rates rose.”⁹¹ Consequently, simply applying the long-term average Equity Risk
2 Premium of 4.70 percent would significantly understate the Cost of Equity and
3 produce results well below any reasonable estimate. Based on the regression
4 coefficients in Chart 12, however, the implied ROE is between 9.87 percent and
5 10.01 percent (see, Table 10, below, and Exhibit No.____(RBH-6)).

6 **Table 10: Summary of Bond Yield Plus Risk Premium Results⁹²**

7

	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%

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9
10

11 **D. Expected Earnings Analysis**

12 **Q. 102 Please describe the Expected Earnings analysis.**

13 **A. 102** The Expected Earnings analysis is based on the principle of opportunity costs.
14 Because investors may invest in, and earn returns on alternative investments of
15 similar risk, those rates of return can provide a useful benchmark in determining
16 the appropriate rate of return for a firm. Further, because those results are based
17 solely on the returns expected by investors, exclusive of market-data or models,
18 the Expected Earnings approach provides a direct comparison.

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23
24 ⁹¹ Roger A: Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 128 [clarification added]

25 ⁹² Exhibit No.____(RBH-6).

1 **Q. 103 Please explain how the Expected Earnings analysis is conducted.**

2 A. 103 The Expected Earnings analysis typically takes the actual earnings on book
3 value of investment for each of the members of the proxy group and compares
4 those values to the rate of return in question. Although the traditional approach
5 uses data based on historical accounting records, it is common to use forecasted
6 data in conducting the analysis. Projected returns on book investment are
7 provided by various industry publications (e.g., Value Line), which I have used
8 in my analysis.

9 I relied on Value Line's projected Return on Common for the period 2022-
10 2024, and adjusted those projected returns to account for the fact that they
11 reflect common shares outstanding at the end of the period, rather than the
12 average shares outstanding over the course of the year.⁹³ The results equal an
13 average value of 10.83 percent and a median value of 10.85 percent (see,
14 Exhibit No.__(RBH-7)).

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24 ⁹³ The rationale for that adjustment is straightforward: Earnings are achieved over the course of a year,
25 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.



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 Rate-making 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 rate-making 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 Unittl	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 Unittl	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 Unittl	06/15	Fitchburg Gas and Electric Light Company d/b/a Unittl	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 Unifil	07/13	Fitchburg Gas and Electric Light Company d/b/a Unifil	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
Unifil 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
Offer Tail Power Corporation	02/16	Offer 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
Offer Tail Power Corporation	04/10	Offer 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
Offer Tail Power Corporation	10/07	Offer 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 Rate-making 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
Connectiv	06/03	Atlantic City Electric Company	Docket No. E003020091	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
Offer Tail Power Company	10/08	Offer 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, 2018
- [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]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
		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	\$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, 2018
- [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

Company	Ticker	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
		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, 2018
- [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	Projected Earnings per share 2022-2024	Projected Dividend 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
ATM	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 Corporation	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	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.	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.	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%
Spiral Inc.	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] Source: Value Line
 [7] Source: Value Line
 [8] Equals [6] / [7] - 0.33 - 1
 [9] Source: Value Line
 [10] Source: Value Line
 [11] Source: Value Line
 [12] Equals Average ([10], [11])
 [13] Source: Value Line
 [14] Equals [12] / [13]
 [15] Equals [9] x [14]
 [16] Equals 1 - (1 / [14])
 [17] Equals [15] x [16]
 [18] Equals [6] + [17]

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

[1]	[2]	[3]
S&P 500	Current 30-Year	
Est. Required	Treasury (30-day	Implied Market
Market Return	average)	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%
Ancor 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	APTIV	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%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	Weighted DCF Result
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]	[5]	[6]	[7]	[8]	[9]
		Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	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	GP	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]	[5]	[6]	[7]	[8]	[9]
		Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	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%
Omnicon 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	PFGB	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%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	Weighted DCF Result
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	SYU	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]	[2]	[3]
S&P 500	Current 30-Year	
Est. Required	Treasury (30-day	Implied Market
Market Return	average)	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%
Ancor 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	APTIV	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	BMJ	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%
Energy 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%
Flowerserve 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%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	Weighted DCF Result
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%
Neffix 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%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	Weighted DCF Result
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	SYU	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

		[1]	[2]
Company	Ticker	Bloomberg	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]
	Risk-Free Rate	Average Beta Coefficient	Ex-Ante Bloomberg Market DCF Derived	Ex-Ante Market Risk Premium Value Line Market DCF Derived	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	Bloomberg Market DCF Derived	Value Line Market DCF Derived	ECAPM Result 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%					

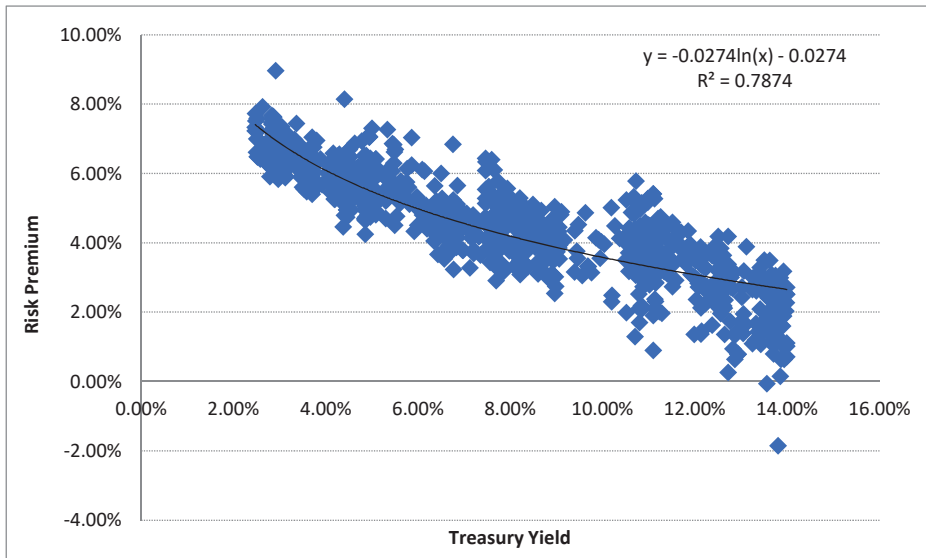
	[3]		[4]		[5]		[6]		[7]		[8]
	Ex-Ante Bloomberg Market DCF Derived	Ex-Ante Market Risk Premium Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived	ECAPM Result Value Line Market DCF Derived
PROXY GROUP AVERAGE VALUE LINE AVERAGE BETA COEFFICIENT											
Current 30-Year Treasury [9]	12.25%	12.15%	10.90%	10.83%	11.89%	11.82%					
Near Term Projected 30-Year Treasury [10]	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]	[2]	[3]	[4]	[5]
	Constant	Slope	30-Year Treasury Yield	Risk Premium	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]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	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]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	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]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	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]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	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]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	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]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	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]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	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]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	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]	[2]	[3]	[4]	[5]	[6]
		Expected ROE 2022-24	Shares Outstanding 2019	Shares Outstanding 2022-24	% Increase	Adjustment Factor	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 $(2 \times (1 + [4])) / (2 + [4])$
 - [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%
Almos 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%
Almos 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	\$350,000	\$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		2,674%

WEIGHTED AVERAGE FLOTATION COSTS:

Constant Growth Discounted Cash Flow Model Adjusted for Flotation Costs - 30 Day Average Stock Price

Company	[1] Ticker	[2] Annualized Dividend	[3] Average Stock Price	[4] Dividend Yield	[5] Expected Dividend Yield Adjusted for Flot. Costs	[6] Zacks Earnings Growth	[7] First Call Earnings Growth	[8] Value Line Earnings Growth	[9] Value Line Retention Growth	[10] Average Earnings Growth	[11] DCF K(e)	[12] Flotation Adjusted DCF K(e)
Almos Energy Corporation	ATO	\$2.10	\$103.85	2.02%	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%	2.51%	7.00%	6.00%	3.50%	5.84%	5.59%	8.03%	8.10%
Northwest Natural Holding Company	NWN	\$1.90	\$88.91	2.14%	2.36%	4.50%	4.00%	27.00%	6.66%	10.54%	13.44%	13.52%
ONE Gas, Inc.	OGS	\$2.00	\$89.61	2.23%	2.36%	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%	3.74%	7.20%	5.50%	10.50%	6.12%	7.33%	10.97%	11.07%
Spire Inc.	SR	\$2.37	\$84.59	2.80%	2.95%	4.90%	3.43%	5.50%	5.18%	4.75%	7.62%	7.70%
PROXY GROUP MEAN											9.70%	9.77%

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.

DCF Result Unadjusted For Flotation Costs: 9.70%

DCF Result Adjusted For Flotation Costs: 9.77%

Difference (Flotation Cost Adjustment): 0.07% [13]

[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

Company	Ticker	% Common Equity								
		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%

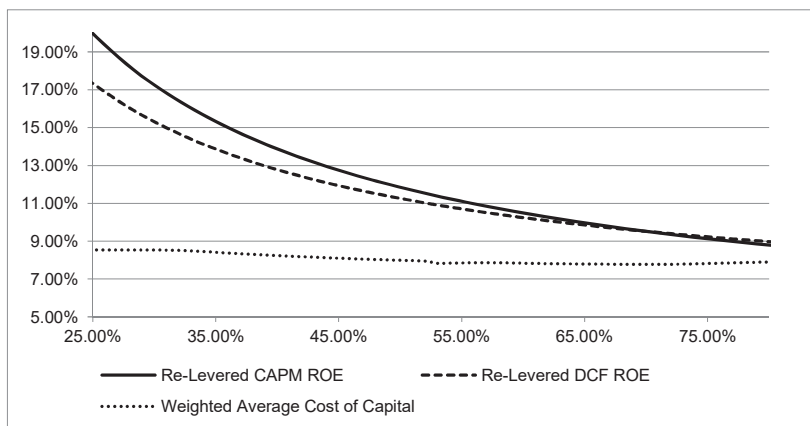
Company	Ticker	% Long-Term Debt								
		2019Q1	2018Q4	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	Average
Atmos Energy Corporation	ATO	39.88%	40.63%	39.15%	39.20%	39.39%	40.20%	44.03%	44.01%	40.81%
New Jersey Resources Corporation	NJR	45.39%	46.66%	47.89%	46.51%	44.23%	46.41%	48.45%	45.77%	46.41%
Northwest 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		DCF Adjustment	
Proxy Average Value Line Equity Ratio	57.08%	Levered ROE	10.50%
Proxy Average Value Line D/E Ratio	75.18%	Cost of Debt	4.36%
Proxy Average Tax Rate	21.00%	Debt/Total Capital Ratio	42.92%
Proxy Average Value Line Beta	0.68	Debt/Equity Ratio	75.18%
Proxy Average Value Line Asset Beta	0.42	Combined Tax Rate	21.00%
Check: Re-Levered Beta	0.68	Calculated Unlevered ROE	8.21%
Value Line Risk Premium	12.15%	Check: Re-Levered ROE	10.50%
Risk Free Rate	2.63%		
Moody's A Utility Index	3.86%		
Moody's Baa Utility Index	4.36%		
Spread	0.50%		

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:

$$B_a = \frac{B_e}{(1 + (1 - T) \times \frac{D}{E})}$$

or, rearranged:

$$B_e = B_a \times (1 + (1 - T) \times DE)$$

Where:

B_a	= Asset Beta
B_e	= Equity Beta
T	= Tax Rate
D/E	= Debt/Equity Ratio

Under Modigliani-Miller Proposition:

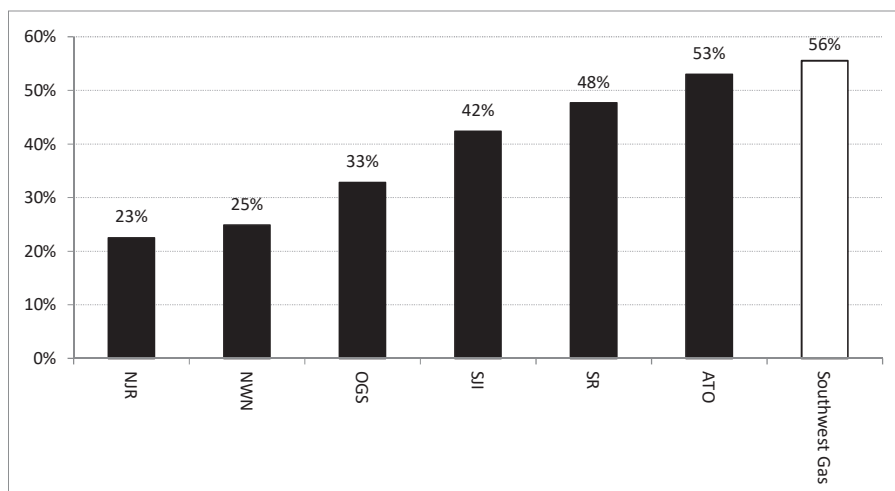
$$R_e = R_a + \frac{D}{E} (R_a - R_d) \times (1 - T)$$

or, rearranged:

$$R_a = \frac{(R_e + \frac{D}{E} \times R_d \times (1 - T))}{(1 + \frac{D}{E} \times (1 - T))}$$

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

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Appendix A – Summary of Qualifications of Celine Louise R. Apo

Exhibit No.__(CLA-1)

Exhibit No.__(CLA-2)

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).

1 **Q. 6 Please summarize your prepared direct testimony.**

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

- 3
- 4 • An overview of Southwest Gas' existing CEE Plan for 2014-2020
 - 5 • An overview of the Company's proposed CEE Plan for 2021-2025
 - 6 • An explanation of the purpose and process for minor program modifications
 - 7 • Proposed CEE Plan cost recovery

7 **II. OVERVIEW OF SOUTHWEST GAS' EXISTING CEE PLAN FOR YEARS 2014-2020**

8 **Q. 7 Did Southwest Gas receive approval of its existing CEE Plan in its last**
9 **general rate case proceeding?**

10 A. 7 Yes. Southwest Gas received approval for a 5-year CEE Plan June 12, 2014,
11 as part of its last general rate case filing (Decision (D.) 14-06-028). The
12 Company launched the approved CEE Plan in July 2014. Subsequently,
13 Southwest Gas received approval to extend its existing CEE Plan through
14 December 31, 2020 (D.17-06-006).

15 **Q. 8 What programs are included in Southwest Gas' existing CEE Plan?**

16 A. 8 Southwest Gas currently offers the *Smarter Greener Better*[®] Residential
17 Rebates program and the *Smarter Greener Better* Commercial Rebates
18 program, which are designed to reduce residential and commercial customers'
19 energy consumption and utility bills. Rebates are offered for energy efficient
20 water heating and space heating equipment, as well as for commercial
21 foodservice equipment. A list of all measures in Southwest Gas' existing CEE
22 Plan, including expenditures, therm savings and participation levels for program
23 years 2014-2018 is provided in Exhibit No.____(CLA-1).
24
25

1 **Q. 9 Has Southwest Gas expended its annual CEE Plan budget of \$1 million?**

2 A. 9 No. The Company developed its initial CEE Plan using measures it anticipated
3 customers would be most interested in and participation and budget levels
4 estimated to be sufficient for market demand. Due to the limited participation
5 and expenditures experienced under Southwest Gas' CEE Plan during 2014-
6 2018, the Company has adjusted its program and measure offerings in its
7 proposed CEE Plan in an effort to increase program participation and
8 expenditures, as discussed in more detail below.

9 **III. OVERVIEW OF THE COMPANY'S PROPOSED CEE PLAN FOR YEARS 2021-2025**

10 **Q. 10 What programs are included in the Company's proposed CEE Plan for**
11 **years 2021-2025?**

12 A. 10 Southwest Gas is proposing the following programs to customers in the
13 Company's California service territories:

- 14 • **Residential Equipment Direct-Install (RED)** – The RED program is a no
15 cost to the customer energy assistance program, which will offer the
16 direct-installation of water heating and space heating equipment to
17 residential customers. This program, which will include single family,
18 multifamily, and mobile homes, will offer a limited number of measures,
19 and is specifically targeted for residential customers that do not qualify
20 for Southwest Gas' Energy Savings Assistance program for low income
21 households. The measures offered to residential customers under the
22 RED program include:

- 23 ○ Faucet Aerator – Kitchen
- 24 ○ Faucet Aerator – Lavatory/Bathroom

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- 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

1 natural gas appliances. Homebuilders will be offered rebates for homes
2 built with the following measures under the New Home Rebates Program:

- 3 ○ Natural Gas Tankless Water Heater
- 4 ○ Natural Gas Furnace

5 • **Commercial Equipment Rebates** – The Commercial Equipment Rebates
6 program will offer energy audits, direct-install measures, and rebates for
7 qualifying energy-efficient water heating, space heating, and commercial
8 food service equipment to commercial customers. The Commercial
9 Equipment Rebates Program will offer the direct-installation of or rebates
10 for the following measures:

- 11 ○ Energy Audit
- 12 ○ Faucet
- 13 ○ Low-Flow Showerhead
- 14 ○ Pre-Rinse Spray Valve
- 15 ○ Natural Gas Storage Water Heater
- 16 ○ Natural Gas Tankless Water Heater
- 17 ○ Natural Gas Condensing Furnace
- 18 ○ Natural Gas Condensing HVAC Boiler
- 19 ○ Combination Oven
- 20 ○ Convection Oven
- 21 ○ Conveyor Broiler
- 22 ○ Underfired Broiler
- 23 ○ Conveyor Oven
- 24 ○ Fryer

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- 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

1 those with a TRC ratio of 1.0 or above, have been included in Southwest Gas'
2 proposed CEE Plan for years 2021-2025.

3 **Q. 12 What is the budget for the Company's proposed CEE Plan for years 2021-**
4 **2025?**

5 A. 12 The Company is proposing to maintain its current annual CEE Plan budget of \$1
6 million. The \$1 million annual budget, which includes all programs mentioned
7 above, will be utilized for program administration, program outreach, and
8 customer rebates, including the costs of direct-install measures. The Company
9 anticipates that its proposal to offer additional programs and measures for years
10 2021-2025 will result in additional customer participation and program
11 expenditures.

12 **IV. PURPOSE & PROCESS FOR MINOR PROGRAM MODIFICATIONS**

13 **Q. 13 Does Southwest Gas see a need to make minor program modifications in**
14 **between plan filings?**

15 A. 13 Yes. Since Southwest Gas files for approval of its CEE Plan as part of its general
16 rate case applications, the Company believes minor program modifications may
17 be needed in between general rate case filings to adjust the approved CEE
18 programs to market and customer demands. Having the flexibility to timely
19 respond to market needs and industry and technology changes will help
20 Southwest Gas maintain up-to-date program offerings and maximize program
21 participation.

1 **Q. 14 What process will the Company follow to request minor program**
2 **modifications?**

3 A. 14 The Company proposes to submit an advice letter to request minor program
4 modifications as needed for its approved CEE Plan in between general rate case
5 applications.

6 **V. PROPOSED CEE PLAN COST RECOVERY**

7 **Q. 15 How does Southwest Gas currently recover its CEE Plan costs?**

8 A. 15 Southwest Gas currently recovers its CEE Plan costs under the CEE rate
9 component of the Company's Public Purpose Program (PPP) surcharge as
10 approved in D.14-06-028.

11 **Q. 16 Does the Company propose any changes to the existing cost recovery**
12 **method?**

13 A. 16 No. The Company seeks to continue utilizing its current methodology.

14 **Q. 17 Is the Company proposing to update the CEE rate as part of this general**
15 **rate case?**

16 A. 17 No. Southwest Gas is only requesting approval of the CEE Plan budget in this
17 general rate case. To develop the CEE rate, Southwest Gas will use the
18 approved CEE Plan budget and the appropriate month-ending Conservation and
19 Energy Efficiency Balancing Account (CEEBA) balance in year 2020. Because
20 the Company does not know what the 2020 CEEBA balance will be at this time,
21 the Company proposes to update the CEE rate component when it updates its
22 PPP surcharges through the Commission's Advice Letter process.

23 **Q. 18 Does this conclude your prepared direct testimony in this matter?**

24 A. 18 Yes.
25

**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 / MBtu	0.65	0.76	1.90	2.19
Natural Gas Storage Water Heater (≤ 75,000 Btu/hr) - Tier 2	Thermal Efficiency ≥ 90%	\$5.00 / MBtu	2.01	2.32	1.75	2.02
Natural Gas Storage Water Heater (> 75,000 Btu/hr) - Tier 1	Thermal Efficiency ≥ 83%	\$1.50 / MBtu	0.59	0.75	2.02	2.57
Natural Gas Storage Water Heater (> 75,000 Btu/hr) - Tier 2	Thermal Efficiency ≥ 90%	\$5.00 / MBtu	1.80	2.31	1.89	2.43
Natural Gas Tankless Water Heater (≤ 200,000 Btu/hr)	UEF ≥ 0.81	\$10.00 / MBtu	2.28	2.61	1.09	1.25
Natural Gas Condensing Furnace	AFUE ≥ 95%	\$2.50 / MBtu	1.26	1.57	2.99	3.72
Natural Gas Condensing HVAC Boiler (≥ 300,000 Btu/hr)	Thermal Efficiency ≥ 94%	\$2.50 / MBtu	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.