SOUTHWEST GAS CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

In the Matter of the Application of Southwest Gas Corporation for Authority to Increase its Retail Natural Gas Utility Service Rates in its Southern and Northern Nevada Rate Jurisdictions.	Docket No.: 23-09___

VOLUME 5 of 27

Prepared Direct Testimony of Dylan W. D'Ascendis
Prepared Direct Testimony of Byron C. Williams
Prepared Direct Testimony of Lisa McRae
Prepared Direct Testimony of James L. Stein
Prepared Direct Testimony of Jerome T. Schmitz
Prepared Direct Testimony of Raied N. Stanley
Prepared Direct Testimony of William Brincefield
Prepared Direct Testimony of Matthew A. Helmers

Index

Southwest Gas Corporation

Volume 5 of 27

Index

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 23-09___

PREPARED DIRECT TESTIMONY

OF

DYLAN W. D'ASCENDIS

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTMEBER 1, 2023

Table of Contents
of
Prepared Direct Testimony
of
Dylan W. D'Ascendis

Description | Page No.

List of Exhibits Accompanying
Prepared Direct Testimony
of
Dylan W. D'Ascendis

Exhibit No.___(DWD-1)	Summary of Overall Cost of Capital and Return on Equity
Exhibit No.___(DWD-2)	Range of Capital Structures for the Utility Proxy Group and their Operating Subsidiaries
Exhibit No.___(DWD-3)	Weighted Average Variable Interest Rate Calculation
Exhibit No.___(DWD-4)	Application of the Discounted Cash Flow Model
Exhibit No.___(DWD-5)	Application of the Risk Premium Model
Exhibit No.___(DWD-6)	Application of the Capital Asset Pricing Model
Exhibit No.___(DWD-7)	Basis of Selection for the Non-Price Regulated Companies Comparable in Total Risk to the Utility Proxy Group
Exhibit No.___(DWD-8)	Application of Cost of Common Equity Models to the Non-Price Regulated Proxy Group
Exhibit No.___(DWD-9)	Derivation of the Indicated Size Premium for Southwest Gas Corporation Relative to the Utility Proxy Group
Exhibit No.___(DWD-10)	Derivation of Flotation Costs

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Dylan W. D'Ascendis

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, NJ 08054.

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

A. 2 I am employed by ScottMadden, Inc. as Partner.

Q. 3 On whose behalf are you submitting this testimony?

A. 3 I am submitting this prepared direct testimony (Direct Testimony) before the Public Utilities Commission of Nevada (PUCN or Commission) on behalf of Southwest Gas Corporation (Southwest Gas or Company).

Q. 4 Please summarize your educational background and relevant business experience.

A. 4 I have offered expert testimony on behalf of investor-owned utilities before over 35 state regulatory commissions in the United States, the Federal Energy Regulatory Commission (FERC), the Alberta Utility Commission, the Canadian Energy Regulator, an American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association (AGA), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund (AGIF) is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts (SURFA). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts (NACVA) and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are shown in Appendix A.

Q. 5 What is the purpose of your Direct Testimony in this proceeding?

A. 5 The purpose of my Direct Testimony is to present evidence on behalf of the Company and recommend a weighted average cost of capital (WACC) to be used in setting rates in this proceeding. My testimony first provides a summary of financial theory and regulatory principles pertinent to the development of the recommended cost of capital. I then present evidence and analysis on: (1) the appropriate capital structure, (2) the appropriate cost of long- and short-term debt, and (3) the appropriate range of return on common equity (ROE) on the Company's Nevada jurisdictional rate base.

Q. 6 Are you sponsoring any statements for the Company's minimum filing requirements?

A. 6 Yes. I am sponsoring Statement F, which contains Schedules F-1 through F-4 for the Company's Southern and Northern Nevada rate jurisdictions.

Q. 7 Have you prepared any Exhibits in support of your Direct Testimony?

A. 7 Yes. Exhibit No.___(DWD-1) through Exhibit No.___(DWD-10) were prepared by me or under my direction.

II. SUMMARY

Q. 8 What are your recommendations for Southwest Gas' Southern and Northern rate jurisdictions with regards to capital structure and associated cost rates?

A. 8 I recommend that the Commission authorize a ratemaking capital structure applicable to both the Southern and Northern Nevada jurisdictional rate bases consisting of 50.00% common equity and 50.00% total debt[1] at embedded debt cost rates of 4.53% (Southern) and 4.55% (Northern). Regarding the ROE, I find that ranges between 9.65% - 12.15% (excluding Company-specific adjustments), and 10.08% - 12.58% (including Company-specific adjustments), are appropriate. Given these ranges, the Company requests an ROE of 10.00% as discussed in the prepared direct testimony of Company Witness Amy L. Timperley. The Company's requested capital structure and associated cost rates for each rate

[1] Total debt includes long-term debt, short-term debt, and customer deposits.

jurisdiction are summarized on page 1 of Exhibit No.___(DWD-1) and in Tables 1 and 2 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital – Southern Nevada Rate Jurisdiction

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Total Debt	50.00%	4.53%	2.27%
Common Equity	50.00%	10.00%	5.00%
Total	100.00%		7.27%

Table 2: Summary of Recommended Weighted Average Cost of Capital – Northern Nevada Rate Jurisdiction

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Total Debt	50.00%	4.55%	2.27%
Common Equity	50.00%	10.00%	5.00%
Total	100.00%		7.27%

Q. 9 Please summarize your recommended range of common equity cost rates.

A. 9 My recommended range of common equity costs rates between 9.65% to 12.15% (unadjusted) and 10.08% to 12.58% (adjusted) is summarized on page 2 of Exhibit No.___(DWD-1). I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to Southwest Gas. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[2] and *Bluefield*[3] decisions. No proxy group can be identical in risk to any single company, consequently, there

[2] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).
[3] *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922) (*Bluefield*).

must be an evaluation of relative risk between the Company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from the application of several cost of common equity models, specifically the Discounted Cash Flow (DCF) model, the Risk Premium Model (RPM), and the Capital Asset Pricing Model (CAPM), to the market data of the Utility Proxy Group whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a Non-Price Regulated Proxy Group. The results derived from each are as follows:

Table 3: Summary of Common Equity Cost Rate

Discounted Cash Flow Model (DCF)	9.65%
Risk Premium Model (RPM)	10.85%
Capital Asset Pricing Model (CAPM)	11.69%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.15%
Indicated Range of Common Equity Cost Rates Before Adjustments	9.65% - 12.15%
Business Risk Adjustment	0.10%
Credit Risk Adjustment	0.23%
Flotation Cost Adjustment	0.10%
Recommended Range	10.08 % - 12.58%

The indicated range of common equity cost rates applicable to the Utility Proxy Group is between 9.65% and 12.15% before any Company-specific adjustments.

To reflect Southwest Gas' specific risks, I then adjusted the indicated common equity cost rate model results upward by 0.10% and 0.23% to reflect the Company's greater relative business risk and lower bond rating, as compared to the Utility Proxy Group, respectively. I then adjusted the indicated common equity cost rate upward by 0.10% to account for flotation costs. These adjustments resulted in a Company-specific indicated range of common equity cost rates between 10.08% and 12.58%. The Company's requested ROE of 10.00% is within my unadjusted range of ROEs, but slightly below my adjusted range of ROEs. Given the adjusted range of ROEs applicable to Southwest Gas exceeds its request, I consider the Company's request conservative.

Q. 10 Please summarize your recommendation with respect to the Company's capital structure.

A. 10 As mentioned briefly above, I recommend a target capital structure which consists of 50.00% debt (including short-term debt and customer deposits) and 50.00% common equity. The target capital structure requested in this proceeding is consistent with the Company's capital structure after adjusting for the significant temporary impact of historically high gas prices, the capital structures maintained by the Utility Proxy Group (both current and projected), and the operating subsidiaries of the Utility Proxy Group. Moreover, this recommended capital structure supports the Company's credit ratings, which provides long-term cost benefits to customers.

Q. 11 Please summarize your recommendation with respect to the Company's debt cost rates.

A. 11 I recommend debt cost rates of 4.53% and 4.55% for the debt cost rates applicable to the Southern and Northern rate jurisdictions, respectively.

Q. 12 How is the rest of your Direct Testimony organized?

A. 12 The remainder of my Direct Testimony is organized as follows:

- Section III – Provides a summary of financial theory and regulatory principles pertinent to the development of the cost of capital;
- Section IV – Provides a description of the Company and explains the selection of the Utility Proxy Group used to develop my ROE recommendation;
- Section V – Explains the proposed capital structure;
- Section VI – Explains the proposed cost of debt;
- Section VII – Describes the analyses on which my ROE recommendation is based;
- Section VIII – Summarizes the range of applicable ROEs before adjustments for Company-specific factors;
- Section IX – Explains my adjustments to the applicable range of ROEs to reflect Company-specific factors; and
- Section X – Presents my conclusions.

III. GENERAL PRINCIPLES

Q. 13 What general principles have you considered in your analysis?

A. 13 In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, and is consistent with the fair rate of return standards established by the

Supreme Court of the United States in the previously cited *Hope* and *Bluefield* cases.

The Court explained the fair rate of return standards in *Hope*, when it stated the following:

> The rate-making process under the Act, *i.e.*, the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the *Natural Gas Pipeline Co.* case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. p. 590. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. *Chicago & Grand Trunk R. Co. v. Wellman*, 143 U.S. 339, 345-346. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[4]

In summary, the Supreme Court of the United States determined that a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Commission's decision in this proceeding, therefore, should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

[4] *Hope*, 320 U.S. 591, at 603.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective as measured by its combined business and financial risks.

Q. 14 Within that broad framework, how is the cost of capital estimated in regulatory proceedings?

A. 14 Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (i.e., rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

A. Business Risk

Q. 15 Please define business risk and explain why it is important for determining a fair rate of return.

A. 15 The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, emerging technologies, the vagaries of weather, and the like, all of which have a direct bearing on earnings. Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. Therefore, it is difficult to specifically and numerically quantify the effect of any individual risk on investors' required return, i.e., the cost of capital. For determining an appropriate return on common equity, the relevant issue is where investors see the subject company in relation to other similarly situated utility companies (i.e., the Utility Proxy Group). To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. 16 Please define financial risk and explain why it is important for determining a fair rate of return.

A. 16 Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (i.e., failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. 17 What is a credit rating?

A. 17 A credit rating reflects an independent rating agency's opinion of the creditworthiness of a particular company, security, or obligation. Credit ratings play an important role in capital markets by providing an effective and objective tool for market participants to evaluate and assess credit risk. In a report on the role and function of credit rating agencies, the Securities and Exchange Commission (SEC) concluded:

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

---

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

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

Q. 18 Can bond and credit ratings be a proxy for a firm's combined business and financial risks to equity owners (i.e., investment risk)?

A. 18 Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (i.e., total risk) faced by bond investors.[6] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

IV. SOUTHWEST GAS AND THE UTILITY PROXY GROUP

Q. 19 Why is it necessary to develop a proxy group when estimating the ROE for the Company?

A. 19 Because the Company is not publicly traded and does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company:

[6] Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, e.g., within the A category, an S&P rating can be an A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations; e.g., within the A category, a Moody's rating can be A1, A2 and A3.

a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses and, necessarily, must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group-indicated results.

My analyses are based on the Utility Proxy Group containing U.S. natural gas utilities. As discussed earlier, utilities must compete for capital with other companies with commensurate risk (including non-utilities) and, to do so, must be provided the opportunity to earn a fair and reasonable return. Consequently, it is appropriate to consider the Utility Proxy Group's market data in determining the Company's ROE.

Q. 20 Are you familiar with Southwest Gas' operations?

A. 20 Yes. Southwest Gas provides natural gas distribution services to approximately 816,000 customers.[7] Southwest Gas has long-term issuer ratings of Baa1 from

[7] Southwest Gas Holdings, Inc. SEC Form 10-K, Exhibit 13.01 (December 31, 2022) at 1.

Moody's Investor Services (Moody's) and BBB from Standard and Poor's (S&P). Southwest Gas is not publicly-traded as it comprises an operating subsidiary of Southwest Gas Holdings, Inc. (SWX or the Parent), which is publicly-traded under ticker symbol SWX.

Q. 21 Please explain how you chose the companies in the Utility Proxy Group.

A. 21 Because the cost of common equity is a comparative exercise, my objective in developing a proxy group was to select companies that are comparable to the Company. Because the Company is a 100% rate-regulated natural gas utility, I applied the following criteria to select my Utility Proxy Group:

(i) They were included in the Natural Gas Utility Group of *Value Line's Standard Edition* (May 26, 2023) (*Value Line*);

(ii) They have 60% or greater of fiscal year 2022 total operating income derived from, or 60% or greater of fiscal year 2022 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another) or any other major development;

(iv) They have not cut or omitted their common dividends during the five years ended 2022 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services (Bloomberg) adjusted Beta coefficients (beta);

(vi) They have positive *Value Line* five-year dividends per share (DPS) growth rate projections; and

(vii) They have *Value Line*, Zacks, or Yahoo! Finance consensus five-year earnings per share (EPS) growth rate projections.

The following six companies met these criteria:

Table 4: Utility Proxy Group Companies

Company Name	Ticker Symbol
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire Inc.	SR

V. CAPITAL STRUCTURE

Q. 22 What capital structure do you recommend for Southwest Gas in this proceeding?

A. 22 I am recommending the use of the Company's currently effective target capital structure, which consists of 50.00% total debt and 50.00% common equity. I am recommending a target capital structure in this proceeding primarily due to recent events out of the control of the Company's management which has put temporary downward pressure on Southwest Gas' common equity ratio. A target capital structure of 50.00% total debt and 50.00% common equity is consistent with the Company's capital structure after adjusting for the significant temporary impact of historically high gas prices, the capital structures maintained by the Utility Proxy Group (both current and projected), and the operating subsidiaries of the Utility Proxy Group. Moreover, this recommended capital structure supports the Company's credit ratings, which provides long-term cost benefits to customers.

Q. 23 How does the capital structure affect the rate of return?

A. 23 As discussed above, there are two general categories of risk: business risk and financial risk. The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations and is a function of the percentage of debt (or financial leverage) in its capital structure. In that regard, as the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress (i.e., financial risk) also increases.[8] In essence, even if two firms face the same business risks, a company with meaningfully higher levels of debt in its capital structure is likely to have a higher cost of both debt and equity. Since the capital structure can affect the subject company's overall level of risk, it is an important consideration in establishing a just and reasonable rate of return.

Q. 24 Is there support for the proposition that the capital structure is a key consideration in establishing an appropriate rate of return?

A. 24 Yes. The Supreme Court and various utility commissions have long recognized the role of capital structure in the development of a just and reasonable rate of return for a regulated utility. In particular, a utility's leverage, or debt ratio, has been explicitly recognized as an important element in determining a just and reasonable rate of return:

> Although the determination of whether bonds or stocks should be issued is for management, the matter of debt ratio is not exclusively within its province. Debt ratio substantially affects the manner and cost of obtaining new capital. It is therefore an important factor in the rate of return and must necessarily be considered by and come within the authority of the body charged

[8] *See,* Roger A. Morin, Modern Regulatory Finance, Public Utility Reports, Inc., 2021, at 51-52. (Morin).

> by law with the duty of fixing a just and reasonable rate of return.[9]

Perhaps ultimate authority for balancing the issues of cost and financial integrity is found in the Supreme Court's statement in *Hope*:

> The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests.[10]

And as the U.S. Court of Appeals, District of Columbia Circuit found in *Communications Satellite Corp. et. al. v. FCC*:

> The equity investor's stake is made less secure as the company's debt rises, but the consumer rate-payer's burden is alleviated.[11]

That is, the U.S. Court of Appeals, District of Columbia Circuit reasoned that because there is a relationship between the capital structure and the cost of common equity, investor and consumer interests must be balanced. Consequently, the principles of fairness and reasonableness with respect to the allowed rate of return and capital structure are considered at both the federal and state levels.

Q. 25 Is the actual capital structure, at any point in time, solely determined by a firm's management?

A. 25 No. The management of the firm determines the appropriate target capital structure. At any point in time, the firm's actual capital structure may deviate from that target due to factors outside the control of the firm's management. In addition, a firm's capital structure is fluid and will fluctuate month-to-month, as it is impacted by numerous factors including profitability, seasonality in earnings, external

---

[9] *New England Telephone & Telegraph Co. v. State*, 98 N.H. 211, 97 A.2d 213, (1953) (*citing New England Tel. & Tel. Co. v. Department of Pub. Util.*, 327 Mass. 81, 97 N.E. 2d 509, 514 (1951)); *see also Petitions of New England Tel. & Tel. Co.*, 116 Vt. 480, 80 A2d 671, 685-86 (1951).
[10] *Hope*, at 603 (1944).
[11] Communications Satellite Corp. et. al. v. FCC, 198 U.S. App. D.C. 60, 63-64611 F.2d 883.

financings, and dividends. The existence of actual and target capital structures, and the speed of adjustment of the actual capital structure to the target capital structure, has been observed and is the focus of numerous empirical studies on the capital structure decisions of firms.[12]

Q. 26 Please summarize the components of the Company's capital structure and proposed overall WACCs in this proceeding.

A. 26 The Company's proposed capital structure used to determine the WACCs consist of 50.00% total debt and 50.00% common equity. The recommended capital structure is an achievable target capital structure and the and the structure the Company likely would have achieved prior to the temporary impact of historically high gas costs, as discussed below. The Company's proposed revenue requirement reflects a WACC of 7.27% for both the Southern and Northern rate jurisdictions, as shown on Page 1 of Exhibit No.___(DWD-1) and Tables 1 and 2, above.

Q. 27 Please discuss the negative capital structure impacts from Winter Storm Uri and increased gas costs incurred in the 2022/2023 winter season.

A. 27 In mid-February 2021, Winter Storm Uri hit the central U.S. (from south Texas to North Dakota and the eastern Rocky Mountains) and produced extremely cold temperatures, which increased natural gas demand and caused supply issues due to wellhead freeze-offs, power outages, and/or other adverse operating conditions upstream of Southwest Gas' distribution systems. These conditions contributed to daily natural gas prices reaching unprecedented levels. During that time, the

[12] For example, see Baum, C.F., Caglayan, M. & Rashid, A. Capital structure adjustments: Do macroeconomic and business risks matter? *Empirical Economics* 53, 1463–1502 (2017) and Harry DeAngelo, Linda DeAngelo, Toni M. Whited, Capital structure dynamics and transitory debt, *Journal of Financial Economics,* Volume 99, Issue 2, 2011, p. 235-261

Company secured natural gas supplies, to ensure service to its customers was maintained. The incremental cost for these gas supplies was approximately $250 million (companywide), which was funded using a 364-day $250 million bank term loan executed in March 2021. This term loan was renewed in March of 2022[13] as a result of gas costs remaining higher than anticipated and was paid off in its entirety in March 2023, when the Company issued a 5-year bond[14] to replace the term loan. Beginning in December 2022 and continuing through January 2023, natural gas prices spiked as a result of numerous outside market forces, including historically low national natural gas storage levels, maintenance events on upstream pipelines and cold weather conditions across the central United States, and regional pricing dislocation on the West Coast. As a result of the unexpected increase in gas prices in combination with a colder than normal winter, the Company entered into a $450 million term loan (companywide) to pay for those additionally incurred gas costs.

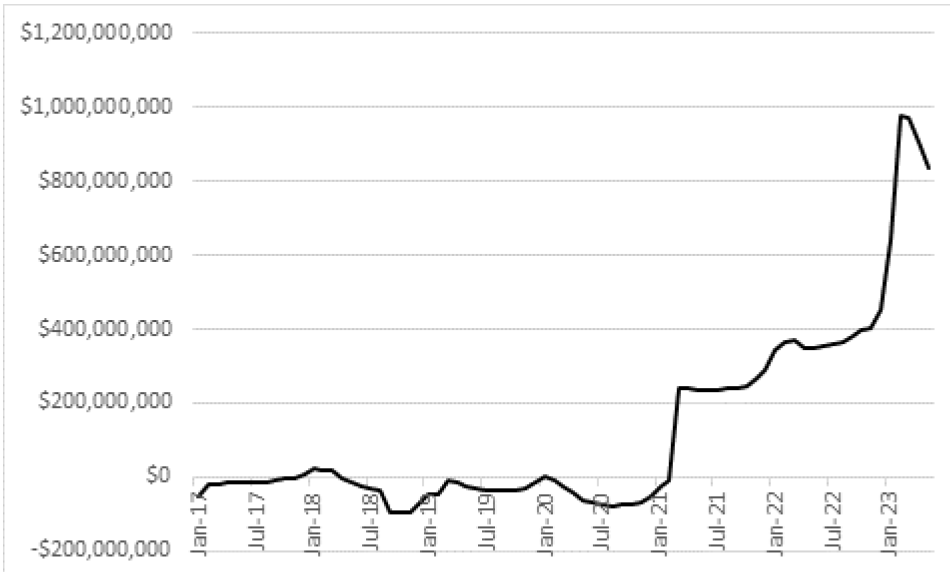
Q. 28 Please describe the status of the unrecovered purchased gas cost (FERC Account 191) (UPGC) receivable balance and the impact on the balance due to the volatile and sharp gas prices increases during the last several years.

A. 28 In May of 2023, the companywide UPGC receivable balance was approximately $836.9M.[15] The chart below illustrates the companywide UPGC balances since January 2017. As shown, prior to Winter Storm Uri, the average account balance was approximately negative $32M and ranged from approximately negative $97M to positive $25M.

---

[13] 8-K filed with SEC on 3/22/22 https://investors.swgasholdings.com/static-files/162b9172-92fe-40d3-b650-da3837a40dda
[14] 8-K filed with SEC on 3/23/23 https://investors.swgasholdings.com/static-files/e86528ec-47c1-498f-8858-63f9b00cfe62
[15] Company-provided information.

Chart 1: UPCG Account Balance (2017-2023)[16]



Q. 29 Does the Company expect the balance of the UPGC to decline significantly?

A. 29 Yes, it does. As presented in its second quarter 2023 earnings call, SWX expects receipts of approximately $200M and $700M in the third and fourth quarter of 2023, respectively,[17] based on its currently approved regulatory mechanisms, which includes the Arizona Corporation Commission's approval of an increase to the Company's Gas Cost Balancing Account rate to facilitate timely recovery of an approximate $358 million in UPGC.[18] The increase to the GCBA rate, in tandem with the other existing mechanisms, is anticipated to dramatically impact the balance of the UPGC.[19] Because the UPGC is a moving target, the Company does not expect the UPGC balance to reach zero, but does expect it to move toward its pre-Uri balances over the short- to medium term.

---

[16] Company-provided information.
[17] Southwest Gas Earnings Conference Call, Second Quarter 2023, August 9 2023.
[18] Id. Presentation at slide 18.

Q. 30 What would be the Company's indicated equity ratio if the UPGC balance declines to the average for the period from 2017 to present?

A. 30 The Company's actual Test Year equity capital ratio is calculated at 45.76%. If the approximate Test-Year end $836.9M UPGC balance declined to the average UPGC balance for the period January 2017 - May 2023 (approximately $126M), the estimated equity capital ratio is 50.91%.[20] In view of this, the Company's recommended target capital structure is reasonable.

Q. 31 How does the Company's recommended common equity ratio of 50.00% compare with the common equity ratios maintained by the Utility Proxy Group?

A. 31 The Company's requested ratemaking common equity ratio of 50.00% is reasonable and consistent with the range of common equity ratios maintained by the Utility Proxy Group. In order to assess the reasonableness of the Company's requested ratemaking common equity ratio, I reviewed the actual common equity ratios maintained by the companies within the Utility Proxy Group. As shown on page 1 of Exhibit No.___(DWD-2), common equity ratios of the utilities range from 29.62% to 61.03% for fiscal year end 2022, and 30.86% to 62.56% for the five-quarter average ending March 31, 2023.

I also considered *Value Line's* projected capital structures for the Utility Proxy Group for 2026-2028. That analysis shows a range of projected common equity ratios between 40.00% and 60.00%.

[20] As discussed above, revenues received from the UPGC are used either to (1) repay debt or (2) fund operations. As such, calculating the exact levels of debt and equity would be impossible. For simplicity, I have assumed all of the revenues received from the UPGC less the average UPGC balance were used to pay down debt.

In addition to comparing the Company's ratemaking common equity ratio with common equity ratios currently and expected to be maintained by the Utility Proxy Group (i.e., at the holding company level), I also compared the Company's ratemaking common equity ratio with the common equity ratios maintained by the operating subsidiaries of the Utility Proxy Group companies. As shown on page 2 of Exhibit No.___(DWD-2), common equity ratios of the operating utility subsidiaries of the Utility Proxy Group range from 29.62% to 60.66% for fiscal year end 2022, and 30.86% to 59.24% for the five-quarter average ending March 31, 2023.

Q. 32 In view of all of the above, is the Company's proposed common equity ratio of 50.00% appropriate for ratemaking purposes?

A. 32 Yes. The Company's proposed common equity ratio of 50.00% is appropriate for ratemaking purposes in the current proceeding because it is consistent with the common equity ratio the Company likely would have obtained but for historically high gas costs and could obtain in the future as UGPA balances are received and the historical and projected common equity ratios of the Utility Proxy Group and their operating subsidiaries. Setting the capital structure as requested by the Company will continue to support the long-term financial health of the Company.

VI. EMBEDDED COST OF DEBT

Q. 33 Have you determined the appropriate projected cost rate for debt capital for the certification period?

A. 33 Yes. An overall embedded cost of debt of 4.53% for the Southern Nevada rate jurisdiction and 4.55% for the Northern Nevada rate jurisdiction are required to service the Company's debt. The projected cost of debt is comprised of the cost of fixed-rate debentures and notes, fixed-rate medium-term notes, a variable-rate term facility, short-term debt, and customer deposits. For the Southern Nevada rate jurisdiction, the cost of debt includes the variable-rate Clark County Industrial Development Revenue Bonds (IDRBs). The components of the cost of debt are displayed in Schedule F-1, Sheet 1 of 12. The Company's projected cost of debt will be updated and certified for the certification period ending November 30, 2023.

Q. 34 Please describe the development of the cost rates of debentures and notes.

A. 34 The Company will have eleven outstanding debenture and note issues totaling $3.3 billion of gross principal at the end of the certification period (November 30, 2023). The debentures and notes have a weighted average cost of 4.34% as shown on line 12, column (e), of Schedule F-1, Sheet 3 of 12.

Q. 35 Please describe the cost rate of the medium-term notes.

A. 35 The Company established a $150 million medium-term note program in November 1997. The name is somewhat of a misnomer because medium-term notes can be issued with maturities of nine months to 30 years. The Company issued the entire $150 million under the medium-term notes program and will have two remaining outstanding medium-term note issues totaling $32.5 million of gross principal at November 30, 2023. The medium-term notes had a weighted average effective cost of 7.72% as shown on line 15, column (e), of Schedule F-1, Sheet 3 of 12.

Q. 36 Please describe and discuss the cost of unamortized loss on reacquired debt.

A. 36 In March 2010, the Company redeemed at par $100 million in Trust Originated Preferred Securities (TOPrS), which had an effective cost of 8.20%. The redemption expenses and the remaining unamortized balance at the time of the redemption are being amortized on a straight-line basis to the original maturity date of the called TOPrS, due September 2043. The effective cost for the unamortized loss on reacquired debt is calculated by dividing the annual amortization of $171,862 by the remaining recorded amount, ($3,408,592) as shown on line 16, column (f) and column (d), of Schedule F-1, Sheet 3 of 12.

Q. 37 Please describe and discuss the amortization of the gains and losses on the retirement of fixed-rate Clark County IDRBs.

A. 37 The Company has retired $396 million in gross principal of fixed-rate Clark County IDRBs. At the time of retirement for each IDRB, the unamortized debt costs were recognized as a loss on retirement and are being amortized over the remaining life of the IDRBs retired, consistent with Nevada Administrative Code (NAC) 703.2301(9). In addition, the Company recognized a gain on retirement on a portion of the IDRBs retired. On December 17, 2008, the Company completed a tender offer to purchase for cash up to $75 million of the Clark County 2004 Series B, 2006 Series A, and 2003 Series D IDRBs. The Company accepted and retired approximately $74.95 million in aggregate principal of the IDRBs pursuant to an offer to purchase the IDRBs for $57.7 million. The transaction resulted in a net gain of approximately $14 million, which has been deferred as a regulatory liability as a gain on retirement and is being amortized over the remaining life of the IDRBs retired, consistent with NAC 703.2301(9). In aggregate, the unamortized balance reflects a net gain on retirement of $2.1 million and reduces the effective cost of debt for the Southern Nevada jurisdiction. The annual amortization of the gain is $175,029, which is shown on line 27, column (f), of Schedule F-1, Sheet 3 of 12.

Q. 38 Please describe and discuss development of the cost of the variable-rate IDRBs for Southern Nevada.

A. 38 The Company has $150 million in gross principal of variable rate Clark County IDRBs. The variable rate Clark County IDRBs are projected to have an effective rate of 4.64% as shown on line 32, column (e), of Schedule F-1, Sheet 3 of 12. The interest rate on these IDRBs is set weekly. In addition, the variable rate IDRBs have been credit enhanced with standby letter of credit facilities. The annual credit facilities fees are included to determine the effective cost. The Variable Interest Expense Recovery (VIER) mechanism and the associated Average Variable Interest Rate (AVIR) calculations are discussed in the next section.

Q. 39 Why are the Big Bear IDRBs excluded from both Northern and Southern Nevada, and the Clark County IDRBs excluded from Northern Nevada in calculating the cost of debt?

A. 39 Southwest Gas has issued IDRBs in its Southern Nevada rate jurisdiction and its Southern California rate jurisdiction. As reflected in the IDRB indentures and financing agreements, the proceeds from the issuance of this type of debt are restricted to funding qualified construction expenditures for additions and improvements in the specific distribution systems to which the IDRBs relate. In addition, there are Internal Revenue Service (IRS) rules which stipulate that the benefits of the tax-exempt, lower cost IDRBs must accrue to customers in the specific jurisdiction to which the IDRBs apply. Deviation from the requirements of the IRS rules could result in the loss of the IDRB tax-exempt status.

Q. 40 How have Southwest Gas' regulatory bodies treated the cost of IDRBs in past regulatory proceedings?

A. 40 Southwest Gas has historically excluded the IDRBs from the cost of debt calculation in all regulatory jurisdictions, except for the specific jurisdictions (Southern Nevada for Clark County IDRBs and Southern California for City of Big Bear IDRBs), to which the relevant IDRBs apply. This Commission, the Arizona Corporation Commission, the California Public Utilities Commission, and the FERC have all accepted this treatment for IDRBs in past regulatory proceedings.

Q. 41 Please describe and discuss the development of the cost rate for the variable-rate term facility debt.

A. 41 Southwest Gas has a $400 million credit facility that is scheduled to expire in April 2025. Interest rates for the credit facility are calculated at either the Secured Overnight Financing Rate (SOFR) or an "alternate base rate," plus in each case an applicable margin that is determined based on the Company's senior unsecured debt rating. The applicable margin ranges from 0.75% to 1.50% for loans bearing interest with reference to SOFR and from 0.00% to 0.50% for loans bearing interest with reference to the alternative base rate. Southwest Gas is also required to pay a commitment fee on the unfunded portion of the commitments based on its senior unsecured long-term debt rating. The commitment fee ranges from 0.075% to 0.20% per annum. In addition, Southwest Gas has a $50 million uncommitted F-2 commercial paper program, which is supported by the revolving credit facility. Southwest Gas views $150 million of the facility as a permanent intermediate-term component of its debt portfolio. Accordingly, Southwest Gas has classified it as long-term debt. The remaining $250 million of the facility is used to fund recurring, seasonal working capital needs. For the certification period, the term facility debt is projected to have an effective rate of 7.26% as shown on line 1, column (c), of Schedule F-1, Sheet 7 of 12., based on the expectation of having approximately $63 million in outstanding SOFR loans.

Q. 42 Please describe and discuss development of the cost for short-term debt including the Term Loan facility that was established during the test period.

A. 42 As discussed previously, $250 million of the revolving credit bank facility is classified as short-term debt. During the test period, the Company paid off the term loan entered into in March of 2021 (initial borrowed amount of $250 million) and also paid off the term loan entered into in January of 2023 (initial borrowed amount of $450 million). At the end of the test period, the Company had no short-term debt outstanding. For the certification period, the Company anticipates having no short-term debt outstanding, but consistent with prior precedent for the use of short-term debt, reflects the 12-month average balance during the certification period of $179 million, with an effective cost rate of 6.20% as shown on line 1, column (c), of Schedule F-1, Sheet 9 of 12.

Q. 43 Please describe and discuss the development of the cost of customer deposits.

A. 43 As a normal part of the business, the Company receives deposits from its customers. The Company pays interest to these customers on these deposits as set forth by tariffs in each rate jurisdiction. The cost for the Nevada jurisdictional customer deposits at the end of the certification period (November 30, 2023) is 5.29% as shown on line 3 of Statement F, Sheet 1 of 4. The projected rate is consistent with Nevada Revised Statutes (NRS) 704.655, reflecting the six-month Treasury bill rate at the first auction on or after June 1, 2023, effective for the period July 1, 2023 to December 31, 2023. The customer deposit balances and costs by state regulatory jurisdiction are displayed on Schedule F-1, Sheet 11 of 12.

Q. 44 Please explain how the overall cost of debt specific to the Southern Nevada jurisdiction was derived.

A. 44 Due to the multi-jurisdictional operations of the Company, the embedded cost of debt for the Southern Nevada jurisdiction was derived by an allocation process, which included the following steps:

- First, the implicit amount of debt required to finance the jurisdictional rate base was determined by multiplying the percent of target total debt in the capital structure by the amount of rate base. For the Southern Nevada jurisdiction, the implicit amount of debt was calculated as follows:

Implicit Debt = Target Debt to Capital Ratio X Southern Nevada Rate Base

= 50% X $1,751,758,348

= $875,879,174

- Second, the jurisdiction-specific debt was allocated first to the total amount of implicit debt. The jurisdiction-specific debt is customer deposits and, for the Southern Nevada jurisdiction only, the Clark County IDRBs. For the Southern Nevada jurisdiction, the jurisdiction-specific debt consisted of the following components:

Customer Deposits	$11,708,150
Clark County Variable-Rate IDRBs	$145,688,767
Clark County Fixed-Rate IDRBs	$1,491,767
= Total Jurisdictional Allocated Debt	$158,888,685

- Third, the remaining portion of other debt was calculated as the difference between the implicit debt and the jurisdictional-specific debt. The other debt was comprised of the Company's non-jurisdictional-specific debt applied on a pro rata basis to the Nevada jurisdictions. For the Southern Nevada jurisdiction, other debt was calculated as follows:

Implicit Amount of Debt	$875,879,174
Less Jurisdiction-Specific Debt	$158,888,685
= Other Debt	$716,990,489

- The fourth and final step uses the components of jurisdictional debt identified and the pro rata share of other debt to calculate the weighted cost of debt for the jurisdiction. The allocation process and the calculation of the weighted embedded cost of debt for the Southern Nevada jurisdiction are displayed in the Southern Nevada Schedule F-1, Sheet 1 of 12.

Q. 45 Please explain how the overall cost of debt specific to the Northern Nevada jurisdiction was derived.

A. 45 For Northern Nevada, the allocation process included the following steps:

- First, the implicit amount of debt required to finance the jurisdictional rate base was determined by multiplying the percent of target total debt in the capital structure by the amount of rate base. For the Northern Nevada jurisdiction, the implicit amount of debt was calculated as follows:

  Implicit Debt = Target Debt to Capital Ratio X Northern Nevada Rate Base
  = 50% X $213,207,678
  = $106,603,839

- Second, the jurisdiction-specific debt was allocated first to the total amount of implicit debt. For the Northern Nevada jurisdiction, the jurisdiction-specific debt is customer deposits which amounted to the following:

  Customer Deposits $ 2,488,518

- Third, the remaining portion of other debt was calculated as the difference between the implicit debt and the jurisdictional-specific debt. The other debt was comprised of the Company’s non-jurisdictional-specific debt applied on a pro rata basis to the Nevada jurisdictions. For the Northern Nevada jurisdiction, other debt was calculated as follows:

Implicit Amount of Debt	$ 106,603,839
Less Jurisdiction-Specific Debt	$ 2,488,518
= Other Debt	$ 104,115,321

- The fourth and final step uses the components of jurisdictional debt identified and the pro rata share of other debt to calculate the weighted cost of debt for the jurisdiction. The allocation process and the calculation of the weighted embedded cost of debt for the Northern Nevada jurisdiction are displayed in the Northern Nevada Schedule F-1, Sheet 1 of 12.

A. Average Variable Interest Rate – Variable Interest Expense Recovery Mechanism

Q. 46 Please provide an overview of the VIER mechanism.

A. 46 In Docket No. 04-3011, the Company requested and received approval for a VIER mechanism as defined by NAC 704.210 through NAC 704.222, specifically for $100 million (gross principal) of variable rate Clark County IDRBs. In the Company's general rate case, Docket No. 12-04005, the Company requested and was granted authority to include an incremental $50 million of variable rate IDRBs in the VIER mechanism.[21] The VIER mechanism adjusts the Base Tariff General Rate (BTGR) for changes in the AVIR and accumulated deferred interest. The Company implemented the VIER mechanism in September 2004 and has filed periodically to update the VIER mechanism. Because a new BTGR will be established in this proceeding, a new authorized AVIR will be embedded in the new BTGR. The new authorized AVIR will also be used to calculate the deferred interest expense at the time rates from this proceeding go into effect.

[21] Second Modified Final Order in Docket No. 12-04005, at p. 26-27.

Q. 47 For the Clark County IDRBs proposed under the VIER mechanism for the Southern Nevada rate jurisdiction, please describe the development of the estimated AVIR for the certification period ended November 30, 2023.

A. 47 For the certification period ended November 30, 2023, the projected 12-month weighted AVIR for the Clark County variable rate IDRBs was 0.3859%. The calculation of the estimated new AVIR is follows:

AVIR = (Clark County Variable Rate IDRB/Rate Base)

X Embedded Cost of Clark County Variable Rate IDRB

= ($145,688,767/$1,751,758,348) X 4.64%

= 0.3859%

The variable rate 2003 Clark County Series A, 2008 Clark County Series A, and the 2009 Clark County Series A IDRBs are projected to have a 12-month average effective cost rate of 4.64% for the certification period ended November 30, 2023. The AVIR will be updated in the Company's certification filing.

Q. 48 Please summarize your recommendations regarding capital structure and debt cost rates.

A. 48 I recommend the use of the Company's target capital structure consisting of 50.00% debt and 50.00% common equity at embedded debt cost rates of 4.53% and 4.55% for the Southern and Northern rate jurisdictions, respectively.

VII. COMMON EQUITY COST RATE

Q. 49 Is it important that cost of common equity models be market-based?

A. 49 Yes. As discussed previously, regulated public utilities, like the Company must compete for equity in capital markets along with all other companies of comparable risk, which includes non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies of comparable risk, they will choose a company providing a higher return over a company providing a lower return.

Q. 50 Are your cost of common equity models market-based?

A. 50 Yes. The DCF model uses market prices in developing the model's dividend yield component. The RPM uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk. In addition, betas (β), which reflect the market/systematic risk component of equity risk premium, are derived from regression analyses of market prices. The Predictive Risk Premium Model (PRPM) uses monthly market returns in addition to expectations of the risk-free rate. The CAPM is market-based for many of the same reasons that the RPM is market-based (i.e., the use of expected bond yields and betas). Selection criteria for comparable risk non-price regulated companies are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. 51 What analytical approaches did you use to determine the Company's ROE?

A. 51 As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I apply to the Utility Proxy Group described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements and provide different insights to investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (i.e., the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

Q. 52 Has the PUCN recognized the importance of considering multiple cost of common equity models in arriving at an ROE recommendation?

A. 52 Yes. For example, in the order in Southwest Gas' most recent fully litigated rate case, the PUCN discussed the importance of considering multiple analytical methods, given the complexity of determining the required ROE:

> In establishing a zone of reasonableness and determining an ROE within that range, the Commission relies upon expert testimony and evidence which applies principles of finance, accounting, and economics to the cost of a particular utility's common equity. This evidence includes the results of each expert's ROE studies, the experts' judgement in assessing macroeconomic conditions, capital markets, and SWG's particular circumstances (e.g., capital structure, risk profile, and regulatory environment).[22]

A. Discounted Cash Flow Model

Q. 53 What is the theoretical basis of the DCF model?

A. 53 The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an

[22] Application of Southwest Gas Corporation for authority to increase its retail natural gas utility service rates for Southern and Northern Nevada, Public Utilities Commission of Nevada, Order, Docket No. 20-02023, at 32-33, September 23, 2020.

expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; i.e., the total common equity return rate expected by investors.

$$K_e = (D_0\,(1+g))/P + g$$

where:

K_e = the required Return on Common Equity;

D_0 = the annualized Dividend Per Share;

P = the current stock price; and

g = the growth rate.

Q. 54 Which version of the DCF model did you use?

A. 54 I used the single-stage constant growth DCF model in my analyses.

Q. 55 Please describe the dividend yield you used in applying the constant growth DCF model.

A. 55 The unadjusted dividend yields are based on the proxy companies' dividends as of July 14, 2023, divided by the average closing market price for the 60 trading days ended July 14, 2023.[23]

Q. 56 Please explain your adjustment to the dividend yield.

A. 56 Because dividends are paid periodically (e.g., quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group

[23] *See,* Column 1, page 1 of Exhibit No.___(DWD-4).

increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Exhibit No.___(DWD-4) have been adjusted upward to reflect one-half the average projected growth rate shown in Column 5.

Q. 57 Please explain the basis for the growth rates you apply to the Utility Proxy Group in your constant growth DCF model.

A. 57 Investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using projected earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. 58 Please summarize the constant growth DCF model results.

A. 58 As shown on page 1 of Exhibit No.___(DWD-4), for the Utility Proxy Group, the mean result of applying the single-stage DCF model is 9.79%, the median result is 9.50%, and the average of the two is 9.65%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF.

B. The Risk Premium Model

Q. 59 Please describe the theoretical basis of the RPM.

A. 59 The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. 60 Please explain how you derived your indicated cost of common equity based on the RPM.

A. 60 To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the PRPM and the second method was a risk premium model using a total market approach. The PRPM estimates the risk-return relationship directly, while the total market approach indirectly derives a risk premium by using known metrics as a proxy for risk.

Q. 61 Please explain the PRPM

A. 61 The PRPM, published in the *Journal of Regulatory Economics*,[24] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility" or ARCH.[25] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (i.e., the variance of historical equity risk premiums).

The inputs to the model are the historical returns on the common shares of each Utility Proxy Group company minus the historical monthly yield on long-term U.S. Treasury securities through June 2023. Using a generalized form of ARCH,[26] known as GARCH, I calculated each Utility Proxy Group company's projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series[27] and a GARCH coefficient.[28] Multiplying the predicted monthly variance by

---

[24] Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, A New Approach for Estimating the Equity Risk Premium for Public Utilities, *The Journal of Regulatory Economics* (December 2011), 40:261-278.
[25] Autoregressive conditional heteroscedasticity; *see also* www.nobelprize.org.
[26] Autoregressive conditional heteroskedasticity.
[27] Illustrated on Columns 1 and 2, page 2 of Exhibit No.___(DWD-5).
[28] Illustrated on Column 4, page 2 of Exhibit No.___(DWD-5).

the GARCH coefficient and then annualizing it[29] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 3.85%[30] to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury bond yield is a consensus forecast derived from *Blue Chip Financial Forecasts* (*Blue Chip*).[31] The mean PRPM-indicated common equity cost rate for the Utility Proxy Group is 11.20%, the median is 10.28%, and the average of the two is 10.74%. Consistent with my reliance on the average of the median and mean results of the DCF models, I relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 10.74%.

Q. 62 Please explain the total market approach RPM.

A. 62 The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium; (2) an equity risk premium based on the S&P Utilities Index; and (3) an equity risk premium based on authorized ROEs for natural gas distribution utilities.

Q. 63 Please explain the basis of the expected bond yield of 5.44% applicable to the Utility Proxy Group.

A. 63 The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly rated long-term debt is essential. I relied on a consensus forecast of about

---

[29] Annualized Return = (1 + Monthly Return) ^12 - 1.
[30] *See,* Column 6, page 2 of Exhibit No.___(DWD-5).
[31] *See,* Blue Chip Financial Forecasts, June 30, 2023 at page 2; June 1, 2023 at page 14.

50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the fourth calendar quarter of 2024, and *Blue Chip's* long-term projections for 2025 to 2029 and 2030 to 2034. As shown on line 1, page 3 of Exhibit No.___(DWD-5), the average expected yield on Moody's Aaa-rated corporate bonds is 4.75%. In order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield, I made an upward adjustment of 0.69%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[32] Adding that recent 0.69% spread to the expected Aaa-rated corporate bond yield of 4.75% results in an expected A2-rated public utility bond yield of 5.44%.

I then reviewed the average credit rating for the Utility Proxy Group from Moody's to determine if an adjustment to the estimated A2-rated public utility bond was necessary. Since the Utility Proxy Group's average Moody's long-term issuer rating is A2, no other adjustment is needed to make the A2 prospective bond yield applicable to the A2-rated public utility bond. The results are a 5.44% expected bond yield applicable to the Utility Proxy Group.

Table 5: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[33]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip*)	4.75%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.69%
Prospective Bond Yield Applicable to the Utility Proxy Group	5.44%

[32] As shown on line 2 and explained in note 2, page 3 of Exhibit No.___(DWD-5).
[33] As shown on page 3 of Exhibit No.___(DWD-5).

Q. 64 Please explain how the beta-derived equity risk premium is determined.

A. 64 The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) the beta. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 9, on page 8 of Exhibit No.___(DWD-5). The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums, and a Bloomberg-based equity risk premium. Each of these is described below.

Q. 65 How did you derive a market equity risk premium based on long-term historical data?

A. 65 To derive an historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the Stocks, Bonds, Bills, and Inflation (SBBI) Yearbook 2023 (SBBI - 2023)[34] less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2022. Using holding period returns over a very long time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, i.e., a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks was 11.78% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 5.96%.[35] As shown on line 1, page 8 of Exhibit No.___(DWD-5), subtracting the mean monthly bond yield from

---

[34] *See,* SBBI-2023 Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2022.
[35] As explained in note 1, page 9 of Exhibit No.___(DWD-5).

the total return on large company stocks results in a long-term historical equity risk premium of 5.82%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in SBBI - 2023.[36] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. 66 Please explain the derivation of the regression-based market equity risk premium.

A. 66 To derive the regression-based market equity risk premium of 7.46% shown on line 2, page 8 of Exhibit No.___(DWD-5), I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares (OLS) regression, in which

[36] *See*, SBBI - 2023, at 194.

the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

Q. 67 Please explain the derivation of the PRPM equity risk premium.

A. 67 I used the same PRPM approach described above to derive the PRPM equity risk premium. The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate bonds during the period from January 1928 through June 2023.[37] Using the previously discussed generalized form of ARCH, known as GARCH, the projected equity risk premium is determined using Eviews© statistical software. The resulting PRPM predicted a market equity risk premium of 8.70%.[38]

Q. 68 Please explain the derivation of a projected equity risk premium based on *Value Line* data for your RPM analysis.

A. 68 As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 8 of Exhibit No.___(DWD-5). Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended July 14, 2023, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line* (Standard Edition).[39]

---

[37] Data from January 1926 to December 2022 is from SBBI - 2023. Data from January 2023 to June 2023 is from Bloomberg.
[38] Shown on line 3, page 8 of Exhibit No.___(DWD-5).
[39] As explained in detail in note 1, page 2 of Exhibit No.___(DWD-6).

The average median expected price appreciation is 63%, which translates to a 12.99% annual appreciation, and when added to the average of *Value Line's* median expected dividend yields of 2.32%, equates to a forecasted annual total return rate on the market of 15.31%. The forecasted Moody's Aaa-rated corporate bond yield of 4.75% is deducted from the total market return of 15.31%, resulting in an equity risk premium of 10.56%, as shown on line 4, page 8 of Exhibit No.___(DWD-5).

Q. 69 Please explain the derivation of an equity risk premium based on the S&P 500 companies.

A. 69 Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 14.14%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 4.75% results in a 9.39% projected equity risk premium.

Q. 70 Please explain the derivation of an equity risk premium based on Bloomberg data.

A. 70 Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for capital appreciation, identical to the method described above. The expected total return for the S&P 500 is 16.04%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 4.75% results in an 11.29% projected equity risk premium.

Q. 71 What is your conclusion of a beta-derived equity risk premium for use in your RPM analysis?

A. 71 I gave equal weight to all six equity risk premiums based on each source – historical, *Value Line*, and Bloomberg – in arriving at an 8.87% equity risk premium.

Table 6: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[40]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa-Rated Corporate Bond Yields (1928 – 2022)	5.82%
Regression Analysis on Historical Data	7.46%
PRPM Analysis on Historical Data	8.70%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	10.56%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected Aaa Corporate Bond Yields	9.39%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected Aaa Corporate Bond Yields	11.29%
Average	8.87%

After calculating the average market equity risk premium of 8.87%, I adjusted it by the beta to account for the risk of the Utility Proxy Group. As discussed below, the beta is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Exhibit No.___(DWD-6), the average of the mean and median beta for the Utility Proxy Group is 0.77. Multiplying the 0.77 average

[40] As shown on page 8 of Exhibit No.___(DWD-5).

beta by the market equity risk premium of 8.87% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 6.83%.

Q. 72 How did you derive the equity risk premium based on the S&P Utility Index and Moody's A2-rated public utility bonds?

A. 72 I estimated three equity risk premiums based on S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium, between the S&P Utility Index total returns of 10.63% and monthly Moody's A2-rated public utility bond yields of 6.44% from 1928 to 2022, to arrive at an equity risk premium of 4.20%.[41] I then used the same historical data to derive an equity risk premium of 5.16% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to June 2023 to arrive at a PRPM-derived equity risk premium of 5.24% for the S&P Utility Index.

I then derived an expected total return on the S&P Utilities Index of 10.00% using data from *Value Line* and subtracted the prospective Moody's A2-rated public utility bond yield of 5.44%[42] which resulted in an equity risk premium of 4.56%. As with the market equity risk premiums, I averaged each risk premium based on each source (i.e., historical and *Value Line*) to arrive at my utility-specific equity risk premium of 4.79%.

[41] As shown on line 1, page 12 of Exhibit No.___(DWD-5).
[42] Derived on line 3, page 3 of Exhibit No.___(DWD-5).

Table 7: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[43]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2022)	4.20%
Regression Analysis on Historical Data	5.16%
PRPM Analysis on Historical Data	5.24%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P Utilities Index less Projected A2 Utility Bond Yields	4.56%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P Utilities Index less Projected A2 Utility Bond Yields	NMF
Average	4.79%

Q. 73 How did you derive an equity risk premium of 4.92% based on authorized ROEs for natural gas distribution utilities?

A. 73 The equity risk premium of 4.92% shown on line 3, page 7 of Exhibit No.___(DWD-5) is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds. That analysis is shown on page 13 of Exhibit No.___(DWD-5), which contains the graphical results of a regression analysis of 821 rate cases for natural gas distribution utilities that were fully litigated during the period from January 1, 1980 through July 14, 2023. It shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with

[43] As shown on page 12 of Exhibit No.___(DWD-5).

financial literature on the subject.[44] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds. Given the expected A2-rated utility bond yield of 5.44%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.92%, which is shown on line 3, page 7 of Exhibit No.___(DWD-5).

Q. 74 What is your conclusion of an equity risk premium for use in your total market approach RPM analysis?

A. 74 The equity risk premium I applied to the Utility Proxy Group is 5.51%, which is the average of the beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums of 6.83%, 4.79%, and 4.92%, respectively.[45]

Q. 75 What is the indicated RPM common equity cost rate based on the total market approach?

A. 75 As shown on line 5, page 3 of Exhibit No.___(DWD-5), and shown on Table 8, below, I calculated a common equity cost rate of 10.95% for the Utility Proxy Group based on the total market approach RPM.

Table 8: Summary of the Total Market Return Risk Premium Model[46]

Prospective Moody's A2-Rated Utility Bond Applicable to the Utility Proxy Group	5.44%
Prospective Equity Risk Premium	5.51%
Indicated Cost of Common Equity	10.95%

[44] *See, e.g.*, Robert S. Harris and Felicia C. Marston, The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts, *Journal of Applied Finance*, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, The Risk Premium Approach to Measuring a Utility's Cost of Equity, *Financial Management*, Spring 1985, at 33-45.

[45] As shown on page 7 of Exhibit No.___(DWD-5).

[46] As shown on page 3 of Exhibit No.___(DWD-5).

Q. 76 What are the results of your application of the PRPM and the total market approach RPM?

A. 76 As shown on page 1 of Exhibit No.___(DWD-5), the indicated RPM-derived common equity cost rate is 10.85%, which gives equal weight to the PRPM (10.74%) and the adjusted-market approach results (10.95%).

C. The Capital Asset Pricing Model

Q. 77 Please explain the theoretical basis of the CAPM.

A. 77 CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta (β). A beta less than 1.0 indicates lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta (R_m - R_f)$$

Where: R_s = Return rate on the common stock;

R_f = Risk-free rate of return;

R_m = Return rate on the market as a whole; and

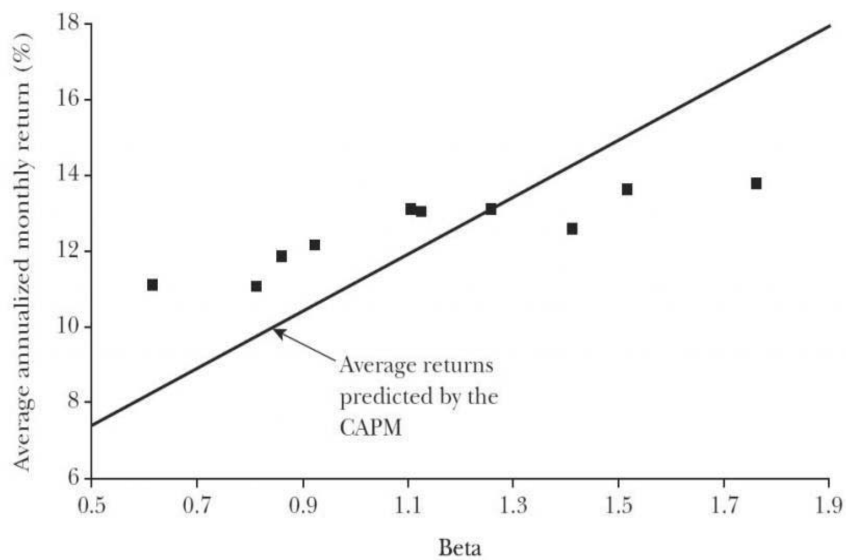
β = Adjusted beta (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have measured the extent to which security returns and beta are related as predicted by the CAPM, confirming its validity. The empirical CAPM (ECAPM) reflects the reality that while the results of these tests support the notion that the beta is related to security returns, the empirical Security Market Line (SML) described by the CAPM formula is not as steeply sloped as the predicted SML.[47]

The ECAPM reflects this empirical reality. Fama and French clearly state regarding Figure 2, below, that “[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low.”[48]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



[47] Morin, at page 223.

[48] Eugene F. Fama and Kenneth R. French, The Capital Asset Pricing Model: Theory and Evidence, *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004 at 33 (Fama & French).

In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[49]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K \quad = \qquad RF + x\,(RM - RF) + (1\text{-}x)\ \ \beta(RM - RF)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = RF + 0.25(RM - RF) + 0.75\ \beta(RM - RF)$$[50]

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[51]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return `for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[52]

---

[49] Morin, at 207.
[50] Morin, at 221.
[51] Fama & French, at 32.
[52] Fama & French, at 33.

Clearly, the justification from Morin, Fama, and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

Q. 78 What betas did you use in your CAPM analysis?

A. 78 For the betas in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg. While both of those services adjust their calculated (or "raw") beta to reflect their tendency to regress to the market mean of 1.00, *Value Line* calculates their beta over a five-year period, while Bloomberg calculates theirs over a two-year period.

Q. 79 Please describe your selection of a risk-free rate of return.

A. 79 As shown in Column 5, page 1 of Exhibit No.___(DWD-6), the risk-free rate adopted for both applications of the CAPM is 3.85%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the fourth calendar quarter of 2024, and long-term projections for the years 2025 to 2029 and 2030 to 2034.

Q. 80 Why is the yield on long-term U.S. Treasury bonds appropriate for use as the risk-free rate?

A. 80 The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (i.e., cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. 81 Please explain the estimation of the expected risk premium for the market used in your CAPM analyses.

A. 81 The basis of the market risk premium is explained in detail in note 1 on Exhibit No.___(DWD-6). As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums, and one Bloomberg data-based market risk premium.

The long-term income return on U.S. Government securities of 5.00% was deducted from the SBBI - 2023 monthly historical total market return of 12.03%, which results in an historical market equity risk premium of 7.03.[53] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from SBBI - 2023. That regression analysis yielded a market equity risk premium of 8.59%. The PRPM market equity risk premium is 9.69% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through June 2023.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 3.85%, discussed above, from the *Value Line* projected total annual market return of 15.31%, resulting in a forecasted total market equity risk premium of 11.46%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the

[53] SBBI - 2023, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

projected risk-free rate of 3.85% from the projected total return of the S&P 500 of 14.14%. The resulting market equity risk premium is 10.29%.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 3.85% from the projected total return of the S&P 500 of 16.04%. The resulting market equity risk premium is 12.19%. These six measures, when averaged, result in an average total market equity risk premium of 9.87%.

Table 9: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[54]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2022)	7.03%
Regression Analysis on Historical Data	8.59%
PRPM Analysis on Historical Data	9.69%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	11.46%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected 30-Year Treasury Bond Yields	10.29%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected 30-Year Treasury Bond Yields	12.19%
Average	9.87%

Q. 82 What are the results of your application of the traditional and empirical CAPM to the Utility Proxy Group?

A. 82 As shown on page 1 of Exhibit No.___(DWD-6), the mean result of my CAPM/ECAPM analyses is 11.68%, the median is 11.70%, and the average of the

[54] As shown on page 2 of Exhibit No.___(DWD-6).

two is 11.69%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 11.69%.

D. Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies based on the DCF, RPM, and CAPM

Q. 83 Why do you also consider a proxy group of domestic, non-price regulated companies?

A. 83 In the *Hope* and *Bluefield* cases, the Supreme Court of the United States did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. 84 How did you select non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. 84 In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the betas and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (i.e., five years). These selection criteria resulted in a proxy group of 46 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, i.e., not utilities;

(iii) Their unadjusted betas must lie within plus or minus two standard deviations of the average unadjusted beta of the Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Betas measure market, or systematic, risk which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas <u>and</u> similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. 85 Have you prepared an Exhibit which shows the data from which you selected the 46 domestic, non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. 85 Yes, the basis of my selection and both proxy groups' regression statistics are shown in Exhibit No.___(DWD-7).

Q. 86 Did you calculate common equity cost rates using the DCF model, RPM, and CAPM for the Non-Price Regulated Proxy Group?

A. 86 Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where

I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual non-price regulated companies.

Page 2 of Exhibit No.___(DWD-8) derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group, is 10.60%.

Pages 3 through 5 of Exhibit No.___(DWD-8) contain the data and calculations that support the 13.10% RPM common equity cost rate. As shown on line 1, page 3 of Exhibit No.___(DWD-8), the consensus prospective yield on Moody's Baa2-rated corporate bonds for the six quarters ending in the fourth quarter of 2024, and for the years 2025 to 2029 and 2030 to 2034, is 5.73%.[55] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of Baa1, a downward adjustment of 0.17%[56] to the projected Baa2 corporate bond yield is necessary to reflect the difference in ratings, which results in a projected Baa1 corporate bond yield of 5.56%.

When the beta-adjusted risk premium of 7.54%[57] relative to the Non-Price Regulated Proxy Group is added to the prospective Baa1-rated corporate bond yield of 5.56%, the indicated RPM common equity cost rate is 13.10%.

Page 6 of Exhibit No.___(DWD-8) contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 12.30%.

---

[55] Blue Chip Financial Forecasts, June 30, 2023, at page 2; June 1, 2023, at page 14.
[56] As demonstrated in line 2 and described in note 2 of page 3 of Exhibit No.___(DWD-8).
[57] Derived on page 5 of Exhibit No.___(DWD-8).

Q. 87 What is the cost rate of common equity based on the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group?

A. 87 As shown on page 1 of Exhibit No.___(DWD-8), the results of the common equity models applied to the Non-Price Regulated Proxy Group – which group is comparable in total risk to the Utility Proxy Group – are as follows: 10.60% (DCF), 13.10% (RPM), and 12.30% (CAPM). The average of the mean and median of these models is 12.15%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

VIII. RANGE OF COMMON EQUITY COST RATES BEFORE ADJUSTMENT

Q. 88 What is the range of indicated common equity cost rates produced by your ROE models?

A. 88 The range of indicated ROEs is from 9.65% (DCF model) to 12.15% (Non-Price Regulated Market Models), which is applicable to the Utility Proxy Group. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

As will be discussed below, Southwest Gas has greater risk than the Utility Proxy Group. Because of this, the indicated range of model results based on the Utility Proxy Group must be adjusted to reflect Southwest Gas' greater relative risk.

IX. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

A. Business Risk Adjustment

Q. 89 Please compare Southwest Gas' size with that of the Utility Proxy Group.

A. 89 As shown on Table 10, below, Southwest Gas is smaller than the median utility in the Utility Proxy Group, as measured by market capitalization.

Table 10: Size as Measured by Market Capitalization for Southwest Gas' Natural Gas Distribution Operations and the Utility Proxy Group

	Market Capitalization* ($ Millions)	Times Greater than the Company
Southwest Gas	$1,680.46	
Utility Proxy Group	$4,331.038	2.6x
*From page 1 of Exhibit No.___(DWD-9).		

Southwest Gas' estimated market capitalization was $1,680 million as of July 14, 2023,[58] compared with the median market capitalization of the Utility Proxy Group of $4,331 million as of July 14, 2023. The Utility Proxy Group's market capitalization is 2.6 times the size of Southwest Gas' estimated market capitalization.

Q. 90 Since Southwest Gas is part of a larger company, why is the size of the total company not more appropriate to use when determining the size adjustment?

A. 90 The return derived in this proceeding will not apply to SWX's operations as a whole, but only to Southwest Gas. SWX is the sum of its constituent parts, including those constituent parts' ROEs. Potential investors in the Parent are aware that it is a

[58] $1,677.395 = $1,964.966M (Certification period rate base (Southern + Northern) * requested equity ratio) * 171.0% (market-to-book ratio of the Utility Proxy Group) as demonstrated on page 2 of Exhibit No.___(DWD-9).

combination of operations in each state, and that each state's operations experience the regulatory and operating risks specific to their jurisdiction. The market's expectation of SWX's return is commensurate with the realities of the Company's composite operations in each of the states in which it operates.

Q. 91 Does Southwest Gas' smaller size relative to the Utility Proxy Group companies increase its business risk?

A. 91 Yes. Southwest Gas' smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a smaller company than on a bigger company with a larger, more diverse, customer base.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll's <u>Cost of Capital Navigator: U.S. Cost of Capital Module</u> ("<u>Kroll</u>") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," <u>Kroll</u> states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in

> valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[59]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 38, they note:

> …the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[60]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[61] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms.** (emphasis added).[62]

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of

---

[59] Kroll, Cost of Capital Navigator: U.S. Cost of Capital Module, Size as a Predictor of Equity Returns, at 1.
[60] Fama & French, at 25-43.
[61] Richard A. Brealey and Steward C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.
[62] Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of Southwest Gas, including its small relative size, which is justified and supported above by evidence in the financial literature.

Q. 92 Is there a way to quantify a relative risk adjustment due to Southwest Gas' smaller size when compared to the Utility Proxy Group?

A. 92 Yes. Southwest Gas has greater relative risk than the average utility in the Utility Proxy Group. As a proxy for the business risk adjustment, I will use the SBBI-2023 size study. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2022 period. The median size premium for the Utility Proxy Group with a market capitalization of $4,331 million falls in the fourth decile, while the Company's estimated market capitalization of $1,680 million places it in the sixth decile. The size premium spread between the fourth decile and the sixth decile is 0.58%. Even though an 0.58% upward size adjustment is indicated, I applied a size premium of 0.10% to the Company's indicated common equity cost rate.

B. Credit Risk Adjustment

Q. 93 Please discuss your proposed credit risk adjustment.

A. 93 Southwest Gas' long-term issuer ratings are Baa1 and BBB from Moody's and S&P, respectively, which are riskier and equal to the average long-term issuer ratings for the Utility Proxy Group of A2/A3 and A-, respectively.[63]

[63] Source: S&P Global Market Intelligence.

An indication of the magnitude of the necessary upward adjustment to reflect the greater credit risk inherent in Southwest Gas' Baa1 bond rating relative to the Utility Proxy Group average rating of A2 is two-thirds of a recent three-month average spread between Moody's A2 and Baa2-rated public utility bond yields of 0.35%, shown on page 4 of Exhibit No.___(DWD-5), or 0.23%.[64]

C. Flotation Costs

Q. 94 What are flotation costs?

A. 94 Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (e.g., underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

Q. 95 Why is it important to recognize flotation costs in the allowed common equity cost rate?

A. 95 It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit the recovery of these costs….
>
> The simple fact of the matter is that common equity capital is not free….[Flotation costs] must be recovered through a rate of return adjustment.[65]

[64] 0.23% = 0.35% * (2/3); differences due to rounding.
[65] Morin, at p. 329.

Q. 96 Should flotation costs be recognized only if there was an issuance during the test year or there is an imminent post-test year issuance of additional common stock?

A. 96 No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, $0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in investment. Assuming the investor in that stock requires a 10% return on his or her invested $1.00 (i.e., a return of $0.10), the company needs to earn approximately 10.5% on its invested $0.95 to receive a $0.10 return.

Q. 97 Do the common equity cost rate models you have used already reflect investors' anticipation of flotation costs?

A. 97 No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[66] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[67] Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. 98 How did you calculate the flotation cost allowance?

A. 98 I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing equity that were incurred by Southwest Gas since 2000. Based on the issuance costs shown on page 1 of Exhibit No.___(DWD-10), an adjustment of 0.10% is required to reflect the flotation costs applicable to the Utility Proxy Group.

---

[66] Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at 342.
[67] Morin, at 337-339.

Q. 99 What is the indicated cost of common equity after your Company-specific adjustments?

A. 99 Applying the 0.10% size adjustment, the 0.23% credit risk adjustment, and the 0.10% flotation cost adjustment to the indicated range of common equity cost rates between 9.65% and 12.15% results in a Company-specific range of common equity rates between 10.08% and 12.58%.

X. CONCLUSION

Q. 100 What is your recommended range of ROEs for the Company?

A. 100 Given the discussion above and the results from the analyses, I conclude that a range of ROEs from 10.08% to 12.58% is appropriate for the Company at this time.

Q. 101 In your opinion, is the Company's requested ROE of 10.00% fair and reasonable to Southwest Gas and its customers?

A. 101 Given my range of ROEs applicable to Southwest Gas, the Company's requested ROE is reasonable, if not conservative.

Q. 102 In your opinion, is Southwest Gas' proposed capital structure consisting of 50.00% long-term debt and 50.00% common equity fair and reasonable?

A. 102 Yes, it is.

Q. 103 In your opinion, is Southwest Gas' proposed costs of debt of 4.53% (Southern) and 4.55% (Northern) fair and reasonable?

A. 103 Yes, it is.

Q. 104 Does this conclude your Direct Testimony?

A. 104 Yes, it does.

scottmadden
MANAGEMENT CONSULTANTS

Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and has become a leading expert witness with respect to cost of capital and capital structure. He has served as a consultant for investor-owned and municipal utilities and authorities for 15 years. Dylan has testified as an expert witness on over 150 occasions regarding rate of return, cost of service, rate design, and valuation before more than 35 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Regulation and Rates
- Rate of Return
- Valuation
- Mutual Fund Benchmarking
- Capital Market Risk
- Regulatory Strategy
- Cost of Service

Recent Expert Testimony Submission/Appearance

- Regulatory Commission of Alaska – Capital Structure
- Federal Energy Regulatory Commission – Rate of Return
- Public Utility Commission of Texas – Return on Equity
- Hawaii Public Utilities Commission – Cost of Service / Rate Design
- Pennsylvania Public Utility Commission - Valuation

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the City
- Co-authored a valuation report on behalf of a large investor-owned utility company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Recent Articles and Speeches

- Co-Author of: "Decoupling, Risk Impacts and the Cost of Capital", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal, March, 2020
- Co-Author of: "Decoupling Impact and Public Utility Conservation Investment", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal, 130 (2019), 311-319
- "Establishing Alternative Proxy Groups", before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum, April 4, 2019, New Orleans, LA
- "Past is Prologue: Future Test Year", Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit, May 2, 2017, Savannah, GA.
- Co-author of: "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley, The Electricity Journal, May, 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN

scottmadden
MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/23	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	Proceeding ID. 27084	Determination of Cost-of-Capital Parameters
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
California Public Utilities Commission				
San Gabriel Valley Water Company	05/23	San Gabriel Valley Water Company	Docket No. A23-05-001	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Commission of the Canada Energy Regulator				
Trans-Northern Pipelines Inc.	11/22	Trans-Northern Pipelines Inc.	Docket No. C-22197	Cost of Capital
Delaware Public Service Commission				
Artesian Water Company, Inc.	04/23	Artesian Water Company, Inc.	Docket No. 23-0601	Rate of Return
Delmarva Power & Light Co.	12/22	Delmarva Power & Light Co.	Docket No. 22-0897 (Electric)	Return on Equity
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				

scottmadden
MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Peoples Gas System, Inc.	04/23	Peoples Gas System, Inc.	Docket No. 20230023-GU	Rate of Return
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System, Inc.	09/20	Peoples Gas System, Inc.	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0082 (Electric)	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0067 (Gas)	Return on Equity
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company	02/23	Bluegrass Water Utility Operating Company	2022-00432	Return on Equity
Atmos Energy Corporation	07/22	Atmos Energy Corporation	2022-00222	PRP Rider Rate
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return

scottmadden
MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy	04/20	Atmos Energy	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unitil	05/23	Northern Utilities, Inc. d/b/a Unitil	Docket No. 2023-00051	Return on Equity
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	05/23	Washington Gas Light Company	Case No. 9704	Rate of Return
FirstEnergy, Inc.	03/23	Potomac Edison Company	Case No. 9695	Rate of Return
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy, Inc.	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	D.P.U. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy	03/19	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Atmos Energy	07/18	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Confluence Rivers Utility Operating Company, Inc.	01/23	Confluence Rivers Utility Operating Company, Inc.	Case No. WR-2023-0006/SR-2023-0007	Rate of Return
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Middlesex Water Company	05/23	Middlesex Water Company	Docket No. WR23050292	Rate of Return
FirstEnergy	03/23	Jersey Central Power & Light Co.	Docket No. ER23030144	Rate of Return
Atlantic City Electric Company	02/23	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return

scottmadden
MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
Southwestern Public Service Co.	11/22	Southwestern Public Service Co.	Case No. 22-00286-UT	Return on Equity
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	11/22	Aqua Ohio, Inc.	Case No. 22-1094-WW-AIR	Rate of Return
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Columbia Water Company	05/23	Columbia Water Company	Docket No. R-2023-3040258	Rate of Return
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return

scottmadden MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Co.	02/23	Southwestern Public Service Co.	Docket No. 54634	Return on Equity
CSWR – Texas Utility Operating Company, LLC	02/23	CSWR – Texas Utility Operating Company, LLC	Docket No. 54565	Rate of Return
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Texas Railroad Commission				
Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	Docket No. OS-23-00013758	Return on Equity
Virginia State Corporation Commission				
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
Monongahela Power Company and The Potomac Edison Company	05/23	Monongahela Power Company and The Potomac Edison Company	Case No. 23-0460-E-42T	Return on Equity
Monongahela Power Company and The Potomac Edison Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
Monongahela Power Company and The Potomac Edison Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

Resume and Testimony Listing of:

Dylan W. D'Ascendis, CRRA, CVA

Partner

Southwest Gas Corporation
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Southern Nevada Rate Jurisdiction

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	50.00%	4.53%	(1)	2.27%
Common Equity	50.00%	10.00%	(2)	5.00%
Total	100.00%			7.27%

Northern Nevada Rate Jurisdiction

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	50.00%	4.55%	(1)	2.27%
Common Equity	50.00%	10.00%	(2)	5.00%
Total	100.00%			7.27%

Notes:
(1) See page 1 of Statement F for the respective rate jurisdictions.
(2) The 10.00% requested ROE by the Company is discussed in the Direct Testimony of Amy L. Timperley.

Southwest Gas Corporation
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Six Natural Gas Distribution Companies
1.	Discounted Cash Flow Model (DCF) (1)	9.65%
2.	Risk Premium Model (RPM) (2)	10.85%
3.	Capital Asset Pricing Model (CAPM) (3)	11.69%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	12.15%
5.	Indicated Range of Common Equity Cost Rates before Adjustment for Company-Specific Risk	9.65% - 12.15%
6.	Business Risk Adjustment (5)	0.10%
7.	Credit Risk Adjustment (6)	0.23%
8.	Flotation Cost Adjustment (7)	0.10%
9.	Indicated Range of Common Equity Cost Rates after Adjustment	10.08% - 12.58%

Notes:
(1) From page 1 of Exhibit No.___(DWD-4).
(2) From page 1 of Exhibit No.___(DWD-5).
(3) From page 1 of Exhibit No.___(DWD-6).
(4) From page 1 of Exhibit No.___(DWD-8).
(5) Adjustment to reflect the Company's greater business risk relative to the Utility Proxy Group as detailed in Mr. D'Ascendis' direct testimony.
(6) Company-specific risk adjustment to reflect Southwest Gas' greater risk due to a lower long-term issuer rating relative to the proxy group as detailed in Mr. D'Ascendis' direct testimony.
(7) From page 1 of Exhibit No.___(DWD-10).

Southwest Gas Corporation
Range of Capital Structures for the Past Five Quarters for the
Proxy Group of Six Natural Gas Distribution Companies

Common Equity Ratio

Company	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1	FY 2022	5Q average ending Q1 2023
Atmos Energy Corporation	70.04%	59.97%	61.03%	61.24%	60.50%	61.03%	62.56%
New Jersey Resources Corporation	39.95%	36.98%	37.59%	37.55%	40.09%	37.59%	38.43%
NiSource Inc.	31.46%	30.25%	29.62%	31.17%	31.78%	29.62%	30.86%
Northwest Natural Holding Company	43.71%	42.43%	43.12%	47.30%	41.77%	43.12%	43.66%
ONE Gas, Inc.	69.95%	64.66%	56.75%	51.79%	51.57%	56.75%	58.94%
Spire Inc.	36.39%	34.73%	36.07%	38.12%	38.66%	36.07%	36.80%
					Minimum	29.62%	30.86%
					Maximum	61.03%	62.56%

Total Debt Ratio

Company	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1	FY 2022	5Q average ending Q1 2023
Atmos Energy Corporation	29.96%	40.03%	38.97%	38.76%	39.50%	38.97%	37.44%
New Jersey Resources Corporation	60.05%	63.02%	62.41%	62.45%	59.91%	62.41%	61.57%
NiSource Inc.	60.60%	60.58%	60.76%	58.77%	57.92%	60.76%	59.72%
Northwest Natural Holding Company	56.29%	57.57%	56.88%	52.70%	58.23%	56.88%	56.34%
ONE Gas, Inc.	30.05%	35.34%	43.25%	48.21%	48.43%	43.25%	41.06%
Spire Inc.	60.40%	62.06%	60.54%	58.33%	57.74%	60.54%	59.81%
					Minimum	38.97%	37.44%
					Maximum	62.41%	61.57%

Source: S&P Global Market Intelligence; S&P Capital IQ; Company Filings

Southwest Gas Corporation
Range of Capital Structures for the Past Five Quarters for the
Proxy Group of Six Natural Gas Distribution Companies at the Operating Company Level

Common Equity Ratio

Company	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1	FY 2022	5Q average ending Q1 2023
Atmos Energy Corporation	60.89%	52.91%	60.66%	61.24%	60.50%	60.66%	59.24%
New Jersey Natural Gas Company	54.56%	51.00%	53.10%	54.09%	55.98%	53.10%	53.75%
NiSource Inc.	31.46%	30.25%	29.62%	31.17%	31.78%	29.62%	30.86%
Northwest Natural Gas Company	43.71%	42.43%	43.12%	47.30%	41.77%	43.12%	43.66%
ONE Gas, Inc.	46.76%	43.98%	49.31%	52.34%	52.12%	49.31%	48.90%
Spire Alabama Inc.	51.18%	49.45%	51.26%	54.00%	55.39%	51.26%	52.26%
Spire Missouri Inc.	44.90%	43.79%	45.43%	47.76%	47.59%	45.43%	45.89%
					Minimum	29.62%	30.86%
					Maximum	60.66%	59.24%

Total Debt Ratio

Company	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1 0	FY 2022 0	5Q average ending Q1 2023
Atmos Energy Corporation	39.11%	47.09%	39.34%	38.76%	39.50%	39.34%	40.76%
New Jersey Natural Gas Company	45.44%	49.00%	46.90%	45.91%	44.02%	46.90%	46.25%
NiSource Inc.	60.60%	60.58%	60.76%	58.77%	57.92%	60.76%	59.72%
Northwest Natural Gas Company	56.29%	57.57%	56.88%	52.70%	58.23%	56.88%	56.34%
ONE Gas, Inc.	53.24%	56.02%	50.69%	47.66%	47.88%	50.69%	51.10%
Spire Alabama Inc.	48.82%	50.55%	48.74%	46.00%	44.61%	48.74%	47.74%
Spire Missouri Inc.	55.10%	56.21%	54.57%	52.24%	52.41%	54.57%	54.11%
					Minimum	39.34%	40.76%
					Maximum	60.76%	59.72%

Source: S&P Global Market Intelligence; S&P Capital IQ; Company Filings

SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
VARIABLE INTEREST EXPENSE RECOVERY MECHANISM
WEIGHTED AVERAGE VARIABLE INTEREST RATE ("AVIR") CALCULATION

Line No.	Description (a)	Amount (b)	Line No.
	AVIR(new) - Certification Period Ended November 30, 2023		
1	Average Net Proceeds Variable Interest IDRBs[1]	$ 145,688,767	1
2	Requested Rate Base[2]	$ 1,751,758,348	2
3	Percent Variable Interest IDRBs	8.3167%	3
4	Average Effective Cost Variable Interest IDRBs[3]	4.6400%	4
5	Average Variable Interest Rate(new)	0.3859%	5

AVIR = Net Proceeds Variable Rate IDRB Debt / Rate Base X Effective Cost Variable Rate IDRB Debt
[1] From page 2 of this Exhibit, Ln 14, Col (d)
[2] Rate Base for Southern Nevada at end of certification period, November 30, 2023.
[3] From page 2 of this Exhibit, Ln 14, Col (e)

Annual Authorized	6,764,919.00
Monthly Authorized	563,743.25

SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
VARIABLE INTEREST EXPENSE RECOVERY MECHANISM
WEIGHTED AVERAGE VARIABLE INTEREST RATE
CERTIFICATION PERIOD ENDED NOVEMBER 30, 2023

Line No.	Year (a)	Month (b)	Monthly Interest[1] (c)	Net Proceeds[2] (d)	Effective Rate[3] (e)	Rate Base (f)	AVIR[4] (g)	Line No.
1	2022	December	$ 535,203	$ 145,485,388	4.41%	$ 1,751,758,348	0.3666%	1
2	2023	January	464,377	$ 145,525,635	3.83%	$ 1,751,758,348	0.3181%	2
3	2023	February	522,213	$ 145,565,883	4.30%	$ 1,751,758,348	0.3577%	3
4	2023	March	546,459	$ 145,606,131	4.50%	$ 1,751,758,348	0.3743%	4
5	2023	April	522,592	$ 145,646,379	4.31%	$ 1,751,758,348	0.3580%	5
6	2023	May	578,938	$ 145,686,627	4.77%	$ 1,751,758,348	0.3966%	6
7	2023	June	588,523	$ 145,683,715	4.85%	$ 1,751,758,348	0.4032%	7
8	2023	July	567,866	$ 145,726,840	4.68%	$ 1,751,758,348	0.3890%	8
9	2023	August	603,050	$ 145,769,965	4.96%	$ 1,751,758,348	0.4131%	9
10	2023	September	584,988	$ 145,813,090	4.81%	$ 1,751,758,348	0.4007%	10
11	2023	October	634,899	$ 145,856,215	5.22%	$ 1,751,758,348	0.4349%	11
12	2023	November	615,810	$ 145,899,341	5.06%	$ 1,751,758,348	0.4218%	12
13	12-Month Total		$ 6,764,919			$ 1,751,758,348	0.3859%	13
14	12-Month Average			$ 145,688,767	4.64%			14

[1] Certification Workpaper No. 1, Sheet 5 of 10, Col (o)
[2] Certification Workpaper No. 1, Sheet 7 of 10, Col (l)
[3] Effective Rate = (Column (c) X 12) / Column (d) = (Monthly Interest X 12) / Net Proceeds.
[4] AVIR = Column (e) X Column (d) / Column (f)

Southwest Gas Corporation
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Six Natural Gas Distribution Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.54 %	7.00 %	7.50 %	7.80 %	7.43 %	2.63 %	10.06 %
New Jersey Resources Corporation	3.18	5.00	6.00	6.00	5.67	3.27	8.94
NiSource Inc.	3.62	9.50	7.00	6.70	7.73	3.76	11.49
Northwest Natural Holding Company	4.38	6.50	3.70	2.80	4.33	4.47	8.80
ONE Gas, Inc.	3.28	6.50	5.00	5.00	5.50	3.37	8.87
Spire Inc.	4.36	8.00	4.20	NA	6.10	4.49	10.59
						Average	9.79 %
						Median	9.50 %
						Average of Mean and Median	9.65 %

Notes:

(1) Indicated dividend at 07/14/2023 divided by the average closing price of the last 60 trading days ending 07/14/2023 for each company.
(2) From pages 2 through 7 of this Exhibit.
(3) Average of columns 2 through 4.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 5) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.54% x (1+(1/2 x 7.43%)) = 2.63%.
(5) Column 5 + column 6.

Source of Information:

Value Line Investment Survey
www.zacks.com Downloaded on 07/14/2023
www.yahoo.com Downloaded on 07/14/2023

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE **117.59** | P/E RATIO **18.9** (Trailing: 20.2; Median: 20.0) | RELATIVE P/E RATIO **1.15** | DIV'D YLD **2.7%** | VALUE LINE

TIMELINESS	3 Lowered 2/10/23
SAFETY	1 Raised 6/6/14
TECHNICAL	2 Raised 5/26/23
BETA	.85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$96-$159	$128 (10%)

2026-28 PROJECTIONS

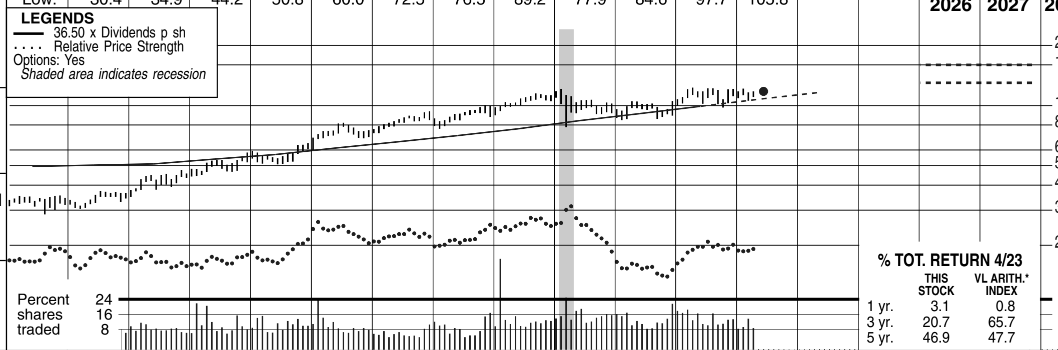
	Price	Gain	Ann'l Total Return
High	160	(+35%)	10%
Low	130	(+10%)	5%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	333	331	345
to Sell	231	251	266
Hld's(000)	126964	128317	132007

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	37.3	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0	121.4
Low:	30.4	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	97.7	105.8

LEGENDS
—— 36.50 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2026 | 2027 | 2028

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.1	0.8
3 yr.	20.7	65.7
5 yr.	46.9	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	*32.65*	*36.85*	Revenues per sh A	*50.00*
4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	*10.00*	*10.60*	"Cash Flow" per sh	*12.60*
1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	*6.00*	*6.40*	Earnings per sh AB	*7.85*
1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	*2.96*	*3.20*	Div'ds Decl'd per sh C■	*3.90*
4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	*18.35*	*18.55*	Cap'l Spending per sh	*18.30*
22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	*70.20*	*73.05*	Book Value per sh	*79.40*
89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	*147.00*	*152.00*	Common Shs Outst'g D	*170.00*
15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
.84	.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	*Value Line*		Relative P/E Ratio	*1.05*
4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*2.7%*

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
3886.3	4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	*4800*	*5600*	Revenues ($mill) A	*8500*
230.7	289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	*875*	*965*	Net Profit ($mill)	*1325*
38.2%	39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	*11.5%*	*13.0%*	Income Tax Rate	*25.0%*
5.9%	5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	*18.2%*	*17.2%*	Net Profit Margin	*15.6%*
48.8%	44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
51.2%	55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
5036.1	5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	*17200*	*18500*	Total Capital ($mill)	*22500*
6030.7	6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	*19300*	*20400*	Net Plant ($mill)	*25000*
5.9%	6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	*8.5%*	*8.5%*	Return on Shr. Equity	*10.0%*
8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	*8.5%*	*8.5%*	Return on Com Equity	*10.0%*
4.0%	4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
56%	50%	51%	50%	50%	48%	48%	49%	49%	49%	*50%*	*50%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 3/31/23
Total Debt $6554.6 mill. **Due in 5 Yrs** $2900.0 mill.
LT Debt $6553.1 mill. **LT Interest** $105.0 mill.
(LT interest earned: 9.3x; total interest coverage: 9.3x)
Leases, Uncapitalized Annual rentals $43.1 mill.

Pfd Stock None

Pension Assets-9/22 $479.0 mill.
Oblig. $449.5 mill.
Common Stock 144,487,306 shs.
as of 4/28/23

MARKET CAP: $17.0 billion (Large Cap)

CURRENT POSITION ($MILL.)	2021	2022	3/31/23
Cash Assets	116.7	51.6	95.2
Other	2722.0	2996.1	977.9
Current Assets	2838.7	3047.7	1073.1
Accts Payable	423.2	496.0	365.0
Debt Due	2400.5	2386.4	1.5
Other	686.7	720.2	746.5
Current Liab.	3510.4	3602.6	1113.0
Fix. Chg. Cov.	1457%	1238%	1245%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-5.5%	-4.5%	*11.5%*
"Cash Flow"	6.5%	7.0%	*6.5%*
Earnings	9.0%	9.0%	*7.0%*
Dividends	6.5%	8.5%	*7.5%*
Book Value	9.0%	12.0%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	875.6	977.6	493.0	474.9	2821.1
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	*930*	*845*	*4800*
2024	*1675*	*1860*	*1065*	*1000*	*5600*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	1.47	1.95	.79	.53	4.72
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	*1.03*	*.58*	*6.00*
2024	*2.12*	*2.53*	*1.11*	*.64*	*6.40*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.525	.525	.525	.575	2.15
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2022: 63.7%, residential; 28.8%, commercial; 5.8%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/22 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Earnings for Atmos Energy showed some improvement through the first half of fiscal 2023 (ended March 31st). Share net of $4.39 was nearly 4% higher than last year's $4.23 tally. This was brought about partly by the distribution unit, helped largely by higher rates, especially in the Mid-Tex division. Furthermore, the performance of the pipeline and storage business benefited nicely from a rise in revenue from a Gas Reliability Infrastructure Program filing approved in fiscal 2022. Operating expenses did increase significantly during the period, but that's to be expected as the company expands. So, it seems that full-year profits will advance around 7%, to $6.00 a share, versus fiscal 2022's $5.60 total. Concerning next year, share net may grow at a similar percentage rate, to $6.40, assuming that operating margins widen further.

Corporate finances are in strong condition. When the second quarter concluded, cash and equivalents resided at $95.2 million. Moreover, long-term debt was quite manageable (almost 40% of total capital) and short-term borrowings were just $1.5 million. Too, $4 billion in common stock and/or debt securities remained available for issuance (out of $5 billion) under a shelf registration statement expiring in March, 2026. Lastly, Atmos can access four revolving credit facilities aggregating $2.5 billion plus a $1.5 billion commercial paper program. All told, there's sufficient liquidity to satisfy various obligations for quite a while.

We believe good things are in store for the company over the 2026-2028 span. It ranks as one of the nation's biggest natural gas-only distributors, with more than three million customers across several states, including Texas, Louisiana, and Mississippi. Also, the pipeline and storage segment appears to have promising overall expansion opportunities, given that it operates in one of the most-active drilling regions in the world. The sound balance sheet is another plus.

The high-quality stock holds unspectacular long-term total return potential. Capital gains possibilities are unenticing. Also, the dividend yield is below the average of *Value Line's* Natural Gas Utility Industry group.

Frederick L. Harris, III *May 26, 2023*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early Aug. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	100

NEW JERSEY RES. NYSE-NJR

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
49.72	19.4 (Trailing: 18.0 Median: 17.0)	1.18	3.2%

VALUE LINE

TIMELINESS **2** Raised 5/12/23
SAFETY **2** Lowered 4/17/20
TECHNICAL **1** Raised 5/26/23
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$33-$62	$48 (-5%)

2026-28 PROJECTIONS

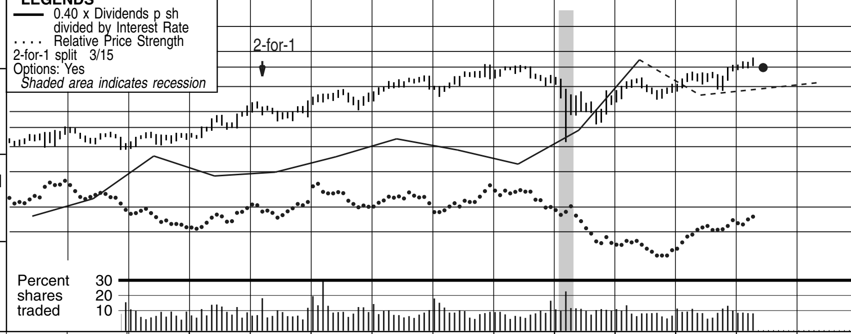
	Price	Gain	Ann'l Total Return
High	65	(+30%)	10%
Low	45	(-10%)	1%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	126	139	166
to Sell	133	112	115
Hld's(000)	71193	72178	73958

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	25.1	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	51.4	55.8
Low:	19.3	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8	48.3

LEGENDS
—— 0.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/15
Options: Yes
Shaded area indicates recession



Target Price Range
2026 | 2027 | 2028

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.6	0.8
3 yr.	70.2	65.7
5 yr.	47.1	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.38	**26.80**	**29.10**	Revenues per sh A	**32.50**
1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.86	**4.20**	**4.35**	"Cash Flow" per sh	**4.25**
.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	**2.70**	**2.80**	Earnings per sh B	**3.25**
.51	.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	**1.56**	**1.68**	Div'ds Decl'd per sh C■	**1.95**
.73	.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	6.50	**6.20**	**6.65**	Cap'l Spending per sh	**7.50**
7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	19.00	**22.15**	**24.70**	Book Value per sh D	**27.90**
83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	95.64	**97.00**	**98.00**	Common Shs Outst'g E	**100.00**
21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	*Bold figures are*		Avg Ann'l P/E Ratio	**17.0**
1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	.98	*Value Line*		Relative P/E Ratio	**.95**
3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	*estimates*		Avg Ann'l Div'd Yield	**4.0%**
						3198.1	3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	**2600**	**2850**	Revenues ($mill) A	**3250**
						113.7	176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	**260**	**275**	Net Profit ($mill)	**325**
						25.4%	30.2%	26.3%	15.5%	17.2%	- -	- -	NMF	10.3%	21.4%	**22.0%**	**22.0%**	Income Tax Rate	**22.0%**
						3.6%	4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	**10.0%**	**9.6%**	Net Profit Margin	**10.0%**
						36.6%	38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	**57.0%**	**56.0%**	Long-Term Debt Ratio	**55.0%**
						63.4%	61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	**43.0%**	**44.0%**	Common Equity Ratio	**45.0%**
						1400.3	1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	**5000**	**5500**	Total Capital ($mill)	**6200**
						1643.1	1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	**5000**	**5200**	Net Plant ($mill)	**5500**
						9.0%	12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	5.6%	**5.0%**	**5.0%**	Return on Total Cap'l	**5.0%**
						12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	**12.0%**	**11.5%**	Return on Shr. Equity	**11.5%**
						12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	**12.0%**	**11.5%**	Return on Com Equity	**11.5%**
						5.2%	11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	**5.0%**	**4.5%**	Retained to Com Eq	**4.5%**
						59%	40%	50%	60%	59%	40%	59%	60%	56%	53%	**58%**	**60%**	All Div'ds to Net Prof	**60%**

CAPITAL STRUCTURE as of 3/31/23
Total Debt $2982.0 mill. **Due in 5 Yrs** $1049 mill.
LT Debt $2642.2 mill. **LT Interest** $85 mill.
Incl. $7.0 mill. capitalized leases.
(LT interest earned: 5.0x; total interest coverage: 5.0x)
Pension Assets-9/22 $484.1 mill. **Oblig.** $464.0 mill.
Pfd Stock None

Common Stock 96,964,456 shs.
as of 5/1/23
MARKET CAP: $4.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	3/31/23
Cash Assets	4.7	1.1	27.1
Other	629.6	755.0	588.9
Current Assets	634.3	756.1	616.0
Accts Payable	429.6	156.6	121.8
Debt Due	450.1	499.1	339.8
Other	171.7	448.5	249.9
Current Liab.	1051.4	1104.2	711.5
Fix. Chg. Cov.	545%	545%	650%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-3.0%	-6.0%	*2.5%*
"Cash Flow"	7.0%	4.5%	*5.0%*
Earnings	5.0%	2.5%	*5.0%*
Dividends	6.5%	6.5%	*5.0%*
Book Value	7.5%	7.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	615.0	639.6	299.0	400.1	1953.7
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	552.3	765.5	2906.0
2023	723.6	644.0	***550***	***682.4***	***2600***
2024	***725***	***875***	***550***	***700***	***2850***

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	.44	1.12	d.06	.57	2.07
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	d.04	.50	2.50
2023	1.14	1.16	***d.05***	***.45***	***2.70***
2024	***1.00***	***1.25***	***.05***	***.50***	***2.80***

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.2925	.2925	.2925	.3125	1.19
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 569,300 cust. at 9/30/22. Fiscal 2022 volume: 144 bill. cu. ft. (23% interruptible, 47% residential, commercial & firm transportation, 30% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2021 dep. rate: 2.7%. Has 1,288 empls. Off./dir. own less than 1% of common; BlackRock, 14.0%; Vanguard, 11.0% (12/22 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources reported slight weakness in its fiscal second quarter. Historically warm weather conditions in the company's operating region during the March period, along with a significant reduction in the price of natural gas, resulted in a sharp decline in revenues. Despite the top line falling 40% below our estimate for the quarter, the company's net financial earnings per share (NFEPS) held its ground reasonably well. The quarter's profits per share of $1.16 ended just four cents lower than our estimate, signaling a strong showing in terms of margin resiliency, thanks in large part to the cost pass-through mechanism of the regulated utilities business. However, March-period earnings have declined for the second consecutive year running. In the quarter, each operating segment declined from the year-ago period, but on a fiscal year-to-date basis, the comparable profit figure is much more positive, showing double-digit growth, owing to a strong December period result.

We look for the company's earnings growth to slow in the years ahead. After a very strong first quarter, the rest of fiscal 2023 should be in for challenging comparisons. We expect NFEPS to fall below the prior-year levels in each of the remaining two quarters. Still, full-year earnings should manage to eke out an improvement of about 8% to reach $2.70, driven by strong customer growth trends and a diversified operating segmentation strategy that differentiates NJR from other highly-regulated pure-play utilities. In turn, we have left our fiscal 2024 earnings call unchanged at $2.80.

Long-term earnings growth potential is a bit uncertain at this juncture. We expect the growth of the Clean Energy Ventures (CEV) segment to be a harbinger of the company's future earnings potential. New Jersey Resources has the opportunity through exclusive rights agreements to triple its clean energy portfolio. However, this notion is being challenged in Washington where debt-limit negotiations put at risk the clean energy incentives introduced in the Inflation Reduction Act.

To wit, long-term total capital appreciation potential appears limited, regardless of CEV's political risk.

Earl B. Humes *May 26, 2023*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early August.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2022: $500 million, $5.23/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	55
Earnings Predictability	60

NISOURCE INC. NYSE-NI

RECENT PRICE **28.04** | P/E RATIO **18.1** (Trailing: 18.8 / Median: 21.0) | RELATIVE P/E RATIO **1.10** | DIV'D YLD **3.6%** | VALUE LINE

TIMELINESS 3 Raised 4/14/23
SAFETY 3 Lowered 3/19/21
TECHNICAL 3 Raised 5/19/23
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$23-$40	$32 (10%)

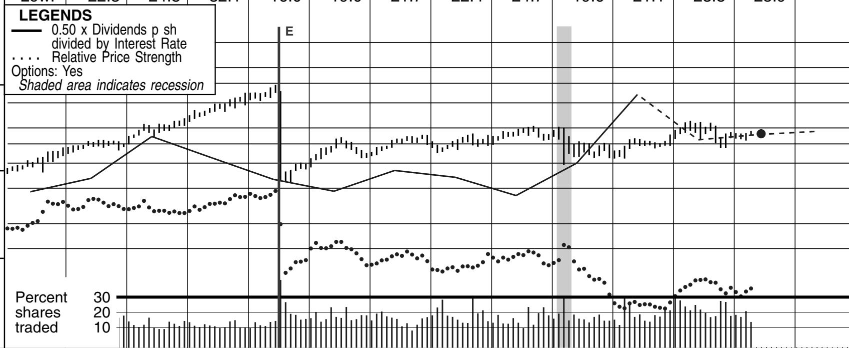
2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+60%)	*15%*
Low	30	(+5%)	*5%*

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	270	255	315
to Sell	208	226	214
Hld's(000)	389752	379081	387502

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	26.2	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6	29.0
Low:	22.3	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	23.8	25.9



Target Price Range
2026 | 2027 | 2028
80 60 50 40 30 25 20 15 10 7.5

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.2	0.8
3 yr.	25.8	65.7
5 yr.	36.4	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
28.96	32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.23	***14.00***	***14.10***	**Revenues per sh**	***15.75***
3.20	3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.47	***3.55***	***3.80***	**"Cash Flow" per sh**	***4.15***
1.14	1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	***1.55***	***1.70***	**Earnings per sh A**	***2.00***
.92	.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	***1.00***	***1.04***	**Div'ds Decl'd per sh B ■**	***1.12***
2.88	3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	6.32	***8.20***	***6.45***	**Cap'l Spending per sh**	***6.75***
18.52	17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	13.14	***14.10***	***17.00***	**Book Value per sh C**	***18.00***
274.18	274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	411.10	***420.00***	***425.00***	**Common Shs Outst'g D**	***445.00***
18.8	12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	64.4	19.3	21.3	18.7	18.0	19.6	***Bold figures are***		**Avg Ann'l P/E Ratio**	***19.0***
1.00	.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	3.24	1.04	1.13	.96	.99	11.8	***Value Line***		**Relative P/E Ratio**	***1.05***
4.3%	5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	***estimates***		**Avg Ann'l Div'd Yield**	***2.5%***
						5657.3	6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	***5875***	***6000***	**Revenues ($mill)**	***7000***
						490.9	530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	***650***	***725***	**Net Profit ($mill)**	***890***
						34.8%	36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	17.2%	***19.0%***	***19.0%***	**Income Tax Rate**	***19.0%***
						- -	- -	- -	- -	- -	- -	- -	- -	2.0%	2.3%	***2.5%***	***2.5%***	**AFUDC % to Net Profit**	***2.5%***
						56.3%	56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	***55.5%***	***55.0%***	**Long-Term Debt Ratio**	***55.0%***
						43.7%	43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	31.6%	***32.5%***	***37.5%***	**Common Equity Ratio**	***40.0%***
						13480	14331	9792.0	10129	11832	12856	13843	14972	16131	17099	***18250***	***19000***	**Total Capital ($mill)**	***20000***
						14365	16017	12112	13068	14360	15543	16912	16620	17882	19843	***22500***	***25000***	**Net Plant ($mill)**	***27500***
						5.2%	5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	***3.5%***	***4.0%***	**Return on Total Cap'l**	***4.5%***
						8.3%	8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	***8.5%***	***8.5%***	**Return on Shr. Equity**	***9.5%***
						8.3%	8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	12.0%	***11.0%***	***10.0%***	**Return on Com Equity**	***11.0%***
						3.1%	3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.0%	***4.0%***	***4.0%***	**Retained to Com Eq**	***5.0%***
						62%	61%	NMF	63%	NMF	60%	64%	67%	64%	64%	***65%***	***61%***	**All Div'ds to Net Prof**	***56%***

CAPITAL STRUCTURE as of 3/31/23
Total Debt $11576.6 mill. **Due in 5 Yrs** $2355 mill.
LT Debt $10264.7 mill. **LT Interest** $368 mill.
(Interest cov. earned: 5.8x) (57% of Cap'l)

Leases, Uncapitalized Annual rentals $8.0 mill.
Pension Assets-12/22 $1.4 bill. **Oblig.** $1.4 bill.

Pfd Stock $1547 mill. **Pfd Div'd** $55.1 mill.

Common Stock 413,063,219 shs.
as of 4/25/23
MARKET CAP: $11.6 billion (Large Cap)

CURRENT POSITION ($MILL.)	**2021**	**2022**	**3/31/23**
Cash Assets	85.2	40.8	106.4
Other	1835.6	2543.5	2230.1
Current Assets	1920.8	2584.3	2336.5
Accts Payable	697.8	899.5	642.2
Debt Due	618.1	1791.9	1311.9
Other	1430.3	1969.1	1952.8
Current Liab.	2746.2	4660.5	3906.9
Fix. Chg. Cov.	250%	255%	260%

ANNUAL RATES of change (per sh)	**Past 10 Yrs.**	**Past 5 Yrs.**	**Est'd '19-'21 to '26-'28**
Revenues	-5.0%	-3.5%	*5.5%*
"Cash Flow"	0.5%	6.5%	*5.5%*
Earnings	1.5%	15.0%	*9.5%*
Dividends	-0.5%	3.5%	*4.5%*
Book Value	-3.0%	0.5%	*5.0%*

Cal-endar	**QUARTERLY REVENUES ($ mill.) Mar.31**	**Jun.30**	**Sep.30**	**Dec.31**	**Full Year**
2020	1605.5	962.7	902.5	1211.0	4681.7
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	1183.2	1089.5	1704.6	5850.6
2023	1966.0	***1170***	***1120***	***1619***	***5875***
2024	***2100***	***1200***	***1150***	***1550***	***6000***

Cal-endar	**EARNINGS PER SHARE A Mar.31**	**Jun.30**	**Sep.30**	**Dec.31**	**Full Year**
2020	.76	.13	.09	.34	1.32
2021	.77	.13	.11	.39	1.37
2022	.75	.12	.10	.50	1.47
2023	.77	***.15***	***.12***	***.51***	***1.55***
2024	***.82***	***.18***	***.15***	***.55***	***1.70***

Cal-endar	**QUARTERLY DIVIDENDS PAID B ■ Mar.31**	**Jun.30**	**Sep.30**	**Dec.31**	**Full Year**
2019	.200	.200	.200	.200	.80
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25			

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 479,185 electric in Indiana, 3,200,000 gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2022: electrical, 31%; gas, 69%; other, less than 1%. Generating sources, coal, 69.4%; purchased & other, 30.6%. 2022 reported depreciation rates: 3.1% electric, 2.3% gas. Has 7,304 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource stock gained in the three months since our February review. The shares are up a modest 3.3%, compared to a slight decline in the S&P 500 Utility Sector index. In that time, the company reported its financial results for both 2022 full year and fourth quarter, and it's 2023 first quarter. In the fourth quarter revenues exceeded our forecast by a significant margin, and the full-year top-line result landed $951 million above the year prior. Earnings per share, however, stayed on target, and in strong form advanced just over 7% in 2022. In the first quarter, our top-line target was reached, while earnings per share of $0.77 fell a bit below our expectation, but still increased 2.7% from the year prior.

Our full-year 2023 and 2024 outlook provides for decent earnings growth. We look for an 8% - 10% rate base average annual growth rate over the next five years to drive performance on the bottom line. Earnings growth should be at a slightly lower level at about 5.5% in 2023, following the earnings miss in the first quarter and a likely economic slowdown ahead due to broad inflation and increased interest rates. Following that, 2024 earnings will likely return to a high growth rate of nearly 10% on anticipated rate-base increases. Over the three- to five-year horizon, returns on planned clean energy projects and investments in sustainable infrastructure, along with continued regulatory support, should allow for expected annual earnings growth of around 8.5% thereafter.

The equity's upside is not without risk. Chief among them, climate change has the potential to cause significant disruption to the company's operations. While there is a potential advantage in volatile temperatures leading to increased energy demand, the risk to established equipment and plant assets is also heightened here. Intensified flooding, windstorms and heatwaves all pose threats to NiSource's infrastructure investments.

These shares do not stand out to us at this juncture. Taking into account the equity's risk premium, with the context of heightened yields on bonds, conservative accounts can likely find a better long-term investment opportunity elsewhere.

Earl B. Humes *May 26, 2023*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '07, 3¢; '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due early August. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '22: $1485.9 million, $3.61/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	55

N.W. NATURAL NYSE-NWN

RECENT PRICE 45.00 | P/E RATIO 16.7 (Trailing: 15.7 Median: 24.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 3 Lowered 1/13/23
SAFETY 3 Lowered 3/19/21
TECHNICAL 2 Raised 5/26/23
BETA .80 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	50.8	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6	52.4
Low:	41.0	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	42.4	44.7

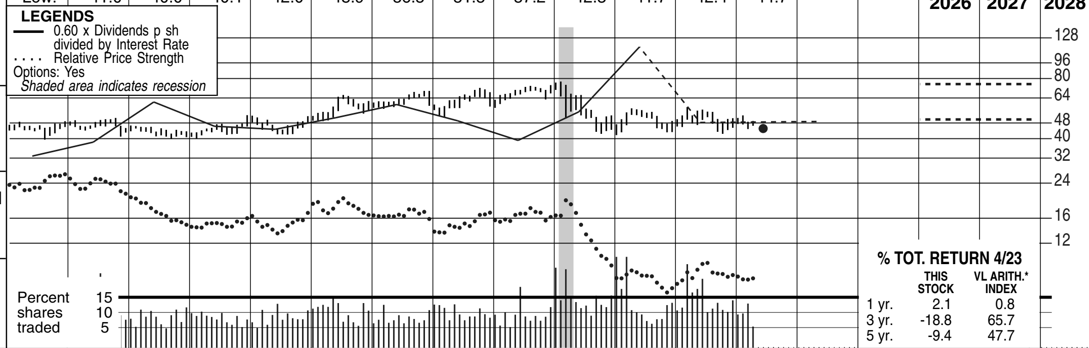
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$39-$65 $52 (15%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+65%)	17%
Low	50	(+10%)	7%

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	139	115	124
to Sell	107	99	90
Hld's(000)	26050	26471	27135



% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.1	0.8
3 yr.	-18.8	65.7
5 yr.	-9.4	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	28.90	29.35	Revenues per sh	31.25
5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	6.15	6.40	"Cash Flow" per sh	6.25
2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	2.70	2.80	Earnings per sh A	3.15
1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.95	1.97	Div'ds Decl'd per sh B■	2.00
4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	9.05	7.75	Cap'l Spending per sh	7.50
22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.08	34.95	34.65	Book Value per sh D	34.40
26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	36.50	37.50	Common Shs Outst'g C	40.00
16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	20.0
.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.06	1.13			Relative P/E Ratio	1.10
3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%			Avg Ann'l Div'd Yield	2.6%

CAPITAL STRUCTURE as of 3/31/23
Total Debt $1608 mill. **Due in 5 Yrs** $713 mill.
LT Debt $1294.6 mill. **LT Interest** $50 mill.

(Total interest coverage: 3.4x)

Pension Assets-12/22 $300.0 mill.
Oblig. $413.4 mill.

Pfd Stock None

Common Stock 35,965,613 shares
as of 4/27/23

MARKET CAP $1.6 billion (Small Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
758.5	754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	1055	1100	Revenues ($mill)	1250
60.5	58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	100	105	Net Profit ($mill)	125
40.8%	41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	25.0%	25.0%	Income Tax Rate	25.0%
8.0%	7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	9.5%	9.5%	Net Profit Margin	10.0%
47.6%	44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	50.0%	50.0%	Long-Term Debt Ratio	50.0%
52.4%	55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	50.0%	50.0%	Common Equity Ratio	50.0%
1433.6	1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	2550	2600	Total Capital ($mill)	2750
2062.9	2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	3250	3400	Net Plant ($mill)	3750
5.8%	5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	3.6%	4.0%	4.0%	Return on Total Cap'l	4.5%
8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	8.0%	8.0%	Return on Shr. Equity	9.0%
8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	8.0%	8.0%	Return on Com Equity	9.0%
1.5%	1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.1%	2.5%	3.0%	Retained to Com Eq	3.5%
81%	85%	92%	87%	NMF	76%	82%	79%	71%	79%	71%	70%	All Div'ds to Net Prof	64%

CURRENT POSITION ($MILL.)	2021	2022	3/31/23
Cash Assets	18.6	29.3	140.8
Other	418.7	714.9	435.4
Current Assets	437.3	744.2	576.2
Accts Payable	133.5	180.7	111.2
Debt Due	389.8	348.9	313.2
Other	201.5	369.1	219.7
Current Liab.	724.8	898.7	644.1
Fix. Chg. Cov.	335%	320%	325%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-2.5%	- -	4.5%
"Cash Flow"	1.0%	2.5%	5.0%
Earnings	-1.0%	2.5%	6.5%
Dividends	1.5%	0.5%	.5%
Book Value	1.0%	0.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	285.2	135.0	93.3	260.2	773.7
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	222.6	125	245	1055
2024	445	225	130	300	1100

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.58	d.17	d.61	1.50	2.30
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.09	d.65	1.25	2.70
2024	2.10	.15	d.70	1.25	2.80

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.475	.475	.475	.4775	1.90
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485			

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 795,000 customers, in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 37%; commercial, 22%; industrial, gas transportation, 41%. Employs 1,258. BlackRock Inc. owns 17.3% of shares; Vanguard, 12.2%; Off./Dir., .95% (4/23 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural's stock price dropped 8% since our February review, despite strong recent operating performance. The company beat our expectations in both quarters that were reported on in the three months since our last review. Northwest posted fourth-quarter revenues 26% above our estimate and roughly 28% above the year prior period, while share-earnings of $1.36 were 4% above both our target and the year prior. This capped off a year that saw solid top-line growth but tighter profit margins, thanks to the heightened price of natural gas. While net profit grew nearly 10%, share-earnings declined due to dilution.

The utility started 2023 in great form. The top line once again beat our expectation, advancing more than 32% year-over-year, which translated to a 28% increase in net income. At $71.7 million, Northwest generated more profit in one quarter than it had in most full years prior to 2020. Recent regulatory approval of higher base-rates in Oregon and Washington are largely responsible, although weather in the March period (5% colder than average) certainly helped comparisons to the year prior (8% warmer).

The natural gas utility's earnings growth should be steady. Main drivers here include population growth, consolidation through acquisition, and investments in sustainability, all three of which have been very active at Northwest this year. We look for earnings per share to increase by 6% and 4% in each of the next two years, respectively, and by 5.5% on average over the next three to five years.

The extra cash will help diversification efforts for sustainable growth. Northwest aims to expand in its renewables, water, gas storage, and now operations & maintenance businesses. These ventures could help to smooth out the earnings cycle, specifically with September period losses, while expanding the scope of its primary gas utility. A recent string of acquisitions has bolstered growth in the water management business, a segment that interests us for its long-term strategic value potential.

The shares are starting to look attractive as an income generating holding, at the recent quotation.

Earl B. Humes *May 26, 2023*

(A) Diluted earnings per share. Excludes non-recurring items: '06, ($0.06); '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early August.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2021: $149 million, $4.20/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	35
Earnings Predictability	10

ONE GAS, INC. NYSE-OGS

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
80.57	19.2	(Trailing: 19.7 Median: NMF)	1.16	3.3%	VALUE LINE

TIMELINESS 3 Raised 5/13/22
SAFETY 2 New 6/2/17
TECHNICAL 2 Raised 5/26/23
BETA .80 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$61-$110 $86 (5%)

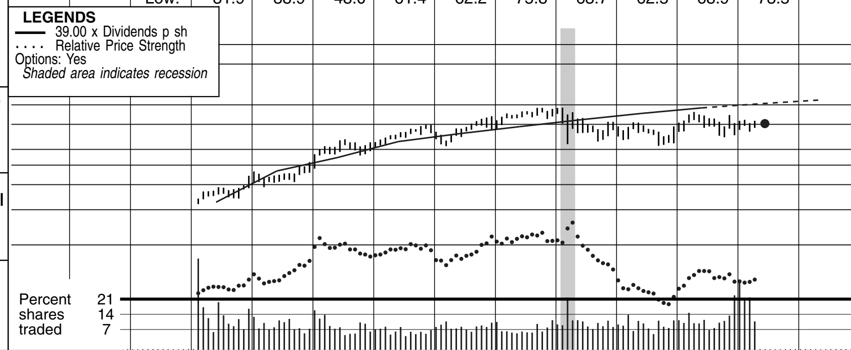
2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+80%)	*18%*
Low	105	(+30%)	*10%*

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	171	136	176
to Sell	112	143	132
Hld's(000)	45263	45390	48298

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3	84.3
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	68.9	73.5



Target Price Range
2026 | 2027 | 2028

% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.0	0.8
3 yr.	5.8	65.7
5 yr.	26.0	47.7

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
- -	34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	*48.45*	*51.35*	Revenues per sh	*70.15*
- -	4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	*9.35*	*9.95*	"Cash Flow" per sh	*12.20*
- -	2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	*4.20*	*4.40*	Earnings per sh A	*5.60*
- -	.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	*2.60*	*2.72*	Div'ds Decl'd per sh B■	*3.15*
- -	5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	*11.25*	*11.55*	Cap'l Spending per sh	*12.30*
- -	34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	*52.70*	*50.90*	Book Value per sh	*64.45*
- -	52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	*55.50*	*55.50*	Common Shs Outst'g C	*57.00*
- -	17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	*Bold figures are*		Avg Ann'l P/E Ratio	*22.5*
- -	.94	1.00	1.19	1.18	1.25	1.35	1.11	1.03	1.16	*Value Line*		Relative P/E Ratio	*1.25*
- -	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*2.5%*
- -	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	*2690*	*2850*	Revenues ($mill)	*4000*
- -	109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	*235*	*245*	Net Profit ($mill)	*320*
- -	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	*16.5%*	*17.0%*	Income Tax Rate	*22.0%*
- -	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	*8.7%*	*8.6%*	Net Profit Margin	*8.0%*
- -	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	*45.0%*	*49.0%*	Long-Term Debt Ratio	*51.0%*
- -	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	39.0%	49.3%	*55.0%*	*51.0%*	Common Equity Ratio	*49.0%*
- -	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	*5320*	*5540*	Total Capital ($mill)	*7500*
- -	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	*6000*	*6375*	Net Plant ($mill)	*7400*
- -	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
- -	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	*8.0%*	*8.5%*	Return on Shr. Equity	*8.5%*
- -	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	*8.0%*	*8.5%*	Return on Com Equity	*8.5%*
- -	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	*3.0%*	*3.5%*	Retained to Com Eq	*4.0%*
- -	40%	53%	52%	55%	56%	56%	58%	60%	60%	*61%*	*62%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 3/31/23
Total Debt $2962.8 mill. **Due in 5 Yrs** $1250.0 mill.
LT Debt $1875.6 mill. **LT Interest** $115.0 mill.
(LT interest earned: 4.5x; total interest coverage: 4.5x)
Leases, Uncapitalized Annual rentals $6.5 mill.
Pfd Stock None
Pension Assets-12/22 $950.8 mill. **Oblig.** $953.0 mill.
Common Stock 55,389,050 shs.

MARKET CAP: $4.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	3/31/23
Cash Assets	8.9	9.7	7.8
Other	2215.7	1207.9	780.7
Current Assets	2224.6	1217.6	788.5
Accts Payable	258.6	360.5	197.6
Debt Due	494.0	572.7	1087.2
Other	227.9	256.2	257.5
Current Liab.	980.5	1189.4	1542.3
Fix. Chg. Cov.	625%	540%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	- -	5.0%	*11.5%*
"Cash Flow"	- -	7.5%	*8.0%*
Earnings	- -	8.0%	*6.5%*
Dividends	- -	10.0%	*5.5%*
Book Value	- -	4.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	528.2	273.3	244.6	484.2	1530.3
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	*470*	*376*	*811.9*	*2690*
2024	*1075*	*515*	*420*	*840*	*2850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.72	.48	.39	1.09	3.68
2021	1.79	.56	.38	1.12	3.85
2022	1.83	.59	.44	1.23	4.08
2023	1.84	*.64*	*.50*	*1.22*	*4.20*
2024	*1.89*	*.68*	*.57*	*1.26*	*4.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.50	.50	.50	.50	2.00
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65			

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 165 Bcf of natural gas supply in 2022, compared to 164 Bcf in 2021. Total volumes delivered by customer (fiscal 2022): transportation, 57.3%; residential, 31.2%; commercial & industrial, 10.8%; other, .7%. ONE Gas has around 3,600 employees. BlackRock owns 12.6% of common stock; The Vanguard Group, 11.5%; State Street Corporation, 11.5%; officers and directors, 1.5% (4/23 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Telephone: 918-947-7000. Internet: www.onegas.com.

ONE Gas, Inc. got off to an unspectacular start in 2023. First-quarter earnings per share of $1.84 were just a penny above last year's $1.83 figure. That's attributable partly to higher depreciation expense, reflecting additional assets being placed into service. Employee-related costs and bad debt expense rose, as well. But the company was aided, to some degree, by benefits from new rates. A lower effective income tax rate plus a decrease in COVID-19-related costs also helped. So, at this juncture, it appears that full-year profits will grow at a 3% rate, to $4.20 a share, relative to 2022's $4.08 tally. Regarding 2024, we expect share net to advance at a somewhat stronger 5% rate, to $4.40, assuming further widening of operating margins.

The Financial Strength rating is solid, at B++. When the March period concluded, cash and equivalents were $7.8 million and cash flows were decent. Moreover, ONE Gas had $720 million available (out of $1 billion) under a commercial paper program. The company also possesses a $1 billion revolving credit facility maturing in March, 2028. Lastly, at the end of the first quarter, long-term debt was a manageable 41% of total capital. All told, the energy firm should continue to be able to meet its working capital requirements, capital expenditures, and other commitments with little trouble.

It's important to mention that operations are concentrated in only three states. Moreover, it seems that leadership is content with maintaining the status quo, given that some businesses are in metropolitan areas, such as Austin, Texas; Wichita, Kansas; and Tulsa, Oklahoma. Nonetheless, this lack of geographic diversification leaves the company somewhat more vulnerable to regional economic downturns and regulations.

What about the stock? It offers worthwhile capital appreciation potential over the 2026-2028 horizon. Consider, too, the 2 (Above Average) Safety rank and high Price Stability score of 90 out of 100. But the dividend yield does not stand out from the average yield in our Natural Gas Utility group. Meanwhile, OGS shares are pegged to just approximate the year-ahead market (Timeliness rank 3: Average).

Frederick L. Harris, III *May 26, 2023*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Aug. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	60
Earnings Predictability	100

SPIRE INC. NYSE-SR

RECENT PRICE	68.03	P/E RATIO	15.9 (Trailing: 14.5 / Median: 19.0)	RELATIVE P/E RATIO	0.96	DIV'D YLD	4.3%	VALUE LINE

TIMELINESS 3 Lowered 5/19/23
SAFETY 2 Raised 6/20/03
TECHNICAL 2 Raised 5/5/23
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$56-$94	$75 (10%)

2026-28 PROJECTIONS

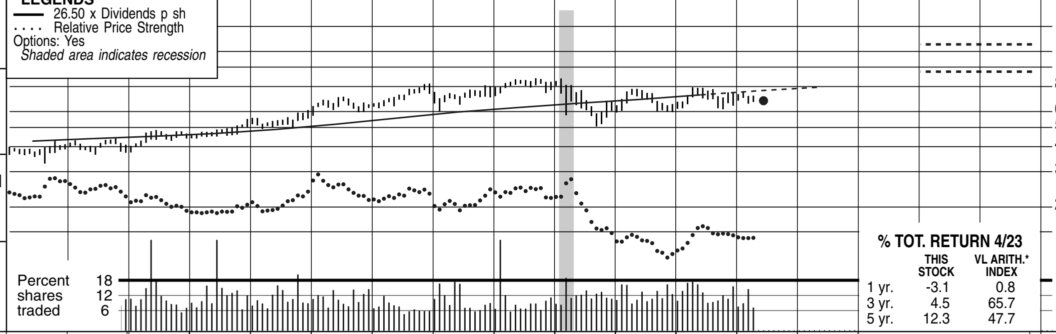
	Price	Gain	Ann'l Total Return
High	130	(+90%)	*20%*
Low	95	(+40%)	*12%*

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	145	128	146
to Sell	121	126	122
Hld's(000)	44899	45113	45462

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	44.0	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	79.2	75.8
Low:	36.5	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.5	65.6

LEGENDS
—— 26.50 x Dividends p sh
. . . . Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 4/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.1	0.8
3 yr.	4.5	65.7
5 yr.	12.3	47.7

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	***51.30***	***47.15***	Revenues per sh A	***63.65***
3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	***9.35***	***9.45***	"Cash Flow" per sh	***11.10***
2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	***4.65***	***4.40***	Earnings per sh A B	***5.50***
1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	***2.88***	***3.00***	Div'ds Decl'd per sh C■	***3.45***
2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	***13.20***	***13.60***	Cap'l Spending per sh	***12.00***
19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	***53.40***	***59.75***	Book Value per sh D	***67.10***
21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	***53.00***	***53.00***	Common Shs Outst'g E	***55.00***
14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	***20.5***
.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01		*estimates*	Relative P/E Ratio	***1.15***
4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%			Avg Ann'l Div'd Yield	***3.1%***

CAPITAL STRUCTURE as of 3/31/23
Total Debt $4520.1 mill. **Due in 5 Yrs** $2775.0 mill.
LT Debt $3702.5 mill. **LT Interest** $200.0 mill.
(Total interest coverage: 3.3x)

Leases, Uncapitalized Annual rentals $9.0 mill.
Pension Assets-9/22 $625.9 mill. **Oblig.** $882.8 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 52,597,027 shs.
as of 4/30/23

MARKET CAP: $3.6 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
1017.0	1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	***2720***	***2500***	Revenues ($mill) A	***3500***
52.8	84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	***245***	***235***	Net Profit ($mill)	***300***
25.0%	27.6%	31.2%	32.5%	32.4%	NMF	15.7%	12.3%	20.1%	21.1%	***20.0%***	***20.5%***	Income Tax Rate	***25.0%***
5.2%	5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	***9.0%***	***9.4%***	Net Profit Margin	***8.6%***
46.6%	55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	***55.0%***	***52.0%***	Long-Term Debt Ratio	***51.0%***
53.4%	44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	***41.0%***	***44.0%***	Common Equity Ratio	***45.0%***
1959.0	3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	***6900***	***7200***	Total Capital ($mill)	***8200***
1776.6	2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	***5700***	***6000***	Net Plant ($mill)	***7100***
3.3%	3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	***5.0%***	***5.0%***	Return on Total Cap'l	***5.0%***
5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	***8.5%***	***7.5%***	Return on Shr. Equity	***8.0%***
5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	***8.5%***	***7.5%***	Return on Com Equity	***8.0%***
1.0%	1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	***2.5%***	***2.0%***	Retained to Com Eq	***2.5%***
81%	73%	58%	59%	60%	51%	66%	NMF	54%	71%	***68%***	***74%***	All Div'ds to Net Prof	***68%***

CURRENT POSITION ($MILL.)	2021	2022	3/31/23
Cash Assets	4.3	6.5	6.9
Other	1312.2	1585.5	1104.7
Current Assets	1316.5	1592.0	1111.6
Accts Payable	409.9	617.4	232.3
Debt Due	727.8	1318.7	817.6
Other	470.6	417.5	357.0
Current Liab.	1608.3	2353.6	1406.9
Fix. Chg. Cov.	448%	393%	405%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-5.0%	1.0%	*8.0%*
"Cash Flow"	5.5%	4.0%	*6.5%*
Earnings	2.5%	1.0%	*8.0%*
Dividends	5.0%	6.0%	*5.0%*
Book Value	6.5%	4.0%	*6.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	566.9	715.5	321.1	251.9	1855.4
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	***447.6***	***335***	***2720***
2024	***660***	***1070***	***430***	***340***	***2500***

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	1.24	2.54	d1.87	d.45	1.44
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	***d.12***	***d.22***	***4.65***
2024	***1.30***	***3.45***	***d.11***	***d.24***	***4.40***

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.5925	.5925	.5925	.5925	2.37
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72			

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2022: 3.2 bill. Revenue mix for regulated operations: residential, 73%; commercial and industrial, 17%; transportation, 6%; other, 4%. Officers and directors own 2.9% of common shares; American Century Companies, 14.9% (12/22 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire Inc. continues to perform nicely in fiscal 2023 (which concludes on September 30th). Through the first half, profits of $4.99 per share were 16.6% higher than the previous year's $4.28 total. This was made possible, in part, by the Gas Marketing division, as very favorable market conditions enabled it to optimize storage and transportation positions. Furthermore, results of the Gas Utility unit benefited from higher gas cost recoveries at the Spire Missouri and Spire Alabama utilities (supported by increased average gas costs being passed through to customers). Spire Missouri also enjoyed the effects of implementing 2022 and 2021 rate orders. Lastly, the Midstream segment was aided, to a big degree, by an improved showing from the Spire Storage business. Right now, it appears that full-year earnings per share will recover roughly 18%, to $4.65, compared to the fiscal 2022 figure of $3.95. Concerning next year, the bottom line might fall back around 5%, to $4.40 a share. This is based partially on our assumption that results for the Gas Marketing arm won't be as strong as in the current year.

Corporate finances are sound. When the March period ended, cash and equivalents stood at nearly $7 million. Moreover, there was $1.3 billion available via a revolving credit facility expiring in July, 2027. Too, long-term debt was a manageable 55% of total capital, and short-term obligations were not a major problem. All told, Spire ought to be able to satisfy its commitments for a while.

Prospects out to 2026-2028 seem decent. The gas utilities boast 1.7 million customers in Mississippi, Alabama, and Missouri. Too, the other businesses, particularly pipelines, hold promise. Additional expansionary projects and technological enhancements in customer service and elsewhere should help Spire, as well. Finally, acquisitions are plausible, given the adequate balance sheet.

These good-quality shares offer decent long-term total return potential. The dividend yield compares nicely to those of other equities in *Value Line's* Natural Gas Utility Industry. Moreover, 3- to 5-year capital appreciation possibilities look worthwhile.

Frederick L. Harris, III *May 26, 2023*

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. (C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '22: $1,171.6 mill., $22.32/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	45

Southwest Gas Corporation
Summary of Risk Premium Models for the
Proxy Group of Six Natural Gas Distribution Companies

	Proxy Group of Six Natural Gas Distribution Companies
Predictive Risk Premium Model (PRPM) (1)	10.74 %
Risk Premium Using an Adjusted Total Market Approach (2)	10.95 %
Average	10.85 %

Notes:
(1) From page 2 of this Exhibit.
(2) From page 3 of this Exhibit.

Southwest Gas Corporation
Indicated ROE
Derived by the Predictive Risk Premium Model (1)

Proxy Group of Six Natural Gas Distribution Companies	[1] LT Average Predicted Variance	[2] Spot Predicted Variance	[3] Recommended Variance (2)	[4] GARCH Coefficient	[5] Predicted Risk Premium (3)	[6] Risk-Free Rate (4)	[4] Indicated ROE (5)
Atmos Energy Corporation	0.34%	0.34%	0.34%	2.2707	9.61%	3.85%	13.46%
New Jersey Resources Corporation	0.39%	0.38%	0.39%	2.1385	10.37%	3.85%	14.22%
NiSource Inc.	0.48%	0.33%	0.40%	0.8238	4.08%	3.85%	7.93%
Northwest Natural Holding Company	0.33%	0.40%	0.36%	1.4263	6.43%	3.85%	10.28%
ONE Gas, Inc.	0.37%	0.48%	0.42%	3.0780	16.85%	3.85%	NMF
Spire Inc.	0.70%	0.38%	0.54%	0.9416	6.26%	3.85%	10.11%
						Average	11.20%
						Median	10.28%
						Average of Mean and Median	10.74%

NMF = Not Meaningful Figure

Notes:
(1) The Predictive Risk Premium Model uses historical data to generate a predicted variance and a GARCH coefficient. The historical data used are the equity risk premiums for the first available trading month as reported by Bloomberg Professional Service.
(2) Average of Column [1] and Column [2].
(3) (1+(Column [3] * Column [4])^12) - 1.
(4) From note 2 on page 2 of Exhibit No.__(DWD-6).
(5) Column [5] + Column [6].

Southwest Gas Corporation
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Six Natural Gas Distribution Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	4.75 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.69
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.44 %
4.	Equity Risk Premium (3)	5.51
5.	Risk Premium Derived Common Equity Cost Rate	10.95 %

Notes:
(1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 10 and 11 of this Exhibit).
(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.69% from page 4 of this Exhibit.
(3) From page 7 of this Exhibit.

Southwest Gas Corporation
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields - Moody's

	[1]	[2]	[3]
	Aaa Rated Corporate Bond	A2 Rated Public Utility Bond	Baa2 Rated Public Utility Bond
Jun-2023	4.65 %	5.38 %	5.73 %
May-2023	4.67	5.36	5.71
Apr-2023	4.47	5.13	5.47
Average	4.60 %	5.29 %	5.64 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:
0.69 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:
0.35 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

Southwest Gas Corporation
Comparison of Long-Term Issuer Ratings for
Proxy Group of Six Natural Gas Distribution Companies

	Moody's Long-Term Issuer Rating July 2023		Standard & Poor's Long-Term Issuer Rating July 2023	
Proxy Group of Six Natural Gas Distribution Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	A-	7.0
Spire Inc.	A1/A2	5.5	A-	7.0
Average	A2	6.4	A-	6.8
Southwest Gas Corporation	Baa1	8.0	BBB	9.0

Notes:
(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 6 of this Exhibit.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Southwest Gas Corporation
Judgment of Equity Risk Premium for
Proxy Group of Six Natural Gas Distribution Companies

Line No.		Proxy Group of Six Natural Gas Distribution Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	6.83 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	4.79
3.	Predicted Equity Risk Premium Based on Regression Analysis of 821 Fully-Litigated Natural Gas Utility Rate Cases (3)	4.92
4.	Average equity risk premium	5.51 %

Notes: (1) From page 8 of this Exhibit.
(2) From page 12 of this Exhibit.
(3) From page 13 of this Exhibit.

Southwest Gas Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Six Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Six Natural Gas Distribution Companies	
1.	Kroll Equity Risk Premium (1)	5.82	%
2.	Regression on Ibbotson Risk Premium Data (2)	7.46	
3.	Ibbotson Equity Risk Premium based on PRPM (3)	8.70	
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	10.56	
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	9.39	
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	11.29	
7.	Conclusion of Equity Risk Premium	8.87	%
8.	Adjusted Beta (7)	0.77	
9.	Forecasted Equity Risk Premium	6.83	%

Notes provided on page 9 of this Exhibit.

Southwest Gas Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Six Natural Gas Distribution Companies

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll 2022 SBBI® Yearbook minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1928-2022.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2022 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the average consensus forecast of Aaa corporate bonds of 4.75% (from page 3 of this Exhibit).

(3) The SBBI equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through June 2023.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 4.75% (from page 3 of this Exhibit) from the projected 3-5 year total annual market return of 15.31% (described fully in note 1 on page 2 of Exhibit No.___(DWD-6)).

(5) Using data from Value Line for the S&P 500, an expected total return of 14.14%% was derived based upon expected dividend yields as a proxy for income returns and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 4.75% results in an expected equity risk premium of 9.39%.

(6) Using data from the Bloomberg Professional Services for the S&P 500, an expected total return of 16.04% was derived based upon expected dividend yields as a proxy for income returns and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 4.75% results in an expected equity risk premium of 11.29%.

(7) Average of mean and median beta from Exhibit No.___(DWD-6).

Sources of Information:

Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll
Value Line Summary and Index
Blue Chip Financial Forecasts, June 1, 2023 and June 30, 2023
Bloomberg Professional Services

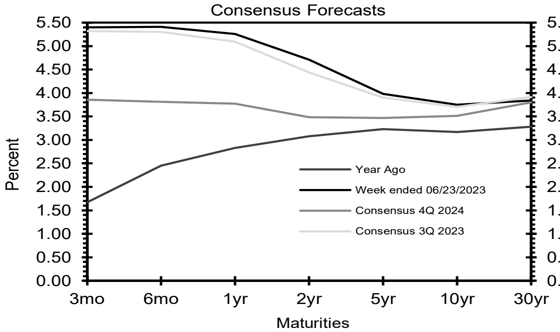
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	3Q	4Q	1Q	2Q	3Q	4Q
Interest Rates	Jun 23	Jun 16	Jun 9	Jun 2	May	Apr	Mar	2Q 2023*	**2023**	**2023**	**2024**	**2024**	**2024**	**2024**
Federal Funds Rate	5.08	5.08	5.08	5.08	5.06	4.83	4.65	4.98	**5.3**	**5.2**	**5.0**	**4.6**	**4.3**	**3.9**
Prime Rate	8.25	8.25	8.25	8.25	8.23	8.00	7.82	8.15	**8.4**	**8.4**	**8.1**	**7.7**	**7.3**	**7.0**
SOFR	5.05	5.05	5.05	5.07	5.02	4.81	4.64	4.96	**5.2**	**5.2**	**5.0**	**4.7**	**4.3**	**3.9**
Commercial Paper, 1-mo.	5.09	5.09	5.12	5.08	5.06	4.82	4.74	4.98	**5.2**	**5.2**	**5.0**	**4.6**	**4.2**	**3.9**
Treasury bill, 3-mo.	5.40	5.36	5.41	5.52	5.31	5.07	4.86	5.26	**5.3**	**5.2**	**5.0**	**4.6**	**4.2**	**3.9**
Treasury bill, 6-mo.	5.41	5.36	5.42	5.48	5.27	4.99	4.99	5.21	**5.3**	**5.1**	**4.9**	**4.5**	**4.1**	**3.8**
Treasury bill, 1 yr.	5.26	5.23	5.16	5.18	4.91	4.68	4.68	4.92	**5.1**	**4.9**	**4.6**	**4.3**	**4.0**	**3.8**
Treasury note, 2 yr.	4.71	4.66	4.53	4.42	4.13	4.02	4.30	4.23	**4.4**	**4.3**	**4.0**	**3.8**	**3.6**	**3.5**
Treasury note, 5 yr.	3.98	3.97	3.88	3.77	3.59	3.54	3.82	3.67	**3.9**	**3.8**	**3.7**	**3.6**	**3.5**	**3.5**
Treasury note, 10 yr.	3.75	3.78	3.73	3.66	3.57	3.46	3.66	3.58	**3.7**	**3.6**	**3.6**	**3.5**	**3.5**	**3.5**
Treasury note, 30 yr.	3.84	3.88	3.90	3.87	3.86	3.68	3.77	3.80	**3.9**	**3.9**	**3.9**	**3.8**	**3.8**	**3.8**
Corporate Aaa bond	4.91	4.97	4.99	4.99	4.95	4.76	4.92	4.89	**4.8**	**4.9**	**4.7**	**4.6**	**4.6**	**4.6**
Corporate Baa bond	5.59	5.66	5.70	5.69	5.66	5.44	5.61	5.59	**5.9**	**5.9**	**5.7**	**5.6**	**5.6**	**5.5**
State & Local bonds	4.21	4.24	4.25	4.30	4.21	4.07	4.23	4.18	**4.2**	**4.2**	**4.1**	**4.0**	**4.0**	**4.0**
Home mortgage rate	6.67	6.69	6.71	6.79	6.43	6.34	6.54	6.49	**6.6**	**6.4**	**6.3**	**6.1**	**6.0**	**5.9**

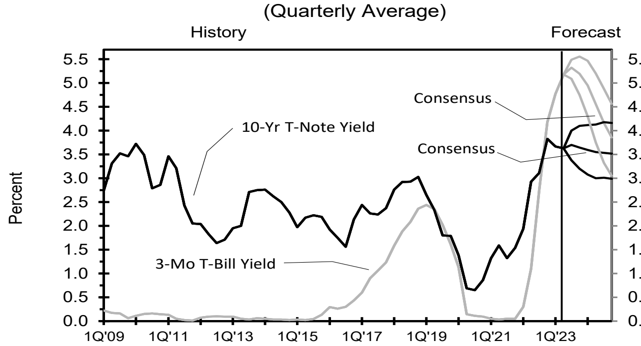
	History								Consensus Forecasts-Quarterly					
	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q
Key Assumptions	2021	2021	2022	2022	2022	2022	2023	2023**	**2023**	**2023**	**2024**	**2024**	**2024**	**2024**
Fed's AFE $ Index	104.9	106.9	108.3	113.5	118.8	119.8	115.5	114.6	**114.7**	**115.1**	**114.9**	**114.7**	**114.7**	**114.1**
Real GDP	2.7	7.0	-1.6	-0.6	3.2	2.6	2.0	0.8	**0.0**	**-0.2**	**0.6**	**1.1**	**1.7**	**2.0**
GDP Price Index	6.2	6.8	8.3	9.0	4.4	3.9	4.1	3.3	**2.9**	**2.8**	**2.5**	**2.4**	**2.2**	**2.2**
Consumer Price Index	6.6	8.8	9.2	9.7	5.5	4.2	3.8	3.3	**3.0**	**2.8**	**2.5**	**2.3**	**2.4**	**2.4**
PCE Price Index	5.6	6.2	7.5	7.3	4.3	3.7	4.1	3.0	**2.9**	**2.7**	**2.5**	**2.2**	**2.2**	**2.2**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed.*Interest rate data for 2Q 2023 based on historical data through the week ended June 23. **Data for 2Q 2023 for the Fed's AFE $ Index based on data through the week ended June 23. Figures for 2Q 2023 Real GDP, GDP Chained Price Index, Consumer Price Index, and PCE Price Index are consensus forecasts from the June 2023 survey.

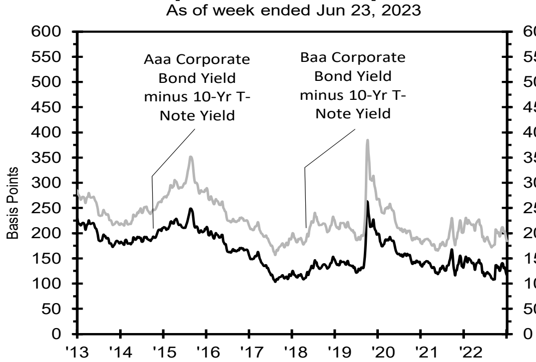
US Treasury Yield Curve
Week ended Jun 23, 2023 & Year Ago vs. 3Q 2023 & 4Q 2024 Consensus Forecasts



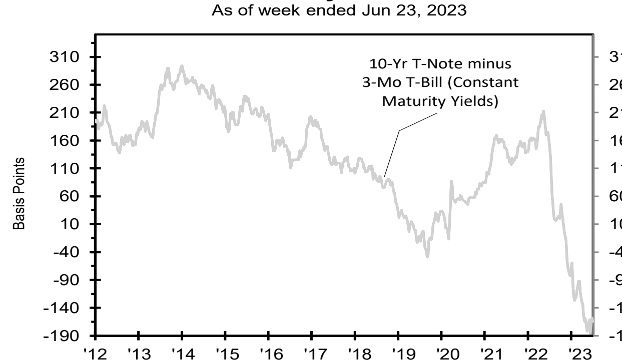
US 3-Mo T-Bills & 10-Yr T-Note Yield
(Quarterly Average)



Corporate Bond Spreads
As of week ended Jun 23, 2023



US Treasury Yield Curve
As of week ended Jun 23, 2023



Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2024 through 2029 and averages for the five-year periods 2025-2029 and 2030-2034. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year						Five-Year Averages	
		2024	2025	2026	2027	2028	2029	2025-2029	2030-2034
1. Federal Funds Rate	**CONSENSUS**	**3.9**	**3.0**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**
	Top 10 Average	4.6	3.5	3.2	3.2	3.2	3.1	3.2	3.1
	Bottom 10 Average	3.1	2.4	2.3	2.2	2.2	2.3	2.3	2.3
2. Prime Rate	**CONSENSUS**	**7.0**	**6.0**	**5.8**	**5.8**	**5.7**	**5.8**	**5.8**	**5.8**
	Top 10 Average	7.7	6.6	6.2	6.3	6.2	6.1	6.3	6.2
	Bottom 10 Average	6.3	5.5	5.4	5.3	5.3	5.4	5.4	5.4
3. SOFR	**CONSENSUS**	**3.8**	**2.9**	**2.6**	**2.7**	**2.6**	**2.6**	**2.7**	**2.6**
	Top 10 Average	4.5	3.4	3.0	3.1	3.0	2.9	3.1	3.0
	Bottom 10 Average	3.2	2.4	2.3	2.2	2.2	2.3	2.3	2.3
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.7**	**2.9**	**2.7**	**2.8**	**2.8**	**2.8**	**2.8**	**2.8**
	Top 10 Average	4.3	3.3	3.0	3.1	3.0	3.0	3.1	3.0
	Bottom 10 Average	3.3	2.6	2.4	2.4	2.4	2.6	2.5	2.5
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.8**	**2.9**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**
	Top 10 Average	4.4	3.4	3.1	3.2	3.2	3.0	3.2	3.1
	Bottom 10 Average	3.1	2.3	2.3	2.3	2.3	2.3	2.3	2.3
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.8**	**3.0**	**2.8**	**2.8**	**2.8**	**2.8**	**2.8**	**2.8**
	Top 10 Average	4.4	3.5	3.2	3.3	3.2	3.1	3.2	3.1
	Bottom 10 Average	3.1	2.5	2.4	2.4	2.4	2.5	2.4	2.5
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.6**	**3.0**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**
	Top 10 Average	4.3	3.5	3.3	3.4	3.3	3.2	3.3	3.3
	Bottom 10 Average	3.0	2.5	2.5	2.5	2.5	2.6	2.5	2.6
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.4**	**3.0**	**3.0**	**3.1**	**3.0**	**3.0**	**3.0**	**3.1**
	Top 10 Average	4.0	3.5	3.5	3.5	3.5	3.4	3.5	3.5
	Bottom 10 Average	2.8	2.6	2.6	2.6	2.5	2.7	2.6	2.7
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.4**	**3.1**	**3.2**	**3.2**	**3.3**	**3.2**	**3.2**	**3.3**
	Top 10 Average	4.0	3.6	3.7	3.8	3.8	3.6	3.7	3.8
	Bottom 10 Average	2.8	2.7	2.7	2.7	2.8	2.8	2.7	2.8
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**3.4**	**3.3**	**3.4**	**3.5**	**3.5**	**3.5**	**3.4**	**3.6**
	Top 10 Average	3.9	3.7	4.0	4.1	4.1	4.0	4.0	4.2
	Bottom 10 Average	3.0	3.0	2.9	2.9	3.0	3.0	3.0	3.1
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**3.8**	**3.6**	**3.7**	**3.8**	**3.9**	**3.8**	**3.8**	**3.9**
	Top 10 Average	4.2	4.0	4.2	4.3	4.3	4.2	4.2	4.5
	Bottom 10 Average	3.4	3.3	3.3	3.3	3.4	3.4	3.3	3.4
12. Corporate Aaa Bond Yield	**CONSENSUS**	**4.7**	**4.6**	**4.7**	**4.8**	**4.9**	**4.8**	**4.8**	**5.0**
	Top 10 Average	5.1	4.9	5.2	5.4	5.4	5.3	5.2	5.6
	Bottom 10 Average	4.3	4.3	4.2	4.3	4.3	4.3	4.3	4.3
13. Corporate Baa Bond Yield	**CONSENSUS**	**5.8**	**5.6**	**5.7**	**5.8**	**5.8**	**5.8**	**5.7**	**5.9**
	Top 10 Average	6.1	5.9	6.1	6.3	6.3	6.2	6.1	6.5
	Bottom 10 Average	5.3	5.3	5.3	5.3	5.4	5.3	5.3	5.4
14. State & Local Bonds Yield	**CONSENSUS**	**4.0**	**3.8**	**4.0**	**4.1**	**4.1**	**4.1**	**4.0**	**4.2**
	Top 10 Average	4.3	4.1	4.3	4.4	4.5	4.3	4.3	4.5
	Bottom 10 Average	3.6	3.6	3.6	3.7	3.7	3.7	3.7	3.8
15. Home Mortgage Rate	**CONSENSUS**	**5.7**	**5.4**	**5.4**	**5.4**	**5.5**	**5.4**	**5.4**	**5.5**
	Top 10 Average	6.4	5.9	6.0	6.1	6.1	5.9	6.0	6.1
	Bottom 10 Average	5.1	4.9	4.7	4.8	4.8	4.9	4.8	4.9
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**113.5**	**111.8**	**111.8**	**110.9**	**110.1**	**110.1**	**111.0**	**110.0**
	Top 10 Average	115.5	114.2	115.1	114.7	114.3	115.2	114.7	115.3
	Bottom 10 Average	111.5	109.5	108.4	107.5	106.3	105.8	107.5	105.3

		Year-Over-Year, % Change						Five-Year Averages	
		2024	2025	2026	2027	2028	2029	2025-2029	2030-2034
B. Real GDP	**CONSENSUS**	**1.1**	**2.1**	**2.2**	**2.1**	**2.0**	**1.9**	**2.1**	**2.0**
	Top 10 Average	2.0	2.5	2.7	2.5	2.3	2.1	2.4	2.3
	Bottom 10 Average	0.4	1.7	1.8	1.8	1.7	1.7	1.7	1.7
C. GDP Chained Price Index	**CONSENSUS**	**2.5**	**2.3**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**	**2.2**
	Top 10 Average	3.0	2.7	2.5	2.5	2.3	2.3	2.5	2.4
	Bottom 10 Average	2.1	1.9	1.9	1.9	2.0	2.0	1.9	1.9
D. Consumer Price Index	**CONSENSUS**	**2.6**	**2.3**	**2.2**	**2.2**	**2.2**	**2.1**	**2.2**	**2.2**
	Top 10 Average	3.0	2.7	2.5	2.5	2.3	2.3	2.5	2.4
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	**CONSENSUS**	**2.4**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.9	2.5	2.4	2.3	2.2	2.2	2.3	2.3
	Bottom 10 Average	2.1	1.9	1.9	1.9	1.9	1.9	1.9	1.9

Southwest Gas Corporation
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1):	Implied Equity Risk Premium
1.	Historical Equity Risk Premium	4.20 %
2.	Regression of Historical Equity Risk Premium (2)	5.16
3.	Forecasted Equity Risk Premium Based on PRPM (3)	5.24
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	4.56
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	NMF
6.	Average Equity Risk Premium (6)	4.79 %

Notes: (1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2022. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2022 referenced in note 1 above.

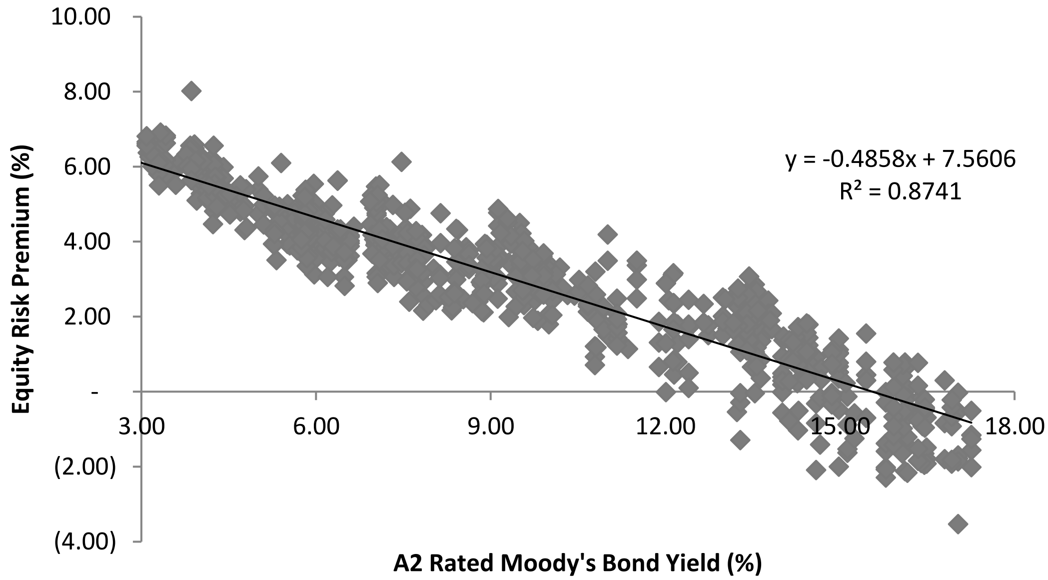
(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - June 2023.

(4) Using data from Value Line for the S&P Utilities Index, an expected return of 10.00% was derived based on expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.44%, calculated on line 3 of page 3 of this Exhibit results in an equity risk premium of 4.56%. (10.00% - 5.44% = 4.56%)

(5) Using data from Bloomberg Professional Services for the S&P Utilities Index, an expected return of 4.25% was derived based on expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.44%, calculated on line 3 of page 3 of this Exhibit results in an equity risk premium of -1.28%. (4.25% - 5.44% = -1.19%). Because a negative risk premium is inconsistent with financial theory, it is not included in the final average.

(6) Average of lines 1 through 5.

Southwest Gas Corporation
Prediction of Equity Risk Premiums Relative to Moody's A2 Rated Utility Bond Yields - Gas Utilities



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.5606 %	-0.4858	5.44 %	4.92 %

Notes:
(1) From line 3 of page 3 of this Exhibit.

Source of Information: Regulatory Research Associates

Southwest Gas Corporation
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Six Natural Gas Distribution Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.85	0.73	0.79	9.87 %	3.85 %	11.65 %	12.17 %	11.91 %
New Jersey Resources Corporation	0.95	0.73	0.84	9.87	3.85	12.14	12.54	12.34
NiSource Inc.	0.85	0.75	0.80	9.87	3.85	11.75	12.24	12.00
Northwest Natural Holding Company	0.80	0.60	0.70	9.87	3.85	10.76	11.50	11.13
ONE Gas, Inc.	0.80	0.63	0.71	9.87	3.85	10.86	11.58	11.22
Spire Inc.	0.80	0.67	0.74	9.87	3.85	11.16	11.80	11.48
Mean			0.76			11.39 %	11.97 %	11.68 %
Median			0.77			11.40 %	11.98 %	11.70 %
Average of Mean and Median			0.77			11.40 %	11.98 %	11.69 %

Notes on page 2 of this Exhibit.

Southwest Gas Corporation
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using six different measures from three sources: Ibbotson, Value Line, and Bloomberg as illustrated below:

Historical Data MRP Estimates:

Measure 1: Ibbotson Arithmetic Mean MRP (1926-2022)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2022:	12.03	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.00	
MRP based on Ibbotson Historical Data:	7.03	%

Measure 2: Application of a Regression Analysis to Ibbotson Historical Data (1926-2022)	8.59	%

Measure 3: Application of the PRPM to Ibbotson Historical Data: (January 1926 - June 2023)	9.69	%

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP (Thirteen weeks ending July 14, 2023)

Total projected return on the market 3-5 years hence*:	15.31	%
Projected Risk-Free Rate (see note 2):	3.85	
MRP based on Value Line Summary & Index:	11.46	%

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Value Line Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	14.14	%
Projected Risk-Free Rate (see note 2):	3.85	
MRP based on Value Line data	10.29	%

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	16.04	%
Projected Risk-Free Rate (see note 2):	3.85	
MRP based on Bloomberg data	12.19	%

Average of Value Line, Ibbotson, and Bloomberg MRP:	9.87	%

(2) For reasons explained in the direct testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 10 and 11 of Exhibit No.___(DWD-5).) The projection of the risk-free rate is illustrated below:

Third Quarter 2023	3.90	%
Fourth Quarter 2023	3.90	
First Quarter 2024	3.90	
Second Quarter 2024	3.80	
Third Quarter 2024	3.80	
Fourth Quarter 2024	3.80	
2025-2029	3.80	
2030-2034	3.90	
	3.85	%

(3) Average of Column 6 and Column 7.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, June 1, 2023 and June 30, 2023
Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll
Bloomberg Professional Services

Southwest Gas Corporation
Basis of Selection of the Group of Non-Price Regulated Companies Comparable in Total Risk to the Utility Proxy Group

The criteria for selection of the proxy group of forty-six non-price regulated companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The Non-Price Regulated Proxy Group were then selected based on the unadjusted beta range of 0.58 – 0.86 and residual standard error of the regression range of 2.8160 – 3.3584 of the Utility Proxy Group.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1356. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus, } 0.1356 = \frac{3.0872}{\sqrt{518}} = \frac{3.0872}{22.7596}$$

Source of Information: Value Line, Inc., June 2023
Value Line Investment Survey (Standard Edition)

Southwest Gas Corporation
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

	[1]	[2]	[3]	[4]
Proxy Group of Six Natural Gas Distribution Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Atmos Energy Corporation	0.85	0.70	2.9159	0.0641
New Jersey Resources Corporation	0.95	0.87	3.1807	0.0699
NiSource Inc.	0.85	0.76	2.6599	0.0585
Northwest Natural Holding Company	0.80	0.66	3.4174	0.0751
ONE Gas, Inc.	0.80	0.66	3.1969	0.0703
Spire Inc.	0.80	0.69	3.1526	0.0693
Average	0.84	0.72	3.0872	0.0679

Beta Range (+/- 2 std. Devs. of Beta)	0.58	0.86	
2 std. Devs. of Beta	0.14		
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.8160	3.3584	
Std. dev. of the Res. Std. Err.	0.1356		
2 std. devs. of the Res. Std. Err.	0.2712	0.87	2.6599

Source of Information: Valueline Proprietary Database, June 2023

Southwest Gas Corporation
Proxy Group of 46 Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

Proxy Group of Forty-Six Non-Price Regulated Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Agilent Technologies	0.95	0.86	2.8174	0.0620
AbbVie Inc.	0.85	0.73	3.2239	0.0709
AmerisourceBergen	0.80	0.69	3.0890	0.0679
Abbott Labs.	0.90	0.81	2.9376	0.0646
Assurant Inc.	0.90	0.81	3.0042	0.0661
Smith (A.O.)	0.90	0.79	3.1089	0.0684
Air Products & Chem.	0.90	0.83	2.9876	0.0657
AutoZone Inc.	0.95	0.85	3.3239	0.0731
Booz Allen Hamilton	0.85	0.73	3.2262	0.0709
Becton, Dickinson	0.75	0.60	2.9735	0.0654
Broadridge Fin'l	0.90	0.80	2.9041	0.0639
CACI Int'l	0.90	0.79	3.0776	0.0677
Casey's Gen'l Stores	0.90	0.79	3.0735	0.0676
Chemed Corp.	0.80	0.62	2.8651	0.0630
Check Point Software	0.75	0.61	2.9399	0.0646
CSG Systems Int'l	0.75	0.60	3.0717	0.0675
CSW Industrials	0.90	0.78	3.2678	0.0719
Quest Diagnostics	0.80	0.63	3.3323	0.0733
Exponent, Inc.	0.95	0.85	3.2135	0.0707
Fastenal Co.	0.90	0.83	3.0532	0.0671
Franklin Electric	0.90	0.83	3.0031	0.0660
Alphabet Inc.	0.90	0.81	3.0446	0.0669
Henry (Jack) & Assoc	0.85	0.72	3.1768	0.0699
L3Harris Technologie	0.90	0.81	3.2934	0.0761
Lockheed Martin	0.90	0.81	2.9531	0.0649
Landstar System	0.80	0.64	2.9536	0.0649
McKesson Corp.	0.85	0.76	3.1802	0.0699
McCormick & Co.	0.80	0.63	3.1425	0.0691
Monster Beverage	0.85	0.72	2.8765	0.0633
Altria Group	0.85	0.76	3.0113	0.0662
MSC Industrial Direc	0.95	0.85	2.9590	0.0651
NewMarket Corp.	0.75	0.60	2.9107	0.0640
Oracle Corp.	0.85	0.72	2.8385	0.0624
O'Reilly Automotive	0.90	0.84	3.0143	0.0663
OSI Systems	0.90	0.80	2.9498	0.0649
Pfizer, Inc.	0.80	0.67	3.0166	0.0663
Progressive Corp.	0.75	0.59	3.1020	0.0682
Service Corp. Int'l	0.90	0.84	3.1595	0.0695
Stepan Company	0.80	0.64	3.2411	0.0713
Selective Ins. Group	0.85	0.76	3.0646	0.0674
Sirius XM Holdings	0.95	0.85	3.2201	0.0708
UniFirst Corp.	0.90	0.82	2.9485	0.0648
VeriSign Inc.	0.95	0.86	2.9893	0.0657
Waters Corp.	0.95	0.85	3.0725	0.0676
Watsco, Inc.	0.90	0.77	3.1149	0.0685
Western Union	0.85	0.72	3.1544	0.0694
Average	0.87	0.75	3.0626	0.0674
Proxy Group of Six Natural Gas Distribution Companies	0.84	0.72	3.0872	0.0679

Source of Information: Valueline Proprietary Database, June 2023

Southwest Gas Corporation
Summary of Cost of Equity Models Applied to
Proxy Group of Forty-Six Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

Principal Methods	Proxy Group of Forty-Six Non-Price Regulated Companies
Discounted Cash Flow Model (DCF) (1)	10.60 %
Risk Premium Model (RPM) (2)	13.10
Capital Asset Pricing Model (CAPM) (3)	12.30
Mean	12.00 %
Median	12.30 %
Average of Mean and Median	12.15 %

Notes:
(1) From page 2 of this Exhibit.
(2) From page 3 of this Exhibit.
(3) From page 6 of this Exhibit.

Southwest Gas Corporation
DCF Results for the Proxy Group of 46 Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Six Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
Agilent Technologies	0.73 %	13.50 %	11.00 %	11.66 %	12.05 %	0.77 %	12.82 %
AbbVie Inc.	4.16	2.00	5.00	(4.25)	3.50	4.23	7.73
AmerisourceBergen	1.10	8.50	8.90	7.95	8.45	1.15	9.60
Abbott Labs.	1.90	4.50	5.10	(2.70)	4.80	1.95	6.75
Assurant Inc.	2.22	10.50	11.40	11.40	11.10	2.34	13.44
Smith (A.O.)	1.73	9.50	9.00	8.00	8.83	1.81	10.64
Air Products & Chem.	2.45	10.50	9.50	9.38	9.79	2.57	12.36
AutoZone Inc.	-	13.00	12.50	9.95	11.82	-	NA
Booz Allen Hamilton	1.85	8.00	10.20	9.75	9.32	1.94	11.26
Becton, Dickinson	1.43	5.00	10.10	9.85	8.32	1.49	9.81
Broadridge Fin'l	1.87	8.50	NA	11.80	10.15	1.96	12.11
CACI Int'l	-	7.00	8.00	6.70	7.23	-	NA
Casey's Gen'l Stores	0.75	8.50	NA	11.04	9.77	0.79	10.56
Chemed Corp.	0.28	6.50	8.80	8.80	8.03	0.29	8.32
Check Point Software	-	9.50	7.30	6.39	7.73	-	NA
CSG Systems Int'l	2.21	15.50	NA	6.30	10.90	2.33	13.23
CSW Industrials	0.51	11.50	NA	12.00	11.75	0.54	12.29
Quest Diagnostics	2.07	4.00	NA	(0.47)	4.00	2.11	6.11
Exponent, Inc.	1.12	12.00	NA	15.00	13.50	1.20	14.70
Fastenal Co.	2.52	6.50	9.00	6.33	7.28	2.61	9.89
Franklin Electric	0.94	10.50	12.00	13.40	11.97	1.00	12.97
Alphabet Inc.	-	10.50	14.50	17.59	14.20	-	NA
Henry (Jack) & Assoc	1.32	7.00	7.30	7.30	7.20	1.37	8.57
L3Harris Technologie	2.39	19.50	2.60	1.14	7.75	2.48	10.23
Lockheed Martin	2.61	7.00	6.20	10.89	8.03	2.71	10.74
Landstar System	0.65	2.50	12.00	12.00	8.83	0.68	9.51
McKesson Corp.	0.55	9.00	10.80	11.22	10.34	0.58	10.92
McCormick & Co.	1.76	4.50	7.50	8.10	6.70	1.82	8.52
Monster Beverage	-	11.00	22.90	25.54	19.81	-	NA
Altria Group	8.28	6.00	4.00	4.47	4.82	8.48	13.30
MSC Industrial Direc	3.38	5.00	NA	9.12	7.06	3.50	10.56
NewMarket Corp.	2.25	(0.50)	NA	7.70	7.70	2.34	10.04
Oracle Corp.	1.50	10.00	8.00	11.46	9.82	1.57	11.39
O'Reilly Automotive	-	12.00	13.20	11.20	12.13	-	NA
OSI Systems	-	10.50	11.00	8.00	9.83	-	NA
Pfizer, Inc.	4.31	2.00	9.00	(15.49)	5.50	4.43	9.93
Progressive Corp.	0.30	12.00	25.10	26.80	21.30	0.33	NMF
Service Corp. Int'l	1.64	5.00	8.20	12.00	8.40	1.71	10.11
Stepan Company	1.56	7.50	NA	4.40	5.95	1.61	7.56
Selective Ins. Group	1.22	15.00	19.30	13.40	15.90	1.32	NMF
Sirius XM Holdings	2.50	28.50	7.10	6.36	13.99	2.67	16.66
UniFirst Corp.	0.75	9.00	NA	10.00	9.50	0.79	10.29
VeriSign Inc.	-	13.00	NA	8.00	10.50	-	NA
Waters Corp.	-	10.00	7.50	7.66	8.39	-	NA
Watsco, Inc.	2.81	12.00	NA	4.42	8.21	2.93	11.14
Western Union	8.08	(0.50)	NA	0.31	0.31	8.09	8.40
						Mean	10.64 %
						Median	10.56 %
						Average of Mean and Median	10.60 %

NA= Not Available
NMF= Not Meaningful Figure

(1) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Group. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of July 14, 2023. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

Source of Information: Value Line Investment Survey
www.zacks.com Downloaded on 07/14/2023
www.yahoo.com Downloaded on 07/14/2023

Southwest Gas Corporation
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Forty-Six Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	5.73 %
2.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	(0.17)
3.	Adjusted Bond Yield Applicable to the Non-Price Regulated Proxy Group	5.56 %
4.	Equity Risk Premium (3)	7.54
5.	Risk Premium Derived Common Equity Cost Rate	13.10 %

Notes: (1) Average forecast of Baa2 corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated June 1, 2023 and June 30, 2023 (see pages 10 and 11 of Exhibit No.___(DWD-5). The estimates are detailed below.

Third Quarter 2023	5.90 %
Fourth Quarter 2023	5.90
First Quarter 2024	5.70
Second Quarter 2024	5.60
Third Quarter 2024	5.60
Fourth Quarter 2024	5.50
2025-2029	5.70
2030-2034	5.90
Average	5.73 %

(2) The average yield spread of Baa rated corporate bonds over A corporate bonds for the three months ending June 2023 . To reflect the Baa1 average rating of the non-utility proxy group, the prosepctive yield on Baa corporate bonds must be adjusted by 1/3 of the spread between A and Baa corporate bond yields as shown below:

	A Corp. Bond Yield	Baa Corp. Bond Yield	Spread
Jun-23	5.24 %	5.75 %	0.51 %
May-23	5.24	5.77	0.53
Apr-23	5.02	5.53	0.51
		Average yield spread	0.52 %
		1/3 of spread	0.17 %

(3) From page 5 of this Exhibit.

Southwest Gas Corporation
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Forty-Six Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Six Natural Gas Distribution Companies

	Moody's Long-Term Issuer Rating July 2023		Standard & Poor's Long-Term Issuer Rating July 2023	
Proxy Group of Forty-Six Non-Price Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Agilent Technologies	Baa1	8.0	BBB+	8.0
AbbVie Inc.	Baa1	8.0	BBB+	8.0
AmerisourceBergen	Baa2	9.0	BBB+	8.0
Abbott Labs.	Aa3	4.0	AA-	4.0
Assurant Inc.	Baa2	9.0	BBB	9.0
Smith (A.O.)	NA	--	NA	--
Air Products & Chem.	A2	6.0	A	6.0
AutoZone Inc.	Baa1	8.0	BBB	9.0
Booz Allen Hamilton	NA	--	NA	--
Becton, Dickinson	Baa2	9.0	BBB	9.0
Broadridge Fin'l	Baa2	9.0	BBB	9.0
CACI Int'l	NA	--	BB+	11.0
Casey's Gen'l Stores	NA	--	NA	--
Chemed Corp.	WR	--	NR	--
Check Point Software	NA	--	NA	--
CSG Systems Int'l	NA	--	BB+	11.0
CSW Industrials	NA	--	NA	--
Quest Diagnostics	Baa2	9.0	BBB+	8.0
Exponent, Inc.	NA	--	NA	--
Fastenal Co.	NA	--	NA	--
Franklin Electric	NA	--	NA	--
Alphabet Inc.	Aa2	3.0	AA+	2.0
Henry (Jack) & Assoc	NA	--	NA	--
L3Harris Technologie	Baa2	9.0	BBB	9.0
Lockheed Martin	A3	7.0	A-	7.0
Landstar System	NA	--	NA	--
McKesson Corp.	Baa1	8.0	BBB+	8.0
McCormick & Co.	Baa2	9.0	BBB	9.0
Monster Beverage	NA	--	NA	--
Altria Group	A3	7.0	BBB	9.0
MSC Industrial Direc	NA	--	NA	--
NewMarket Corp.	Baa2	9.0	BBB+	8.0
Oracle Corp.	Baa2	9.0	BBB	9.0
O'Reilly Automotive	Baa1	8.0	BBB	9.0
OSI Systems	NA	--	NA	--
Pfizer, Inc.	A1	5.0	A+	5.0
Progressive Corp.	A2	6.0	A	6.0
Service Corp. Int'l	Ba3	13.0	BB+	11.0
Stepan Company	NA	--	NA	--
Selective Ins. Group	Baa2	9.0	BBB	9.0
Sirius XM Holdings	NA	--	NA	--
UniFirst Corp.	NA	--	NA	--
VeriSign Inc.	Baa3	10.0	BBB	9.0
Waters Corp.	NA	--	NA	--
Watsco, Inc.	NA	--	NA	--
Western Union	Baa2	9.0	BBB	9.0
Average	Baa1	8.0	BBB+	8.1

Notes:
(1) From page 6 of Exhibit No.___(DWD-5).

Source of Information:
Bloomberg Professional Services

Southwest Gas Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Proxy Group of Forty-Six Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Six Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Forty-Six Non-Price Regulated Companies
1.	Ibbotson Equity Risk Premium (1)	5.82 %
2.	Regression on Ibbotson Risk Premium Data (2)	7.46
3.	Ibbotson Equity Risk Premium based on PRPM (3)	8.70
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	10.56
5	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	9.39
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	11.29
7.	Conclusion of Equity Risk Premium	8.87 %
8.	Adjusted Beta (7)	0.85
9.	Forecasted Equity Risk Premium	7.54 %

Notes:
(1) From note 1 of page 9 of Exhibit No.___(DWD-5).
(2) From note 2 of page 9 of Exhibit No.___(DWD-5).
(3) From note 3 of page 9 of Exhibit No.___(DWD-5).
(4) From note 4 of page 9 of Exhibit No.___(DWD-5).
(5) From note 5 of page 9 of Exhibit No.___(DWD-5).
(6) From note 6 of page 9 of Exhibit No.___(DWD-5).
(7) Average of mean and median beta from page 6 of this Exhibit.

Sources of Information:
Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll
Value Line Summary and Index
Blue Chip Financial Forecasts, June 1, 2023 and June 30, 2023
Bloomberg Professional Services

Southwest Gas Corporation
Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Six Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Agilent Technologies	0.95	1.06	1.01	9.87 %	3.85 %	13.82 %	13.80 %	13.81 %
AbbVie Inc.	0.85	0.63	0.74	9.87	3.85	11.16	11.80	11.48
AmerisourceBergen	0.80	0.74	0.77	9.87	3.85	11.45	12.02	11.74
Abbott Labs.	0.90	0.84	0.87	9.87	3.85	12.44	12.76	12.60
Assurant Inc.	0.90	0.77	0.83	9.87	3.85	12.05	12.47	12.26
Smith (A.O.)	0.90	1.04	0.97	9.87	3.85	13.43	13.50	13.47
Air Products & Chem.	0.90	0.86	0.88	9.87	3.85	12.54	12.84	12.69
AutoZone Inc.	0.95	0.85	0.90	9.87	3.85	12.74	12.98	12.86
Booz Allen Hamilton	0.85	0.78	0.82	9.87	3.85	11.95	12.39	12.17
Becton, Dickinson	0.75	0.74	0.74	9.87	3.85	11.16	11.80	11.48
Broadridge Fin'l	0.90	1.01	0.96	9.87	3.85	13.33	13.43	13.38
CACI Int'l	0.90	0.75	0.83	9.87	3.85	12.05	12.47	12.26
Casey's Gen'l Stores	0.90	0.79	0.84	9.87	3.85	12.14	12.54	12.34
Chemed Corp.	0.80	0.67	0.73	9.87	3.85	11.06	11.73	11.39
Check Point Software	0.75	0.75	0.75	9.87	3.85	11.26	11.87	11.56
CSG Systems Int'l	0.75	0.84	0.79	9.87	3.85	11.65	12.17	11.91
CSW Industrials	0.90	0.78	0.84	9.87	3.85	12.14	12.54	12.34
Quest Diagnostics	0.80	0.72	0.76	9.87	3.85	11.35	11.95	11.65
Exponent, Inc.	0.95	0.99	0.97	9.87	3.85	13.43	13.50	13.47
Fastenal Co.	0.90	0.99	0.94	9.87	3.85	13.13	13.28	13.21
Franklin Electric	0.90	0.96	0.93	9.87	3.85	13.03	13.21	13.12
Alphabet Inc.	0.95	1.13	1.04	9.87	3.85	14.12	14.02	NMF
Henry (Jack) & Assoc	0.85	0.78	0.81	9.87	3.85	11.85	12.32	12.08
L3Harris Technologie	0.90	0.82	0.86	9.87	3.85	12.34	12.69	12.52
Lockheed Martin	0.90	0.66	0.78	9.87	3.85	11.55	12.10	11.82
Landstar System	0.80	0.82	0.81	9.87	3.85	11.85	12.32	12.08
McKesson Corp.	0.85	0.69	0.77	9.87	3.85	11.45	12.02	11.74
McCormick & Co.	0.80	0.73	0.76	9.87	3.85	11.35	11.95	11.65
Monster Beverage	0.85	0.73	0.79	9.87	3.85	11.65	12.17	11.91
Altria Group	0.85	0.59	0.72	9.87	3.85	10.96	11.65	11.31
MSC Industrial Direc	0.95	0.86	0.90	9.87	3.85	12.74	12.98	12.86
NewMarket Corp.	0.75	0.63	0.69	9.87	3.85	10.66	11.43	11.05
Oracle Corp.	0.85	1.05	0.95	9.87	3.85	13.23	13.35	13.29
O'Reilly Automotive	0.90	0.83	0.86	9.87	3.85	12.34	12.69	12.52
OSI Systems	0.90	0.86	0.88	9.87	3.85	12.54	12.84	12.69
Pfizer, Inc.	0.80	0.71	0.76	9.87	3.85	11.35	11.95	11.65
Progressive Corp.	0.75	0.72	0.74	9.87	3.85	11.16	11.80	11.48
Service Corp. Int'l	0.90	0.76	0.83	9.87	3.85	12.05	12.47	12.26
Stepan Company	0.80	0.89	0.85	9.87	3.85	12.24	12.61	12.43
Selective Ins. Group	0.85	0.69	0.77	9.87	3.85	11.45	12.02	11.74
Sirius XM Holdings	0.90	0.84	0.87	9.87	3.85	12.44	12.76	12.60
UniFirst Corp.	0.90	0.79	0.84	9.87	3.85	12.14	12.54	12.34
VeriSign Inc.	0.95	1.11	1.03	9.87	3.85	14.02	13.95	NMF
Waters Corp.	0.95	0.98	0.96	9.87	3.85	13.33	13.43	13.38
Watsco, Inc.	0.90	1.08	0.99	9.87	3.85	13.63	13.65	13.64
Western Union	0.80	0.83	0.82	9.87	3.85	11.95	12.39	12.17
		Mean	0.85			12.21 %	12.59 %	12.33 %
		Median	0.84			12.10 %	12.50 %	12.26 %
		Average of Mean and Median	0.85			12.16 %	12.55 %	12.30 %

Notes:
(1) From note 1 of page 2 of Exhibit No.__(DWD-6).
(2) From note 2 of page 2 of Exhibit No.__(DWD-6)
(3) Average of CAPM and ECAPM cost rates.

Southwest Gas Corporation
Derivation of Investment Risk Adjustment Based upon
Ibbotson Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on July 14, 2023 (1) (millions)	[1] (times larger)	[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	Southwest Gas Corporation	$ 1,680.046		6	1.16%	
2.	Proxy Group of Six Natural Gas Distribution Companies	$ 4,331.038	2.6 x	4	0.58%	0.58%

	[A] Decile	[B] Market Capitalization of Smallest Company (millions)	[C] Market Capitalization of Largest Company (millions)	[D] Size Premium (Return in Excess of CAPM)*
Largest	1	$ 31,549.077	$ 2,203,381.286	-0.26%
	2	12,372.885	31,316.513	0.45%
	3	5,918.981	12,323.854	0.57%
	4	3,770.176	5,916.017	0.58%
	5	2,365.425	3,769.877	0.93%
	6	1,389.851	2,365.076	1.16%
	7	789.019	1,389.118	1.37%
	8	377.076	782.383	1.18%
	9	218.389	373.879	2.15%
Smallest	10	2.015	218.227	4.83%

*From 2023 Kroll Cost of Capital Navigator

Notes:
(1) From page 2 of this Exhibit.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.58% in Column [4], Line No. 2 is derived as follows 0.58% = 1.16% - 0.58%.

Southwest Gas Corporation
Market Capitalization of Southwest Gas Corporation and the
Proxy Group of Six Natural Gas Distribution Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2022 (millions)	[2] Book Value per Share at Fiscal Year End 2022 (1)	[3] Total Common Equity at Fiscal Year End 2022 (millions)	[4] Closing Stock Market Price on July 14, 2023	[5] Market-to-Book Ratio on July 14, 2023 (2)	[6] Market Capitalization on July 14, 2023 (3) (millions)
Southwest Gas Corporation		NA	NA	982.483 (4)	NA		
Based upon Proxy Group of Six Natural Gas Distribution Companies						171.0 (5)	$ 1,680.046 (6)
Proxy Group of Six Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	140.897	$ 66.851	$ 9,419.091	$ 119.440	178.7 %	$ 16,828.690
New Jersey Resources Corporation	NYSE	96.250	18.880	1,817.210	46.170	244.5	4,443.856
NiSource Inc.	NYSE	412.143	14.143	5,828.800	27.940	197.6	11,515.264
Northwest Natural Holding Company	NYSE	35.525	33.088	1,175.441	43.300	130.9	1,538.233
ONE Gas, Inc.	NYSE	55.350	46.692	2,584.426	76.210	163.2	4,218.220
Spire Inc.	NYSE	52.495	53.691	2,818.500	63.030	117.4	3,308.731
Median		75.800	$ 39.890	$ 2,701.463	$ 54.600	171.0 %	$ 4,331.038

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of Southwest Gas Corporation on July 14, 2023 is assumed to be equal to the market-to-book ratio of Proxy Group of Six Natural Gas Distribution Companies on July 14, 2023 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2022 Annual Forms 10K
yahoo.finance.com
Bloomberg Professional Services

Southwest Gas Corporation
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances

		[Column 1]	[Column 2]	[Column 3]	[Column 4]	[Column 5]	[Column 6]	[Column 7]	[Column 8]
Date of Offering	Transaction (1)	Shares Issued	Average Offering Price per Share	Total Offering Expense per Share	Net Proceeds per Share (2)	Gross Equity Issue before Costs	Total Net Proceeds	Total Flotation Costs	Flotation Cost Percentage (7)
3/7/2023	Equity Offering	4,112,607	$ 60.12	$ 2.160	$ 57.9601	$ 247,249,933 (3)	$ 238,367,042 (4)	$ 8,882,891 (5)	3.59%
3/28/2022	Equity Offering	6,325,000	$ 74.00	$ 2.613	$ 71.3871	$ 468,050,000 (3)	$ 451,523,313 (4)	$ 16,526,688 (5)	3.53%
11/26/18	Equity Offering	3,565,000	$ 75.50	$ 2.716	$ 72.7836	$ 269,157,500 (3)	$ 259,473,524 (4)	$ 9,683,977 (5)	3.60%
April 2021 Shelf	Equity Offering					$ 70,360,412 (1)	$ 69,656,808 (1)	$ 703,604 (6)	1.00%
May 2019 Shelf	Equity Offering					$ 253,551,490 (1)	$ 251,015,975 (1)	$ 2,535,515 (6)	1.00%
March 2017 Shelf	Equity Offering					$ 149,999,920 (1)	$ 148,500,011 (1)	$ 1,499,909 (6)	1.00%
March 2015 Shelf	Equity Offering					$ 35,522,812 (1)	$ 35,167,584 (1)	$ 355,228 (6)	1.00%
	Total Public Issuances					$ 1,493,892,067	$ 1,453,704,256	$ 40,187,811	2.69%

Flotation Cost Adjustment

	[Column 9]	[Column 10]	[Column 11]	[Column 12]	[Column 13]	[Column 14]
	Average Dividend Yield (8)	Average Projected EPS Growth Rate (8)	Adjusted Dividend Yield (9)	Average DCF Cost Rate Unadjusted for Flotation (10)	DCF Cost Rate Adjusted for Flotation (11)	Flotation Cost Adjustment (12)
Proxy Group of Six Natural Gas Distribution Companies	3.56 %	6.13 %	3.67 %	9.80 %	9.90 %	0.10 %

Notes:
(1) From Company SEC filings
(2) Col. 2 - Col. 3
(3) Col. 1 x Col. 2
(4) Col. 1 x Col. 4
(5) Col. 1 x Col. 3
(6) Col. 5 - Col. 6
(7) (Col. 5 - Col. 6) / Col. 5
(8) From Exhibit No.___(DWD-4).
(9) Col. 9 * (1 + (0.5 * Col. 10))
(10) Col. 10 + Col. 11
(11) (Col. 11 / (1 - Col. 8)) + Col. 10
(12) Col. 13 - Col. 12

AFFIRMATION OF DYLAN W. D'ASCENDIS

Pursuant to NAC 703.710, Dylan W. D'Ascendis affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 29th day of August, 2023

DYLAN W. D'ASCENDIS

IN THE MATTER OF
SOUTHWEST GAS
CORPORATION DOCKET NO.
23-09___

PREPARED DIRECT TESTIMONY
OF
BYRON C. WILLIAMS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

SEPTEMBER 1, 2023

Table of Contents
Prepared Direct Testimony
of
Byron C. Williams

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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 8360 S. Durango Drive, Las Vegas, Nevada 89113.

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

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

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

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

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

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

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

A. 5 The purpose of my testimony is to provide information concerning Southwest Gas' federal income tax, and state and local taxes.

Q. 6 Are you sponsoring any statements or schedules in support of your prepared direct testimony?

A. 6 Yes. I am sponsoring Statement M and Schedules M-1 through M-5 for the Company's Northern and Southern Nevada rate jurisdictions. I also support the Property Tax Annualization test year adjustment and Nevada Annual Regulatory Assessment (Nevada Mill Assessment) certification adjustment, included on Schedule No. H-17 and Schedule H-C8, respectively.

Q. 7 Are these statements and schedules required by the Commission's regulations?

A. 7 Yes. Nevada Administrative Code (NAC) 703.2265 sets forth filing requirements for utilities with annual gross operating revenues of $250K or more, which includes the filing of Statement M, and its respective schedules, with a general rate case application.

Q. 8 Please summarize your prepared direct testimony.

A. 8 My prepared direct testimony consists of the following key issues:

- The Company's calculation of the provision of federal income taxes;
- The Company's calculation and treatment of Excess Accumulated Deferred Income Taxes (EADIT);
- The impact of the Company's collection of contributions in aid of construction (CIAC) on deferred taxes;
- The Company's calculation of its property, franchise, business, mill assessments and miscellaneous taxes, in addition to its proposed tax adjustments; and
- Support for the Company's Tax Remediation Project.

II. TAX STATEMENTS AND SCHEDULES

Q. 9 Please describe Statement M.

A. 9 Pursuant to NAC 703.2411, Statement M must include the following information:

> *Statement M must contain a statement that shows the computation of allowances for federal income taxes for the period of testing. To indicate the accounting classification applicable to the amount claimed, the computation of the allowance for federal income tax must show separately the amounts designated as current tax and deferred tax.*

Q. 10 Has the Company provided Statement M consistent with NAC 703.2411?

A. 10 Yes. Statement M, Sheets 1 through 3 provides the computation of the provision for federal income tax for the twelve (12) months ended May 31, 2023, for the certification period, and after rate relief. Supporting the computation, Sheet 2 shows the book/tax temporary differences and the resulting calculation of the deferred income tax provision. The calculation of the provision for federal income tax on Sheets 1 and 2 reflects a reduction for the amortization of EADIT, which is supported on Sheet 3.

Q. 11 Please describe Schedule M-1.

A. 11 Pursuant to NAC 703.2415:

> *Schedule M-1 must contain a complete reconciliation of the book net income with taxable net income as reported to the United States Internal Revenue Service for the most recent year for which a tax return was filed and the 3 preceding years. A complete explanation of all items in the reconciliation must be submitted. If the tax allowances claimed give effect to omission of items appearing in the reconciliations for the most recent tax*

return or to inclusion of items not appearing therein, the reasons for the omissions or inclusions must be submitted.

Q. 12 Has the Company provided Schedules M-1 consistent with NAC 703.2415?

A. 12 Yes. Schedule M-1 reconciles financial accounting (book) income with taxable income as reported on Southwest Gas' federal income tax returns for the years 2018 through 2021. Generally, the reconciling amounts represent timing items because of different periods in which an item may be reported as income or claimed as a deduction for federal income tax purposes as compared to financial accounting purposes.

Q. 13 Please describe Schedule M-2.

A. 13 Pursuant to NAC 703.2421:

1. If tax deprecation differs from book depreciation, the applicant must file schedule M-2 showing the computation of the tax depreciation indicating:

a. Differences between book and tax depreciation on a straight-line basis; and

b. The excess of any accelerated depreciation and amortization used for tax purposes over straight-line depreciation.

2. The schedule must pertain to the most recent year for which a tax return was filed and for the 3 previous years.

Q. 14 Has the Company provided Schedule M-2 consistent with NAC 703.2421?

A. 14 Yes. Schedule M-2 provides the depreciation expense calculation for financial accounting and for federal income tax purposes for Southwest Gas' most recent year for which an income tax return was filed (2021) and the three previous years

(2018 through 2020). Depreciation is shown for plant assets by significant category.

Q. 15 Please describe Schedule M-3.

A. 15 Pursuant to NAC 703.2425:

1. If the applicant joins in the filing of a consolidated federal income tax return, the applicant must file schedule M-3 showing the net taxable income or loss for each company or regulated entity in the consolidation, including an adjustment of the excess of accelerated depreciation and amortization of emergency facilities over straight-line deprecation for each company involved.

2. The applicant must also submit the details of consolidation adjustment and a computation of the system tax liability based on the consolidated net income for the last tax year ending within the period of testing, or immediately prior thereto, for which a tax return was filed. In addition, the applicant must include a computation showing the percentage of tax savings arising from consolidation for the taxable year covered by such a period.

Q. 16 Has the Company provided Schedule M-3 consistent with NAC 703.2425?

A. 16 Yes. Schedule M-3 provides net taxable income or loss for each entity included in the Southwest Gas Holdings, Inc. 2021 consolidated federal income tax return (which the Company is a member of), as well as the other required information.

Q. 17 Please describe Schedule M-4.

A. 17 Pursuant to NAC 703.2431:

Schedule M-4 must contain a schedule that shows monthly book balances of accumulated deferred income taxes for each of the 12 months during the period of testing.

Q. 18 Has the Company provided Schedule M-4 consistent with NAC 703.2431?

A. 18 Yes. Schedule M-4 provides, by month, deferred tax balances by Nevada rate jurisdiction. The deferred taxes are recorded in the 282 and 283 series accounts as prescribed by the FERC Uniform System of Accounts.

Q. 19 Please describe Schedule M-5.

A. 19 Pursuant to NAC 703.2435:

1. *Schedule M-5 must contain a schedule that shows the taxes paid by the applicant, other than income taxes in separate columns, as follows:*
   - *a. Tax expense per books for the period of testing;*
   - *b. Any adjustments to the amounts booked; and*
   - *c. The total adjusted taxes claimed.*
2. *The taxes must be shown by states and by kind of taxes.*

Q. 20 Has the Company provided Schedule M-5 consistent with NAC 703.2435?

A. 20 Yes. Schedule M-5, Sheet 1, shows taxes other than income taxes for the 12 months ended May 31, 2023. Sheets 2 and 3 provided the detail of taxes other than income taxes by state and type for each month of the test year.

Q. 21 Are there any post-test year adjustments for the Nevada Mill Assessment?

A. 21 Yes. The Company is proposing to continue a certification adjustment on Schedule H-C8 to update the Nevada Mill Assessment with the most recent Annual Regulatory Assessment received from the Commission. This is consistent with the treatment in Docket 21-09001.

<u>III. EXCESS ACCUMULATED DEFERRED INCOME TAXES (EADIT)</u>

Q. 22 What is EADIT?

A. 22 EADIT is the portion of the accumulated deferred income tax liability that existed at the end of 2017 (calculated at the 35 percent federal income tax) that, barring any other rate changes, would not be paid to the federal government because the federal income tax rate was reduced to 21 percent. At the end of 2017, as a result, the deferred income tax liability accounts were revalued at a 21 percent federal tax rate. The EADIT was reclassified from the deferred income tax liability account to a regulatory liability account, to be refunded to customers of Southwest Gas.

Q. 23 How will the Company's EADIT be returned to customers?

A. 23 The Company proposes to continue to adjust the revenue requirement by the maximum amount of plant-related EADIT amortization using the Average Rate Assumption Method (ARAM) as defined in the Internal Revenue Code and the associated Treasury Regulations. Based on the approved amortization period in Docket No. 21-09001, the Company's non-plant EADIT balance will be fully amortized and returned to customers before new rates go into effect in this proceeding.

Q. 24 What is the ARAM?

A. 24 Under federal income tax law provisions, the ARAM is the methodology used to calculate the maximum amount of protected EADIT returned to customers without triggering penalties for a normalization violation.

. . .

. . .

. . .

Q. 25 How does the ARAM calculate the amortization of EADIT?

A. 25 The ARAM calculation consists of two parts: (1) the calculation of the ratio of aggregate deferred taxes for the property to the aggregate timing differences for the property; and (2) the multiplication of that resulting percentage ratio by the amount of timing differences turning around during the year.

Q. 26 Why must Southwest Gas return EADIT to customers over time, rather than immediately?

A. 26 The Internal Revenue Code penalizes the return of protected EADIT to customers more rapidly, or to a greater extent, than the amount computed using the ARAM. A refund faster than the ARAM limitations is a normalization violation according to the Internal Revenue Code and Treasury Regulations. The estimated turnaround required by the ARAM for the Company's plant-related EADIT is approximately 40 years (i.e., the book life of the underlying plant).

Q. 27 What are the penalties for a normalization violation if the EADIT is returned to customers too quickly?

A. 27 The penalties for a normalization violation are severe and include the following: (1) a current tax penalty equal to the amount by which the entity returned the EADIT to customers more rapidly than permitted under the ARAM; and (2) the entity will no longer be able to claim current or future accelerated depreciation for income tax purposes. These penalties would increase cash tax payments, potentially leading to increased borrowing costs and future customer rate increases.

. . .

. . .

Q. 28 Has the Commission adopted the ARAM method for returning EADIT to customers?

A. 28 Yes. In 1989, the Commission required the use of the ARAM, as provided in Section 203(e) of the Tax Reform Act of 1986, for utilities maintaining vintage accounts. This requirement was codified in NAC 704.6534. In addition, in Docket Nos. 18-05031, 20-02023 and 21-09001, the Commission authorized the use of the ARAM for the Company's EADIT resulting from a change in federal income tax rates.

Q. 29 Please explain the ARAM computations shown on Statement M, Sheet 3.

A. 29 Line 7, column (c) of Sheet 3 shows the annual change in the balance of EADIT caused by the application of the ARAM calculation described in Q&A 25 above. This calculation is performed within utility-specific property accounting software (PowerTax) at the vintage and FERC account level. Numerous calculations are required to determine the amortization amount. The last annual ARAM amortization amount known (based on the 2021 calendar year tax filing) was used to reflect a 12-month period of amortization. This amortization amount reduces the federal income tax component of cost of service, thus passing these savings to our customers.

IV. CONTRIBUTIONS IN AID OF CONSTRUCTION

Q. 30 Was there an effect on deferred taxes from the Company's collection of a tax liability tax factor with respect to taxable CIAC?

A. 30 Yes. Taxable CIAC are reported as taxable income upon receipt, then amortized for tax over the property life. Therefore, deferred taxes are recorded on the tax liability factor, in accordance with NAC 704.6532(5), to reflect the timing difference of the tax treatment versus the book treatment of the taxable CIAC.

The related deferred taxes are considered in computing rate base.

Q. 31 Are there any other accounts that relate to these contributions that have a ratemaking implication?

A. 31 Yes. Consistent with NAC 704.6532(5), the deferred income taxes associated with the CIAC income tax gross-up and customer advance income tax gross-up collected from customers and recorded in regulatory liability accounts 253001473 and 254001472 are recorded in the 282 series accounts. Since regulatory liability accounts 253001473 and 254001472 are not included in rate base, the deferred income tax portion of rate base is adjusted to eliminate the associated deferred income taxes.

V. PROPERTY TAXES

A. Centrally Assessed Property

Q. 32 How are Nevada property taxes assessed on Southwest Gas' utility property?

A. 32 Nevada's public utilities are included in a group of large companies comprised of utilities, railroads, airlines, mining operations, etc., which are assessed property taxes directly by the state of Nevada. The term "centrally assessed" is used to describe this method of taxation and can be contrasted with assessments made by county governments on property owners which are termed "locally assessed."

Q. 33 What procedures are used to establish the property tax liabilities of centrally assessed taxpayers?

A. 33 Centrally assessed taxpayers provide several annual information reports to the Nevada Department of Taxation (Department), which are used by that agency to determine unitary property values. The reports also include information by geographic location that is used by the Department to identify the portion of a company's assessed value within Nevada by specific tax areas. The first report, due in April each year, requires centrally assessed taxpayers to provide the book value of net plant-in-service and audited financial statements. The data provided is for the 12 months ended, or as of, December 31 of the previous calendar year.

Q. 34 What other reports are prepared by Southwest Gas for the Department?

A. 34 Southwest Gas also provides an annual report detailing the monthly additions to construction work-in-progress (CWIP Report) for the 12-month period beginning July of the previous calendar year and ending with June of the current year. The CWIP Report is filed with the Department each August/September.

Q. 35 What does the Department do with the information provided by centrally assessed taxpayers?

A. 35 Based on the information provided by centrally assessed taxpayers, the Department appraises the property using the cost and income value indicators. The Department reports the final appraised value to centrally assessed taxpayers in or around October. Assuming no disagreement, the taxpayer is billed property taxes in the subsequent fiscal year based on the appraised value.

Q. 36 Please provide an example of the timing of the valuation and the related property tax bills.

A. 36 Southwest Gas received a valuation report from the Department in October 2021, based on financial information at December 31, 2020 and adjusted for CWIP additions through June 30, 2021. Southwest Gas then received a property tax bill in July 2022, nine months after receiving the valuation report, which was paid quarterly during the 12 months beginning July 1, 2022 and ended June 30, 2023.

Q. 37 Does the CWIP Report result in additional property tax billed to centrally assessed taxpayers?

A. 37 Yes. In addition to the annual property tax bill, which includes CWIP additions through the previous June, centrally assessed taxpayers also receive an annual property tax bill in and around October/November for CWIP monthly additions through June of that year. Continuing with the property tax example above, Southwest Gas received a bill in October 2022, which was paid in December 2022 for CWIP additions from July 2021 through June 2022.

Q. 38 Is property tax expense shown on Schedule M-5?

A. 38 Yes. As previously stated, Schedule M-5 shows taxes other than income taxes for the 12 months ended May 31, 2023. Column (g) of this schedule identifies the amount of the adjustment for property taxes proposed in this rate case.

B. Proposed Property Tax Adjustments

Q. 39 Are you proposing within test year adjustments to cost of service to annualize Nevada property tax expense in this rate case?

A. 39 Yes. Test year adjustments are proposed for both the Northern Nevada and Southern Nevada rate jurisdictions. The calculation of these adjustments is shown on Schedule H-17.

Q. 40 Are you utilizing the same property tax rate in the adjustment computation on Schedule H-17 as was determined and utilized for the test period?

A. 40 Yes.

Q. 41 How were these rates determined?

A. 41 The rates were determined by dividing the amounts on the property tax bills received in July and October 2022 for the tax year ended June 30, 2023 by the related plant in service at June 30, 2022. This assures that the most recent rates were applied to current property balances.

. . .

Q. 42 Please describe the within test year adjustment.

A. 42 Property tax expense recorded by the Company for the June 1, 2022 to May 31, 2023 test year in this rate case is based substantially on property in service at June 30, 2022. Utility plant placed in service from July 1, 2022 through May 31, 2023 is not yet reflected in property tax expense.

Q. 43 Does the proposed adjustment represent a known and measurable expense?

A. 43 Yes. The proposed adjustment is based on known and measurable amounts for plant in service at the end of the test year. In addition, the property tax rate used in calculating the proposed adjustment is the rate used by the Department in its 2022/2023 tax bills. The plant in service on May 31, 2023 combined with the property tax rate derived from the most recent property tax bills, provides a known and measurable basis for determining the property tax adjustment.

Q. 44 Are there any post-test year adjustments to property tax expense?

A. 44 Yes. The Company is proposing a certification adjustment in Schedule H-C6 to update its rate base through November 30, 2023. The change in property taxes is calculated within that adjustment, using the property tax rate developed for the test period.

Q. 45 Why are these adjustments to property tax expense necessary?

A. 45 The adjustment for property tax expense in the cost of service is necessary primarily due to the requirement to synchronize property tax expense with the amount of plant in rate base at the end of the test period and certification period. This requirement is provided in NAC 704.6528.

. . .

. . .

VI. THE TAX REMEDIATION PROJECT

Q. 46 Please provide an overview of the Tax Remediation Project.

A. 46 The purpose of this project was to enhance the PowerPlan PowerTax and PowerTax Provision modules to fully comply with recent tax law changes and to prepare for potential future tax law changes. Specifically, this allows Southwest Gas to comply with future changes to federal and state income tax rates.

Q. 47 Why was the Tax Remediation Project undertaken at this time?

A. 47 The federal income tax rate decreased in 2017 as part of the Tax Cuts and Jobs Act of 2017 (TCJA), which exposed limitations and system challenges related to tax law changes. Future tax law changes would require significant modifications to PowerPlan's PowerTax and PowerTax Provision modules.

An increase in the federal income tax rate would likely create a deferred income tax deficiency (DITD) that would offset the excess accumulated deferred income tax (EADIT) amount produced by the 2017 tax rate reduction related to the TCJA. The 2017 decrease required the remeasurement of the Company's deferred income tax liabilities at a 21% income tax rate versus the prior income tax rate of 35% and resulted in a reduction of deferred tax liabilities and a corresponding increase in regulatory liabilities of approximately $400 million. Any future rate changes will complicate the Average Rate Assumption Method (ARAM) calculations currently performed by the PowerTax module. As a result, as discussed in the Prepared Direct Testimony of Raied N. Stanley, PowerTax needed configuration changes to provide the level of detail needed to support regulatory scrutiny of the ARAM calculations.

Q. 48 Did Southwest Gas perform an assessment of its existing tax systems to evaluate its limited functionality?

A. 48 Yes. The Tax Department conducted a third-party assessment to review the existing tax systems and data. The assessment analyzed the impact of a change in federal income tax rates on the existing PowerTax and PowerTax Provision configurations, data, and processes. In consultation with Regulated Capital Consultants, LLC (RCC), the Tax Department determined that the PowerTax and PowerTax Provision modules and the related processes lacked the level of detail and transparency needed to (1) respond to regulatory scrutiny of Excess or Deficient ADIT balances and ARAM calculations, and (2) recommended implementing a cloud solution (ASI) to enhance controls over tax data integrity and system validations. It was also noted that the PowerTax and PowerTax Provision modules configurations did not reflect industry best practices.

Q. 49 What was the benefit of the Tax Remediation Project to Southwest Gas?

A. 49 This project enhanced controls over the accuracy and reliability of tax data and calculations that were not historically available in the PowerTax and PowerTax Provision modules. It also increased efficiency by automating reconciliations that were historically performed manually in spreadsheets.

<u>VII. CONCLUSION</u>

Q. 50 Does this conclude your prepared direct testimony?

A. 50 Yes.

SUMMARY OF QUALIFICATIONS
BYRON C. WILLIAMS

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

In 2002, I joined the tax department of PricewaterhouseCoopers LLP in Los Angeles. 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 also became 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.

AFFIRMATION OF BYRON C. WILLIAMS

Pursuant to NAC 703.710, Byron C. Williams affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 14th day of August, 2023

Byron C. Williams

Byron C. Williams

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 23-09___

PREPARED DIRECT TESTIMONY

OF

LISA MCRAE

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTEMBER 1, 2023

Table of Contents
Prepared Direct Testimony
of
Lisa McRae

Description | Page No.

Southwest Gas Corporation
Docket No. 23-09___

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Lisa McRae

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Lisa McRae. My business address is 17875 Von Karman Avenue Suite 300, Irvine, California 92614.

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

A. 2 I am employed by Aon. My title is Senior Partner.

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 testified before the Public Utilities Commission of Nevada (Commission) on behalf of Southwest Gas in 2020 and 2021.

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

A. 5 Aon is the actuary for Southwest Gas Corporation (Southwest Gas or Company) and I have been personally involved in preparing the Company's annual actuarial report since 2010. I therefore support the Company's pension expense for years 2021 through 2023 as presented in the annual Actuarial Reports (Reports), primarily the reasonableness of the discount rate used to determine each year's pension expense and compliance with generally accepted actuarial principles and practices and established accounting standards. Copies of the Reports for each year are attached as Exhibit Nos.__(LM-1) through (LM-3). Company witness, Randi L. Cunningham, supports the Company's pension expense from a ratemaking perspective.

Q. 6 Please summarize your prepared direct testimony.

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

- An overview of the 2021, 2022 and 2023 Reports;
- The process used to determine the pension expense; and
- The reasonableness of the discount rate used.

II. OVERVIEW OF THE ACTUARIAL REPORTS

Q. 7 Please describe the purpose of the Reports prepared by Aon for Southwest Gas.

A. 7 The Reports document the results of the actuarial valuation of the Company's pension plan for the prior calendar year. The information provided in the Reports is intended strictly for documenting: 1) pension cost for the fiscal year; and 2) information relating to Company, and plan disclosure and reporting requirements.

Q. 8 Is the actuarial valuation conducted in accordance with established standards and requirements?

A. 8 Yes. The valuation completed each year is conducted in accordance with generally accepted actuarial principles and practices, including the applicable Actuarial Standards of Practice as issued by the Actuarial Standards Board. The valuation results are also based on Aon's understanding of the financial accounting and reporting requirements under U.S Generally Accepted

Accounting Principles as set forth in Accounting Standards Codification (ASC) Topic 715 (ASC 715), including any guidance or interpretation provided by the Company and reviewed by its auditors prior to the issuance of this report.

Q. 9 How are the Reports relevant to the instant docket?

A. 9 The Reports provide the reasonably incurred pension expense that is used to develop the 3-year average expense amount[1] proposed by the Company for cost recovery, as further discussed by Company witness, Randi Cunningham.

III. DETERMINATION OF THE PENSION EXPENSE

Q. 10 How is pension expense determined?

A. 10 Generally speaking, pension expense is determined by evaluating two key variables - plan liabilities and plan assets. Plan liabilities are driven by plan design, plan demographics, and actuarial assumptions. The market-related value of plan assets is used to determine the component of net periodic pension cost that reflects the expected return on plan assets. This process, including the relevance of each of these variables is discussed in detail in the Reports provided in Exhibit Nos.__(LM-1) through (LM-3).

Q. 11 Please describe the discount rate.

A. 11 One of the key actuarial assumptions within the plan liabilities variable is the discount rate. The pension discount rate is used to determine the present value of future benefits anticipated to be paid from the plan. ASC 715 requires the discount rate to be updated each year to reflect yields on high-quality, corporate bonds as of the measurement date.

[1] 3-year average expense for the test year and certification period uses years 2021, 2022 and 2023.

ASC 715-30-35-43 requires the discount rate to reflect rates at which the pension obligation could be effectively settled. In the estimation of those rates, it would be appropriate for a company to use information about rates implicit in current prices of annuity contracts that could be used to settle the obligation. Alternatively, a company may look to rates of return on high-quality fixed-income investments that are currently available and expected to be available during the plan's pension benefit payment period to maturity.

Q. 12 How is the discount rate determined?

A. 12 As the actuary for the Company's pension plan, Aon determines the appropriate pension discount rate for the plan using one of its proprietary yield curves. Aon publishes three standard yield curves – the "AA-AAA Bond Universe Curve"; the "AA Only Bond Universe Curve; and the "AA Above Median Yield Curve". The derivation of these curves is transparent as Aon provides detailed documentation for each of the curves it publishes and makes a full listing of the bonds included available upon request. Southwest Gas selected the "AA Above Median Yield Curve" (Curve), to derive the pension expense for Southwest Gas. The Curve is based on above median yielding AA-rated bonds which produces a higher discount rate (i.e., lower pension liability and expense) than yield curves based on the full universe of AA and AAA-rated bonds. Had Southwest Gas selected either of the other two curves, they would have produced lower discount rates and higher pension expense. The Curve is updated each measurement date and is widely used across Aon's client base – it is not unique to Southwest Gas. In fact, it is used by over 59% of Aon's clients based on its most recent client survey (data from 214 clients as of fiscal year-end 2022).

. . .

Q. 13 Does Southwest Gas influence the result yielded from the Curve?

A. 13 No. The Curve is proprietary to Aon and no client, including Southwest Gas, has the ability to influence or alter the result.

Q. 14 Does Aon round the results generated from the Curve?

A. 14 Yes. We simply take the unrounded result from the Curve and round to the nearest 25 basis points so as not to imply an overly precise result. This rounding does not have a material impact on pension liabilities or expense. Southwest Gas has consistently used similar rounding methodology and follows the requirements of the Financial Accounting Standards Board and the SEC for discounting pension and other postretirement obligations. Based on its most recent client survey, approximately 37% of Aon clients also round the yield curve result.

Q. 15 Do accounting standards require that the discount rate methodology be applied consistently?

A. 15 Yes. While different methodologies may be acceptable, accounting standards (namely, ASC 715) require that the discount rate methodology (including the yield curve used) be applied consistently year after year, unless the plan's circumstances have materially changed such that the methodology no longer provides management's best estimate.

Q. 16 Is the overall approach and methodology used to determine the 2023 pension expense consistent with the approach taken since at least 2018?

A. 16 Yes. There have been no circumstances under the plan that have materially changed that would support a change in methodology. Therefore, both the discount rate methodology and the curve used to derive the pension expense in

2023 are consistent with what was used to derive the pension expense since at least 2018.

Q. 17 Do the accounting standards allow companies to manipulate the level of pension expense?

A. 17 No. Pension accounting is highly regulated. The standards and rules governing pension accounting, along with the scrutiny from external auditors and the actuarial standards of practice governing the valuation performed by an external actuary, do not allow a company to manipulate pension expense.

IV. REASONABLENESS OF THE DISCOUNT RATES USED TO DETERMINE SOUTHWEST GAS' PENSION EXPENSE

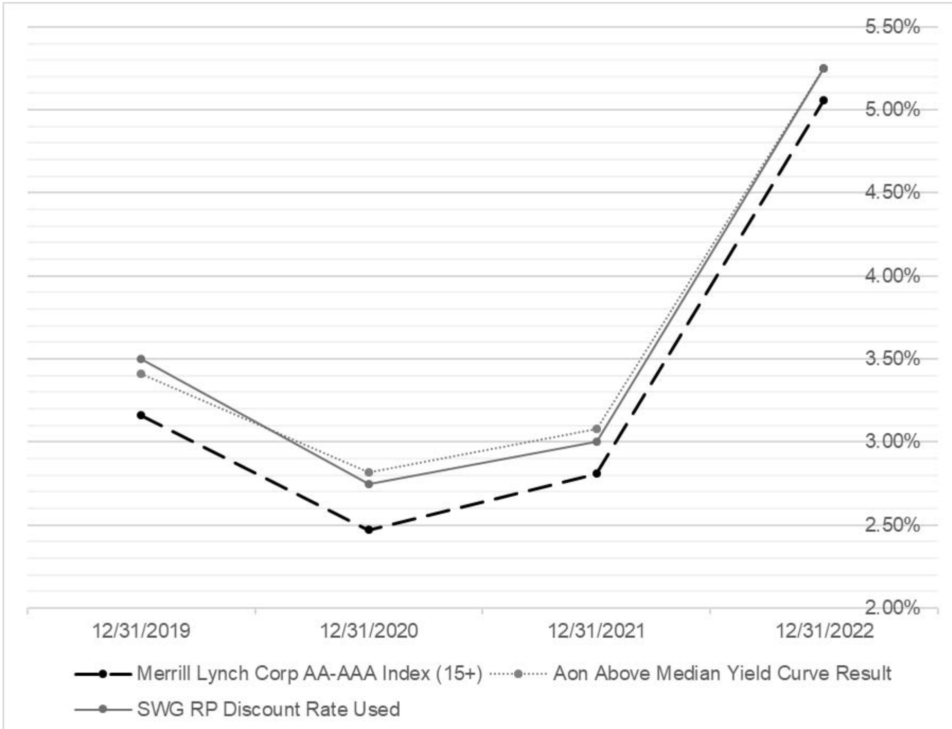
Q. 18 Are the discount rates that have been used in determining Southwest Gas' pension expense since 2021 reasonable[2]?

A. 18 Yes. The Curve is based on above median yielding AA-rated bonds which are representative of the bonds that Southwest Gas would use to settle its pension obligations. The chart below shows a comparison of the discount rate yielded from the Curve used to derive the Southwest Gas pension expense (solid line) and the Merrill Lynch Corp AA-AAA Index (15+) curve. This demonstrates that the year-to-year changes in the Southwest Gas discount rate have matched

---

[2] The Commission approved the Company's proposed pension expense amount of $44,551,451 (before allocation to Nevada) at Certification in its last fully-litigated general rate case filing (Docket No. 20-02023), which was based on the 2018, 2019, 2020 3-year average.

overall movements in the high-quality bond market.



Q. 19 Why is it appropriate for Southwest Gas to use the Curve rather than an index such as the Merrill Lynch Corp AA-AAA Index (15+) curve?

A. 19 As I previously indicated, Southwest Gas' selection of the discount rate based on the Curve is a conservative and reasonable approach because the Curve is based on above median yielding AA-rated bonds, it produces a higher discount rate (i.e., lower pension liability and expense). Further, using a yield curve approach is preferable to an index because the yield curve methodology reflects the anticipated cash flows for Southwest Gas' pension plan.

Q. 20 What was Southwest Gas' annual pension expense for 2021 through 2023?

A. 20 The Company's net periodic pension expense, along with the discount rates used to derive the expense, are shown in the table below.

Table 1
Southwest Gas
Pension Expense Years 2021 Through 2023

As of 12/31 Measurement Date	Pension Expense Year	Aon Above Median Yield Curve Result	Actual Discount Rate Used	Net Periodic Pension Expense
2020	2021	2.81%	2.75%	$51,194,227
2021	2022	3.08%	3.00%	$41,671,514
2022	2023	5.25%	5.25%	$ 1,278,532

Q. 21 What is your conclusion regarding the Company's proposed recovery of pension expense in this proceeding?

A. 21 The annual pension expense reflected in the Reports for years 2021-2023 and summarized in the table above are reasonable and are appropriately used to calculate the 3-year average pension expense discussed in the prepared direct testimony of Company witness, Randi L. Cunningham. These amounts were derived by Aon using the objective and consistently applied methodology described above and reflect appropriate discount rates that comply with the requirements of ASC 715.

Q. 22 Does this conclude your prepared direct testimony?

A. 22 Yes.

SUMMARY OF QUALIFICATIONS
LISA MCRAE

I have over 33 years of experience performing actuarial valuations and consulting with clients on pension-related topics including assumption setting, plan design strategy, financial modeling and pension risk. I am a Fellow of the Society of Actuaries and an Enrolled Actuary. I am a Senior Partner at Aon where I lead Aon's West Region retirement practice. In my role, I lead several client relationships, including Southwest Gas.

I have served as the Enrolled Actuary for the Southwest Gas Retirement Plan since 2010.

I graduated magna cum laude and Phi Beta Kappa from St. Olaf College with a Bachelor of Arts degree in Mathematics and Economics. I joined Aon in 1990.

Proprietary and Confidential

2020 ASC 715 Disclosure

Southwest Gas Corporation

Retirement Plan for Employees of Southwest Gas Corporation

2021 Pension Cost and 2020 Year-end Disclosure

February 2021

AON
Empower Results®

Introduction

This report documents the results of the December 31, 2020 actuarial valuation of the pension plan for Southwest Gas Corporation. The information provided in this report is intended strictly for documenting:

- Pension cost for the 2020 fiscal year
- Information relating to company and plan disclosure and reporting requirements

Determinations for purposes other than the financial accounting requirements may be significantly different from the results in this report. Thus, the use of this report for purposes other than those expressed here may not be appropriate.

This valuation has been conducted in accordance with generally accepted actuarial principles and practices, including the applicable Actuarial Standards of Practice as issued by the Actuarial Standards Board. In addition, the valuation results are based on our understanding of the financial accounting and reporting requirements under U.S. Generally Accepted Accounting Principles as set forth in Accounting Standards Codification (ASC) Topic 715, including any guidance or interpretations provided by Southwest Gas and reviewed by its auditors prior to the issuance of this report. The information in this report is not intended to supersede or supplant the advice and interpretations of Southwest Gas Corporation's auditors.

Future actuarial measurements may differ significantly from the current measurements presented in this report due (but not limited to) to such factors as the following:

- Plan experience differing from that anticipated by the economic or demographic assumptions
- Changes in actuarial methods or in economic or demographic assumptions
- Increases or decreases expected as part of the natural operation of the methodology used for these measurements (such as the end of an amortization period or additional cost or contribution requirements based on the plan's funded status)
- Changes in plan provisions or applicable law

Due to the limited scope of our assignment, we did not perform an analysis of the potential range of such future measurements.

Funded status measurements shown in this report are determined based on various measures of plan assets and liabilities. For company and plan disclosure and reporting purposes, funded status is determined using plan assets measured at market value. Plan liabilities are measured based on the interest rates and other assumptions summarized in the Actuarial Assumptions and Methods section of this report.

These funded status measurements may not be appropriate for assessing the sufficiency of plan assets to cover the estimated cost of settling the plan's benefit obligations, and funded status measurements for company and plan disclosure and reporting purposes may not be appropriate for assessing the need for or the amount of future contributions.

In determining information relating to plan disclosure and reporting requirements, Aon may be assisting the appropriate plan fiduciary as it performs tasks that are required for the administration of an employee benefit plan. Aon also may be consulting with the employer/plan sponsor Southwest Gas as it considers alternative strategies for funding the plan, or as it evaluates information relating to employer reporting requirements. Thus, Aon potentially will be providing assistance to Southwest Gas (and/or certain of its employees) acting in a fiduciary capacity (for the benefit of plan participants and beneficiaries) and to Southwest Gas (and/or its executives) acting in a settlor capacity (for the benefit of the employer sponsoring the Retirement Plan for the Southwest Gas Corporation).

In conducting the valuation, we have relied on personnel, plan design, and asset information supplied by Southwest Gas as of the valuation date. While we cannot verify the accuracy of all the information, the supplied information was reviewed for consistency and reasonableness. As a result of this review, we have no reason to doubt the substantial accuracy or completeness of the information and believe that it has produced appropriate results.

The actuarial assumptions and methods used in this valuation are described in the Actuarial Assumptions and Methods section of this report. Each significant assumption used in this actuarial valuation represents, in our opinion, a reasonable expectation of anticipated experience under the plan.

The undersigned are familiar with the near-term and long-term aspects of pension valuations and collectively meet the Qualification Standards of the American Academy of Actuaries necessary to render the actuarial opinions contained herein. The information provided in this report is dependent upon various factors as documented throughout this report, which may be subject to change. Each section of this report is considered to be an integral part of the actuarial opinions.

To our knowledge, no colleague of Aon providing services to Southwest Gas has any material direct or indirect financial interest in Southwest Gas. Thus, we believe there is no relationship existing that might affect our capacity to prepare and certify this actuarial report for Southwest Gas.

Lisa A. McRae

Lisa A. McRae, FSA, EA
Aon
+949.823.7207
lisa.mcrae@aon.com

John S. Nelson

John S. Nelson, ASA
Aon
+949.823.7616
steve.nelson@aon.com

February 2021

Table of Contents

ASC 715 Pension Cost/(Income)

	2020	2021
Current service cost	$ 34,298,967	$ 41,158,965
Interest cost	45,555,186	40,431,566
Expected asset return	(65,296,459)	(72,351,521)
Amortization of:		
Unrecognized transition obligation/(asset)	0	0
Unrecognized prior service cost	0	0
Unrecognized net loss/(gain)	36,025,290	41,955,217
Net periodic pension cost	$ 50,582,984	$ 51,194,227
Expected benefit payments	$ 56,000,000	$ 58,000,000
Expected contributions	$ 102,000,000	$ 102,000,000
Key assumptions:		
Discount rate	3.50%	2.75%
Expected rate of return on plan assets	6.75%	6.50%
Amortization period for unrecognized net loss/(gain)	10.73	10.60

Market-Related Value of Assets

The market-related value of assets is used to determine the component of net periodic pension cost that reflects the expected return on plan assets. This value can be either fair market value or a smoothed value that recognizes unexpected changes in fair value over a period not exceeding five years. The following presents the development of the plan's market-related value of assets as January 1, 2021.

Development of Market Related Value of Assets

(1) Market value of assets, January 1, 2021		$ 1,186,432,726
Four-fifths of 2020 gain/(loss) of $99,775,702	79,820,562	
Three-fifths of 2019 gain/(loss) of $125,857,896	75,514,738	
Two-fifths of 2018 gain/(loss) of $(126,524,363)	(50,609,745)	
One-fifth of 2017 gain/(loss) of $88,867,570	17,773,514	
(2) Total		122,499,069
Market related value of assets, January 1, 2021, (1) – (2)		$ 1,063,933,657

Development of Asset (Gain)/Loss

Market value, January 1, 2020	$ 974,993,048
Benefit payments during 2020	(55,632,483)
Employer contributions during 2020	102,000,000
Expected return to December 31, 2020 at 6.75%	65,296,459
Expected market value, January 1, 2021	$ 1,086,657,024
Actual market value, January 1, 2021	1,186,432,726
Asset gain/(loss) during 2020	$ 99,775,702

ASC 715 Disclosure

		2019		2020
Change in Projected Benefit Obligation (PBO)				
Benefit obligation at beginning of year	$	1,116,015,541	$	1,329,576,732
Service cost		25,863,464		34,298,967
Interest cost		49,005,699		45,555,186
Plan amendments		0		0
Special termination benefits		0		0
Curtailment gain		0		0
Actuarial (gain)/loss		192,415,545		145,440,378
Benefits paid		(53,723,517)		(55,632,483)
Benefit obligation at end of year	$	1,329,576,732	$	1,499,238,780
Accumulated Benefit Obligation, End of Year	$	1,219,988,651	$	1,367,179,064
Change in Plan Assets				
Fair value of plan assets at beginning of year	$	790,615,129	$	974,993,048
Actual return on plan assets		186,101,436		165,072,161
Company contributions		52,000,000		102,000,000
Benefits paid		(53,723,517)		(55,632,483)
Fair value of plan assets at end of year	$	974,993,048	$	1,186,432,726
Funded Status	$	(354,583,684)	$	(312,806,054)
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	$	0	$	0
Current liabilities		0		0
Noncurrent liabilities		(354,583,684)		(312,806,054)
Net pension asset/(liability) at year-end	$	(354,583,684)	$	(312,806,054)
Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)				
Net actuarial loss/(gain)	$	462,510,721	$	472,150,107
Prior service cost/(credit)		0		0
Net transition obligation/(asset)		0		0
	$	462,510,721	$	472,150,107
Weighted-Average Assumptions as of December 31				
Discount rate		3.50%		2.75%
Rate of compensation increase		3.25%		3.00%

ASC 715 Disclosure

		2019		2020
Components of Net Periodic Pension Cost				
Service cost	$	25,863,464	$	34,298,967
Interest cost		49,005,699		45,555,186
Expected return on plan assets		(60,243,540)		(65,296,459)
Amortization of:				
Unrecognized net (gain)/loss		22,355,945		36,025,290
Unrecognized prior service cost		0		0
Unrecognized net (asset)/obligation		0		0
Net periodic pension cost	$	36,981,568	$	50,582,984
Special termination benefits		0		0
Curtailment (gain)/charge		0		0
Total net periodic pension cost	$	36,981,568	$	50,582,984
Other Changes in Plan Assets and PBO Recognized in AOCI				
Net actuarial loss/(gain)	$	66,557,649	$	45,664,676
Amortization of net actuarial (loss)/gain		(22,355,945)		(36,025,290)
Prior service cost/(credit)		0		0
Amortization of prior service cost		0		0
Amortization of net transition obligation		0		0
Total recognized in AOCI	$	44,201,704	$	9,639,386
Total recognized in net periodic pension cost and AOCI	$	81,183,272	$	60,222,370
Weighted-Average Assumptions Used to Determine Net Periodic Pension Cost for Year Ended December 31				
Discount rate (pension cost)		4.50%		3.50%
Expected rate of return on plan assets		7.00%		6.75%
Rate of compensation increase		3.25%		3.25%

Estimated Future Benefit Payments		Pension Benefits
2021	$	58,000,000
2022	$	60,000,000
2023	$	61,000,000
2024	$	62,000,000
2025	$	63,000,000
Years 2026-2030	$	339,000,000

Participant Data

The actuarial valuation was based on personnel information from Southwest Gas records as of August 1, 2020. Following are some of the pertinent characteristics from the personnel data as of that date. Prior year characteristics are also provided for comparison purposes. Both age and service have been determined using years and months as of the valuation date.

	August 1, 2019	August 1, 2020
Active Participants		
Number	2,281	2,257
Average present age	44.1	44.3
Average service since hire	12.0	12.3
Average compensation	$ 93,139	$ 94,217
Disabled Participants		
Number	40	33
Average age	57.4	58.3
Deferred Vested Participants		
Number	316	329
Average age	50.8	50.7
Average monthly benefit	$ 936	$ 918
Retired Participants		
Number	2,064	2,103
Average age	69.5	69.9
Average monthly benefit	$ 2,439	$ 2,486

Plan Provisions

Effective Date

This summary reflects the plan document amended and restated effective January 1, 2016 and the fifth amendment signed April 2, 2019.

Plan Participation

Employees participate on the first of the month following date of hire.

Normal Retirement

Eligibility

Age 65 and five years of vesting service.

Benefit Amount

An annual benefit amount equal to 1.75% of final average pay times benefit service up to 30 years.

Early Retirement

Eligibility

Age 55 and ten years of vesting service.

Benefit Amount

Early retirement benefits are determined by reducing the normal retirement benefit as follows:

(a) No reduction for employees who retire on or after age 60.

(b) No reduction applies for employees who retire with 85 points (i.e., age plus benefit service).

(c) The following reductions apply for employees who retire prior to age 60 with at least 20 years of benefit service but less than 85 points:

Retirement Age	Early Retirement Factor
59	0.97
58	0.94
57	0.91
56	0.88
55	0.85

(d) For all early retirement eligible participants who do not satisfy (a), (b) or (c), the following reductions apply:

Retirement Age	Early Retirement Factor
59	0.95
58	0.90
57	0.85
56	0.80
55	0.75

Disability Retirement	
Eligibility	Vested and total and permanent disability.
Benefit Amount	Normal or early retirement benefits described above commence as of the date long-term disability benefits cease. Benefit service accrues during the period of disability prior to commencement, and the benefit is calculated based on final average pay at time of disability. Benefits commence at age 65 or upon election to begin early retirement.
Deferred Vested Termination	
Eligibility	Five years of vesting service.
Benefit Amount	Accrued normal retirement benefit payable at age 65 or as early as age 55 on an actuarially reduced basis.
Preretirement Survivor Annuity	
Eligibility	Vested participants married one year or more.
Benefit Amount	A survivor benefit equal to 50% of the normal retirement benefit reduced for early commencement and 50% joint and survivor form of benefit is paid to the spouse of the participant.
Benefit Commencement Date	Later of the first of the month following the participant's date of death or the first of the month following the date the participant would have attained age 55.
Final Average Pay	Average annual compensation during the five highest-paid consecutive calendar years of the employee's last ten years of vesting service.
Compensation	Calendar year compensation from the Company, including base pay, overtime, sales incentive payments, and amounts deferred by salary reduction pursuant to Code Sections 401(k) and 125, but excluding incentive pay, commissions, car allowances, amounts deferred into non-qualified deferred compensation plans, flexible benefit dollars, moving expenses, paid-out vacation and nonrecurring payments such as (but not limited to) bonuses and performance awards.
Benefit Service	One year for each plan year with 1,000 hours of service. Fractional service is accrued in the year of hire and year of termination.
Vesting Service	One year for each plan year with 1,000 hours of service.
Unreduced Form of Payment	Life annuity.

Normal Form of Payment	
Married	50% joint and survivor annuity.
Unmarried	Life annuity.
Optional Forms of Payment	5-year certain and life annuity, age 62 or 65 level income annuity, and large amount lump sum (TEP transferred employees only).
Lump Sums	Lump sums of up to \$5,000. Lump sums of \$1,000 or less are paid automatically.
Actuarial Equivalence	
General	6.5% interest and the RP2000 Combined Healthy Mortality Table weighted 50% for males and 50% for females.
Lump Sums	IRC section 417(e) mortality table for the applicable year and interest based on the 3-segment curve.

Actuarial Assumptions and Methods

For ASC 715 Requirements

Measurement Date	December 31, 2020.
Actuarial Method	Projected unit credit.
Market Related Value of Assets	Market value adjusted to smooth asset gains or losses. Smoothing is done by reflecting gains or losses 20% per year until fully recognized.
Discount Rate	2.75% at December 31, 2020.
Expected Return on Assets	6.50% for 2021 expense.
Salary Increases	Sample pay increases are shown below.

Age	Rate
30	3.75%
40	3.25%
50	2.75%
60	2.25%

Mortality Rates

Healthy Lives	Pri-2012 Private Retirement Plan Mortality Table for Employees and Healthy Annuitants without collar adjustments, and with fully generational mortality projection using the Mortality Improvement Scale MP-2020 for 2020 year-end.
Disabled Lives	Pri-2012 Private Retirement Plan Mortality Table for Disabled Retirees without collar adjustments, and with fully generational mortality projection using the Mortality Improvement Scale MP-2020 for 2020 year-end.

Termination Rates Sample termination rates are as follows:

	Rate by Years of Service					
Age	0	1	2	3	4	5+
30	11.4%	10.7%	9.9%	9.7%	9.7%	9.7%
40	11.4%	10.7%	9.9%	9.2%	8.6%	5.0%
50	11.4%	10.7%	9.9%	9.2%	8.6%	2.4%

Disability Rates

Sample disability rates are as follows:

Age	Male	Female
30	0.03%	0.04%
40	0.08%	0.13%
50	0.33%	0.40%
60	1.15%	0.90%

Retirement Age

Rates of retirement as shown below:

	Rate by Service			Rate by Service	
Age	Under 20	20+	Age	Under 20	20+
55	3%	15%	63	20%	20%
56	3%	12%	64	40%	40%
57	3%	12%	65	40%	40%
58	3%	12%	66	40%	40%
59	10%	15%	67	40%	40%
60	15%	15%	68	40%	40%
61	15%	15%	69	40%	40%
62	30%	30%	70	100%	100%

Marital Status

85% of male participants and 65% of female participants are assumed to be married with wives two years younger than husbands.

Maximum Benefit

As described in IRC 415, $230,000 for 2020, projected 2.25% per year.

Maximum Pensionable Pay

$285,000 for 2020 projected 2.25% per year.

Expenses

Expected asset return is net of investment expenses and net of a 0.4% reduction to reflect administrative expenses paid out of the trust.

Changes in Accounting Assumptions/Methods Since the Prior Year

Assumption Changes

Discount Rate	Changed from 3.50% to 2.75% as of December 31, 2020
Salary Increases	Inflation rate reduced 0.25% for all ages as of December 31, 2020.
Mortality–Healthy Lives	Changed the fully generational mortality projection using the Mortality Improvement Scale MP-2019 to the Mortality Improvement Scale MP-2020 effective December 31, 2020.
Mortality–Disabled Lives	Changed the fully generational mortality projection using the Mortality Improvement Scale MP-2019 to the Mortality Improvement Scale MP-2020 effective December 31, 2020.

Actuarial Assumptions and Methods

Discussion of Actuarial Assumptions and Methods

Southwest Gas selected the economic and demographic assumptions and prescribed them for use for purposes of compliance with ASC 715. Aon provided guidance with respect to these assumptions, and it is our belief that the assumptions represent reasonable expectations of anticipated plan experience. The actuarial cost method used is prescribed by ASC 715. While the method used to value assets is prescribed by Southwest Gas, Aon provided guidance with respect to the use of this method, and it is our belief that the method is appropriate for financial accounting purposes.

Calculation of Normal Costs and Liabilities

The method used to calculate the service cost and projected benefit obligation for determining pension expense is the projected unit credit cost method. Under this method, benefits are estimated at each decrement age by crediting future accruals based on projected pay as applicable. The liability is determined as the present value of the projected benefit based on service at the valuation date. The service cost is the amount of the present value of projected benefits attributable to the valuation year.

Accounting Information Under ASC 715

Benefit obligations and expense/(income) are calculated under U.S. Generally Accepted Accounting Principles as set forth in Accounting Standards Codification (ASC) Topic 715.

The accumulated benefit obligation represents the actuarial present value of benefits based on service and pay earned as of the measurement date. The projected benefit obligation represents the actuarial present value of benefits based on service earned through the measurement date reflecting the effect of assumed future pay increases on ultimate benefit amounts.

The service cost represents the actuarial present value of benefits that are attributed to a fiscal year, reflecting the effect of assumed future pay increases. The service cost includes interest to the end of the measurement period at the ASC 715 discount rate.

The net periodic pension expense/(income) is the annual amount to be recognized in the income statement as the cost of pension benefits for this plan for the fiscal year.

Settlement/curtailment expense/(income) is the amount to be recognized in the income statement as the cost of special events such as settlements, curtailments, and the provision of certain termination benefits during a fiscal year.

Proprietary and Confidential

2021 ASC 715 Disclosure

Southwest Gas Corporation

Retirement Plan for Employees of Southwest Gas Corporation

2022 Pension Cost and 2021 Year-end Disclosure

February 2022

AON

Introduction

This report documents the results of the December 31, 2021 actuarial valuation of the pension plan for Southwest Gas Corporation. The information provided in this report is intended strictly for documenting:

- Pension cost for the 2021 fiscal year
- Information relating to company and plan disclosure and reporting requirements

Determinations for purposes other than the financial accounting requirements may be significantly different from the results in this report. Thus, the use of this report for purposes other than those expressed here may not be appropriate.

This valuation has been conducted in accordance with generally accepted actuarial principles and practices, including the applicable Actuarial Standards of Practice as issued by the Actuarial Standards Board. In addition, the valuation results are based on our understanding of the financial accounting and reporting requirements under U.S. Generally Accepted Accounting Principles as set forth in Accounting Standards Codification (ASC) Topic 715, including any guidance or interpretations provided by Southwest Gas and reviewed by its auditors prior to the issuance of this report. The information in this report is not intended to supersede or supplant the advice and interpretations of Southwest Gas Corporation's auditors.

Future actuarial measurements may differ significantly from the current measurements presented in this report due (but not limited to) to such factors as the following:

- Plan experience differing from that anticipated by the economic or demographic assumptions
- Changes in actuarial methods or in economic or demographic assumptions
- Increases or decreases expected as part of the natural operation of the methodology used for these measurements (such as the end of an amortization period or additional cost or contribution requirements based on the plan's funded status)
- Changes in plan provisions or applicable law

Due to the limited scope of our assignment, we did not perform an analysis of the potential range of such future measurements.

Funded status measurements shown in this report are determined based on various measures of plan assets and liabilities. For company and plan disclosure and reporting purposes, funded status is determined using plan assets measured at market value. Plan liabilities are measured based on the interest rates and other assumptions summarized in the Actuarial Assumptions and Methods section of this report.

These funded status measurements may not be appropriate for assessing the sufficiency of plan assets to cover the estimated cost of settling the plan's benefit obligations, and funded status measurements for company and plan disclosure and reporting purposes may not be appropriate for assessing the need for or the amount of future contributions.

In determining information relating to plan disclosure and reporting requirements, Aon may be assisting the appropriate plan fiduciary as it performs tasks that are required for the administration of an employee benefit plan. Aon also may be consulting with the employer/plan sponsor Southwest Gas as it considers alternative strategies for funding the plan, or as it evaluates information relating to employer reporting requirements. Thus, Aon potentially will be providing assistance to Southwest Gas (and/or certain of its employees) acting in a fiduciary capacity (for the benefit of plan participants and beneficiaries) and to Southwest Gas (and/or its executives) acting in a settlor capacity (for the benefit of the employer sponsoring the Retirement Plan for the Southwest Gas Corporation).

In conducting the valuation, we have relied on personnel, plan design, and asset information supplied by Southwest Gas as of the valuation date. While we cannot verify the accuracy of all the information, the supplied information was reviewed for consistency and reasonableness. As a result of this review, we have no reason to doubt the substantial accuracy or completeness of the information and believe that it has produced appropriate results.

The actuarial assumptions and methods used in this valuation are described in the Actuarial Assumptions and Methods section of this report. Each significant assumption used in this actuarial valuation represents, in our opinion, a reasonable expectation of anticipated experience under the plan.

The undersigned are familiar with the near-term and long-term aspects of pension valuations and collectively meet the Qualification Standards of the American Academy of Actuaries necessary to render the actuarial opinions contained herein. The information provided in this report is dependent upon various factors as documented throughout this report, which may be subject to change. Each section of this report is considered to be an integral part of the actuarial opinions.

To our knowledge, no colleague of Aon providing services to Southwest Gas has any material direct or indirect financial interest in Southwest Gas. Thus, we believe there is no relationship existing that might affect our capacity to prepare and certify this actuarial report for Southwest Gas.

Lisa A. McRae, FSA, EA
Aon
+949.823.7207
lisa.mcrae@aon.com

John S. Nelson, ASA
Aon
+949.823.7616
steve.nelson@aon.com

February 2022

Table of Contents

ASC 715 Pension Cost/(Income)

	2021	2022
Current service cost	$ 41,158,965	$ 44,110,145
Interest cost	40,431,566	45,005,914
Expected asset return	(72,351,521)	(79,913,104)
Amortization of:		
Unrecognized transition obligation/(asset)	0	0
Unrecognized prior service cost	0	0
Unrecognized net loss/(gain)	41,955,217	32,468,559
Net periodic pension cost	$ 51,194,227	$ 41,671,514
Expected benefit payments	$ 58,000,000	$ 62,000,000
Expected contributions	$ 102,000,000	$ 56,000,000
Key assumptions:		
Discount rate	2.75%	3.00%
Expected rate of return on plan assets	6.50%	6.50%
Amortization period for unrecognized net loss/(gain)	10.60	11.03

Market-Related Value of Assets

The market-related value of assets is used to determine the component of net periodic pension cost that reflects the expected return on plan assets. This value can be either fair market value or a smoothed value that recognizes unexpected changes in fair value over a period not exceeding five years. The following presents the development of the plan's market-related value of assets as January 1, 2022.

Development of Market Related Value of Assets

(1) Market value of assets, January 1, 2022		$	1,366,042,730
Four-fifths of 2021 gain/(loss) of $63,799,981	51,039,985		
Three-fifths of 2020 gain/(loss) of $99,775,702	59,865,421		
Two-fifths of 2019 gain/(loss) of $125,857,896	50,343,158		
One-fifth of 2018 gain/(loss) of $(126,524,363)	(25,304,873)		
(2) Total			135,943,691
Market related value of assets, January 1, 2022, (1) – (2)		$	1,230,099,039

Development of Asset (Gain)/Loss

Market value, January 1, 2021	$	1,186,432,726
Benefit payments during 2021		(58,541,498)
Employer contributions during 2021		102,000,000
Expected return to December 31, 2021 at 6.50%		72,351,521
Expected market value, January 1, 2022	$	1,302,242,749
Actual market value, January 1, 2022		1,366,042,730
Asset gain/(loss) during 2021	$	63,799,981

ASC 715 Disclosure

		2020		2021
Change in Projected Benefit Obligation (PBO)				
Benefit obligation at beginning of year	$	1,329,576,732	$	1,499,238,780
Service cost		34,298,967		41,158,965
Interest cost		45,555,186		40,431,566
Plan amendments		0		0
Special termination benefits		0		0
Curtailment gain		0		0
Actuarial (gain)/loss		145,440,378		8,909,316
Benefits paid		(55,632,483)		(58,541,498)
Benefit obligation at end of year	$	1,499,238,780	$	1,531,197,129
Accumulated Benefit Obligation, End of Year	$	1,367,179,064	$	1,395,773,032
Change in Plan Assets				
Fair value of plan assets at beginning of year	$	973,084,082	$	1,186,432,726
Actual return on plan assets		166,981,127		136,151,502
Company contributions		102,000,000		102,000,000
Benefits paid		(55,632,483)		(58,541,498)
Fair value of plan assets at end of year	$	1,186,432,726	$	1,366,042,730
Funded Status	$	(312,806,054)	$	(165,154,399)
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	$	0	$	0
Current liabilities		0		0
Noncurrent liabilities		(312,806,054)		(165,154,399)
Net pension asset/(liability) at year-end	$	(312,806,054)	$	(165,154,399)
Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)				
Net actuarial loss/(gain)	$	472,150,107	$	375,304,225
Prior service cost/(credit)		0		0
Net transition obligation/(asset)		0		0
	$	472,150,107	$	375,304,225
Weighted-Average Assumptions as of December 31				
Discount rate		2.75%		3.00%
Rate of compensation increase		3.00%		3.25%

ASC 715 Disclosure

		2020		2021
Components of Net Periodic Pension Cost				
Service cost	$	34,298,967	$	41,158,965
Interest cost		45,555,186		40,431,566
Expected return on plan assets		(65,296,459)		(72,351,521)
Amortization of:				
Unrecognized net (gain)/loss		36,025,290		41,955,217
Unrecognized prior service cost		0		0
Unrecognized net (asset)/obligation		0		0
Net periodic pension cost	$	50,582,984	$	51,194,227
Special termination benefits		0		0
Curtailment (gain)/charge		0		0
Total net periodic pension cost	$	50,582,984	$	51,194,227
Other Changes in Plan Assets and PBO Recognized in AOCI				
Net actuarial loss/(gain)	$	45,664,676	$	(54,890,665)
Amortization of net actuarial (loss)/gain		(36,025,290)		(41,955,217)
Prior service cost/(credit)		0		0
Amortization of prior service cost		0		0
Amortization of net transition obligation		0		0
Total recognized in AOCI	$	9,639,386	$	(96,845,882)
Total recognized in net periodic pension cost and AOCI	$	60,222,370	$	(45,651,655)

Weighted-Average Assumptions Used to Determine Net Periodic Pension Cost for Year Ended December 31

	2020	2021
Discount rate (pension cost)	3.50%	2.75%
Expected rate of return on plan assets	6.75%	6.50%
Rate of compensation increase	3.25%	3.00%

Estimated Future Benefit Payments		Pension Benefits
2022	$	62,000,000
2023	$	64,000,000
2024	$	65,000,000
2025	$	67,000,000
2026	$	68,000,000
Years 2027-2031	$	365,000,000

Participant Data

The actuarial valuation was based on personnel information from Southwest Gas records as of August 1, 2021. Following are some of the pertinent characteristics from the personnel data as of that date. Prior year characteristics are also provided for comparison purposes. Both age and service have been determined using years and months as of the valuation date.

	August 1, 2020	August 1, 2021
Active Participants		
Number	2,257	2,250
Average present age	44.3	44.2
Average service since hire	12.3	12.1
Average compensation	$ 94,217	$ 96,203
Disabled Participants		
Number	33	34
Average age	58.3	58.4
Deferred Vested Participants		
Number	329	340
Average age	50.7	50.6
Average monthly benefit	$ 918	$ 919
Retired Participants		
Number	2,103	2,168
Average age	69.9	70.3
Average monthly benefit	$ 2,486	$ 2,561

Plan Provisions

Effective Date

This summary reflects the plan document amended and restated effective January 1, 2015 and the seventh amendment signed December 31, 2021.

Plan Participation

Employees hired prior to or on December 31, 2021, participate on the first of the month following date of hire.

Normal Retirement

Eligibility

Age 65 and five years of vesting service.

Benefit Amount

An annual benefit amount equal to 1.75% of final average pay times benefit service up to 30 years.

Early Retirement

Eligibility

Age 55 and ten years of vesting service.

Benefit Amount

Early retirement benefits are determined by reducing the normal retirement benefit as follows:

(a) No reduction for employees who retire on or after age 60.

(b) No reduction applies for employees who retire with 85 points (i.e., age plus benefit service).

(c) The following reductions apply for employees who retire prior to age 60 with at least 20 years of benefit service but less than 85 points:

Retirement Age	Early Retirement Factor
59	0.97
58	0.94
57	0.91
56	0.88
55	0.85

(d) For all early retirement eligible participants who do not satisfy (a), (b) or (c), the following reductions apply:

Retirement Age	Early Retirement Factor
59	0.95
58	0.90
57	0.85
56	0.80
55	0.75

Disability Retirement

Eligibility	Vested and total and permanent disability.
Benefit Amount	Normal or early retirement benefits described above commence as of the date long-term disability benefits cease. Benefit service accrues during the period of disability prior to commencement, and the benefit is calculated based on final average pay at time of disability. Benefits commence at age 65 or upon election to begin early retirement.

Deferred Vested Termination

Eligibility	Five years of vesting service.
Benefit Amount	Accrued normal retirement benefit payable at age 65 or as early as age 55 on an actuarially reduced basis.

Preretirement Survivor Annuity

Eligibility	Vested participants married one year or more.
Benefit Amount	A survivor benefit equal to 50% of the normal retirement benefit reduced for early commencement and 50% joint and survivor form of benefit is paid to the spouse of the participant.
Benefit Commencement Date	Later of the first of the month following the participant's date of death or the first of the month following the date the participant would have attained age 55.

Final Average Pay	Average annual compensation during the five highest-paid consecutive calendar years of the employee's last ten years of vesting service.
Compensation	Calendar year compensation from the Company, including base pay, overtime, sales incentive payments, and amounts deferred by salary reduction pursuant to Code Sections 401(k) and 125, but excluding incentive pay, commissions, car allowances, amounts deferred into non-qualified deferred compensation plans, flexible benefit dollars, moving expenses, paid-out vacation and nonrecurring payments such as (but not limited to) bonuses and performance awards.
Benefit Service	One year for each plan year with 1,000 hours of service. Fractional service is accrued in the year of hire and year of termination.
Vesting Service	One year for each plan year with 1,000 hours of service.
Unreduced Form of Payment	Life annuity.

Normal Form of Payment	
Married	50% joint and survivor annuity.
Unmarried	Life annuity.
Optional Forms of Payment	5-year certain and life annuity, age 62 or 65 level income annuity, and large amount lump sum (TEP transferred employees only).
Lump Sums	Lump sums of up to $75,000. Lump sums of $1,000 or less are paid automatically.
Actuarial Equivalence	
General	6.5% interest and the RP2000 Combined Healthy Mortality Table weighted 50% for males and 50% for females.
Lump Sums	IRC section 417(e) mortality table for the applicable year and interest based on the 3-segment curve.

Actuarial Assumptions and Methods

For ASC 715 Requirements

Measurement Date

December 31, 2021.

Actuarial Method

Projected unit credit.

Market Related Value of Assets

Market value adjusted to smooth asset gains or losses. Smoothing is done by reflecting gains or losses 20% per year until fully recognized.

Discount Rate

3.00% at December 31, 2021.

Expected Return on Assets

6.50% for 2022 expense.

Salary Increases

Sample pay increases are shown below:

Age	2021 Expense	Year-End
30	3.75%	4.00%
40	3.25%	3.50%
50	2.75%	3.00%
60	2.25%	2.50%

Mortality Rates

Healthy Lives

Pri-2012 Private Retirement Plan Mortality Table for Employees and Healthy Annuitants without collar adjustments, and with fully generational mortality projection using the Mortality Improvement Scale MP-2021 for 2021 year-end.

Disabled Lives

Pri-2012 Private Retirement Plan Mortality Table for Disabled Retirees without collar adjustments, and with fully generational mortality projection using the Mortality Improvement Scale MP-2021 for 2021 year-end.

Termination Rates

Sample termination rates for 2021 expense are as follows:

	Rate by Years of Service					
Age	**0**	**1**	**2**	**3**	**4**	**5+**
30	11.4%	10.7%	9.9%	9.7%	9.7%	9.7%
40	11.4%	10.7%	9.9%	9.2%	8.6%	5.0%
50	11.4%	10.7%	9.9%	9.2%	8.6%	2.4%

Sample termination rates for year-end are as follows:

	Rate by Years of Service					
Age	**0**	**1**	**2**	**3**	**4**	**5+**
30	8.0%	8.0%	8.0%	5.0%	5.0%	5.0%
40	8.0%	8.0%	8.0%	5.0%	4.0%	3.0%
50	8.0%	8.0%	8.0%	5.0%	4.0%	3.0%

Disability Rates

Sample disability rates are as follows:

Age	Male	Female
30	0.03%	0.04%
40	0.08%	0.13%
50	0.33%	0.40%
60	1.15%	0.90%

Retirement Age

Rates of retirement as shown below based on age and service:

	2021 Expense		Year-End		
				20+	
Age	Under 20	20+	Under 20	<85 pts	85+ pts
55	3%	15%	4%	10%	30%
56	3%	12%	4%	10%	30%
57	3%	12%	4%	10%	30%
58	3%	12%	4%	20%	30%
59	10%	15%	15%	20%	30%
60	15%	15%	25%	25%	25%
61	15%	15%	25%	25%	25%
62	30%	30%	30%	30%	30%
63	20%	20%	15%	15%	15%
64	40%	40%	30%	30%	30%
65	40%	40%	40%	40%	40%
66	40%	40%	40%	40%	40%
67	40%	40%	25%	25%	25%
68	40%	40%	25%	25%	25%
69	40%	40%	25%	25%	25%
70+	100%	100%	100%	100%	100%

Marital Status

85% of male participants and 65% of female participants are assumed to be married with wives two years younger than husbands.

Maximum Benefit

As described in IRC 415, $230,000 for 2021, projected 2.25% per year.

Maximum Pensionable Pay

$290,000 for 2021 projected 2.25% per year.

Expenses

Expected asset return is net of investment expenses and net of a 0.4% reduction to reflect administrative expenses paid out of the trust.

Changes in Accounting Assumptions/Methods Since the Prior Year

Assumption Changes

Discount Rate	Changed from 2.75% to 3.00% as of December 31, 2021
Salary Increases	Changed for year-end as noted above.
Mortality–Healthy Lives	Changed the fully generational mortality projection using the Mortality Improvement Scale MP-2020 to the Mortality Improvement Scale MP-2021 effective December 31, 2021.
Mortality–Disabled Lives	Changed the fully generational mortality projection using the Mortality Improvement Scale MP-2020 to the Mortality Improvement Scale MP-2021 effective December 31, 2021.
Termination Rates	Changed for year-end as noted above.
Retirement Age	Changed for year-end as noted above.

Actuarial Assumptions and Methods

Discussion of Actuarial Assumptions and Methods

Southwest Gas selected the economic and demographic assumptions and prescribed them for use for purposes of compliance with ASC 715. Aon provided guidance with respect to these assumptions, and it is our belief that the assumptions represent reasonable expectations of anticipated plan experience. The actuarial cost method used is prescribed by ASC 715. While the method used to value assets is prescribed by Southwest Gas, Aon provided guidance with respect to the use of this method, and it is our belief that the method is appropriate for financial accounting purposes.

Calculation of Normal Costs and Liabilities

The method used to calculate the service cost and projected benefit obligation for determining pension expense is the projected unit credit cost method. Under this method, benefits are estimated at each decrement age by crediting future accruals based on projected pay as applicable. The liability is determined as the present value of the projected benefit based on service at the valuation date. The service cost is the amount of the present value of projected benefits attributable to the valuation year.

Accounting Information Under ASC 715

Benefit obligations and expense/(income) are calculated under U.S. Generally Accepted Accounting Principles as set forth in Accounting Standards Codification (ASC) Topic 715.

The accumulated benefit obligation represents the actuarial present value of benefits based on service and pay earned as of the measurement date. The projected benefit obligation represents the actuarial present value of benefits based on service earned through the measurement date reflecting the effect of assumed future pay increases on ultimate benefit amounts.

The service cost represents the actuarial present value of benefits that are attributed to a fiscal year, reflecting the effect of assumed future pay increases. The service cost includes interest to the end of the measurement period at the ASC 715 discount rate.

The net periodic pension expense/(income) is the annual amount to be recognized in the income statement as the cost of pension benefits for this plan for the fiscal year.

Settlement/curtailment expense/(income) is the amount to be recognized in the income statement as the cost of special events such as settlements, curtailments, and the provision of certain termination benefits during a fiscal year.

Proprietary and Confidential

2022 ASC 715 Disclosure

Southwest Gas Corporation

Retirement Plan for Employees of Southwest Gas Corporation

2023 Pension Cost and 2022 Year-end Disclosure

February 2023

AON

Introduction

This report documents the results of the December 31, 2022 actuarial valuation of the pension plan for Southwest Gas Corporation. The information provided in this report is intended strictly for documenting:

- Pension cost for the 2022 fiscal year
- Information relating to company and plan disclosure and reporting requirements

Determinations for purposes other than the financial accounting requirements may be significantly different from the results in this report. Thus, the use of this report for purposes other than those expressed here may not be appropriate.

This valuation has been conducted in accordance with generally accepted actuarial principles and practices, including the applicable Actuarial Standards of Practice as issued by the Actuarial Standards Board. In addition, the valuation results are based on our understanding of the financial accounting and reporting requirements under U.S. Generally Accepted Accounting Principles as set forth in Accounting Standards Codification (ASC) Topic 715, including any guidance or interpretations provided by Southwest Gas and reviewed by its auditors prior to the issuance of this report. The information in this report is not intended to supersede or supplant the advice and interpretations of Southwest Gas Corporation's auditors.

Future actuarial measurements may differ significantly from the current measurements presented in this report due (but not limited to) to such factors as the following:

- Plan experience differing from that anticipated by the economic or demographic assumptions
- Changes in actuarial methods or in economic or demographic assumptions
- Increases or decreases expected as part of the natural operation of the methodology used for these measurements (such as the end of an amortization period or additional cost or contribution requirements based on the plan's funded status)
- Changes in plan provisions or applicable law

Due to the limited scope of our assignment, we did not perform an analysis of the potential range of such future measurements.

Funded status measurements shown in this report are determined based on various measures of plan assets and liabilities. For company and plan disclosure and reporting purposes, funded status is determined using plan assets measured at market value. Plan liabilities are measured based on the interest rates and other assumptions summarized in the Actuarial Assumptions and Methods section of this report.

These funded status measurements may not be appropriate for assessing the sufficiency of plan assets to cover the estimated cost of settling the plan's benefit obligations, and funded status measurements for company and plan disclosure and reporting purposes may not be appropriate for assessing the need for or the amount of future contributions.

In determining information relating to plan disclosure and reporting requirements, Aon may be assisting the appropriate plan fiduciary as it performs tasks that are required for the administration of an employee benefit plan. Aon also may be consulting with the employer/plan sponsor Southwest Gas as it considers alternative strategies for funding the plan, or as it evaluates information relating to employer reporting requirements. Thus, Aon potentially will be providing assistance to Southwest Gas (and/or certain of its employees) acting in a fiduciary capacity (for the benefit of plan participants and beneficiaries) and to Southwest Gas (and/or its executives) acting in a settlor capacity (for the benefit of the employer sponsoring the Retirement Plan for the Southwest Gas Corporation).

In conducting the valuation, we have relied on personnel, plan design, and asset information supplied by Southwest Gas as of the valuation date. While we cannot verify the accuracy of all the information, the supplied information was reviewed for consistency and reasonableness. As a result of this review, we have no reason to doubt the substantial accuracy or completeness of the information and believe that it has produced appropriate results.

The actuarial assumptions and methods used in this valuation are described in the Actuarial Assumptions and Methods section of this report. Each significant assumption used in this actuarial valuation represents, in our opinion, a reasonable expectation of anticipated experience under the plan.

The undersigned are familiar with the near-term and long-term aspects of pension valuations and collectively meet the Qualification Standards of the American Academy of Actuaries necessary to render the actuarial opinions contained herein. The information provided in this report is dependent upon various factors as documented throughout this report, which may be subject to change. Each section of this report is considered to be an integral part of the actuarial opinions.

To our knowledge, no colleague of Aon providing services to Southwest Gas has any material direct or indirect financial interest in Southwest Gas. Thus, we believe there is no relationship existing that might affect our capacity to prepare and certify this actuarial report for Southwest Gas.

Lisa A. McRae

Lisa A. McRae, FSA, EA
Aon
+949.823.7207
lisa.mcrae@aon.com

John S. Nelson

John S. Nelson, ASA
Aon
+949.823.7616
steve.nelson@aon.com

February 2023

Table of Contents

ASC 715 Pension Cost/(Income)

	2022	2023
Current service cost	$ 44,110,145	$ 25,839,823
Interest cost	45,005,914	59,164,909
Expected asset return	(79,913,104)	(84,061,670)
Amortization of:		
Unrecognized transition obligation/(asset)	0	0
Unrecognized prior service cost	0	0
Unrecognized net loss/(gain)	32,468,559	335,470
Net periodic pension cost	$ 41,671,514	$ 1,278,532
Expected benefit payments	$ 62,000,000	$ 65,000,000
Expected contributions	$ 56,000,000	$ 56,000,000
Key assumptions:		
Discount rate	3.00%	5.25%
Expected rate of return on plan assets	6.50%	6.75%
Amortization period for unrecognized net loss/(gain)	11.03	10.96

Market-Related Value of Assets

The market-related value of assets is used to determine the component of net periodic pension cost that reflects the expected return on plan assets. This value can be either fair market value or a smoothed value that recognizes unexpected changes in fair value over a period not exceeding five years. The following presents the development of the plan's market-related value of assets as January 1, 2023.

Development of Market Related Value of Assets

(1) Market value of assets, January 1, 2023		$ 1,030,044,059
Four-fifths of 2022 gain/(loss) of ($410,115,655)	(328,092,524)	
Three-fifths of 2021 gain/(loss) of $63,799,981	38,279,989	
Two-fifths of 2020 gain/(loss) of $99,775,702	39,910,281	
One-fifth of 2019 gain/(loss) of $125,857,896	25,171,579	
(2) Total		(224,730,675)
Market related value of assets, January 1, 2023, (1) – (2)		$ 1,244,550,268

Development of Asset (Gain)/Loss

Market value, January 1, 2022	$ 1,366,042,730
Benefit payments during 2022	(61,796,120)
Employer contributions during 2022	56,000,000
Expected return to December 31, 2022 at 6.50%	79,913,104
Expected market value, January 1, 2023	$ 1,440,159,714
Actual market value, January 1, 2023	1,030,044,059
Asset gain/(loss) during 2022	$ (410,115,655)

ASC 715 Disclosure

	2021	2022
Change in Projected Benefit Obligation (PBO)		
Benefit obligation at beginning of year	$ 1,499,238,780	$ 1,531,197,129
Service cost	41,158,965	44,110,145
Interest cost	40,431,566	45,005,914
Plan amendments	0	0
Special termination benefits	0	0
Curtailment gain	0	0
Actuarial (gain)/loss	8,909,316	(399,066,421)
Benefits paid	(58,541,498)	(61,796,120)
Benefit obligation at end of year	$ 1,531,197,129	$ 1,159,450,647
Accumulated Benefit Obligation, End of Year	$ 1,395,773,032	$ 1,074,493,413
Change in Plan Assets		
Fair value of plan assets at beginning of year	$ 1,186,432,726	$ 1,366,042,730
Actual return on plan assets	136,151,502	(330,202,551)
Company contributions	102,000,000	56,000,000
Benefits paid	(58,541,498)	(61,796,120)
Fair value of plan assets at end of year	$ 1,366,042,730	$ 1,030,044,059
Funded Status	$ (165,154,399)	$ (129,406,588)
Amounts Recognized in the Statement of Financial Position		
Noncurrent assets	$ 0	$ 0
Current liabilities	0	0
Noncurrent liabilities	(165,154,399)	(129,406,588)
Net pension asset/(liability) at year-end	$ (165,154,399)	$ (129,406,588)
Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)		
Net actuarial loss/(gain)	$ 375,304,225	$ 353,884,900
Prior service cost/(credit)	0	0
Net transition obligation/(asset)	0	0
	$ 375,304,225	$ 353,884,900
Weighted-Average Assumptions as of December 31		
Discount rate	3.00%	5.25%
Rate of compensation increase	3.25%	3.25%

ASC 715 Disclosure

	2021	2022
Components of Net Periodic Pension Cost		
Service cost	$ 41,158,965	$ 44,110,145
Interest cost	40,431,566	45,005,914
Expected return on plan assets	(72,351,521)	(79,913,104)
Amortization of:	0	
Unrecognized net (gain)/loss	41,955,217	32,468,559
Unrecognized prior service cost	0	0
Unrecognized net (asset)/obligation	0	0
Net periodic pension cost	$ 51,194,227	$ 41,671,514
Special termination benefits	0	0
Curtailment (gain)/charge	0	0
Total net periodic pension cost	$ 51,194,227	$ 41,671,514
Other Changes in Plan Assets and PBO Recognized in AOCI		
Net actuarial loss/(gain)	$ (54,890,665)	$ 11,049,234
Amortization of net actuarial (loss)/gain	(41,955,217)	(32,468,559)
Prior service cost/(credit)	0	0
Amortization of prior service cost	0	0
Amortization of net transition obligation	0	0
Total recognized in AOCI	$ (96,845,882)	$ (21,419,325)
Total recognized in net periodic pension cost and AOCI	$ (45,651,655)	$ 20,252,189
Weighted-Average Assumptions Used to Determine Net Periodic Pension Cost for Year Ended December 31		
Discount rate (pension cost)	2.75%	3.00%
Expected rate of return on plan assets	6.50%	6.50%
Rate of compensation increase	3.00%	3.25%

Estimated Future Benefit Payments	Pension Benefits
2023	$ 65,000,000
2024	$ 67,000,000
2025	$ 68,000,000
2026	$ 69,000,000
2027	$ 71,000,000
Years 2028-2032	$ 377,000,000

Participant Data

The actuarial valuation was based on personnel information from Southwest Gas records as of August 1, 2022. Following are some of the pertinent characteristics from the personnel data as of that date. Prior year characteristics are also provided for comparison purposes. Both age and service have been determined using years and months as of the valuation date.

	August 1, 2021	August 1, 2022
Active Participants		
Number	2,250	2,133
Average present age	44.2	44.3
Average service since hire	12.1	12.3
Average compensation	$ 96,203	$ 98,866
Disabled Participants		
Number	34	35
Average age	58.4	57.2
Deferred Vested Participants		
Number	340	376
Average age	50.6	49.7
Average monthly benefit	$ 919	$ 1,024
Retired Participants		
Number	2,168	2,230
Average age	70.3	70.6
Average monthly benefit	$ 2,561	$ 2,634

Plan Provisions

Effective Date

This summary reflects the plan document amended and restated effective January 1, 2015 and the eighth amendment signed January 22, 2022.

Plan Participation

Employees hired prior to or on December 31, 2021, participate on the first of the month following date of hire.

Normal Retirement

Eligibility

Age 65 and five years of vesting service.

Benefit Amount

An annual benefit amount equal to 1.75% of final average pay times benefit service up to 30 years.

Early Retirement

Eligibility

Age 55 and ten years of vesting service.

Benefit Amount

Early retirement benefits are determined by reducing the normal retirement benefit as follows:

(a) No reduction for employees who retire on or after age 60.

(b) No reduction applies for employees who retire with 85 points (i.e., age plus benefit service).

(c) The following reductions apply for employees who retire prior to age 60 with at least 20 years of benefit service but less than 85 points:

Retirement Age	Early Retirement Factor
59	0.97
58	0.94
57	0.91
56	0.88
55	0.85

(d) For all early retirement eligible participants who do not satisfy (a), (b) or (c), the following reductions apply:

Retirement Age	Early Retirement Factor
59	0.95
58	0.90
57	0.85
56	0.80
55	0.75

Disability Retirement	
Eligibility	Vested and total and permanent disability.
Benefit Amount	Normal or early retirement benefits described above commence as of the date long-term disability benefits cease. Benefit service accrues during the period of disability prior to commencement, and the benefit is calculated based on final average pay at time of disability. Benefits commence at age 65 or upon election to begin early retirement.
Deferred Vested Termination	
Eligibility	Five years of vesting service.
Benefit Amount	Accrued normal retirement benefit payable at age 65 or as early as age 55 on an actuarially reduced basis.
Preretirement Survivor Annuity	
Eligibility	Vested participants married one year or more.
Benefit Amount	A survivor benefit equal to 50% of the normal retirement benefit reduced for early commencement and 50% joint and survivor form of benefit is paid to the spouse of the participant.
Benefit Commencement Date	Later of the first of the month following the participant's date of death or the first of the month following the date the participant would have attained age 55.
Final Average Pay	Average annual compensation during the five highest-paid consecutive calendar years of the employee's last ten years of vesting service.
Compensation	Calendar year compensation from the Company, including base pay, overtime, sales incentive payments, and amounts deferred by salary reduction pursuant to Code Sections 401(k) and 125, but excluding incentive pay, commissions, car allowances, amounts deferred into non-qualified deferred compensation plans, flexible benefit dollars, moving expenses, paid-out vacation and nonrecurring payments such as (but not limited to) bonuses and performance awards.
Benefit Service	One year for each plan year with 1,000 hours of service. Fractional service is accrued in the year of hire and year of termination.
Vesting Service	One year for each plan year with 1,000 hours of service.
Unreduced Form of Payment	Life annuity.

Normal Form of Payment	
Married	50% joint and survivor annuity.
Unmarried	Life annuity.
Optional Forms of Payment	5-year certain and life annuity, age 62 or 65 level income annuity, and large amount lump sum (TEP transferred employees only).
Lump Sums	Lump sums of up to $75,000. Lump sums of $1,000 or less are paid automatically.
Actuarial Equivalence	
General	6.5% interest and the RP2000 Combined Healthy Mortality Table weighted 50% for males and 50% for females.
Lump Sums	IRC section 417(e) mortality table for the applicable year and interest based on the 3-segment curve.

Actuarial Assumptions and Methods

For ASC 715 Requirements

Measurement Date

December 31, 2022.

Actuarial Method

Projected unit credit.

Market Related Value of Assets

Market value adjusted to smooth asset gains or losses. Smoothing is done by reflecting gains or losses 20% per year until fully recognized.

Discount Rate

5.25% at December 31, 2022.

Expected Return on Assets

6.75% for 2023 expense.

Salary Increases

Sample pay increases are shown below:

Age	Rate
30	4.00%
40	3.50%
50	3.00%
60	2.50%

Mortality Rates

Healthy Lives

Pri-2012 Private Retirement Plan Mortality Table for Employees and Healthy Annuitants without collar adjustments, and with fully generational mortality projection using the Mortality Improvement Scale MP-2021 for 2022 year-end.

Disabled Lives

Pri-2012 Private Retirement Plan Mortality Table for Disabled Retirees without collar adjustments, and with fully generational mortality projection using the Mortality Improvement Scale MP-2021 for 2022 year-end.

Termination Rates

Sample termination rates are as follows:

	Rate by Years of Service					
Age	**0**	**1**	**2**	**3**	**4**	**5+**
30	8.0%	8.0%	8.0%	5.0%	5.0%	5.0%
40	8.0%	8.0%	8.0%	5.0%	4.0%	3.0%
50	8.0%	8.0%	8.0%	5.0%	4.0%	3.0%

Disability Rates

Sample disability rates are as follows:

Age	Male	Female
30	0.03%	0.04%
40	0.08%	0.13%
50	0.33%	0.40%
60	1.15%	0.90%

Retirement Age

Rates of retirement as shown below based on age and service:

	Service / Age & Service Points		
		20+	
Age	Under 20	<85 pts	85+ pts
55	4%	10%	30%
56	4%	10%	30%
57	4%	10%	30%
58	4%	20%	30%
59	15%	20%	30%
60	25%	25%	25%
61	25%	25%	25%
62	30%	30%	30%
63	15%	15%	15%
64	30%	30%	30%
65	40%	40%	40%
66	40%	40%	40%
67	25%	25%	25%
68	25%	25%	25%
69	25%	25%	25%
70+	100%	100%	100%

Marital Status

85% of male participants and 65% of female participants are assumed to be married with wives two years younger than husbands.

Maximum Benefit

As described in IRC Section 415, $245,000 for 2022, projected 2.25% per year.

Maximum Pensionable Pay

$305,000 for 2022, projected 2.25% per year.

Expenses

Expected asset return is net of investment expenses and net of a 0.1% reduction to reflect administrative expenses paid out of the trust.

Changes in Accounting Assumptions/Methods Since the Prior Year

Assumption Changes

Discount Rate	Changed from 3.00% to 5.25% as of December 31, 2022
Expected Return on Assets	The expected return on assets changed from 6.50% to 6.75%, effective January 1, 2023.

Actuarial Assumptions and Methods

Discussion of Actuarial Assumptions and Methods

Southwest Gas selected the economic and demographic assumptions and prescribed them for use for purposes of compliance with ASC 715. Aon provided guidance with respect to these assumptions, and it is our belief that the assumptions represent reasonable expectations of anticipated plan experience. The actuarial cost method used is prescribed by ASC 715. While the method used to value assets is prescribed by Southwest Gas, Aon provided guidance with respect to the use of this method, and it is our belief that the method is appropriate for financial accounting purposes.

Calculation of Normal Costs and Liabilities

The method used to calculate the service cost and projected benefit obligation for determining pension expense is the projected unit credit cost method. Under this method, benefits are estimated at each decrement age by crediting future accruals based on projected pay as applicable. The liability is determined as the present value of the projected benefit based on service at the valuation date. The service cost is the amount of the present value of projected benefits attributable to the valuation year.

Accounting Information Under ASC 715

Benefit obligations and expense/(income) are calculated under U.S. Generally Accepted Accounting Principles as set forth in Accounting Standards Codification (ASC) Topic 715.

The accumulated benefit obligation represents the actuarial present value of benefits based on service and pay earned as of the measurement date. The projected benefit obligation represents the actuarial present value of benefits based on service earned through the measurement date reflecting the effect of assumed future pay increases on ultimate benefit amounts.

The service cost represents the actuarial present value of benefits that are attributed to a fiscal year, reflecting the effect of assumed future pay increases. The service cost includes interest to the end of the measurement period at the ASC 715 discount rate.

The net periodic pension expense/(income) is the annual amount to be recognized in the income statement as the cost of pension benefits for this plan for the fiscal year.

Settlement/curtailment expense/(income) is the amount to be recognized in the income statement as the cost of special events such as settlements, curtailments, and the provision of certain termination benefits during a fiscal year.

AFFIRMATION OF LISA A. McRAE

Pursuant to NAC 703.710, LISA A. McRAE affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 29 day of August, 2023

Lisa A. McRae

LISA A. McRAE

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 23-09___

PREPARED DIRECT TESTIMONY

OF

JAMES L. STEIN

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTEMBER 1, 2023

Table of Contents
Prepared Direct Testimony
of
James L. Stein

Description	Page No.

Appendix A – Summary of Qualifications of James L. Stein

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of

James L. Stein

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is James L. Stein. My business address is 8360 S. Durango Drive, Las Vegas, Nevada 89113.

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

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company). My title is Manager/Emerging Technology & Innovation.

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

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

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

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada (Commission).

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

A. 5 My testimony supports the Company's construction and installation of a compressed natural gas (CNG) fueling station at the Company's North Operations Center in Las Vegas (CNG Station Project).

Q. 6 Please summarize your prepared direct testimony.

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

- The need and benefits of the CNG Station Project; and
- The prudency of the CNG Station Project.

II. BACKGROUND

Q. 7 What is CNG?

A. 7 CNG is natural gas that has been compressed to 3,600 pounds per square inch gauge (PSIG) and may be used to power specially equipped internal combustion engines in vehicles. It is compressed to increase the distance traveled while using CNG as a transportation fuel.

Q. 8 Are there environmental benefits associated with utilizing CNG as a vehicle fuel when compared to diesel or gasoline?

A. 8 Yes. When compared to diesel or gasoline, CNG burns cleaner and emits as much as 28 percent fewer greenhouse gas (GHG) emissions.

Q. 9 How much CNG is delivered Company-wide?

A. 9 In 2022, Southwest Gas delivered 37 million therms of natural gas to be used as CNG to Arizona, California, and Nevada fleet customers.

Q. 10 What are the GHG emissions eliminated Company-wide due to CNG delivery?

A. 10 By using CNG over other vehicle fuels, Southwest Gas' CNG customers emitted 79,012 fewer metric tons of carbon dioxide equivalent ("MTCO2 e") in 2022 – the equivalent of 17,025 fewer gasoline-powered passenger vehicles operating on the roadway per year (4.6 metric tons per passenger vehicle).[1]

---

[1] U.S. Environmental Protection Agency Greenhouse Gas Equivalencies Calculator (https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator)

Q. 11 How much CNG is delivered in Southern Nevada?

A. 11 In 2022, Southwest Gas delivered 16.7 million therms of natural gas to be used as CNG for Southern Nevada fleet customers.

Q. 12 How much GHG emissions has been eliminated In Southern Nevada due to CNG delivery?

A. 12 By using CNG over other vehicle fuels, Southwest Gas' Southern NV CNG customers emitted 35,680 fewer MTCO2 e in 2022 – the equivalent of 7,940 fewer gasoline-powered passenger vehicles operating on the roadway per year (4.6 metric tons per passenger vehicle).[2]

Q. 13 What led to the Company constructing the CNG Station Project at its North Operations Center?

A. 13 In 2017, the Company committed to reducing GHG emissions by 20 percent from its fleet and facilities by 2025.[3] In Docket No. 20-02023, Southwest Gas introduced, and the Commission approved[4], its CNG Conversion Project which supported the Company's conversion of its fleet's vehicles from gasoline to CNG to help reduce GHG emissions for its vehicle fleet. Over the last several years, Company CNG vehicles have been filling at one of two public stations in the Las Vegas Valley - one located at 3333 Losee Road and another located at 3683 Industrial Road. These public CNG stations are not located close to the Company's North Operations Center where many of the Company's CNG vehicles are located. As more companies move to CNG vehicles, limited fueling

---

[2] U.S. Environmental Protection Agency Greenhouse Gas Equivalencies Calculator (https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator)
[3] See Southwest Gas Holdings' 2022 Sustainability Report at pgs. 28-29. https://www.swgas.com/1409216536723/Southwest-Gas-2022-Sustainability-Report.pdf
[4] September 25, 2020 Order at page 123, paragraph 350.

options present inefficiencies. Also, as the Company's fleet continues to grow, an on-site station provides an efficient option to fill onsite at the North Operations Center.

Q. 14 How many CNG vehicles does the Company have in Southern Nevada?

A. 14 There are currently 71 active CNG vehicles in Southern Nevada. These vehicles support the Company's core functions and are necessary in providing safe and reliable natural gas service to the Company's customers.

<u>III. CNG STATION PROJECT</u>

Q. 15 Please provide an overview of CNG Station Project.

A. 15 The Company's CNG Station Project is comprised of a 75 HP, 4-stage compressor, and onsite storage of approximately 335 gasoline gallon equivalent (GGE) that serves a single dispenser with two fueling hoses/nozzles. The onsite storage allows for multiple vehicles to fuel simultaneously as well as having the capability to fill directly from the compressor. The configuration of the CNG Station Project allows for CNG vehicles to refuel in about the same amount of time as a typical gasoline or diesel light duty vehicle would take to refuel at a gasoline or diesel refueling station.

Q. 16 How much did the CNG Station Project cost to construct?

A. 16 The total cost of the CNG Station Project (0021W0006606) was $1,252,962.

Q. 17 Did the Company submit an RFP for the CNG Station Project?

A. 17 Yes. The Company performed an RFP process and had two bidders respond. Lancer Energy was the successful bidder submitting a lower bid.

Q. 18 When was the CNG Station Project completed and placed into service?

A. 18 The CNG Station Project was placed in service November 2022.

Q. 19 Is the CNG Station Project reasonable and prudent?

A. 19 Yes. The CNG Station Project is both reasonable and prudent. The CNG Station Project is consistent with what the Commission approved in Docket 20-02023, regularly used since being placed into service in November 2022, provides an efficient fueling option for Company CNG vehicles, and is in the public interest as it supports GHG emissions reductions in Nevada.

Q. 20 How many GGEs did the Company's CNG vehicles consume from January through July 2023?

A. 21 The Company's CNG vehicles used 13,256 GGEs (16,791 therms) across all Las Vegas stations of which approximately 10,641 GGEs (13,479 therms) were dispensed from the CNG Station Project.

Q. 22 Were GHG emissions reduced by use of the CNG Station Project and Company use of CNG vehicles?

A. 22 Yes. When comparing CNG to gasoline as a vehicle fuel, the CNG Station Project supported the reduction of approximately 23.3 metric tons of CO_2 from January through July 2023. By using CNG instead of gasoline, the Southern Nevada CNG fleet, as a whole, helped reduce GHG emissions by approximately 29 metric tons of CO_2 in the same period.

IV. CONCLUSION

Q. 23 Does this conclude your prepared direct testimony?

A. 23 Yes.

SUMMARY OF QUALIFICATIONS
JAMES L. STEIN

I have over 22 years of energy industry experience, 20 of which have been with Southwest Gas. In my current position, I am responsible for emerging technology in Nevada, California and Arizona. Over the years, I have gained extensive experience in both the residential and commercial market sectors within Southwest Gas' service territories.

I began my career at Southwest Gas as an Industrial Gas Engineer. In this role, I managed large commercial, industrial and agricultural accounts in Las Vegas. My key responsibilities included sales engineering and contract negotiations.

Prior to joining Southwest Gas, I was a heating, ventilation and air conditioning (HVAC) Sales Engineer with the Trane Company. In addition to Sales with the Trane Company, I was also responsible for technical knowledge of different HVAC systems. Preceding the Trane Company, I was a plumbing and HVAC Design Engineer for a Las Vegas based consulting firm specializing in the commercial sector.

I graduated with a Bachelor of Science degree in Mechanical Engineering from the University of Nevada, Las Vegas, and have received a Certified Energy Manager designation from the Association of Energy Engineers.

AFFIRMATION OF JAMES L. STEIN

Pursuant to NAC 703.710, James L. Stein affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 25 day of August, 2023

JAMES L. STEIN

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 23-09___

PREPARED DIRECT TESTIMONY

OF

JEROME T. SCHMITZ

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTEMBER 1, 2023

Table of Contents
Prepared Direct Testimony
of
Jerome T. Schmitz

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Jerome T. Schmitz

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Jerome (Jerry) T. Schmitz. My business address is 8360 S. Durango Drive, Las Vegas, Nevada 89113.

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

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

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.

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

A. 5 The purpose of my prepared direct testimony is to provide an overview of the planning process and management of capital investments for equipment within Engineering Staff to support Operations, the Company's Integrity Management Program, and the Company's Radio Console Upgrade Project (Radio Project). I also provide support for the Company's American Gas Association (AGA) membership dues from an operational and pipeline safety perspective.

Q. 6 Please summarize your prepared direct testimony.

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

- Provide an overview of the planning process and management of capital projects for Engineering Staff-related equipment to support Operations and the Company's Integrity Management Program;
- Support the reasonableness of corporate (system allocable) and Southern Nevada Engineering Staff-related projects, including a discussion of projects in excess of $1 million that were placed into service since the end of the certification period in Southwest Gas' 2021 general rate case (GRC); and
- Provide support for the Company's American Gas Association (AGA) membership dues from an operational and pipeline safety perspective, which benefit and support the enhancement of the Company through access to industry safety best practices and operational excellence initiatives.

II. ENGINEERING STAFF CAPITAL INVESTMENTS

Q. 7 Please describe the scope of the Engineering Staff capital investment projects discussed in your prepared direct testimony.

A. 7 I support capital investments made by Engineering Staff at Southern Nevada and corporate locations placed into service since December 1, 2021.[1] Projects represented by work orders greater than $100,000 in total are listed in Exhibit

[1] The certification period in the Company's most recent GRC filing (Docket No. 21-09001) ended November 30, 2021.

No.__(JTS-1). My prepared direct testimony specifically discusses one work order with incurred costs equal to $1 million or more as of May 31, 2023.[2]

III. RADIO CONSOLE UPGRADE PROJECT (RADIO PROJECT)

Q. 8 Please provide a brief overview of the Radio Project.

A. 8 The Radio Console Upgrade Project (Radio Project) replaced the Company's analog radio system with modern digital technologies to enhance safety, communications, efficiency, portability, and reliability. The upgrade in radio technology extends connectivity to automate and encrypt connections to radio towers based on the best available signal strength. In addition, the Radio Project supports dedicated talk groups across large geographical areas and can handle high-traffic communications to support the dispatch of emergency communications and workload management.

Q. 9 What are the benefits of the Radio Project from an operational perspective?

A. 9 Effective emergency response is a critical function of safely operating a natural gas system. A key aspect of emergency response is the ability to communicate with company field personnel reliably and clearly.

The new digital system deployed as part of the Radio Project will enhance safety, communications, efficiency, portability, and reliability for all users from an emergency response perspective. Please see the testimony of Company witness Raied N. Stanley who discusses the three primary drivers of the Radio Project which include enhanced safety, service, and reliability of field communications with Company dispatch, Emergency Operations Center, and

[2] All Engineering Services-related work orders presented on Master Data Request 106, and work order 0021W0007768.

Incident Command System sectors during incidents and other emergency events.

Southwest Gas operates in both urban and rural parts of Nevada. Having reliable and clear communications technologies are a crucial part of safely operating a natural gas system in Nevada. While cellular technologies have become the mainstream, the use of the Company's dedicated radio network allows for an independent and primary methodology for communicating that does not rely upon local cellular networks or face the same challenges of call drops or interruptions of service during major regional emergencies such as wildfires, extreme weather, or other extreme events.

Q. 10 Is the Company currently using the Radio Project?

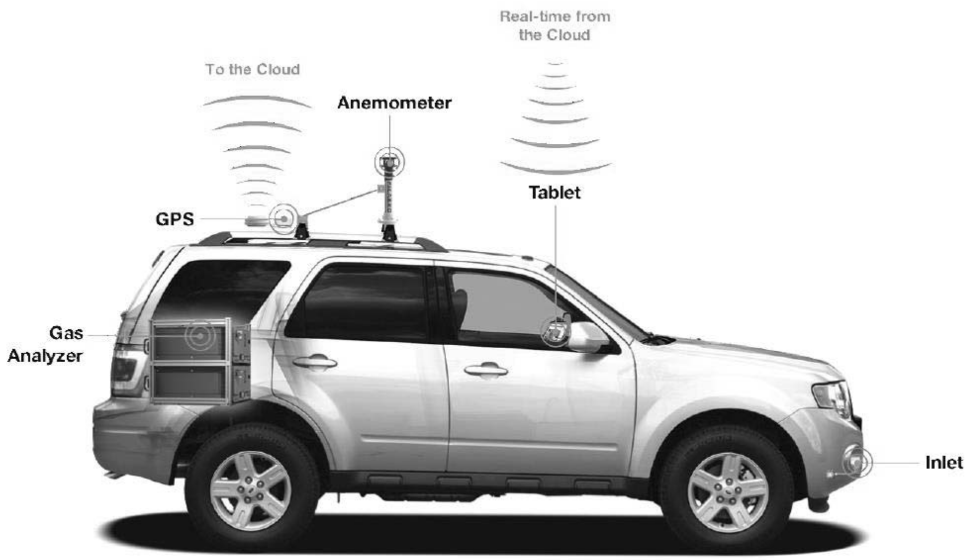
A. 10 Yes. The Company is currently implementing the Radio Project and is expected to be fully implemented in Nevada by the end of 2023.

IV. PICARRO ADVANCED MOBILE LEAK DETECTION EQUIPMENT

Q. 11 Please provide an overview of the Picarro Advanced Mobile Leak Detection (AMLD) equipment purchase.

A. 11 The Picarro AMLD equipment purchase represented in work order 0021W0007768 involves the acquisition of an advanced cavity ring down spectroscopy-based methane leak detection device for use in identifying and quantifying leaks on the Company's facilities. The Picarro AMLD device is mounted on a vehicle in combination with hardware, software, and a data analytics system used to conduct multiple leak patrols on natural gas infrastructure. Figure 1 provides a schematic of a typical Picarro AMLD set up on a vehicle.

Figure 1 – Picarro AMLD Typical Install Schematic



While less than $100,000, the Picarro AMLD also included the purchase of a vehicle under work order 0042W0007758, which was inter-district transferred to Southern Nevada where the Picarro AMLD is installed and operated. In addition to leak patrols, the Company uses Picarro AMLD to collect methane plume data which is routed to back-end data analytics software.

Q. 12 Why did Southwest Gas purchase the Picarro AMLD equipment for use in Nevada?

A. 12 Safety is paramount at Southwest Gas and the Company has a long history incorporating new and innovative technologies to further the tenants of safety, quality, and excellence throughout the Company's operations. Southwest Gas routinely engages with industry peers through organizations such as the American Gas Association (AGA) and the Western Energy Institute (WEI). A key aspect of these ongoing engagements includes the sharing and benchmarking of best practices throughout the industry. Through these interactions, the Company identified several industry peers that leverage the Picarro AMLD technology to improve leak detection efficiency and to assist in the quantification of methane emissions from natural gas facilities when leaks occur. CenterPoint Energy, Consumers Energy, DTE, National Grid, ONE Gas, PG&E, and Southern Company are among industry peers currently using Picarro AMLD equipment.

The benefits of the Picarro AMLD include enhanced leak detection capabilities and methane detection sensitivities down to 1 part per billion (ppb), mobile leak detection at higher speeds than conventional equipment, and back-end data analytics and methane plume analysis, as well as methane emissions quantification. The latter aspect allows the Company to further its primary objective of maintaining and operating a safe system while also eliminating hazardous leaks and minimizing releases of natural gas from its facilities, a requirement under the Section 114 of the Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020).

Q. 13 Are there any legislative or regulatory drivers the Company considered prior to purchasing the Picarro AMLD equipment?

A. 13 Yes. Congress placed explicit legislative focus on the elimination of leaks and minimization of natural gas releases with the enactment of a self-executing federal mandate under Section 114 of the PIPES Act of 2020.[3] Section 114 requires operators, including Southwest Gas, to update inspection and maintenance plans required under 49 U.S.C. 60108(a) to address eliminating

[3] Pub. L 116-260, Division "R" – PIPES Act of 2020 signed into law on December 27, 2020.

hazardous leaks and minimizing releases of natural gas. Subsequently, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published an Advisory Bulletin ADB-2021-01 to operators of natural gas facilities advising them of this self-executing federal mandate. The Advisory Bulletin also reminded operators of the requirement under 49 U.S.C. 60108(a)(2) to continue updating these plans to meet the requirements of any future regulations related to leak detection and repair that are promulgated under 49 U.S.C. 60102(q).

PHMSA released the Gas Pipeline Leak Detection and Repair Notice of Proposed Rulemaking (NPRM)[4] on May 18, 2023, which includes draft provisions for operators to conduct engineering tests and analyses in the development of an Advanced Leak Detection Program (ALDP) and accompanying performance standards. PHMSA proposes, among other regulatory enhancements and new programs in the NPRM, a minimum equipment sensitivity requirement of 5 parts per million (ppm) through the development of a new §192.763 Advance Leak Detection Program section of the federal pipeline safety code. Advanced Leak Detection equipment such as the Picarro AMLD meets or exceeds this proposed requirement.

Q 14 Are there any operational and safety-related drivers for the timing of the Company's Picarro AMLD equipment purchase?

A. 14 Yes. In addition to the legislative and regulatory reasons provided in Q/A 13, Las Vegas is hosting several high-profile events in the coming year including the Formula 1 Las Vegas Grand Prix race on November 16-18, 2023, and Super Bowl LVIII on February 11, 2024. The Company intends to use the Picarro AMLD

[4] Docket No. PHMSA-2021-0039, RIN 2137-AF51.

to enhance its planned leak surveys and pre-event safety patrols ahead of these events, leveraging the Picarro AMLD in addition to its existing suite of leak detection technologies.

Q. 15 What was the total cost of the Picarro AMLD equipment?

A. 15 The total cost of the Picarro AMLD equipment (0021W0007768) recorded as of May 31, 2023, was $1,288,800[5]. The equipment was placed into service in December 2022.

Q. 16 Is the Picarro AMLD equipment being used as of May 31, 2023?

A. 16 Yes, upon receipt of the equipment, the Company began using the Picarro AMLD equipment to train its employees, develop policies and procedures, and integrate the technology into the Company's applicable systems. Moreover, as discussed in Q&A 14 above, the Company is preparing, planning, and intending to use the Picarro ALMD to enhance its safety patrols to support upcoming high-profile events, including the Formula 1 Las Vegas Grand Prix race which takes place during the certification period of the instant application.

Q. 17 Is Picarro AMLD equipment currently being used in any of the Company's other rate jurisdictions?

A. 17 Yes. The Company purchased three Picarro AMLD units for use throughout its service territories. However, the unit described in Work Order 0021W0007768 is specifically designated for use in Nevada.

As part of the integration of the Picarro AMLD equipment, the Company discovered two notable leakage events that would not likely have been detected utilizing conventional leak detection equipment. The discovery of these two

---

[5] The cost of the vehicle that the Picarro AMLD unit is installed was approximately $37,287 and was placed into service under work order 0042W0007758.

situations, although neither occurred within Nevada, showcased the operational value of the Picarro AMLD equipment in elevating the safe operation of the Company's natural gas system. In one situation, the Company received an indication of gas and discovered an unoccupied home with gas readings in the explosive range. The Company was able to act quickly with local emergency responders to eliminate sources of ignition and address the hazardous condition. In another situation, one of the Picarro units identified indications of gas at a residential structure and subsequently discovered that the customer had a leaking Customer Owned Yard Line (COYL) that created a hazardous condition. The hazardous condition was resolved and the customer's leaking COYL isolated for repairs.

<u>V. AMERICAN GAS ASSOCATION MEMBERSHIP DUES</u>

Q. 18 Please provide an overview of the American Gas Association (AGA) and the service provided to its member companies and natural gas consumers.

A. 18 The AGA, founded in 1918, is a natural gas industry trade association with more than 200 member companies (including Southwest Gas) throughout America that provide service to 180 million consumers.[6] The AGA supports natural gas utilities in their efforts to make their operations safe, more efficient, and more environmentally friendly, providing state-of the art solutions for its members to safely and securely deliver reliable and affordable natural gas to homes and businesses across the nation.

From an operations and pipeline safety perspective, the AGA offers a comprehensive range of benefits to its members including access to the sharing

[6] www.aga.org/about

of industry best practices and innovations. First, the AGA provides valuable resources, programs, and committees to assist member companies in achieving operational excellence. Second, AGA recognizes the importance of safety, security, and resilience in the natural gas industry and offers a range of security programs and services to assist member companies in maintaining secure operations. Third, the AGA offers substantial technical support including ensuring that new rules are technically feasible, reasonable, cost-effective, and practicable. Fourth, the AGA fosters member discussion groups to address key areas of interest and facilitate industry collaboration.

Put simply, the Company's membership in AGA provides direct benefits to Nevada ratepayers by providing Southwest Gas robust resources to ensure Company personnel are well informed and positioned to operate the Company's natural gas facilities safely, efficiently, and effectively. Company witness Randi L. Cunningham provides the amount of AGA dues being requested in this application. She also describes the additional benefits that the Company's AGA membership provides beyond those related to pipeline safety, operational best practices, and innovative solutions for the safe and reliable delivery of natural gas.

Q. 19 Does this conclude your prepared direct testimony?

A. 19 Yes.

SUMMARY OF QUALIFICATIONS
JEROME T. SCHMITZ

Jerome Schmitz is the Vice President/Engineering Staff for Southwest Gas Corporation. He directs support to five operating divisions for pipeline safety code compliance; transmission and distribution integrity management; damage prevention, pipeline safety management systems, technical training and qualifications; emergency response training; pipeline security; rights-of-way; quality assurance; material specifications and approval; environmental compliance; pipeline system planning; laboratory services; operations research and development including decarbonization initiatives; measurement; pipeline cathodic protection; SCADA support; GIS support; and project design.

He holds a Bachelor of Science degree in Genetics from the University of California, Davis, and a Bachelor of Science degree in Mechanical Engineering from Arizona State University. He is a registered Professional Engineer in the States of Arizona, California and Nevada with a proficiency in Mechanical Engineering, and is certified as a Quality Auditor with the American Society for Quality.

Mr. Schmitz serves on the AGA Operating Section Managing Committee; he is also a member of the ASME B31 Standards Committee. He is a member of the Advisory Board of UNLV's Multicultural Program for STEM (Science, Technology, Engineering and Math) related disciplines. He also is a member of the Advisory Board of the University of Idaho's Energy Executive Course and serves on the Board of Directors for Goodwill of Southern Nevada.

SOUTHWEST GAS CORPORATION
NEVADA
ENGINEERING SERVICES - RELATED WORK ORDERS GREATER THAN $100,000 IN TOTAL COST
CLOSED TO PLANT IN SERVICE DECEMBER 2021 - MAY 2023

Line No.	Work Order Number	Work Order Description	Date First Transferred to Plant	Total Amount Excluding CIAC	CIAC	AFUDC	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Southern Nevada						
1	0021W0007768	Picarro Unit-Henderson	Dec-22	1,288,800.00	0.00	0.00	1
	System Allocable						
2	0052W0007564	Thermal Gravimetric Analyzer-SOPS	May-23	208,404.28	0.00	0.00	2
3	0052W0007406	TA ElectroForce 3300-SOPS	Apr-23	197,249.88	0.00	0.00	3
4	0052W0007560	Lab Service Dynamic Mech Analyz-SOP	May-23	186,580.66	0.00	0.00	4
5	0052W0006234	Hitachi Tabletop Microscope - SOPS	Apr-22	151,977.69	0.00	0.00	5

AFFIRMATION OF JEROME T. SCHMITZ

Pursuant to NAC 703.710, Jerome T. Schmitz affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 28 day of August, 2023

JEROME T. SCHMITZ

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 23-09___

PREPARED DIRECT TESTIMONY

RAIED N. STANLEY

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTEMBER 1, 2023

Table of Contents
Prepared Direct Testimony
of
Raied N. Stanley

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Raied N. Stanley

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Raied N. Stanley. My business address is 8350 S. Durango Drive, Las Vegas, Nevada 89113.

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

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Information Services (IS) department. My title is Vice President/Chief Information Officer.

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 written testimony to the Public Utilities Commission of Nevada (Commission) and the Arizona Corporation Commission.

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

A. 5 The purpose of my prepared direct testimony is to provide an overview of the project governance and oversight structure for approved technology-related capital projects and to support the reasonableness and prudence of the Company's investment in technology-related capital projects that are included in the Company's revenue requirement.

Q. 6 Please summarize your prepared direct testimony.

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

- Provide an overview of the project governance and oversight for all technology-related capital projects;
- Support the reasonableness of technology-related capital investment projects and provide support for technology-related projects equal to or exceeding $1 million which have been placed in service since the end of the certification period in Southwest Gas' 2021 general rate case (GRC); and
- Support the reasonableness of technology-related capital investment projects that at the time of this filing are anticipated to be placed in service by November 30, 2023.

Q. 7 Please describe why you are designated to testify about the matters that are presented in your testimony.

A. 7 I am currently responsible for the Company's IS function as well as the Enterprise Project Management Office (EPMO), and portfolio governance, and, as such, I am familiar with the EPMO functions and the technology-related capital projects presented for cost recovery in this case.

///

///

II. PROJECT GOVERNANCE AND OVERSIGHT

Q. 8 Please describe the project governance structure and oversight process at Southwest Gas for technology-related capital projects.

A. 8 Southwest Gas maintains an EPMO to support technology-related capital projects, a Portfolio Review Board (PRB), and a Portfolio Planning Committee (PPC) (previously titled the Portfolio Approval Council or PAC) to centralize the governance of processes, tools, and resources to maximize the business value and prioritization of these capital projects based on business need. Southwest Gas also maintains a staff of dedicated business analysts and project managers and has developed project management frameworks and processes to support each project. The Company promotes Project Management Professional (PMP) certifications for EPMO employees and consultants with the title of Project Manager to validate the core competencies of those managing some of the Company's largest initiatives.

The EPMO is founded on standards and practices from the Project Management Institute (PMI) as a basis for its project governance. PMI is globally recognized as a non-profit organization that creates the standards for project and portfolio management practices that are written in the Project Management Book of Knowledge (PMBOK) and certifies project management professionals. The PMBOK provides guidance on project governance and includes specified criteria to determine the appropriate project organizational structure. Some other notable features associated with the Company's EPMO project management include:

- Each project is sponsored by a minimum of one Company executive and typically operates using a governance structure consisting of a Steering Committee, an Oversight Committee, a dedicated project manager from the EPMO, and a project team.
- Each project undertakes a planning phase for purposes of identifying the key objectives, governance structure with associated stakeholders, scope, budget, duration, staffing decisions including system implementor selection (if applicable) and need to hire other potential contractors, and the identification of all project deliverables through project completion.
- Each project follows standard Southwest Gas procurement guidelines in the evaluation and selection of the system implementation partner and platform solution.

Q. 9 Please further describe the PRB and the PPC.

A. 9 The PRB is a resource to help improve and standardize policies, practices, and tools to facilitate project portfolio management for significant capital and O&M projects meeting the specified criteria for review. The PRB is a committee consisting of Vice President-level company stakeholders that play an essential role in the proposal review, capacity planning, and tracking of enterprise portfolio projects necessary to support the Company's operations. The PRB serves the PPC as a technical resource specifically to provide recommendations on the initiation, planning, and maintenance of the project portfolio. PRB members are the "gate keepers" of proposed projects for the portfolio and their responsibilities include:

- Screening preliminary project proposals and documentation;

- Ensuring consistent project prioritization and ranking assessment;
- Monitoring project portfolio status;
- Validating portfolio reporting information; and
- Proposing recommendations to the PPC for improved portfolio management processes, procedures, and tools.

The PRB convenes periodically to assess project proposals, monitor the status of active projects to support the Company's financial investments, and review resource capacity to determine the appropriate timing to launch new projects and initiatives. The primary purpose of the PPC is to institute portfolio governance and sustain it with disciplined oversight. To that end, the PPC builds and maintains a portfolio based on corporate strategies/initiatives, risk profile, and capital distribution as determined by senior management. In addition, the PPC brings together influential company leaders in conversation with each other to explore and evaluate the business rationale and justification for requested projects. The PPC also evaluates project requests against Company objectives and promotes innovations in project and portfolio management. The PPC has the ultimate authority to oversee the management of major capital projects. The PPC promotes decision transparency, standardized policies, accountability, and buy-in. A copy of the EPMO and Portfolio Governance Overview and Portfolio Governance Roles are attached hereto as Exhibits Nos._(RNS-01) and _(RNS-02), respectively.

Q. 10 Does Southwest Gas use contractors for certain EPMO projects?

A. 10 Yes. Southwest Gas frequently uses experienced contractors for resource flexibility based on the need of the project. As mentioned above, considerations for system implementors and other supplemental contractors are typically identified in the planning phase of a project as enterprise projects require specialized technical and functional skills. Many enterprise technology implementations require subject matter expertise in systems integration, business process, and software configuration. In many instances, those skills are not readily available locally and may vary according to the solution selected for implementation. The amount of time that a consultant works on a project depends on the consultant's role, scope complexity, timeline, deliverables, and target completion date. Consultant invoices and timesheets are ultimately reviewed and validated by internal Company personnel responsible for the project.

Q. 11 Has the Company modified its oversight processes and procedures for technology-related capital projects since its 2021 GRC?

A. 11 Yes. In May of 2022, Southwest Gas enhanced its EPMO and Enterprise Technology Portfolio Governance to further support and advance the fundamental principles upon which the EPMO was established.[1] Through continuous education, partnerships, and lessons learned, the Company recognized the necessity to add key skillsets to supplement the EPMO capabilities and expand participation of the portfolio governance committees to include key and diverse Company departments such as Regulation, Risk Management, and Legal to supplement the involvement from traditional departments. The Company recognizes the value of portfolio governance and strives for continuous improvement with an enhanced focus on quality and costs.

[1] The EPMO was founded upon three fundamental principles: 1) established governance mechanisms; 2) dedicated project managers; and 3) developed project management frameworks and processes.

To ensure financial prudence, the EPMO also recruited a financial analyst to provide financial analysis of the project portfolio in support of the EPMO and portfolio governance committee goals and initiatives. The responsibility of this position is to oversee the development, tracking, and reporting of the budget and associated costs, burn rate, and total cost of ownership for enterprise technology projects.

III. THE SOFTWARE PROJECTS/PURCHASES IN EXCESS OF $1 MILLION THAT CLOSED TO PLANT SINCE THE CERTIFICATION PERIOD IN THE COMPANY'S LAST GRC

Q. 12 Is Southwest Gas seeking recovery for the costs incurred for technology-related projects that closed to plant since the certification period in the Company's last GRC?

A. 12 Yes. The Company is seeking recovery for the technology-related projects that have been placed in service since November 2021, which was the end of the certification period in the Company's 2021 GRC. Below, I provide further discussion on each of the projects or initiatives where the costs incurred were greater than $1 million.

IV. OVERVIEW OF STRATEGIC FINANCIAL AND REGULATORY PLANNING PROJECT (SFRP) PHASE II – REGULATORY (0061W0005847 & 0061W006138)

Q. 13 Please provide an overview of the Strategic Financial and Regulatory Planning (SFRP) Project.

A. 13 The SFRP Project includes Southwest Gas' procurement of UI Planner, defined below, from Utilities International Solutions Group (UISG) to support various Company functions including regulatory filings and analyses and long-range financial forecasting. The provided solution will enable the Company to perform high-value tasks more quickly and efficiently based on integrated data from multiple systems and built-in logic, calculations, reports, and working model exports to Excel. The Company anticipates it will help automate certain filing procedures and processes, enhance financial and regulatory modeling and analytics, and improve response velocity for various inquiries.

Southwest Gas has historically used complex and manually intensive, individual Excel-based models for long-range financial forecasting, regulatory filings, cost recovery mechanisms, deferral calculations, and other analyses across its six state rate jurisdictions and federal rate jurisdiction to perform similar functionality that is not under any vendor or support mechanism. Furthermore, the Company's legacy long-range financial forecasting models were built on underlying user-specific formulas that I/S considers outdated and a potential security vulnerability to the Company's information as discussed further in Q&A 15. The work orders referenced above are for Phase II of the project. The scope of Phase II was to begin building out the Regulatory portion of the project.

Q. 14 What are the expected benefits of the SFRP Project?

A. 14 The SFRP Project – Financial and Regulatory (UI Planner) improves the Company's efficiency performing high-value tasks by integrating data from multiple systems into a single platform that can be leveraged to produce the Company's regulatory filings and analyses, as well as long-range financial modeling. Moreover, UI Planner provides additional flexibility supporting the Company's historical and forecasted test period analyses, applicable allocations which are used to determine rate jurisdictional revenue requirements, class cost of service, and rate design as well as reporting capability. As a result, the Company anticipates its regulatory filings and analyses filings to become more efficient for various departments with enhanced visibility of metrics that will help the Company's planning and filing processes.

Q. 15 Provide an overview of the improvements and efficiencies that UI Planner provides when compared to the Company's existing solution?

A. 15 UI Planner is a flexible, expandable system that reduces manual entries and model updates, and has robust security capabilities; therefore, is expected to reduce the time to prepare filings and analyses and mitigate security threats. Efficiency is accomplished by UI Planner's ability to map to data sources derived directly from the Company's general ledger (Oracle) and other systems such as SAP and PowerPlan, and to pre-configure reports and Excel working models.

Next, UI Planner improves system security by integrating with Company's directory authentication systems through lightweight directory access protocol (LDAP). It provides a robust security model over all objects and actions by user or role. Additionally, the data is encrypted in transfer and at rest. Moreover, UI Planner has also achieved SOC 2 Type II certification from the American Institute of Certified Public Accountants (AICPA) which focuses on the controls in place and the operational effectiveness of those controls for security, availability, processing integrity, confidentiality, and privacy. Please refer to the prepared direct testimony of Company witness Randi L. Cunningham for additional, detailed descriptions of the benefits of UI Planner.

Q. 16 What evaluation did Southwest Gas perform to determine if developing its own in-house model was a viable solution?

A. 16 To evaluate this option, Southwest Gas assembled a cross-functional team to investigate the possibility of developing an in-house system to automate data flow into one source and feed the data into multiple Excel-based models. This option was ultimately rejected because of the complexity of modeling required to develop a system, the risk involved due to a lack of internal expertise in developing and maintaining such a system, and the lack of resources available to devote to the project. As a result, Southwest Gas determined that developing an in-house model was not a reasonable alternative.

Q. 17 Why did Southwest Gas choose to purchase UI Planner over other software solutions that the Company evaluated?

A. 17 Southwest Gas researched software solutions and was unable to find another comparable product designed specifically for the Company's business needs. The Company consulted with peer utilities of similar size and service capabilities, the AGA (American Gas Association), and Gartner. All of the major gas utilities who joined the discussion reported using either UI Planner or an Excel-based model, with higher levels of satisfaction expressed by those using UI Planner. Southwest Gas reached out to the individual utilities who reported using UI Planner. Southwest Gas asked more detailed questions about their experiences with the software — feedback on overall satisfaction, the implementation process, how the software was used, lessons learned, and tips for Southwest Gas.

In general, the utilities' feedback with respect to UI Planner was positive, with most reporting being very pleased with the product. The positive feedback, along with the lack of other feasible alternatives, and the multi-jurisdictional regulatory structure of the Company support Southwest Gas' decision to purchase UI Planner to meet its business needs.

Q. 18 What was the cost to implement Phase II of UI Planner?

A. 18 UI Planner Phase II costs are comprised of project implementation/software and infrastructure costs. The following is a more detailed breakdown of the various implementation costs.

- Implementation/Software Costs (0061W0005847, $7.09 million before allocation to Nevada)
    - Design SOW – UII $109,900
    - Reg & Rev Imp SOW - UII $4,073,750
    - Project closeout (7.5% of imp costs) $325,898
    - License Fees $1,800,000
    - SWG contractor $358,118
    - AFUDC costs $182,392
    - Employee Labor $197,798
    - Freight $60
    - Change order 1-Labor Annualization $45,292
- Infrastructure Costs (0061W0006138, $381,038 before allocation to Nevada)
    - Server cost $99,283
    - Additional required memory cost $281,570

The approximate cost of the UI Planner after allocation to Northern Nevada and Southern Nevada is $383,581 and $2,026,427, respectively.

Q. 19 Do you believe the costs associated with UI Planner were reasonably incurred?

A. 19 Yes. As stated above in Q/A 8 through Q/A 11, the Company maintains an EPMO, PRB, and PPC to centralize the governance of processes, tools, and resources to maximize the business value and prioritization of capital projects, including UI Planner. Consequently, UI Planner costs were reasonably incurred based upon the business need as described herein and Confidential Exhibit No._(RNS-4).

V. OVERVIEW OF THE RADIO CONSOLE UPGRADE PROJECT

Q. 20 Please provide an overview of the Company's legacy system as well as the Radio Console Upgrade Project.

A. 20 Southwest Gas currently utilizes a Raytheon WAIS (Wide Area Interoperability System) for dispatch consoles, which is a computer-controlled radio system utilized to dispatch Southwest Gas technicians for emergency situations and operational activities. The current system is based on a legacy operating system that is no longer supported. The Radio Console Upgrade Project (Radio Project) replaced the existing analog radio system with modern digital technologies to enhance safety, communications, efficiency, portability, and reliability. The upgrade in radio technology extends connectivity to automate and encrypt connections to radio towers based on the best available signal strength. In addition, the Radio Project supports dedicated talk groups across large geographical areas and can handle high-traffic communications to support the dispatch of emergency communications and workload management.

Q. 21 Provide a summary of the Company's reasons for replacing its existing radio console and related equipment as well as benefits the Radio Project provides.

A. 21 The main three drivers to replace the existing radio consoles and related equipment are the Company's commitment to safety, continuous service, and reliability. Below are benefits in each of the respective areas in which the Radio Project provides improvement.

<u>Safety</u>

- Improved communication during emergencies and operational activity.
- System security capabilities through digital encryption.
- Emergency "panic" button to support employee safety.
- System capable of providing priority on the system (e.g., can be used as a "mayday" button and in the event an employee is unable to talk). Supported through GPS and is user identifiable.
- Dedicated talk groups for use during emergencies/operational activity.
- Proven/tested system used by first responders and other utilities including Arizona Public Service, Salt River Project, Sempra, and PG&E.
- Trunking system is best practice for those involved in emergency response and is ideal for large operating groups with high traffic and the need to manage multiple incidents/communication (a must for efficient Centralized Dispatching).

Service

- Reliable communication through the trunking system.
- A trunking system provides transmission strength and clarity of the communication signal. Trunking tracks users and automatically routes the transmission. Patching requires a manual interface by the dispatcher for the intended user. A trunking system automatically finds a user much like a cellular phone system. Radios are designed to automatically connect to the site with the best signal strength. On the current system, the user must manually choose the site to stay in communication with Dispatch.
- Multiple talk groups through the trunking system.
- Trunking is common in large utility companies due to demand for multiple talk groups. It provides flexibility to automatically connect to the best/continuous communications signal.
- Remote maintenance and troubleshooting capabilities.
- Additional option for Supervisory Control and Data Acquisition (SCADA) communication that augments other communication types.
- Existing MDS (Microwave Data Systems) SCADA sites talk to one site, SCADA site on a trunking system would find the best available signal to communicate.
- Expandable system functionality to incorporate other users through dedicated/assigned talk groups (i.e. building services, security, etc.). Talk groups are programmed for specific users, with no crossover.

- Enhanced usage of portables.
- Optional mobile phone application to allow users to use their phone to communicate as a portable radio. This expands the company audience to support emergency response.
- Help support dispatch workload management through the utilization of talk groups.
- Caller ID support, unit number or name displayed for each caller on the system.
- GPS capable, potential backup to Telogis (business continuity).

Reliability

- Enhanced coverage area with the ability for expansion.
- Programmable to automatically finds the best signal.
- Versatility, user permissions based on operational/support needs.
- Administrator rights, talk groups, layers of permission, etc.
- Ability to map coverage area and focus enhancement to areas in the most need. Data is captured via GPS radios and available for review (similar to Telogis).
- Clear/consistent communication.
- Alarm mode provides notification if the communication area is down or having issues.
- Automated selection of channels (as opposed to the existing manual process).
- New system will have recording and replay options to prevent talking over or cutting out communications.

- Supports the ability to supplement dispatch resources from other divisions through technology enhancements.

Q. 22 Why did Southwest Gas implement the Radio Project rather than continue maintaining its current solution?

A. 22 The Company evaluated alternative solutions, including maintaining the current system. Continuing to use the current solution requires use of workarounds in locations where the currently used radio equipment is no longer available and does not support the required coverage area. This includes using mobile phone voice, text, and email functionality. The current WAIS radio system technology is becoming more difficult to maintain and support, and eventually will cease to work as designed. Through extensive research, and the identified risk of having cell service interrupted without a backup communication device, continuing to use the existing solution with its existing workarounds was not an option. Pursuing a fully integrated, digital trunking radio system, meeting defined business requirements supports added safety, service, and reliability to the Company's employees and customers.

Q. 23 Provide an overview of the operational efficiencies the Radio Project provides.

A. 23 Southwest Gas uses radio communications networks in its operations to support the safe, secure, and reliable delivery of natural gas. Such operational communications networks facilitate utility networks and endeavor to be resilient with low latency enabling use of certain utility applications. Moreover, the Radio Project is an important alternative for the Company to reach most of its industrial sites (plants, pump stations) and the locations of its customers (urban and rural areas). The radio upgrade utilizes communications networks with a high grade of availability and reliability to support for operational safety of the underlying gas services that the Company supports. This includes redundant routing of backbone and backhaul networks and extended backup power at every tower station. Finally, some of the key characteristics of the radio upgrade operational components included are highly ruggedized for extreme conditions within the relevant environment, so the communications network devices must last for an extended period of time. The upgrade of the radio console and related equipment will enable more efficient resilience and restore service more quickly after an outage and protect the utilities' employees and customers. Please refer to the prepared direct testimony of Company witness Jerome T. Schmitz for additional benefits of the Radio Project.

Q. 24 What are the benefits of the Radio Project over utilizing mobile phones?

A. 24 While Southwest Gas utilizes mobile phones to meet day to day or routine operational needs, mobile phones may not be the best option for communication in an emergency or on a construction job site. The better choice, based on the Company's research, was to upgrade its consoles and related equipment. The five benefits of using radios instead of mobile phones include:

- Service during emergencies - Cell service towers and landlines may fail during an emergency or disaster. However, radios will continue to work during those situations. Additionally, all workers can be contacted at once, as opposed to dialing individual phone numbers via phone.
- Lightweight durability - Radios are designed to be lightweight and long-lasting. While some phones may require a protective case for use on the job

site, two-way radios are often built to military and IP specifications, so they are less likely to crack or break when dropped. They are also designed with long battery life, with many models able to continue operating for 12-26 hours.

- Cost effective. There are no monthly fees, service contracts, or calling minutes. Also, several workers can share a radio, cutting costs by avoiding the need to issue one per employee.
- Communication clarity - Unlike many cell phones, two-way radios are designed to offer clear communication in most conditions. They often include features that reduce wind noise and allow resistance to vibration, extreme temperatures, and wet conditions.
- Ease of use - Two-way radios feature touch-button talk communication, creating a simple means of communication. Some models also include cloning capabilities, which simplify the process of copying radio settings.

Q. 25 What was the cost to upgrade the radio console and related equipment?

A. 25 The total cost to upgrade the radio console and related equipment was $1,787,286.22 (before allocation to Nevada). This cost was split between two specific work orders: $1,308,388.44 (0061W0006834) and $478,897.78 (0061W0006835). The approximate cost of the Radio Project after allocation to Northern Nevada and Southern Nevada is $91,764 and $484,779, respectively.

Q. 26 Do you believe the costs associated with the Radio Project were reasonably incurred?

A. 26 Yes. As stated above in Q/A 8 through Q/A 11, the Company maintains an EPMO, PRB, and PPC to centralize the governance of processes, tools, and resources to maximize the business value and prioritization of capital projects, including the Radio Console Project. Consequently, Radio Console Project costs were reasonably incurred based upon the business need as described herein and Confidential Exhibit No._(RNS-5).

VI. OVERVIEW OF THE TAX REMEDIATION PROJECT

Q. 27 Please provide an overview of the Tax Remediation Project.

A. 27 The purpose of this project was to enhance the PowerPlan PowerTax and PowerTax Provision modules to fully comply with recent tax law changes and to prepare for potential future tax law changes. Specifically, this allowed Southwest Gas to comply with future changes to federal and state income tax rates.

Q. 28 Why was the Tax Remediation Project undertaken at this time?

A. 28 The federal income tax rate decreased in 2017 as part of the Tax Cuts and Jobs Act of 2017 (TCJA), which exposed limitations and system challenges related to tax law changes. Future tax law changes would require significant modifications to PowerPlan's PowerTax and PowerTax Provision modules. This would include the following:

- As discussed in the prepared direct testimony of Company witness Byron C. Williams, which further addresses the need for the Tax Remediation Project, PowerTax required configuration changes to provide the level of detail needed to support regulatory scrutiny of the Average Rate Assumption Method (ARAM) calculations which may be complicated by tax rate changes. Controls over tax data integrity and system reconciliations needed to be enhanced and improved to ensure reporting in PowerTax remained reliable and supportable.

- The Tax Remediation Project modified the PowerTax Provision module to conform with industry best practices by reconfiguring the company structure into independent rate jurisdiction "companies" with common components allocated automatically. The new configuration utilized the PowerTax Provision consolidation functionality to capture consolidating adjustments more efficiently.

Q. 29 What was the total cost for the Tax Remediation Project?

A. 29 The total cost for the Tax Remediation Project (0061W0006855) was $1,001,889 (before allocation to Nevada). The approximate cost of the Tax Remediation Project after allocation to Northern Nevada and Southern Nevada is $51,439 and $271,750, respectively.

Q. 30 Do you believe the costs associated with Tax Remediation Project were reasonably incurred?

A. 30 Yes. As stated above in Q/A 8 through Q/A 11, the Company maintains an EPMO, PRB, and PPC to centralize the governance of processes, tools, and resources to maximize the business value and prioritization of capital projects, including the Tax Remediation Project. Specifically, related to the Tax Remediation Project, RCC (Regulated Capital Consultants) performed configuration changes in each PowerPlan module, including training and HyperCare support. Those specific PowerPlan modules include the following:

- <u>PowerTax Module: Cost of Removal & Deferred Tax Module</u> – RCC broke out the Cost of Removal (COR) from the method/life, and performed other data, process, and integration updates to allow for a more optimal functioning of the deferred tax calculations. RCC also ensured that none of the changes to the PowerTax, PowerPlant, or Provision modules will adversely affect the Company's ability to upgrade to future versions of these modules.

- General PowerTax Updates – RCC performed updates to data and configuration to resolve various systems issues.
- Fixed Asset (Plant) Module: Cost of Removal Breakout – RCC broke out the COR from the life reserve and configured the automatic tracking of COR in the Plant and PowerTax modules.
- Provision Module: Provision Module Updates – RCC performed updates to data, configuration, and processes to resolve various Provision system issues and improve future-state processes.
- ASI Module: ASI Bridge Installation – RCC installed and deployed the ASI Bridge, which facilitates communication with the ASI application. ASI Controls – RCC documented and implemented various controls to ensure that the data in the various modules are accurate and identify out-of-balances so they can be remediated in a timely fashion. This also included implementing the Rate Change Analysis tool in ASI to help with Tax Reform Readiness.
- Training and HyperCare: Training – RCC provided no less than 4.5 days of in-person training to Company staff related to the changes to the modules described above. Training materials were provided by RCC. HyperCare – RCC provided post-go-live support for the changes to the modules described above from the time the changes are moved into production through the completion of the first quarterly close.

Consequently, the Tax Remediation Project costs were reasonably incurred based upon the business need as described herein and Confidential Exhibit No._(RNS-6).

<u>VII. CONCLUSION</u>

Q. 31 Does this conclude your prepared direct testimony?

A 31 Yes.

SUMMARY OF QUALIFICATIONS
Raied Stanley

Mr. Stanley is the Vice President/Chief Information Officer where his responsibilities include leading all aspects of information technology, information security, data, and analytics.

In his position, Mr. Stanley leads and oversees the Information Services (IS) division as well as sets IT direction, and coordinates infrastructure and service delivery across the organization. He is responsible for IS units that support enterprise applications, enterprise data, operations support, user support, infrastructure, communications, and cyber security.

Mr. Stanley joined Southwest in January of 2020. Most recently, Raied held the role of Senior Vice President and Chief Information Officer for Metropolitan Utilities District located in Omaha, Nebraska. In this role, he led the Information Technology organization where he was responsible for developing and maintaining core applications, network, computing, server, storage, collaboration, and infrastructure solutions across the enterprise. Before that, he led the IT Business Systems organization where he managed the computing application systems that supported Finance, Human Resources, Corporate, and Commercial Engineering Business Units, as well as the organization's internal systems.

Raied holds a Bachelor's Degree in Business Administration and Finance from Temple University, as well as a Master's Degree in Business from Morehead State University.

EPMO PORTFOLIO GOVERNANCE ROLES

ENTERPRISE PROJECT MANAGEMENT OFFICE (EPMO)

1. Focuses on business-driven technology projects
2. Acts as a neutral support department
3. Drives roadmaps in collaboration with functional and technical stakeholders
4. Tracks resources and conducts capacity planning
5. Manages the project intake
6. Provides project management professional services, standardized processes, and supporting tools
7. Performs post-project evaluations for continuous improvement
8. Provides the information for the governance committees to make informed decisions
9. Reports the ongoing status of the project portfolio

PORTFOLIO REVIEW BOARD (PRB)

1. Ensures the portfolio governance process is followed
2. Prioritizes projects in the portfolio backlog
3. Acts as stewards of the portfolio guiding principles
4. Stays informed of active projects
5. Submits a recommended portfolio to the PPC for budget approval
6. Submits portfolio updates and changes to the PPC for approval
7. Evaluates governance performance metrics for value realization
8. Prioritizes roadmaps for portfolio budgeting

PORTFOLIO PLANNING COMMITTEE (PPC)

1. Approves the portfolio and makes changes when needed based on recommendations from the PRB
2. Provides financial guidance to the PRB to aid in the portfolio construction process
3. Authorizes project expenditures as set forth in the approved portfolio

Updated 11/2/22

EPMO

PROVIDING COLLABORATION, TRANSPARENCY, AND PORTFOLIO GOVERNANCE

Presented By: Robin Pierce/Steve Spurlock

AGENDA

- THE ENTERPRISE PROJECT MANAGEMENT OFFICE (EPMO) MISSION
- PORTFOLIO GOVERNANCE ROLES & RESPONSIBILITIES
- PORTFOLIO GUIDING PRINCIPLES
- PROJECT INTAKE PROCESS & WORKFLOW
- PORTFOLIO STATUS UPDATE

THE MISSION

EPMO

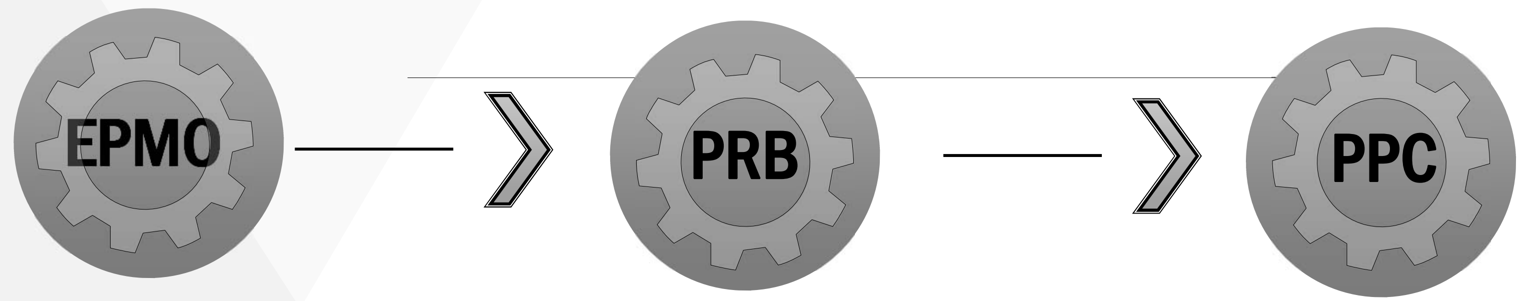
PROVIDING COLLABORATION, TRANSPARENCY, AND PORTFOLIO GOVERNANCE

To provide collaboration, transparency, and portfolio governance while continually aiming for excellence.

THE MISSION

The EPMO acts as the bridge between the business and technical project stakeholders to support the successful delivery of enterprise technology solutions.

THE GOVERNANCE



ENTERPRISE PROJECT MANAGEMENT OFFICE

<u>Project Management Resources</u>

Director
Portfolio and Project Managers
Business Analysts
Analysts
Financial Analyst (tbd)
3rd Party Partners

PORTFOLIO REVIEW BOARD

<u>Cross-Functional VP's</u>

Albert Taylor
Lori Colvin
Matt Derr
Brad Harris
Catherine Mazzeo
Jerry Schmitz
Raied Stanley

Guest: Randy Gabe

PORTFOLIO PLANNING COMMITTEE

<u>Cross-Functional SVP's</u>

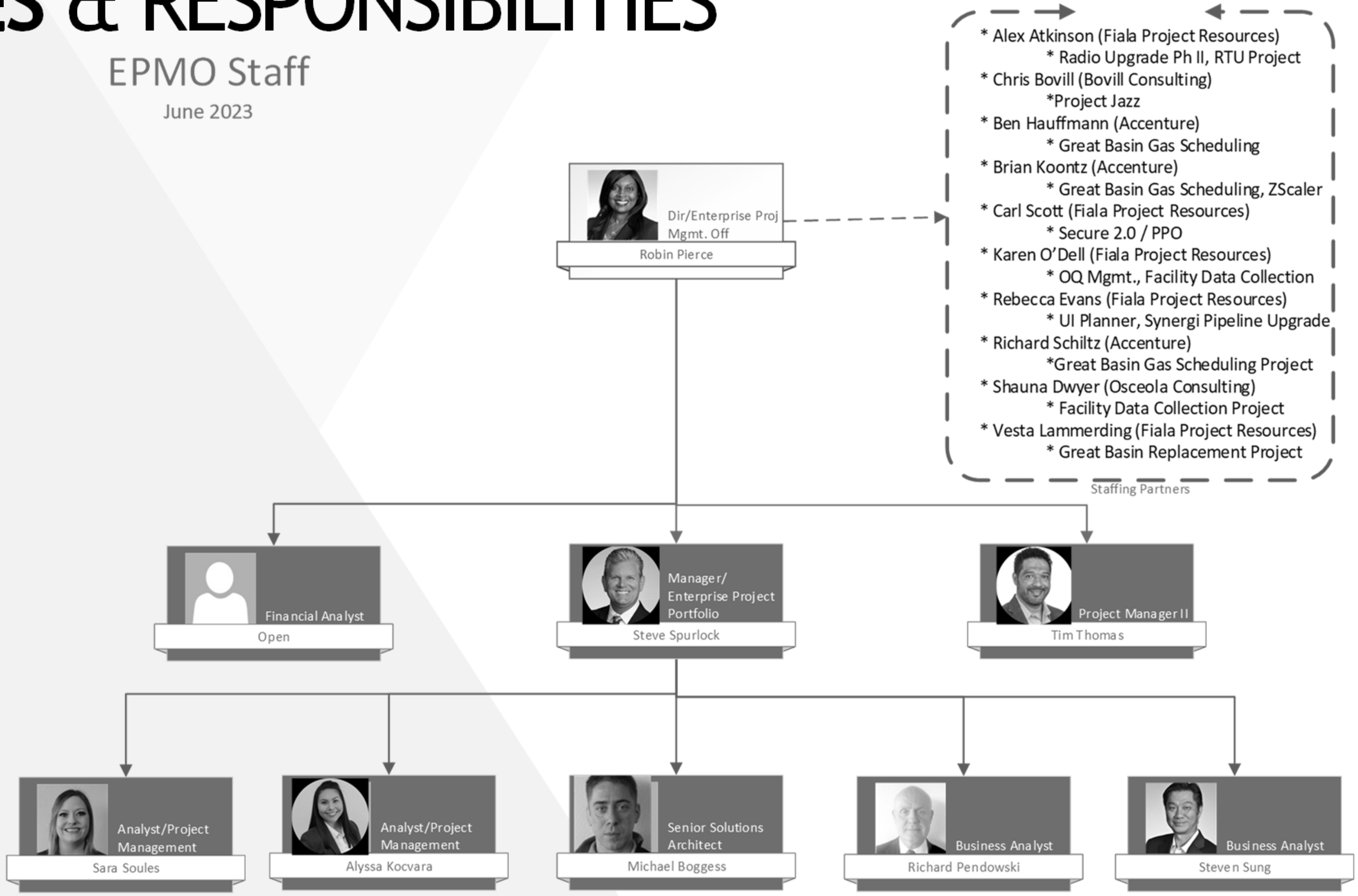
Randy Gabe (Chair)
Sharon Braddy-McKoy (Pending)
Amy Timperley
Julie Williams

Advisor: Raied Stanley
Facilitator: Robin Pierce

ROLES & RESPONSIBILITIES

EPMO Staff

June 2023



Total
9 Employees
10 Contractors +

ROLES & RESPONSIBILITIES
EPMO

- Focus on business-driven technology projects
- Act as a neutral support department
- Drive roadmaps in collaboration with functional and technical stakeholders
- Track resources and conducts capacity planning
- Manage the project intake and project backlog
- Provide project management services, standardized process, and supporting tools
- Perform post project evaluations for continuous improvement
- Provide the information for the governance committees to make informed decisions
- Report the status of the project portfolio

ROLES & RESPONSIBILITIES

PRB

- Ensure the portfolio governance process is followed
- Prioritize projects in the portfolio backlog
- Act as stewards of the portfolio guiding principles
- Stay informed of active projects
- Submit a recommended portfolio to the PPC for budget approval
- Submit portfolio updates and changes to the PPC for approval
- Evaluate governance performance metrics for value realization
- Prioritize roadmaps for portfolio budgeting

ROLES & RESPONSIBILITIES
PPC

- Approve the portfolio and makes changes when needed based on recommendations from the PRB
- Provide financial guidance to the PRB to aid in the portfolio construction process
- Authorize project expenditures as set forth in the approved portfolio

GUIDING PRINCIPLES - DRAFT

- ✓ New products must comply with federal regulations
- ✓ New products must comply with I/S policies and procedures.
  (Note: PRB will refine, and I/S will provide direction.)
  - ✓ Cloud first strategy
  - ✓ Security requirements met
  - ✓ Vendor supported and upgradable
  - ✓ Minimal to no customizations
  - ✓ Single source for technology solutions
- ✓ Any new solution must leverage or replace an existing solution.
  - ✓ Minimize technical debt.
- ✓ Projects must fit into the company technology architecture.
- ✓ Business owners prioritize and own the business roadmaps.
- ✓ Modify the business process first, not the software.
- ✓ Adhere to Company Core Values
  - ✓ Safety, Excellence, Quality, Partnership, Stewardship, Value
- ✓ Projects must have defined SMART performance metrics.
  - ✓ Specific, Measurable, Achievable, Relevant, and Timely

DEFINE "APPROVED" PROJECT

- Project was submitted to EPMO for preliminary review.
- Project scope is clearly defined.
- Project estimates are within 80% or higher level of confidence.
- Project resources are called out.
- The business case has been reviewed by project leadership and signed by the business sponsor(s) and CIO.

APPROVAL PROCESS

Step 1

The requester contacts the EPMO for initial vetting at EPMO@swgas.com

Note: The project will require a "Product Owner" (Director) and an Executive Sponsor (VP and up).

Step 2

The EPMO works with Project Leadership (business and technical) to develop the business case.

Note: This includes the Risks, Total Cost of Ownership, named/dedicated project resources, Current Architecture, and Current support structure.

Step 3

The PRB reviews the project business case and prioritizes the proposal with other projects.

Note: Prioritization factors include availability of financial and team resources, implementation readiness, project dependencies, and risk considerations.

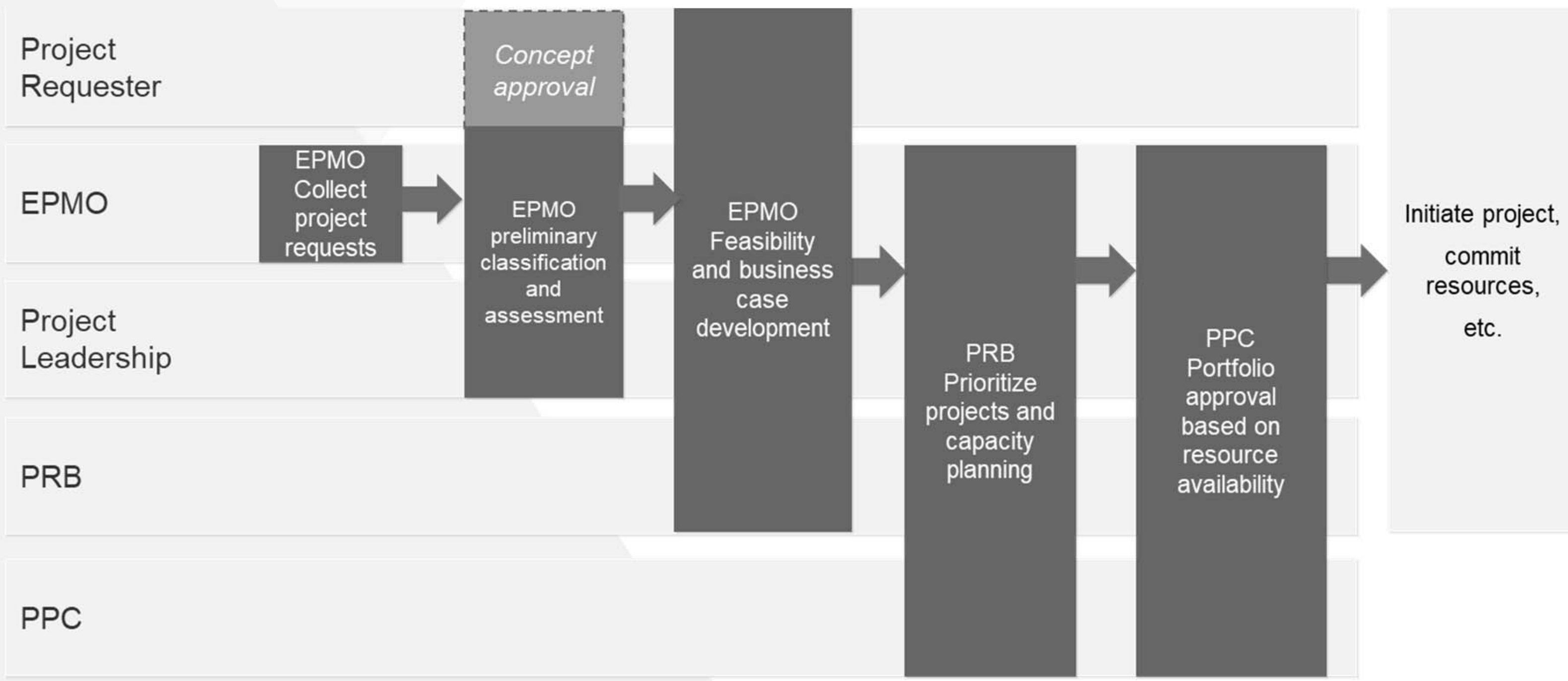
Step 4

The PPC approves the overall enterprise technology 3-year plan budget in addition to any overages.

Note: The PRB can authorize the launch of projects within the established/approved plan.

INTAKE PROCESS & WORKFLOW

5-step process for managing project intake, prioritization, and portfolio approval.



ACTIVE PROJECTS

Radio Upgrade "RU Phase 2" Project
Sponsors – Chris Sohus and Frank Stanbrough
Product Owners – Russ Vallejo and Tony Hills
Business & Technical Lead – Ken Block
Project Manager – Alex Atkinson

Facility Data Collection Project
Sponsors – Luis Frisby and Jerry Schmitz
Product Owner – Reagan Monroe
Business Lead – Lumi Matthys
Technical Lead – Vikram Tharigonda
Project Manager - Karen O'Dell

Synergi Pipeline Project
Sponsor – Jerry Schmitz
Product Owner – Reagan Monroe
Business Lead – Lumi Matthys
Technical Lead – Vikram Tharigonda
Project Manager – Rebecca Evans

Great Basin Gas Purchasing Replacement Project
Sponsors – Amy Timperley & Raied Stanley
Product Owner – Frank Maglietti
Business Lead – Carol Vogel
Technical Lead – Dina Lewis
Project Manager – Vesta Lammerding

RTU Replacement
Sponsor – Jerry Schmitz
Product Owner – Kevin Lang
Business Lead – Ron Castle
Technical Lead – Dina Lewis
Project Manager – Alex Atkinson

Strategic Financial/Regulatory Planning Phase II
Sponsor – Amy Timperley
Product Owner/Business Lead – Randi Cunningham
Technical Lead – Vikram Tharigonda
Project Manager – Rebecca Evans

Other Active Initiatives

- Secure 2.0
- PPO Enhancement
- SCADA Program
- Diverse Supplier Analytics

INTAKE PROJECTS

Active Intake

- ITSM Remedy Replacement Project
- Project Nucleus
- Physical Security Operations
- SCADA Upgrade
- Tax Repair Module

Active Intake Initiatives are actively being researched and documented by the EPMO Business Analysts and have not been submitted to the PRB and/or PCC

On Deck – PRB/PPC Approved

- Enterprise Landlord
- Cloud IVR Migration
- GIS Utility Network
- Gas Resources Optimization

On Deck Initiatives have been approved by the PRB and PCC and are awaiting resources or contracts

On Hold / Pending

- Damage Prevention
- Digital Forms
- Above Ground Leak Reporting
- Financial Close/Reporting Roadmap
- GTreasury Replacement

On Hold/Pending Initiatives have been identified as projects that will likely be addressed by another initiative. Holding until this is confirmed.

TALENT / EPMO OPPORTUNITIES

EPMO Staff Training

- Business Alignment
- Solution Adaptation
- Quality Management
- Communication Plans
- Risk Identification
- Risk Response
- Procurement Management
- Budget Reporting

Stakeholder Training

- Project Input Process
- Project Requirements
- Communication Expectations
- Change Management
- Implementation / Support
- Risk Reporting
- Risk Response
- Resource Allocation

Project Resource Training

- Project Resource Expectations
- Project Flow
- Project Reporting / Escalation
- Project Resource Approvals

WRAP UP

THE EPMO IS HERE TO SUPPORT AND MANAGE BUSINESS-DRIVEN TECHNOLOGY IMPLEMENTATIONS.

Please contact Steve Spurlock, EPMO@swgas.com, or Robin Pierce with any questions.

THE EPMO MISSION IS TO PROVIDE COLLABORATION, TRANSPARENCY, AND PORTFOLIO GOVERNANCE.

The goal is to provide the communication and tools to bring visibility and alignment to enterprise technology efforts.

THE TEAM IS THE KEY TO A SUCCESSFUL PROJECT.

YOU make it happen!

SOUTHWEST GAS CORPORATION
NEVADA
TECHNOLOGY-RELATED WORK ORDERS GREATER THAN $100,000 IN TOTAL COST
CLOSED TO PLANT IN SERVICE DECEMBER 2021 - MAY 2023

Line No.	Work Order Number	Work Order Description	Date First Transferred to Plant	Total Amount Excluding CIAC	CIAC	AFUDC	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	0061W0005847	Strategic Financial Planning PH II	Dec-22	7,093,208.32	0.00	182,392.46	1
2	0061W0006834	Radio Console Upgrade Implement-Cor	Dec-21	1,308,388.44	0.00	692.09	2
3	0061W0006855	Tax Remediation System Improvements	May-22	1,001,889.13	0.00	0.00	3
4	0061W0006560	Durango Laptop Replacement Project	Aug-22	701,616.19	0.00	0.00	4
5	0061W0006967	Pure Storage Controller Upgrade	Feb-22	657,646.41	0.00	0.00	5
6	0057W0006516	8350 Durango - AV Equipment	Jul-22	576,989.43	0.00	0.00	6
7	0061W0006835	Radio Console Upgrade Comm Equip	Dec-21	478,897.78	0.00	0.00	7
8	0061W0007353	Zero Trust-Duo MFA-Cloud based	Nov-22	419,143.49	0.00	0.00	8
9	0061W0006953	OpenText Extended ECM-Cloud-based	Apr-22	406,173.00	0.00	0.00	9
10	0061W0006138	Server for SFR Project-SWITCH	May-22	381,038.00	0.00	0.00	10
11	0061W0007177	C4C Development-Cloud Based	Jun-22	289,000.00	0.00	0.00	11
12	0061W0006858	HCM Phase III-Benefits Confi-cloud	Feb-22	285,547.26	0.00	0.00	12
13	0061W0007031	4 Kodak Scanners - Replacement 2021	Mar-22	232,724.51	0.00	0.00	13
14	0061W0006966	VXRail Servers for Out-of-Band Mgmt	Nov-22	226,126.22	0.00	0.00	14
15	0061W0007467	ZScaler-Netmotion (VPN) Replc-Cloud	May-23	218,235.77	0.00	0.00	15
16	0061W0007203	Audio Visual Room Upgrades	Aug-22	217,835.65	0.00	0.00	16
17	0061W0006484	Zero Trust ID Mgmt OKTA-Cloud-Based	Dec-21	146,353.65	0.00	0.00	17
18	0061W0006708	GasBoy CNG Management System-Cloud	Aug-22	138,449.46	0.00	0.00	18
19	0061W0006643	Spanish Bill Development-Corp	Dec-21	105,763.19	0.00	0.00	19

Docket No. 23-09___

General Rate Case

Confidential Exhibit No._(RNS-4)

CONFIDENTIAL

SOUTHWEST GAS CORPORATION

Docket No. 23-09___

Confidential Exhibit No._(RNS-4)

Southwest Gas is providing this information pursuant to the protective agreements executed with Staff and BCP in the above-referenced docket.

Docket No. 23-09___

General Rate Case

Confidential Exhibit No._(RNS-5)

CONFIDENTIAL

SOUTHWEST GAS CORPORATION

Docket No. 23-09___

Confidential Exhibit No._(RNS-5)

Southwest Gas is providing this information pursuant to the protective agreements executed with Staff and BCP in the above-referenced docket.

CONFIDENTIAL

SOUTHWEST GAS CORPORATION

Docket No. 23-09___

Confidential Exhibit No._(RNS-6)

Southwest Gas is providing this information pursuant to the protective agreements executed with Staff and BCP in the above-referenced docket.

AFFIRMATION OF RAIED N. STANLEY

Pursuant to NAC 703.710, Raied N. Stanley affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 14 day of August, 2023

RAIED N. STANLEY

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 23-09___

PREPARED DIRECT TESTIMONY

WILLIAM BRINCEFIELD

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTEMBER 1, 2023

Table of Contents
Prepared Direct Testimony
of
William Brincefield

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
William Brincefield

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is William Brincefield. My business address is 8350 S. Durango Drive, Las Vegas, NV 89113.

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

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Real Estate & Facilities Department. My title is Director.

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

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

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

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

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

A. 5 The purpose of my prepared direct testimony is to provide an overview of the planning process for and management of capital investments and support the reasonableness and prudence of the Company's investment in corporate (system allocable) and Northern Nevada real estate and facilities-related capital projects that are included in the Company's revenue requirement.

Q. 6 Please summarize your prepared direct testimony.

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

- Description of the planning process for and management of capital investments in real estate and facilities-related projects; and
- Support for the reasonableness and prudence of Northern Nevada and corporate facilities-related capital investment projects, including a discussion on projects in excess of $1 million that were placed into service since the end of the certification period in the Company's 2021 general rate case (GRC) and those capital investment projects that at the time of this filing are anticipated to be placed in service by November 30, 2023[1].

II. CAPITAL INVESTMENT PROJECT PLANNING AND OVERSIGHT PROCESS

Q. 7 Describe the process/oversight applicable to real estate and facilities-related capital investments.

A. 7 The need for facilities-related capital projects is generally realized by demand signals originating from Division Operations management or data/direct observation by Real Estate & Facilities department personnel. The planning process for capital projects is driven by and relative to the complexity, magnitude, time frame and potential impact of the project. Management of on-going capital projects is dependent upon the same parameters. As related to financial planning for capital projects, a five-year capital budget is created to address the operational needs as articulated by Division-based operations leadership.[2] The overall capital budget is then prioritized pursuant to operational

[1] The Company will update plant in its certification filing in the instant docket based on capital projects placed into service on or before November 30, 2023.

[2] In 2023, the Company modified its financial planning horizon for capital projects from 3-year to 5-year.

criticality, seasonal weather fluctuations and available capital resources. Once a specific project has been approved, project requirements are compiled and Vetted, contractors and/or vendors are procured for requests for proposal activities, bids are secured, and contracts are subsequently authored. The projects are managed to completion using various personnel, potentially including Real Estate & Facilities employees, contracted personnel, and on-site owner representatives for ground-up construction activities.

III. REAL ESTATE AND FACILITIES-RELATED CAPITAL INVESTMENT PROJECTS

Q. 8 Please describe the scope of the real estate and facilities-related capital investment projects discussed in your prepared direct testimony.

A. 8 I support all real estate and facilities-related capital investments in the Northern Nevada Division and corporate locations placed in service since December 1, 2021.[3] Projects represented by work orders greater than $100,000 in total are listed on Exhibit No._(WB-1). My prepared direct testimony specifically discusses two work orders with incurred costs equal to $1 million or more as of May 31, 2023.[4]

Q. 9 Please provide an overview of the real estate and facilities-related capital investment projects of more than $1 million that closed to plant in service between December 1, 2021 and May 31, 2023.

A. 9 The real estate and facilities-related projects with work orders of more than $1 million include the completion of energy efficiency and space optimization work

---

[3] The certification period in the Company's most recent general rate case (Docket No. 21-09001) ended November 30, 2021.

[4] Real estate and facilities-related work orders presented on Master Data Request 106. Work order 0057W0005418 reflected in in MDR 106 and shows a total cost of $2,072,557. That entire amount is recorded to FERC Account 121.00 – Nonutility Property and is not contemplated in the Company's rate base.

performed at the Company's northern Nevada Operations Center (Operations Center) and new furniture required for the Company's corporate headquarters location in Las Vegas, Nevada.

IV. NORTHERN NEVADA OPERATIONS CENTER RENNOVATIONS

Q. 10 Please provide an overview of the work included in the Company's Northern Nevada Operations Center Renovations Project (0024W0006808, 0024W0006605 and 0024W0007776).

A. 10 The Northern Nevada Operations Center (NNVOC) Renovations Project (NNVOC Project or Project) consists of three works order. Work order 0024W0006808 included the reconfiguration of the NNVOC lobby to remove an obsolete public office and repurpose the area to include a conference room for internal and external meetings and the renovation of the main break room. Moreover, work order 0024W0006808 included replacement of antiquated ceiling tiles that were more than 25 years old and the replacement of fluorescent lights with more energy efficient LED lights. Work order 0024W0006605 included the installation of rain gutters and snow breaks at the NNVOC and work order 0024W0007776 included the installation of furniture.

Q. 11 Why did Southwest Gas undertake the NNVOC Project?

A. 11 The NNVOC Project was designed and constructed to accomplish multiple objectives. First, there was a need to modernize and more efficiently utilize space in the Operations Center. The Project converted space that was previously designed as a public office area which was not frequently utilized, to a conference room that is now used for internal and external meeting purposes. The Project also improved the lighting and energy efficiency of the NNVOC by replacing antiquated fluorescent lights with more energy efficient LED lights.

Moreover, due to the existing 25 plus year old ceiling tiles' weather damage, and the fact that the lighting fixtures housed within those ceiling tiles were being replaced, the Company replaced the existing ceiling tiles in conjunction with the lighting fixtures.

Work order 0024W0007776 was necessary as it included the purchase and installation of furniture needed to accommodate the newly created conference room, lobby area guest seating, security desk seating, main break room furniture, and other pieces such as desks and chairs for various other locations and users throughout the NNVOC.

Lastly, work order 0024W0006605 included installation of rain gutters and snow breaks necessary for employee safety and vehicle protection. The rain gutters divert water from walkways providing safer conditions around the Operations Center and the snow breaks help prevent buildup of large snow and ice masses which reduce the likelihood of large falling ice from the roof that could cause personal harm or property damage.

Q. 12 What was the total cost of the renovation of the NNVOC?

A. 12 The total cost of the NNVOC was $2,156,725.[5] Work order 0024W0006605 was placed into service March 2022 and work orders 0024W0006808 and 0024W0007776 were placed into service May 2023.

Q. 13 Are the renovations associated with the NNVOC used and useful?

A. 13 Yes. All work orders contemplated in the NNVOC were used and useful as of May 2023.

[5] The total costs of work orders 0024W0006808, 0024W0006605 and 0024W0007776 were $1,863,942.24, $180,441.18, and $112,341.25, respectively.

V. CONCLUSION

Q. 14 Does this conclude your prepared direct testimony?

A. 14 Yes.

SUMMARY OF QUALIFICATIONS

WILLIAM BRINCEFIELD

I am a graduate of North Carolina State University having received a Bachelor of Sciences in Environmental Engineering in 1995.

In 1997, I joined the corporate engineering department of Qualex Inc. in North Carolina. In 2003, I joined PM Inc. in Durham, North Carolina as Director of Facilities. In 2007, I joined Johnson Controls, Inc RTP North Carolina and held positions of Director of Facilities Management, Eastern US, NW Region Facilities Director and Director of Facilities Operations. In 2015, I joined Cisco Systems, Inc. TRP and lead the delivery of integrated facilities management services for North, Central and South American real estate portfolio in 15 countries. In 2017, I joined Southwest Gas Corporation as Director/Real Estate and Facilities. I am responsible for Real Estate and Facilities Maintenance services enterprise-wide.

I am also a member of cornet, Leadership in Energy and Environmental Design and the International Facility Management Association.

SOUTHWEST GAS CORPORATION
NEVADA
REAL ESTATE AND FACILITIES - RELATED WORK ORDERS GREATER THAN $100,000 IN TOTAL COST
CLOSED TO PLANT IN SERVICE DECEMBER 2021 - MAY 2023

Line No.	Work Order Number		Work Order Description	Date First Transferred to Plant	Total Amount Excluding CIAC	CIAC	AFUDC	Line No.
	(a)		(b)	(c)	(d)	(e)	(f)	
	Northern Nevada							
1	0024W0006808		Carson City Lobby, EOC, & Breakroom	May-23	1,863,942.24	0.00	0.00	1
2	0024W0006605		Rain Gutter Installation - Carson	Mar-22	180,441.18	0.00	0.00	2
3	0024W0007776		Furniture - Carson City Remodel	May-23	112,341.25	0.00	0.00	3
	System Allocable							
4	0057W0005418	[1]	Land Purchase Durango	Oct-22	2,072,556.83	0.00	0.00	4
5	0057W0006478	[2]	8350 Durango Furniture - 2nd Floor	Nov-21	435,423.09	0.00	0.00	5

[1] Work order 0057W0005418 is recorded to FERC Account 121.00 - Nonutility Property and not contemplated in the Company's Rate Base.
[2] $375,228 in project costs for work order 0057W0006478 were previously contemplated in the Company's certification filing in Docket No. 21-09001. See Certification Exhibit No.__(WB-1) Sheet 1 of 3 of Company witness William Brincefield's Certification Testimony. The $435,423.09 included in the instant docket represent trailing charges incurred after November 2021 that were not included in Company's last general rate case.

AFFIRMATION OF WILLIAM BRINCEFIELD

Pursuant to NAC 703.710, William Brincefield affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 14 day of August, 2023

WILLIAM BRINCEFIELD

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 23-09___

PREPARED DIRECT TESTIMONY

OF

MATTHEW A. HELMERS

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTEMBER 1, 2023

Table of Contents
Prepared Direct Testimony
of
Matthew A. Helmers

Southwest Gas Corporation
Docket No. 23-09___

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Matthew A. Helmers

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Matthew A. Helmers. My business address is 400 Eagle Station Lane, Carson City, Nevada 89701.

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

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Northern Nevada Division. My title is Director/District Operations.

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

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

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

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada (Commission).

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

A. 5 The purpose of my prepared direct testimony is to provide an overview of the planning process for and management of capital investments and support the reasonableness and prudence of the Company's investment in capital projects for the Northern Nevada rate jurisdiction that are included in the Company's revenue requirement.

Q. 6 Please summarize your prepared direct testimony.

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

- Description of the planning for and oversight of capital investments for projects in the Northern Nevada Division;
- A discussion on the incremental costs incurred and recorded to the Nevada annual leak survey regulatory asset to support the leak survey requirements adopted by the Commission in Docket No. 19-09011;
- A discussion on the incurred costs recorded to the Customer Owned Yard Line (COYL) regulatory asset approved by the Commission in Docket No. 21-08033;
- Determination of prudency of capital investment projects and provide discussion on capital investment projects equal to or exceeding $1 million which have been placed in service in the Company's Northern Nevada system since the end of the certification period in Southwest Gas' 2021 general rate case (GRC) and those capital investment projects that at the time of this filing are anticipated to be placed in service by November 30, 2023[1]; and,
- Determination of prudency of Gas Infrastructure Replacement (GIR) projects to be included in rate base in accordance with Nevada Administrative Code (NAC) 704.7984.

---

[1] The Company will update plant in its certification filing in the instant docket based on capital projects placed into service on or before November 30, 2023.

II. CAPITAL INVESTMENT PROJECT PROCEDURAL PLANNING AND OVERSIGHT PROCESS

Q. 7 Describe the planning/oversight applicable to Northern Nevada capital investments.

A. 7 The procedural framework for Northern Nevada capital investment projects consists of controls, processes, and procedures for anticipating and mitigating the variability in capital projects. The four key components are transparency of controls, accountability of responsibilities, a project evaluation program, and project risk management process.

Q. 8 Describe the four key components.

A. 8 First, transparency of control for capital projects cuts across different business units. To coordinate the process that strengthens project outcomes, Northern Nevada uses a capital procedural framework composed of six project lifecycle phases and ten project elements. Depending on the complexity and size of the project some or all of the phases and elements may be used. The project lifecycle is planning, design, construction, completion, acceptance, and operations and maintenance. The ten project elements that support the project lifecycle are project organization framework, procurement and contracts, project scope and change management, costs, schedules, systems and tools, issue management, communication and reporting, quality and safety.

Second, accountability of responsibilities supports the processes important for successful project outcomes. The processes are backed with definition of responsibilities and reporting hierarchy so there is accountability for each level in the organization. This is accomplished using policies, procedures, best practices and guidelines, reporting dashboards and reports, and training for the correct use of policies and procedures. This clarity helps the organization manage capital projects more efficiently by avoiding gaps. Key stakeholders include: Gas Operations Support Staff, Engineering Services, System Integrity, Staff Planning, Regulation and Compliance, Supply Chain, Internal Audit, Risk Management and Safety, Purchasing, and Legal.

Third, the project evaluation program benefits capital projects in several ways: (1) improves policies, procedures and controls; (2) prevents deviations from policies, procedures, and controls; (3) identifies higher risk activities requiring management focus; (4) recommends cost reduction, avoidance, or recovery activities; and (5) provides opportunities for lessons learned and actionable recommendations for continuous improvement for existing and future projects.

Finally, the project risk management process advances an opportunity to monitor risks and identify when a mitigation plan is needed to manage the risk. The process provides the ability to recognize and respond to the early signs of project deviations, such as budgets, construction schedules, project scope changes, material delays, quality and safety concerns, design revisions, contract change orders, and other delays. These situations signal when it is necessary for management to investigate and gather key stakeholders to discuss causes and solutions.

III. ANNUAL LEAK SURVEY

Q. 9 Please provide an overview of the Commission's Order in Docket No. 19-09011.

A. 9 The Commission's Order in Docket No. 19-09011 (Order), adopts the regulations set forth in Legislative Counsel Bureau File No. R032-20 (Regulations), which require, among other things, that a person who operates or maintains any intrastate pipeline in Nevada which is used to transport natural gas, to conduct a leakage survey with leak detector equipment on any such intrastate pipeline at least once per calendar year, at an interval not to exceed 15 months.[2] The Order allows for incremental costs associated with the compliance with the new Regulations to be tracked in a regulatory asset account and brought for consideration in a utility's next general rate case (Annual Leak Survey Costs). The Order issued July 14, 2021, approved the Regulations effective January 1, 2023. The Order also authorized the establishment of a regulatory asset, described below.

Q. 10 Please describe the estimated costs anticipated to be incurred to meet the new requirements of the Regulations.

A. 10 In support of Nevada's transition to an annual leak survey, the Company requested, and the Commission authorized, the establishment of a regulatory asset to allow utilities to track and defer the incremental expenses (including capital and O&M expenditures) incurred in compliance with the Regulations. Specifically, the regulatory asset permits utilities to track and defer the revenue requirement (consisting of an amount equal to depreciation and amortization

[2] See Section 1 of LCB File No. R032-20.

expense, the pretax rate of return and incremental operations and maintenance expenses) associated with the implementation of the new regulation (Annual Leak Survey Costs).[3] Based on the Company's evaluation as of 2020, it estimated incremental Annual Leak Survey Costs of approximately $6M. In 2021, the Company provided its updated estimated incremental Annual Leak Survey Costs of approximately $8.8 million.[4]

Q. 11 When did the Company begin incurring incremental Annual Leak Survey Costs to ensure compliance with the Regulations?

A. 11 As indicated in the Company's Comments filed in Docket 19-09011, the Company estimated that it could take anywhere between 18 and 24 months to transition to annual leak surveys[5], therefore, in anticipation of the implementation of the new regulation, the Company began incurring costs in July 2022 to ensure a smooth and effective transition to the annual leak survey requirement. As of May 31, 2023, the Company has incurred both capital and O&M-related Annual Leak Survey Costs to ensure compliance with the Regulations. Below is a summary of the incurred Annual Leak Survey Costs by cost category:

[3] Southwest Gas comments filed January 24, 2020, in Docket No. 19-09011 at page 2.
[4] Southwest Gas comments filed June 17, 2021, in Docket No. 19-09011 at page 2.
[5] Southwest Gas comments filed January 24, 2020, in Docket No. 19-09011 at page 2.

Table 1
Incremental Annual Leak Survey Costs
Estimated Year 1 and Actual as of May 31, 2023

Jurisdiction	Operation & Maintenance Expense		Capital Expenditures	
	Estimated	Actual	Estimated	Actual[6]
Northern Nevada	$1,767,900	$321,150	$232,100	$206,055
Southern Nevada	$5,797,500	$2,871,660	$1,002,500	$586,412
Total Nevada	$7,565,400	$3,192,810	$1,234,600	$792,467

The Company intends to update the Annual Leak Survey Costs in its certification filing.

Q. 12 Were the incremental Annual Leak Survey Costs incurred in Northern Nevada required to ensure compliance with the Regulations reasonable and prudent?

A. 12 Yes. The Company's Northern Nevada leak survey schedule prior to the Regulation effective date contemplated the leak survey of all facilities every three years, not annually. Consolidating leak survey activity historically spread over a three-year period to a twelve-month period effectively increased the mileage of facilities to be surveyed in Nevada. Consequently, as described in the Company's comments in Docket No. 19-09011, incremental resources, expenses, and capital expenditures were required to ensure compliance with the

[6] Includes amounts for vehicles and equipment purchased by Fleet Management.

Regulations.[7] As such the incurred Annual Leak Survey Costs are reasonable and prudent.

Q. 13 Is the Company able to demonstrate that the Annual Leak Survey Costs deferred to the regulatory asset are incremental to costs it was previously incurring for leak survey activities?

A. 13 Yes. Prior to the adoption of the annual leak survey in Nevada, the Company conducted leak surveys pursuant to the requirements of the Company's Distribution Integrity Management Program (DIMP) and the Pipeline and Hazardous Materials Safety Administration (PHMSA) (collectively, the Scheduled Leak Surveys). The Company conducted a leak survey once every three calendar years, and DIMP-identified facilities were surveyed more frequently, such as annual, bi-annual, and quarterly. Regulatory asset treatment, pursuant to Nevada Revised Statutes (NRS) 704.185(2), addressed incremental expenses (including capital and operations and maintenance expenditures) to meet compliance with the Regulations. The incremental leak survey addresses facilities surveyed outside of the Scheduled Leak Surveys conducted by the Company prior to implementation of the Regulations.

For example, the information listed in Exhibit No.__(MAH-1) in my prepared direct testimony identifies three areas: Leak survey region (LSR) 1, LSR 2, and LSR 3. LSR 1 was scheduled for a leak survey in 2023; therefore, LSR 1 is classified as Scheduled Leak Surveys. LSR 2 and LSR 3 were scheduled for 2024 and 2025, respectively, and, because of the Regulations, must now be surveyed in 2023, and are, therefore, classified as incremental.

[7] See Southwest Gas' comments in Docket No. 19-09011 dated January 24, 2020, and June 17, 2021.

Certain facilities located in LSR 2 and LSR 3, which have a more frequent survey pursuant to DIMP, are not classified as incremental and costs related to these specific facilities are not included in the regulatory asset.

Because utilities were authorized to defer only the incremental annual leak survey costs into a regulatory asset, the Company established a program reference number (PRN) to enable the tracking of incremental costs separately from the costs incurred for the Scheduled Leak Surveys.

Q. 14 Has the Company incurred a full year of incremental Annual Leak Survey Costs under the Regulations?

A. 14 No. Notwithstanding the Annual Leak Survey Costs incurred through May 2023 being in alignment with the preliminary Company estimates provided in its June 17, 2021, comments in Docket No. No. 19-09011, the Company has not yet completed the first full year of annual leak surveys required under the Regulations. As such, the Company seeks approval to include the Annual Leak Survey Costs incurred through November 30, 2023, in base rates and to continue tracking Annual Leak Survey Costs incurred thereafter in a regulatory asset as further discussed in the prepared direct testimony of Company witness Christopher M. Brown.

IV. COYL REGULATORY ASSET

Q. 15 Please provide an overview of the COYL Program approved by the Commission in Docket No. 21-08003.

A. 15 Southwest Gas and the Regulatory Operations Staff of the Commission (Staff) jointly filed a joint petition in Docket No. 21-08003, and the Commission approved, the creation of a new, broader program for the Company's COYL replacements which allows for replacement of primarily residential and public school COYLs in its northern and southern Nevada service territories (COYL Program).[8] The COYL Program has an estimated annual investment amount of $5 million per year ($25 million total program cost) with approximately $2 million/year allocated to Northern Nevada and approximately $3 million/year allocated to Southern Nevada.[9] The Commission authorized the COYL Program to include replacements of COYLs discovered at non-profit or other publicly funded facilities where private funding is limited or unavailable for COYL replacement and the COYL is believed to be a safety concern. Moreover, the Commission authorized the Company to record COYL Program capital costs in a regulatory asset account.[10] The Company would then seek recovery of those deferred COYL Program capital costs in a future GRC application.[11]

Q. 16 Provide an overview of the Northern Nevada's COYL progress and the related capital costs incurred to date.

A. 16 The Company has replaced 150 COYLs in Northern Nevada under this program. This includes 13 at schools, 19 at the 4H Camp in Stateline, NV, and 118 residential services. Northern Nevada has replaced five public school COYLs with approximately 35 remaining throughout its service territory.

Single service COYL replacements are completed under a blanket work order which are reflected in 0024CB025120 and 0026CB025120. Specific jobs that include installation or replacement of main to facilitate the elimination of the COYL(s) include 0023W4366512 – 4H Camp COYL Replacement,

---

[8] The Commission previously approved a Northern Nevada COYL program in Docket No. 18-06004 which was granted GIR treatment. That program concluded December 31, 2021. Costs incurred under the previous COYL program are further discussed in my testimony, below.
[9] See the Commission's Order in Docket No. 21-08003 at page 4.
[10] See the Commission's Order in Docket No. 21-08003 at pages 4 and 5.
[11] See the Company's compliance filings in Docket No. 21-08003 dated March 15, 2022 and April 13, 2022.

0024W4428636 – Carson Valley Middle School, and 0026W4202388 – Chukar Hills Mobile Home Park Replacement. This work represents a total capital investment of $943,049.17 to improve safety.

Q. 17 Were the COYL Program capital costs incurred in Northern Nevada reasonable and prudent?

A. 17 Yes. In coordination with Staff, the Company identified, prioritized, and successfully completed the construction of multiple COYL projects, as contemplated by the Commission's order approving the COYL Program.

V. CAPITAL INVESTMENT PROJECTS

Q. 18 Please describe the scope of the capital investment projects discussed in your prepared direct testimony.

A. 18 I support all capital investments for distribution projects in Northern Nevada placed in service since December 1, 2021. Projects represented by work orders greater than $100,000 in total cost are listed in Exhibit No.__(MAH-2). My prepared direct testimony specifically discusses work orders which incurred costs equal to $1 million or more as of May 31, 2023.

Spring Creek Expansion Area (SCEA) capital projects placed into service between December 2021 and May 2023 are not included in the Company's rate base or revenue requirement in the instant application.[12] Consequently, there is no specific discussion or prudency packages included for those SCEA work orders in my testimony.

[12] See identified projects in Exhibit No.__(MAH-2)

Q. 19 Please provide an overview of the capital investment projects more than $1 million that closed to plant in service between December 1, 2021 and May 31, 2023.

A. 19 The capital investment projects more than $1 million include four blanket work orders for meter installations, meter replacements, and random new business service installations. The blanket work order projects are more fully discussed below.

VI. BLANKET WORK ORDERS

Q. 20 Please describe the purpose of blanket work orders.

A. 20 Blanket work orders (BWOs) were established to efficiently capture the cost of many small main, service, meter, and COYL transactions into a BWO for similar type of work. BWOs, in essence, combine what would otherwise be many different work orders for similar work (i.e., meter installations) into one BWO. The BWO structure helps Southwest Gas manage the multitude of projects and lowers the administrative burden of tracking and accounting for a large number of separate work orders. Southwest Gas has a series of BWO numbers for Northern Nevada that are used to capture the material acquisition and installation charges related to the following: 1) new meter installations; 2) regular service replacements; 3) new main installations of less than 100 feet; 4) new service installations; 5) new random service installations; (6) new service commercial installations; (7) regular replacement mains of less than 100 feet; (8) franchise related main replacement of less than 100 feet.[13].

---

[13] The six districts included in the Northern Nevada Division are 0023-Tahoe, 0024-Carson, 0025-Elko, 0026-Winnemucca, 0027-Fernley (includes Fallon and Yerington), and 0028-Spring Creek.

Q. 21 Please describe the BWO's with recorded costs of at least $1 million.

A. 21 As of May 31, 2023, the following blanket work orders had incurred costs of at least $1 million:

- New Meters BWO 0024CB030000 - The New Meters BWO recorded costs associated with the purchase of meters for all Northern Nevada districts and installation of meter set assemblies in the Carson district. As of May 31, 2023, this BWO had incurred costs of $1,751,173.
- Replacement Meters BWO 0024CB035000 - The Replacement Meters BWO recorded costs associated with the purchase of replacement meters for all Northern Nevada districts and replacement of meter set assemblies in the Carson district. As of May 31, 2023, this BWO had incurred costs of $1,054,052.
- New Service Subdivision BWO 0024CB041000 - The New Service Subdivision BWO recorded costs associated with the installation of services to new residential homes within a subdivision in the Carson district. As of May 31, 2023, this BWO had incurred costs of $1,352,133.
- New Random Services – Southwest Gas Trench BWO 0024CB043000 - New Random Services – Southwest Gas Trench BWO recorded costs associated with the installation of services to random residential homes outside of a subdivision within the Carson district. As of May 31, 2023, this BWO had incurred costs of $1,676,846 with a corresponding contribution in aid of construction (CIAC) of ($278,436).

Q. 22 Are the facilities installed under the New Meters BWO (0024CB030000) used and useful?

A. 22 Yes. Each new customer requires the installation of a meter set assembly to regulate the delivery pressure to the customer and to measure the amount of natural gas for billing purposes. The New Meter BWOs capture the costs associated with installing a meter set assembly, including labor, the meter purchase, Encoder Receiver Transmitter (ERT), regulator, nipples, tees, elbows, and any miscellaneous parts involved with the placement of the new meter set. This work happens on a daily basis across the Division. The meter set assemblies captured in the New Meters BWOs are necessary and utilized in the provision of natural gas service to the Company's customers.

Q. 23 Are the facilities installed under the Replacement Meters BWO (0024CB035000) used and useful?

A. 23 Yes. Each customer requires a meter set assembly to regulate the delivery pressure to the customer and to measure the amount of natural gas for billing purposes. At times, one or more of the parts of the meter set assembly may need replacement. The Replacement Meter BWOs capture the costs involved with the purchase and partial or full replacement of meter set assemblies. This work happens on a daily basis throughout the service territory, and the Replacement BWO captures the associated costs with that partial or full replacement. The replacement of meter set assemblies that are captured in the Replacement Meters BWO are necessary and utilized in the provision of natural gas service to the Company's customers.

Q. 24 Are the facilities installed under the New Service Subdivision BWO (0024CB041000) used and useful?

A. 24 Yes. Each customer requires a service to deliver the natural gas from the main to the meter set. While the main in a subdivision is installed at one time or in a phased format, the services are not run at the same time. For safety, the service is not installed from the main to the riser until a majority of excavation is complete on the homesite. Once the service is installed, it is gassed and placed into service.

Q. 25 Are the facilities installed under the New Random Services – Southwest Gas Trench BWO (0024CB043000) used and useful?

A. 25 Yes. Each customer requires a service to deliver the natural gas from the main to the meter set. If required, the main to a new random residential home is installed at one time, but the service is not run at the same time. For safety, the service is not installed from the main to the riser until a majority of excavation is complete on the homesite. Once the service is installed, it is gassed and placed into service.

VII. DETERMINATION OF PRUDENCY OF GIR PROJECTS

Q. 26 Please provide an overview of the previously approved GIR projects included in this Application.

A. 26 Southwest Gas was authorized to defer costs associated with certain pipe replacement projects into regulatory assets for inclusion in the GIR mechanism in the following dockets:

1. Docket 17-05027: In its 2017 GIR Advance Application, Southwest Gas was authorized to establish a regulatory asset for costs related to approved VSP and EVPP Projects in Southern Nevada and VSP and COYL Projects in Northern Nevada.

2. Docket 18-06004: In its 2018 GIR Advance Application, Southwest Gas was authorized to establish a regulatory asset for costs related to approved VSP and EVPP Projects in Southern Nevada and customer-owned yard line (COYL) in Northern Nevada.

Please refer to Exhibit No.__(MAH-3) to my prepared direct testimony for a summary of the GIR plant in service for each of the above-referenced dockets, by work order, as of the test period ended May 31, 2023.

Q. 27 Have the GIR projects previously been presented to the Commission?

A. 27 Yes. The Company's GIR projects have already been evaluated and approved by the Commission in various dockets.

Q. 28 Please describe the requirements for seeking a determination of prudency for GIR projects.

A. 28 Pursuant to NAC 704.7984, a utility must seek a determination of prudency for GIR projects previously approved by the Commission which have been accounted for in a GIR rate and is required to submit evidence in support of the recorded cost for each GIR project completed since the last general rate application filed. This evidence should include invoices for each project, a copy of the work order, a breakout of labor costs, and any other evidence that demonstrates prudency.

Q. 29 Is the Company seeking a determination of prudency for GIR projects in this Application?

A. 29 Yes, the Company is seeking a determination of prudency for the costs of the previously approved GIR projects and inclusion of the projects in rate base.

Q. 30 Were the GIR projects prudent?

A. 30 Yes. Each of the GIR projects proposed for inclusion into rate base and general rates were approved by the Commission, most of which were reviewed on multiple occasions through Commission-approved GIR Advance Applications (Docket Nos. 17-05027, 18-06004) and GIR Rate Applications. The benefits of the GIR projects were discussed at length the above referenced dockets and are incorporated herein by this reference. The plant involved in those projects is used and useful as it continues to be used to provide natural gas service to the Company's customers. Accordingly, the GIR projects are prudent and should be included in rate base and general rates.

Q. 31 Please describe the evidence the Company submitted in this Application supporting the recorded costs for the GIR projects.

A. 31 Southwest Gas compiled prudency packages for each work order related to an approved GIR project which include the following: (1) a copy of the work order with cost breakout by charge type, (2) a summary of all invoices by the six cost categories, as applicable, described in NAC 704.7984(2), and (3) a copy of each invoice. This information is included as Exhibit No.___(MAH-4) to my prepared direct testimony.

Q. 32 Does this conclude your prepared direct testimony?

A. 32 Yes.

SUMMARY OF QUALIFICATIONS
MATTHEW A. HELMERS

Matthew A. Helmers is the director/District Operations for the Northern Nevada Division for Southwest Gas Corporation (Southwest Gas). Mr. Helmers joined Southwest Gas in 2001 as an engineer in Carson City, NV. He was subsequently promoted to engineer II in 2003 and then transferred to Paiute Pipeline (currently known as Great Basin Gas Transmission Company), a wholly owned subsidiary of Southwest Gas, in 2004. He was promoted to transmission engineer in 2005, and then returned to Southwest Gas as supervisor/Engineering in 2006. During this period, Mr. Helmers oversaw the design of transmission and distribution facilities for new business, franchise and system reinforcements; PVC pipeline replacements, pipeline safety code compliance, pipeline pigging plans, MAOP studies; and preparation of short and long-term capital budgets.

He was promoted to manager/Operations Planning and Analysis in 2012 where he organized operational metric tracking, represented the company and became the chairperson for the American Gas Association's Best Practices program, represented operations in various projects and initiatives, budget planning; and oversaw company-wide initiatives to improve safety, quality and reliability.

Mr. Helmers was promoted director/District Operations in 2017 where he is responsible for the engineering, GIS, construction, and customer service departments throughout the Northern Nevada Division. He focuses on improving safety and quality initiatives that reduce emergency response times and pipeline damages, while improving the customer experience.

He holds a Bachelor of Science degree in Mechanical Engineering and Master of Business Administration from the University of Nevada, Reno.

MAH-1

Northern Nevada Annual Leak Survey Regions

District	Survey Area City	Latitude	Longitude	Tile	LSR
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2128	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2130	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2132	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2134	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2136	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2138	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2140	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2142	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2144	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2146	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2148	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x957y2150	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2108	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2110	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2112	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2114	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2116	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2118	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2120	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2122	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2124	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2126	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2128	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2144	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x960y2146	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x963y2146	LSR1
26	BATTLE MOUNTAIN	40.6421	-116.9343	x945y2154	LSR2
26	BATTLE MOUNTAIN	40.6421	-116.9343	x948y2154	LSR2
26	BATTLE MOUNTAIN	40.6421	-116.9343	x951y2150	LSR2
26	BATTLE MOUNTAIN	40.6421	-116.9343	x951y2152	LSR2
26	BATTLE MOUNTAIN	40.6421	-116.9343	x951y2154	LSR2
26	BATTLE MOUNTAIN	40.6421	-116.9343	x954y2144	LSR2
26	BATTLE MOUNTAIN	40.6421	-116.9343	x954y2146	LSR2
26	BATTLE MOUNTAIN	40.6421	-116.9343	x954y2148	LSR2
26	BATTLE MOUNTAIN	40.6421	-116.9343	x954y2150	LSR2
26	BATTLE MOUNTAIN	40.6421	-116.9343	x954y2152	LSR2
26	BATTLE MOUNTAIN	40.6421	-116.9343	x897y2096	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x897y2098	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x900y2098	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x900y2100	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x945y2144	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x945y2146	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x948y2138	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x948y2140	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x948y2142	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x948y2144	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x948y2146	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x948y2148	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x951y2138	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x951y2140	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x951y2142	LSR3

26	BATTLE MOUNTAIN	40.6421	-116.9343	x951y2144	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x951y2146	LSR3
26	BATTLE MOUNTAIN	40.6421	-116.9343	x951y2148	LSR3
25	CARLIN	40.7138	-116.104	x1077y2134	LSR1
25	CARLIN	40.7138	-116.104	x1077y2136	LSR1
25	CARLIN	40.7138	-116.104	x1089y2138	LSR1
25	CARLIN	40.7138	-116.104	x1131y2156	LSR1
25	CARLIN	40.7138	-116.104	x1131y2158	LSR1
25	CARLIN	40.7138	-116.104	x1182y2178	LSR1
25	CARLIN	40.7138	-116.104	x1182y2180	LSR1
25	CARLIN	40.7138	-116.104	x1182y2188	LSR1
25	CARLIN	40.7138	-116.104	x1182y2190	LSR1
25	CARLIN	40.7138	-116.104	x1182y2192	LSR1
25	CARLIN	40.7138	-116.104	x1185y2188	LSR1
25	CARLIN	40.7138	-116.104	x1185y2178	LSR2
25	CARLIN	40.7138	-116.104	x1185y2180	LSR2
25	CARLIN	40.7138	-116.104	x1188y2180	LSR2
25	CARLIN	40.7138	-116.104	x1188y2182	LSR2
25	CARLIN	40.7138	-116.104	x1182y2182	LSR3
25	CARLIN	40.7138	-116.104	x1185y2182	LSR3
25	CARLIN	40.7138	-116.104	x1185y2184	LSR3
25	CARLIN	40.7138	-116.104	x1185y2186	LSR3
25	CARLIN	40.7138	-116.104	x1188y2184	LSR3
25	CARLIN	40.7138	-116.104	x1188y2186	LSR3
25	CARLIN	40.7138	-116.104	x1191y2184	LSR3
25	CARLIN	40.7138	-116.104	x1191y2186	LSR3
24	CARSON CITY	39.1638	-119.7674	x147y1620	LSR1
24	CARSON CITY	39.1638	-119.7674	x147y1622	LSR1
24	CARSON CITY	39.1638	-119.7674	x150y1616	LSR1
24	CARSON CITY	39.1638	-119.7674	x150y1618	LSR1
24	CARSON CITY	39.1638	-119.7674	x150y1620	LSR1
24	CARSON CITY	39.1638	-119.7674	x150y1622	LSR1
24	CARSON CITY	39.1638	-119.7674	x150y1624	LSR1
24	CARSON CITY	39.1638	-119.7674	x153y1606	LSR1
24	CARSON CITY	39.1638	-119.7674	x153y1608	LSR1
24	CARSON CITY	39.1638	-119.7674	x153y1610	LSR1
24	CARSON CITY	39.1638	-119.7674	x153y1616	LSR1
24	CARSON CITY	39.1638	-119.7674	x153y1618	LSR1
24	CARSON CITY	39.1638	-119.7674	x153y1620	LSR1
24	CARSON CITY	39.1638	-119.7674	x153y1622	LSR1
24	CARSON CITY	39.1638	-119.7674	x153y1624	LSR1
24	CARSON CITY	39.1638	-119.7674	x156y1606	LSR1
24	CARSON CITY	39.1638	-119.7674	x156y1608	LSR1
24	CARSON CITY	39.1638	-119.7674	x156y1610	LSR1
24	CARSON CITY	39.1638	-119.7674	x156y1612	LSR1
24	CARSON CITY	39.1638	-119.7674	x156y1614	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1596	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1610	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1620	LSR1
24	CARSON CITY	39.1638	-119.7674	x156y1616	LSR1
24	CARSON CITY	39.1638	-119.7674	x156y1618	LSR1
24	CARSON CITY	39.1638	-119.7674	x156y1622	LSR1
24	CARSON CITY	39.1638	-119.7674	x165y1616	LSR1
24	CARSON CITY	39.1638	-119.7674	x165y1618	LSR1
24	CARSON CITY	39.1638	-119.7674	x168y1598	LSR1

24	CARSON CITY	39.1638	-119.7674	x168y1600	LSR1
24	CARSON CITY	39.1638	-119.7674	x168y1602	LSR1
24	CARSON CITY	39.1638	-119.7674	x168y1604	LSR1
24	CARSON CITY	39.1638	-119.7674	x168y1606	LSR1
24	CARSON CITY	39.1638	-119.7674	x168y1608	LSR1
24	CARSON CITY	39.1638	-119.7674	x168y1610	LSR1
24	CARSON CITY	39.1638	-119.7674	x168y1616	LSR1
24	CARSON CITY	39.1638	-119.7674	x168y1618	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1598	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1600	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1602	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1604	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1606	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1608	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1612	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1618	LSR1
24	CARSON CITY	39.1638	-119.7674	x171y1622	LSR1
24	CARSON CITY	39.1638	-119.7674	x174y1602	LSR1
24	CARSON CITY	39.1638	-119.7674	x174y1604	LSR1
24	CARSON CITY	39.1638	-119.7674	x174y1606	LSR1
24	CARSON CITY	39.1638	-119.7674	x174y1608	LSR1
24	CARSON CITY	39.1638	-119.7674	x174y1610	LSR1
24	CARSON CITY	39.1638	-119.7674	x174y1612	LSR1
24	CARSON CITY	39.1638	-119.7674	x174y1618	LSR1
24	CARSON CITY	39.1638	-119.7674	x174y1620	LSR1
24	CARSON CITY	39.1638	-119.7674	x174y1622	LSR1
24	CARSON CITY	39.1638	-119.7674	x177y1602	LSR1
24	CARSON CITY	39.1638	-119.7674	x177y1604	LSR1
24	CARSON CITY	39.1638	-119.7674	x177y1606	LSR1
24	CARSON CITY	39.1638	-119.7674	x177y1608	LSR1
24	CARSON CITY	39.1638	-119.7674	x177y1620	LSR1
24	CARSON CITY	39.1638	-119.7674	x180y1606	LSR1
24	CARSON CITY	39.1638	-119.7674	x180y1608	LSR1
24	CARSON CITY	39.1638	-119.7674	x159y1594	LSR2
24	CARSON CITY	39.1638	-119.7674	x159y1612	LSR2
24	CARSON CITY	39.1638	-119.7674	x162y1622	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1586	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1588	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1594	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1622	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1624	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1584	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1592	LSR2
24	CARSON CITY	39.1638	-119.7674	x171y1594	LSR2
24	CARSON CITY	39.1638	-119.7674	x171y1626	LSR2
24	CARSON CITY	39.1638	-119.7674	x171y1628	LSR2
24	CARSON CITY	39.1638	-119.7674	x159y1596	LSR2
24	CARSON CITY	39.1638	-119.7674	x159y1606	LSR2
24	CARSON CITY	39.1638	-119.7674	x159y1608	LSR2
24	CARSON CITY	39.1638	-119.7674	x159y1616	LSR2
24	CARSON CITY	39.1638	-119.7674	x159y1618	LSR2
24	CARSON CITY	39.1638	-119.7674	x159y1620	LSR2
24	CARSON CITY	39.1638	-119.7674	x159y1622	LSR2
24	CARSON CITY	39.1638	-119.7674	x159y1624	LSR2
24	CARSON CITY	39.1638	-119.7674	x162y1594	LSR2

24	CARSON CITY	39.1638	-119.7674	x162y1596	LSR2
24	CARSON CITY	39.1638	-119.7674	x162y1598	LSR2
24	CARSON CITY	39.1638	-119.7674	x162y1600	LSR2
24	CARSON CITY	39.1638	-119.7674	x162y1602	LSR2
24	CARSON CITY	39.1638	-119.7674	x162y1608	LSR2
24	CARSON CITY	39.1638	-119.7674	x162y1610	LSR2
24	CARSON CITY	39.1638	-119.7674	x162y1620	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1590	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1592	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1596	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1598	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1600	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1608	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1610	LSR2
24	CARSON CITY	39.1638	-119.7674	x165y1620	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1586	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1588	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1590	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1594	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1596	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1620	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1622	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1624	LSR2
24	CARSON CITY	39.1638	-119.7674	x168y1626	LSR2
24	CARSON CITY	39.1638	-119.7674	x171y1588	LSR2
24	CARSON CITY	39.1638	-119.7674	x171y1590	LSR2
24	CARSON CITY	39.1638	-119.7674	x171y1592	LSR2
24	CARSON CITY	39.1638	-119.7674	x171y1624	LSR2
24	CARSON CITY	39.1638	-119.7674	x174y1624	LSR2
24	CARSON CITY	39.1638	-119.7674	x162y1618	LSR3
24	CARSON CITY	39.1638	-119.7674	x159y1614	LSR3
24	CARSON CITY	39.1638	-119.7674	x162y1604	LSR3
24	CARSON CITY	39.1638	-119.7674	x162y1606	LSR3
24	CARSON CITY	39.1638	-119.7674	x162y1612	LSR3
24	CARSON CITY	39.1638	-119.7674	x162y1614	LSR3
24	CARSON CITY	39.1638	-119.7674	x162y1616	LSR3
24	CARSON CITY	39.1638	-119.7674	x165y1602	LSR3
24	CARSON CITY	39.1638	-119.7674	x165y1604	LSR3
24	CARSON CITY	39.1638	-119.7674	x165y1606	LSR3
24	CARSON CITY	39.1638	-119.7674	x165y1612	LSR3
24	CARSON CITY	39.1638	-119.7674	x165y1614	LSR3
24	CARSON CITY	39.1638	-119.7674	x168y1612	LSR3
24	CARSON CITY	39.1638	-119.7674	x168y1614	LSR3
24	CARSON CITY	39.1638	-119.7674	x171y1614	LSR3
24	CARSON CITY	39.1638	-119.7674	x171y1616	LSR3
24	CARSON CITY	39.1638	-119.7674	x174y1614	LSR3
24	CARSON CITY	39.1638	-119.7674	x174y1616	LSR3
24	CARSON CITY	39.1638	-119.7674	x177y1610	LSR3
24	CARSON CITY	39.1638	-119.7674	x177y1612	LSR3
24	CARSON CITY	39.1638	-119.7674	x177y1614	LSR3
24	CARSON CITY	39.1638	-119.7674	x177y1616	LSR3
24	CARSON CITY	39.1638	-119.7674	x177y1618	LSR3
24	CARSON CITY	39.1638	-119.7674	x180y1614	LSR3
24	CARSON CITY	39.1638	-119.7674	x180y1616	LSR3
24	CARSON CITY	39.1638	-119.7674	x180y1618	LSR3

24	CARSON CITY	39.1638	-119.7674	x180y1620	LSR3
24	CARSON CITY	39.1638	-119.7674	x183y1614	LSR3
24	CARSON CITY	39.1638	-119.7674	x183y1616	LSR3
24	CARSON CITY	39.1638	-119.7674	x183y1618	LSR3
24	CARSON CITY	39.1638	-119.7674	x186y1618	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x174y1540	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x174y1564	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x156y1572	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x156y1574	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x156y1578	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x156y1580	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x156y1582	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x159y1556	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x159y1558	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x159y1560	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x159y1562	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x159y1564	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x159y1572	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x159y1574	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x159y1576	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x159y1578	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x159y1580	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x162y1546	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x162y1548	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x162y1550	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x162y1558	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x162y1560	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x162y1562	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x162y1576	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x162y1578	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x162y1580	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x165y1546	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x165y1548	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x165y1550	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x165y1552	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x165y1554	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x165y1556	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x165y1558	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x165y1560	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x165y1562	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x168y1554	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x168y1556	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x168y1558	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x168y1560	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x174y1562	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x177y1540	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x177y1562	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x177y1564	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x177y1566	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x180y1536	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x180y1562	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x180y1564	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x180y1566	LSR1
24	CARSON VALLEY	38.9265	-119.6499	x156y1552	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x159y1582	LSR2

24	CARSON VALLEY	38.9265	-119.6499	x162y1564	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x162y1566	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x162y1582	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x162y1584	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x162y1586	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x162y1588	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x162y1590	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x165y1564	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x165y1566	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x165y1582	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x165y1584	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x168y1562	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x168y1564	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x168y1566	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x168y1568	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x171y1556	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x174y1556	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x174y1560	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x159y1552	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x162y1592	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x171y1558	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x171y1560	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x174y1558	LSR2
24	CARSON VALLEY	38.9265	-119.6499	x138y1586	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x138y1588	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x141y1582	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x141y1586	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x141y1588	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x144y1580	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x144y1582	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x147y1578	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x147y1580	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x147y1582	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x147y1584	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x150y1578	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x150y1582	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x150y1584	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x153y1584	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x156y1584	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x156y1586	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x156y1588	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x159y1584	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x159y1586	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x159y1588	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x159y1590	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x168y1540	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x171y1564	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x171y1566	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x171y1568	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x171y1570	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x174y1566	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x177y1554	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x177y1556	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x180y1552	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x180y1554	LSR3

24	CARSON VALLEY	38.9265	-119.6499	x180y1556	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x180y1558	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x180y1560	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x141y1584	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x144y1584	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x144y1586	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x150y1580	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x153y1582	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x171y1562	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x177y1558	LSR3
24	CARSON VALLEY	38.9265	-119.6499	x177y1560	LSR3
23	CRYSTAL BAY	39.2278	-120.0047	x96y1630	LSR3
23	CRYSTAL BAY	39.2278	-120.0047	x96y1632	LSR3
23	CRYSTAL BAY	39.2278	-120.0047	x96y1634	LSR3
23	CRYSTAL BAY	39.2278	-120.0047	x96y1636	LSR3
23	CRYSTAL BAY	39.2278	-120.0047	x96y1638	LSR3
23	CRYSTAL BAY	39.2278	-120.0047	x96y1644	LSR3
24	DAYTON	39.2371	-119.593	x219y1636	LSR1
24	DAYTON	39.2371	-119.593	x222y1636	LSR1
24	DAYTON	39.2371	-119.593	x222y1638	LSR1
24	DAYTON	39.2371	-119.593	x222y1640	LSR1
24	DAYTON	39.2371	-119.593	x225y1638	LSR1
24	DAYTON	39.2371	-119.593	x225y1640	LSR1
24	DAYTON	39.2371	-119.593	x228y1638	LSR1
24	DAYTON	39.2371	-119.593	x228y1640	LSR1
24	DAYTON	39.2371	-119.593	x228y1642	LSR1
24	DAYTON	39.2371	-119.593	x231y1640	LSR1
24	DAYTON	39.2371	-119.593	x231y1642	LSR1
24	DAYTON	39.2371	-119.593	x231y1644	LSR1
24	DAYTON	39.2371	-119.593	x231y1646	LSR1
24	DAYTON	39.2371	-119.593	x231y1648	LSR1
24	DAYTON	39.2371	-119.593	x234y1640	LSR1
24	DAYTON	39.2371	-119.593	x234y1642	LSR1
24	DAYTON	39.2371	-119.593	x234y1644	LSR1
24	DAYTON	39.2371	-119.593	x234y1646	LSR1
24	DAYTON	39.2371	-119.593	x234y1648	LSR1
24	DAYTON	39.2371	-119.593	x234y1660	LSR1
24	DAYTON	39.2371	-119.593	x234y1662	LSR1
24	DAYTON	39.2371	-119.593	x234y1664	LSR1
24	DAYTON	39.2371	-119.593	x237y1642	LSR1
24	DAYTON	39.2371	-119.593	x237y1660	LSR1
24	DAYTON	39.2371	-119.593	x237y1662	LSR1
24	DAYTON	39.2371	-119.593	x240y1660	LSR1
24	DAYTON	39.2371	-119.593	x240y1662	LSR1
24	DAYTON	39.2371	-119.593	x240y1664	LSR1
24	DAYTON	39.2371	-119.593	x240y1666	LSR1
24	DAYTON	39.2371	-119.593	x243y1660	LSR1
24	DAYTON	39.2371	-119.593	x243y1662	LSR1
24	DAYTON	39.2371	-119.593	x243y1664	LSR1
24	DAYTON	39.2371	-119.593	x243y1666	LSR1
24	DAYTON	39.2371	-119.593	x213y1636	LSR2
24	DAYTON	39.2371	-119.593	x207y1628	LSR2
24	DAYTON	39.2371	-119.593	x210y1628	LSR2
24	DAYTON	39.2371	-119.593	x210y1630	LSR2
24	DAYTON	39.2371	-119.593	x213y1630	LSR2

24	DAYTON	39.2371	-119.593	x213y1632	LSR2
24	DAYTON	39.2371	-119.593	x213y1634	LSR2
24	DAYTON	39.2371	-119.593	x213y1638	LSR2
24	DAYTON	39.2371	-119.593	x216y1634	LSR2
24	DAYTON	39.2371	-119.593	x216y1636	LSR2
24	DAYTON	39.2371	-119.593	x216y1638	LSR2
24	DAYTON	39.2371	-119.593	x219y1634	LSR2
24	DAYTON	39.2371	-119.593	x222y1632	LSR2
24	DAYTON	39.2371	-119.593	x222y1634	LSR2
24	DAYTON	39.2371	-119.593	x222y1646	LSR2
24	DAYTON	39.2371	-119.593	x225y1632	LSR2
24	DAYTON	39.2371	-119.593	x225y1634	LSR2
24	DAYTON	39.2371	-119.593	x225y1636	LSR2
24	DAYTON	39.2371	-119.593	x225y1648	LSR2
24	DAYTON	39.2371	-119.593	x225y1650	LSR2
24	DAYTON	39.2371	-119.593	x225y1652	LSR2
24	DAYTON	39.2371	-119.593	x225y1658	LSR2
24	DAYTON	39.2371	-119.593	x225y1660	LSR2
24	DAYTON	39.2371	-119.593	x228y1650	LSR2
24	DAYTON	39.2371	-119.593	x228y1652	LSR2
24	DAYTON	39.2371	-119.593	x228y1654	LSR2
24	DAYTON	39.2371	-119.593	x228y1656	LSR2
24	DAYTON	39.2371	-119.593	x228y1658	LSR2
24	DAYTON	39.2371	-119.593	x228y1660	LSR2
24	DAYTON	39.2371	-119.593	x231y1650	LSR2
24	DAYTON	39.2371	-119.593	x231y1652	LSR2
24	DAYTON	39.2371	-119.593	x231y1654	LSR2
24	DAYTON	39.2371	-119.593	x231y1656	LSR2
24	DAYTON	39.2371	-119.593	x213y1640	LSR3
24	DAYTON	39.2371	-119.593	x213y1642	LSR3
24	DAYTON	39.2371	-119.593	x213y1644	LSR3
24	DAYTON	39.2371	-119.593	x213y1646	LSR3
24	DAYTON	39.2371	-119.593	x213y1648	LSR3
24	DAYTON	39.2371	-119.593	x216y1640	LSR3
24	DAYTON	39.2371	-119.593	x216y1642	LSR3
24	DAYTON	39.2371	-119.593	x216y1644	LSR3
24	DAYTON	39.2371	-119.593	x216y1646	LSR3
24	DAYTON	39.2371	-119.593	x216y1648	LSR3
24	DAYTON	39.2371	-119.593	x219y1644	LSR3
24	DAYTON	39.2371	-119.593	x219y1646	LSR3
24	DAYTON	39.2371	-119.593	x219y1648	LSR3
24	DAYTON	39.2371	-119.593	x222y1648	LSR3
24	DAYTON	39.2371	-119.593	x222y1650	LSR3
24	DAYTON	39.2371	-119.593	x231y1658	LSR3
24	DAYTON	39.2371	-119.593	x231y1660	LSR3
24	DAYTON	39.2371	-119.593	x231y1662	LSR3
24	DAYTON	39.2371	-119.593	x231y1664	LSR3
24	DAYTON	39.2371	-119.593	x234y1652	LSR3
24	DAYTON	39.2371	-119.593	x234y1654	LSR3
24	DAYTON	39.2371	-119.593	x234y1656	LSR3
24	DAYTON	39.2371	-119.593	x234y1658	LSR3
24	DAYTON	39.2371	-119.593	x237y1654	LSR3
24	DAYTON	39.2371	-119.593	x237y1656	LSR3
24	DAYTON	39.2371	-119.593	x240y1654	LSR3
24	DAYTON	39.2371	-119.593	x240y1656	LSR3

25	ELKO	40.8324	-115.7631	x1275y2226	LSR1
25	ELKO	40.8324	-115.7631	x1275y2228	LSR1
25	ELKO	40.8324	-115.7631	x1275y2230	LSR1
25	ELKO	40.8324	-115.7631	x1278y2226	LSR1
25	ELKO	40.8324	-115.7631	x1278y2228	LSR1
25	ELKO	40.8324	-115.7631	x1278y2230	LSR1
25	ELKO	40.8324	-115.7631	x1281y2228	LSR1
25	ELKO	40.8324	-115.7631	x1281y2230	LSR1
25	ELKO	40.8324	-115.7631	x1281y2232	LSR1
25	ELKO	40.8324	-115.7631	x1284y2240	LSR1
25	ELKO	40.8324	-115.7631	x1287y2222	LSR1
25	ELKO	40.8324	-115.7631	x1287y2230	LSR1
25	ELKO	40.8324	-115.7631	x1287y2234	LSR1
25	ELKO	40.8324	-115.7631	x1287y2236	LSR1
25	ELKO	40.8324	-115.7631	x1287y2238	LSR1
25	ELKO	40.8324	-115.7631	x1287y2240	LSR1
25	ELKO	40.8324	-115.7631	x1287y2244	LSR1
25	ELKO	40.8324	-115.7631	x1290y2226	LSR1
25	ELKO	40.8324	-115.7631	x1290y2228	LSR1
25	ELKO	40.8324	-115.7631	x1290y2238	LSR1
25	ELKO	40.8324	-115.7631	x1290y2240	LSR1
25	ELKO	40.8324	-115.7631	x1290y2242	LSR1
25	ELKO	40.8324	-115.7631	x1290y2244	LSR1
25	ELKO	40.8324	-115.7631	x1293y2242	LSR1
25	ELKO	40.8324	-115.7631	x1260y2214	LSR2
25	ELKO	40.8324	-115.7631	x1260y2216	LSR2
25	ELKO	40.8324	-115.7631	x1260y2218	LSR2
25	ELKO	40.8324	-115.7631	x1263y2216	LSR2
25	ELKO	40.8324	-115.7631	x1263y2218	LSR2
25	ELKO	40.8324	-115.7631	x1269y2216	LSR2
25	ELKO	40.8324	-115.7631	x1269y2220	LSR2
25	ELKO	40.8324	-115.7631	x1269y2222	LSR2
25	ELKO	40.8324	-115.7631	x1269y2230	LSR2
25	ELKO	40.8324	-115.7631	x1269y2232	LSR2
25	ELKO	40.8324	-115.7631	x1269y2234	LSR2
25	ELKO	40.8324	-115.7631	x1272y2208	LSR2
25	ELKO	40.8324	-115.7631	x1272y2210	LSR2
25	ELKO	40.8324	-115.7631	x1272y2212	LSR2
25	ELKO	40.8324	-115.7631	x1272y2214	LSR2
25	ELKO	40.8324	-115.7631	x1272y2216	LSR2
25	ELKO	40.8324	-115.7631	x1272y2218	LSR2
25	ELKO	40.8324	-115.7631	x1272y2222	LSR2
25	ELKO	40.8324	-115.7631	x1272y2224	LSR2
25	ELKO	40.8324	-115.7631	x1272y2232	LSR2
25	ELKO	40.8324	-115.7631	x1272y2234	LSR2
25	ELKO	40.8324	-115.7631	x1275y2214	LSR2
25	ELKO	40.8324	-115.7631	x1275y2216	LSR2
25	ELKO	40.8324	-115.7631	x1275y2218	LSR2
25	ELKO	40.8324	-115.7631	x1275y2220	LSR2
25	ELKO	40.8324	-115.7631	x1275y2222	LSR2
25	ELKO	40.8324	-115.7631	x1275y2224	LSR2
25	ELKO	40.8324	-115.7631	x1275y2232	LSR2
25	ELKO	40.8324	-115.7631	x1275y2234	LSR2
25	ELKO	40.8324	-115.7631	x1278y2232	LSR2
25	ELKO	40.8324	-115.7631	x1278y2234	LSR2

25	ELKO	40.8324	-115.7631	x1281y2234	LSR2
25	ELKO	40.8324	-115.7631	x1281y2236	LSR2
25	ELKO	40.8324	-115.7631	x1284y2224	LSR2
25	ELKO	40.8324	-115.7631	x1284y2228	LSR2
25	ELKO	40.8324	-115.7631	x1284y2230	LSR2
25	ELKO	40.8324	-115.7631	x1284y2232	LSR2
25	ELKO	40.8324	-115.7631	x1284y2234	LSR2
25	ELKO	40.8324	-115.7631	x1284y2236	LSR2
25	ELKO	40.8324	-115.7631	x1284y2238	LSR2
25	ELKO	40.8324	-115.7631	x1266y2218	LSR3
25	ELKO	40.8324	-115.7631	x1266y2220	LSR3
25	ELKO	40.8324	-115.7631	x1266y2224	LSR3
25	ELKO	40.8324	-115.7631	x1266y2226	LSR3
25	ELKO	40.8324	-115.7631	x1266y2228	LSR3
25	ELKO	40.8324	-115.7631	x1266y2230	LSR3
25	ELKO	40.8324	-115.7631	x1269y2224	LSR3
25	ELKO	40.8324	-115.7631	x1269y2226	LSR3
25	ELKO	40.8324	-115.7631	x1269y2228	LSR3
25	ELKO	40.8324	-115.7631	x1272y2226	LSR3
25	ELKO	40.8324	-115.7631	x1272y2228	LSR3
25	ELKO	40.8324	-115.7631	x1272y2230	LSR3
25	ELKO	40.8324	-115.7631	x1278y2220	LSR3
25	ELKO	40.8324	-115.7631	x1278y2222	LSR3
25	ELKO	40.8324	-115.7631	x1278y2224	LSR3
25	ELKO	40.8324	-115.7631	x1281y2222	LSR3
25	ELKO	40.8324	-115.7631	x1281y2224	LSR3
25	ELKO	40.8324	-115.7631	x1281y2226	LSR3
27	FALLON	39.4749	-118.777	x420y1718	LSR1
27	FALLON	39.4749	-118.777	x420y1720	LSR1
27	FALLON	39.4749	-118.777	x423y1714	LSR1
27	FALLON	39.4749	-118.777	x423y1716	LSR1
27	FALLON	39.4749	-118.777	x423y1718	LSR1
27	FALLON	39.4749	-118.777	x423y1720	LSR1
27	FALLON	39.4749	-118.777	x426y1712	LSR1
27	FALLON	39.4749	-118.777	x426y1714	LSR1
27	FALLON	39.4749	-118.777	x426y1716	LSR1
27	FALLON	39.4749	-118.777	x426y1718	LSR1
27	FALLON	39.4749	-118.777	x426y1720	LSR1
27	FALLON	39.4749	-118.777	x429y1714	LSR1
27	FALLON	39.4749	-118.777	x429y1716	LSR1
27	FALLON	39.4749	-118.777	x429y1718	LSR1
27	FALLON	39.4749	-118.777	x429y1720	LSR1
27	FALLON	39.4749	-118.777	x438y1728	LSR1
27	FALLON	39.4749	-118.777	x438y1730	LSR1
27	FALLON	39.4749	-118.777	x441y1708	LSR1
27	FALLON	39.4749	-118.777	x441y1712	LSR1
27	FALLON	39.4749	-118.777	x441y1714	LSR1
27	FALLON	39.4749	-118.777	x441y1716	LSR1
27	FALLON	39.4749	-118.777	x441y1722	LSR1
27	FALLON	39.4749	-118.777	x441y1724	LSR1
27	FALLON	39.4749	-118.777	x441y1726	LSR1
27	FALLON	39.4749	-118.777	x441y1728	LSR1
27	FALLON	39.4749	-118.777	x444y1708	LSR1
27	FALLON	39.4749	-118.777	x444y1710	LSR1
27	FALLON	39.4749	-118.777	x444y1712	LSR1

27	FALLON	39.4749	-118.777	x444y1714	LSR1
27	FALLON	39.4749	-118.777	x444y1716	LSR1
27	FALLON	39.4749	-118.777	x444y1722	LSR1
27	FALLON	39.4749	-118.777	x444y1724	LSR1
27	FALLON	39.4749	-118.777	x447y1710	LSR1
27	FALLON	39.4749	-118.777	x447y1712	LSR1
27	FALLON	39.4749	-118.777	x447y1714	LSR1
27	FALLON	39.4749	-118.777	x399y1732	LSR2
27	FALLON	39.4749	-118.777	x399y1734	LSR2
27	FALLON	39.4749	-118.777	x402y1730	LSR2
27	FALLON	39.4749	-118.777	x402y1732	LSR2
27	FALLON	39.4749	-118.777	x405y1730	LSR2
27	FALLON	39.4749	-118.777	x405y1732	LSR2
27	FALLON	39.4749	-118.777	x408y1726	LSR2
27	FALLON	39.4749	-118.777	x408y1728	LSR2
27	FALLON	39.4749	-118.777	x408y1730	LSR2
27	FALLON	39.4749	-118.777	x411y1726	LSR2
27	FALLON	39.4749	-118.777	x411y1728	LSR2
27	FALLON	39.4749	-118.777	x414y1726	LSR2
27	FALLON	39.4749	-118.777	x414y1728	LSR2
27	FALLON	39.4749	-118.777	x414y1730	LSR2
27	FALLON	39.4749	-118.777	x417y1726	LSR2
27	FALLON	39.4749	-118.777	x417y1728	LSR2
27	FALLON	39.4749	-118.777	x417y1730	LSR2
27	FALLON	39.4749	-118.777	x420y1728	LSR2
27	FALLON	39.4749	-118.777	x420y1730	LSR2
27	FALLON	39.4749	-118.777	x432y1716	LSR2
27	FALLON	39.4749	-118.777	x432y1718	LSR2
27	FALLON	39.4749	-118.777	x432y1720	LSR2
27	FALLON	39.4749	-118.777	x432y1722	LSR2
27	FALLON	39.4749	-118.777	x435y1714	LSR2
27	FALLON	39.4749	-118.777	x435y1716	LSR2
27	FALLON	39.4749	-118.777	x435y1722	LSR2
27	FALLON	39.4749	-118.777	x435y1724	LSR2
27	FALLON	39.4749	-118.777	x435y1726	LSR2
27	FALLON	39.4749	-118.777	x435y1728	LSR2
27	FALLON	39.4749	-118.777	x438y1714	LSR2
27	FALLON	39.4749	-118.777	x441y1718	LSR2
27	FALLON	39.4749	-118.777	x444y1718	LSR2
27	FALLON	39.4749	-118.777	x447y1694	LSR2
27	FALLON	39.4749	-118.777	x447y1696	LSR2
27	FALLON	39.4749	-118.777	x447y1698	LSR2
27	FALLON	39.4749	-118.777	x447y1700	LSR2
27	FALLON	39.4749	-118.777	x447y1702	LSR2
27	FALLON	39.4749	-118.777	x447y1704	LSR2
27	FALLON	39.4749	-118.777	x447y1706	LSR2
27	FALLON	39.4749	-118.777	x447y1708	LSR2
27	FALLON	39.4749	-118.777	x447y1716	LSR2
27	FALLON	39.4749	-118.777	x447y1718	LSR2
27	FALLON	39.4749	-118.777	x450y1704	LSR2
27	FALLON	39.4749	-118.777	x450y1708	LSR2
27	FALLON	39.4749	-118.777	x450y1710	LSR2
27	FALLON	39.4749	-118.777	x450y1712	LSR2
27	FALLON	39.4749	-118.777	x450y1714	LSR2
27	FALLON	39.4749	-118.777	x450y1716	LSR2

27	FALLON	39.4749	-118.777	x450y1718	LSR2
27	FALLON	39.4749	-118.777	x414y1722	LSR3
27	FALLON	39.4749	-118.777	x414y1724	LSR3
27	FALLON	39.4749	-118.777	x417y1720	LSR3
27	FALLON	39.4749	-118.777	x417y1722	LSR3
27	FALLON	39.4749	-118.777	x417y1724	LSR3
27	FALLON	39.4749	-118.777	x420y1722	LSR3
27	FALLON	39.4749	-118.777	x420y1724	LSR3
27	FALLON	39.4749	-118.777	x420y1726	LSR3
27	FALLON	39.4749	-118.777	x423y1722	LSR3
27	FALLON	39.4749	-118.777	x423y1724	LSR3
27	FALLON	39.4749	-118.777	x423y1726	LSR3
27	FALLON	39.4749	-118.777	x423y1728	LSR3
27	FALLON	39.4749	-118.777	x426y1722	LSR3
27	FALLON	39.4749	-118.777	x426y1724	LSR3
27	FALLON	39.4749	-118.777	x426y1726	LSR3
27	FALLON	39.4749	-118.777	x426y1728	LSR3
27	FALLON	39.4749	-118.777	x429y1722	LSR3
27	FALLON	39.4749	-118.777	x429y1724	LSR3
27	FALLON	39.4749	-118.777	x429y1726	LSR3
27	FALLON	39.4749	-118.777	x432y1724	LSR3
27	FALLON	39.4749	-118.777	x432y1726	LSR3
27	FALLON	39.4749	-118.777	x435y1718	LSR3
27	FALLON	39.4749	-118.777	x435y1720	LSR3
27	FALLON	39.4749	-118.777	x438y1716	LSR3
27	FALLON	39.4749	-118.777	x438y1718	LSR3
27	FALLON	39.4749	-118.777	x438y1720	LSR3
27	FALLON	39.4749	-118.777	x438y1722	LSR3
27	FALLON	39.4749	-118.777	x438y1724	LSR3
27	FALLON	39.4749	-118.777	x438y1726	LSR3
27	FALLON	39.4749	-118.777	x441y1720	LSR3
27	FALLON	39.4749	-118.777	x441y1730	LSR3
27	FALLON	39.4749	-118.777	x444y1720	LSR3
27	FALLON	39.4749	-118.777	x444y1726	LSR3
27	FALLON	39.4749	-118.777	x444y1728	LSR3
27	FALLON	39.4749	-118.777	x444y1730	LSR3
27	FALLON	39.4749	-118.777	x447y1720	LSR3
27	FALLON	39.4749	-118.777	x447y1722	LSR3
27	FALLON	39.4749	-118.777	x447y1726	LSR3
27	FALLON	39.4749	-118.777	x447y1730	LSR3
27	FALLON	39.4749	-118.777	x450y1720	LSR3
27	FALLON	39.4749	-118.777	x450y1722	LSR3
27	FALLON	39.4749	-118.777	x456y1698	LSR3
27	FALLON	39.4749	-118.777	x456y1700	LSR3
27	FALLON	39.4749	-118.777	x459y1692	LSR3
27	FALLON	39.4749	-118.777	x459y1694	LSR3
27	FALLON	39.4749	-118.777	x459y1696	LSR3
27	FALLON	39.4749	-118.777	x459y1698	LSR3
27	FALLON	39.4749	-118.777	x459y1700	LSR3
27	FALLON	39.4749	-118.777	x459y1702	LSR3
27	FALLON	39.4749	-118.777	x459y1704	LSR3
27	FALLON	39.4749	-118.777	x459y1706	LSR3
27	FALLON	39.4749	-118.777	x459y1708	LSR3
27	FALLON	39.4749	-118.777	x462y1686	LSR3
27	FALLON	39.4749	-118.777	x462y1688	LSR3

27	FALLON	39.4749	-118.777	x462y1698	LSR3
27	FALLON	39.4749	-118.777	x462y1700	LSR3
27	FALLON	39.4749	-118.777	x462y1702	LSR3
27	FALLON	39.4749	-118.777	x462y1708	LSR3
27	FALLON	39.4749	-118.777	x465y1688	LSR3
27	FALLON	39.4749	-118.777	x465y1692	LSR3
27	FALLON	39.4749	-118.777	x465y1694	LSR3
27	FALLON	39.4749	-118.777	x465y1698	LSR3
27	FALLON	39.4749	-118.777	x465y1706	LSR3
27	FALLON	39.4749	-118.777	x465y1708	LSR3
27	FALLON	39.4749	-118.777	x468y1684	LSR3
27	FALLON	39.4749	-118.777	x471y1684	LSR3
27	FERNLEY	39.608	-119.2518	x282y1764	LSR1
27	FERNLEY	39.608	-119.2518	x285y1764	LSR1
27	FERNLEY	39.608	-119.2518	x285y1766	LSR1
27	FERNLEY	39.608	-119.2518	x288y1766	LSR1
27	FERNLEY	39.608	-119.2518	x288y1768	LSR1
27	FERNLEY	39.608	-119.2518	x291y1768	LSR1
27	FERNLEY	39.608	-119.2518	x291y1770	LSR1
27	FERNLEY	39.608	-119.2518	x291y1772	LSR1
27	FERNLEY	39.608	-119.2518	x294y1768	LSR1
27	FERNLEY	39.608	-119.2518	x294y1770	LSR1
27	FERNLEY	39.608	-119.2518	x294y1772	LSR1
27	FERNLEY	39.608	-119.2518	x297y1772	LSR1
27	FERNLEY	39.608	-119.2518	x297y1774	LSR1
27	FERNLEY	39.608	-119.2518	x297y1776	LSR1
27	FERNLEY	39.608	-119.2518	x297y1778	LSR1
27	FERNLEY	39.608	-119.2518	x297y1780	LSR1
27	FERNLEY	39.608	-119.2518	x297y1782	LSR1
27	FERNLEY	39.608	-119.2518	x300y1776	LSR1
27	FERNLEY	39.608	-119.2518	x300y1778	LSR1
27	FERNLEY	39.608	-119.2518	x300y1780	LSR1
27	FERNLEY	39.608	-119.2518	x300y1782	LSR1
27	FERNLEY	39.608	-119.2518	x303y1770	LSR1
27	FERNLEY	39.608	-119.2518	x303y1776	LSR1
27	FERNLEY	39.608	-119.2518	x303y1778	LSR1
27	FERNLEY	39.608	-119.2518	x306y1770	LSR1
27	FERNLEY	39.608	-119.2518	x306y1772	LSR1
27	FERNLEY	39.608	-119.2518	x306y1774	LSR1
27	FERNLEY	39.608	-119.2518	x306y1776	LSR1
27	FERNLEY	39.608	-119.2518	x312y1764	LSR1
27	FERNLEY	39.608	-119.2518	x312y1766	LSR1
27	FERNLEY	39.608	-119.2518	x312y1768	LSR1
27	FERNLEY	39.608	-119.2518	x312y1770	LSR1
27	FERNLEY	39.608	-119.2518	x315y1768	LSR1
27	FERNLEY	39.608	-119.2518	x315y1770	LSR1
27	FERNLEY	39.608	-119.2518	x321y1758	LSR1
27	FERNLEY	39.608	-119.2518	x321y1760	LSR1
27	FERNLEY	39.608	-119.2518	x321y1762	LSR1
27	FERNLEY	39.608	-119.2518	x321y1764	LSR1
27	FERNLEY	39.608	-119.2518	x321y1766	LSR1
27	FERNLEY	39.608	-119.2518	x300y1764	LSR2
27	FERNLEY	39.608	-119.2518	x303y1758	LSR2
27	FERNLEY	39.608	-119.2518	x303y1764	LSR2
27	FERNLEY	39.608	-119.2518	x303y1766	LSR2

27	FERNLEY	39.608	-119.2518	x303y1768	LSR2
27	FERNLEY	39.608	-119.2518	x306y1758	LSR2
27	FERNLEY	39.608	-119.2518	x306y1760	LSR2
27	FERNLEY	39.608	-119.2518	x306y1762	LSR2
27	FERNLEY	39.608	-119.2518	x306y1764	LSR2
27	FERNLEY	39.608	-119.2518	x306y1766	LSR2
27	FERNLEY	39.608	-119.2518	x306y1768	LSR2
27	FERNLEY	39.608	-119.2518	x309y1764	LSR2
27	FERNLEY	39.608	-119.2518	x309y1766	LSR2
27	FERNLEY	39.608	-119.2518	x309y1768	LSR2
27	FERNLEY	39.608	-119.2518	x309y1770	LSR2
27	FERNLEY	39.608	-119.2518	x315y1764	LSR2
27	FERNLEY	39.608	-119.2518	x318y1760	LSR2
27	FERNLEY	39.608	-119.2518	x318y1762	LSR2
27	FERNLEY	39.608	-119.2518	x318y1764	LSR2
27	FERNLEY	39.608	-119.2518	x324y1758	LSR2
27	FERNLEY	39.608	-119.2518	x324y1764	LSR2
27	FERNLEY	39.608	-119.2518	x324y1766	LSR2
27	FERNLEY	39.608	-119.2518	x327y1758	LSR2
27	FERNLEY	39.608	-119.2518	x327y1760	LSR2
27	FERNLEY	39.608	-119.2518	x327y1762	LSR2
27	FERNLEY	39.608	-119.2518	x327y1764	LSR2
27	FERNLEY	39.608	-119.2518	x330y1758	LSR2
27	FERNLEY	39.608	-119.2518	x330y1762	LSR2
27	FERNLEY	39.608	-119.2518	x309y1760	LSR3
27	FERNLEY	39.608	-119.2518	x309y1762	LSR3
27	FERNLEY	39.608	-119.2518	x312y1754	LSR3
27	FERNLEY	39.608	-119.2518	x312y1756	LSR3
27	FERNLEY	39.608	-119.2518	x312y1758	LSR3
27	FERNLEY	39.608	-119.2518	x312y1760	LSR3
27	FERNLEY	39.608	-119.2518	x312y1762	LSR3
27	FERNLEY	39.608	-119.2518	x315y1756	LSR3
27	FERNLEY	39.608	-119.2518	x315y1758	LSR3
27	FERNLEY	39.608	-119.2518	x315y1760	LSR3
27	FERNLEY	39.608	-119.2518	x315y1762	LSR3
27	FERNLEY	39.608	-119.2518	x315y1766	LSR3
27	FERNLEY	39.608	-119.2518	x318y1758	LSR3
27	FERNLEY	39.608	-119.2518	x318y1766	LSR3
27	FERNLEY	39.608	-119.2518	x318y1768	LSR3
27	FERNLEY	39.608	-119.2518	x318y1770	LSR3
27	FERNLEY	39.608	-119.2518	x321y1768	LSR3
27	FERNLEY	39.608	-119.2518	x321y1770	LSR3
27	FERNLEY	39.608	-119.2518	x321y1772	LSR3
27	FERNLEY	39.608	-119.2518	x324y1760	LSR3
27	FERNLEY	39.608	-119.2518	x324y1762	LSR3
27	FERNLEY	39.608	-119.2518	x324y1768	LSR3
27	FERNLEY	39.608	-119.2518	x324y1770	LSR3
27	FERNLEY	39.608	-119.2518	x324y1772	LSR3
27	FERNLEY	39.608	-119.2518	x327y1766	LSR3
27	FERNLEY	39.608	-119.2518	x327y1768	LSR3
27	FERNLEY	39.608	-119.2518	x327y1770	LSR3
27	FERNLEY	39.608	-119.2518	x327y1772	LSR3
27	FERNLEY	39.608	-119.2518	x327y1774	LSR3
27	FERNLEY	39.608	-119.2518	x330y1760	LSR3
27	FERNLEY	39.608	-119.2518	x333y1758	LSR3

27	FERNLEY	39.608	-119.2518	x333y1760	LSR3
27	FERNLEY	39.608	-119.2518	x333y1762	LSR3
27	FERNLEY	39.608	-119.2518	x336y1758	LSR3
27	FERNLEY	39.608	-119.2518	x336y1760	LSR3
27	FERNLEY	39.608	-119.2518	x336y1762	LSR3
27	FERNLEY	39.608	-119.2518	x339y1758	LSR3
27	FERNLEY	39.608	-119.2518	x339y1760	LSR3
27	FERNLEY	39.608	-119.2518	x339y1762	LSR3
27	FERNLEY	39.608	-119.2518	x342y1758	LSR3
27	FERNLEY	39.608	-119.2518	x342y1760	LSR3
27	FERNLEY	39.608	-119.2518	x342y1762	LSR3
24	GENOA	39.0041	-119.8472	x138y1546	LSR1
24	GENOA	39.0041	-119.8472	x138y1548	LSR1
24	GENOA	39.0041	-119.8472	x138y1550	LSR1
24	GENOA	39.0041	-119.8472	x138y1552	LSR1
24	GENOA	39.0041	-119.8472	x141y1546	LSR1
24	GENOA	39.0041	-119.8472	x141y1552	LSR1
24	GENOA	39.0041	-119.8472	x141y1554	LSR1
24	GENOA	39.0041	-119.8472	x141y1556	LSR1
24	GENOA	39.0041	-119.8472	x141y1548	LSR1
24	GENOA	39.0041	-119.8472	x141y1550	LSR1
24	GENOA	39.0041	-119.8472	x159y1548	LSR1
24	GENOA	39.0041	-119.8472	x141y1558	LSR2
24	GENOA	39.0041	-119.8472	x141y1560	LSR2
24	GENOA	39.0041	-119.8472	x144y1558	LSR2
24	GENOA	39.0041	-119.8472	x144y1560	LSR2
24	GENOA	39.0041	-119.8472	x144y1562	LSR2
24	GENOA	39.0041	-119.8472	x144y1564	LSR2
24	GENOA	39.0041	-119.8472	x144y1566	LSR2
24	GENOA	39.0041	-119.8472	x144y1568	LSR2
24	GENOA	39.0041	-119.8472	x144y1570	LSR2
24	GENOA	39.0041	-119.8472	x144y1572	LSR2
24	GENOA	39.0041	-119.8472	x147y1562	LSR2
24	GENOA	39.0041	-119.8472	x147y1564	LSR2
24	GENOA	39.0041	-119.8472	x147y1568	LSR2
24	GENOA	39.0041	-119.8472	x147y1570	LSR2
24	GENOA	39.0041	-119.8472	x147y1572	LSR2
24	GENOA	39.0041	-119.8472	x150y1564	LSR2
24	GENOA	39.0041	-119.8472	x150y1566	LSR2
24	GENOA	39.0041	-119.8472	x150y1568	LSR2
24	GENOA	39.0041	-119.8472	x147y1566	LSR2
24	GENOA	39.0041	-119.8472	x141y1536	LSR3
24	GENOA	39.0041	-119.8472	x141y1538	LSR3
24	GENOA	39.0041	-119.8472	x141y1540	LSR3
24	GENOA	39.0041	-119.8472	x144y1540	LSR3
24	GENOA	39.0041	-119.8472	x144y1550	LSR3
24	GENOA	39.0041	-119.8472	x144y1554	LSR3
24	GENOA	39.0041	-119.8472	x144y1556	LSR3
24	GENOA	39.0041	-119.8472	x147y1538	LSR3
24	GENOA	39.0041	-119.8472	x147y1546	LSR3
24	GENOA	39.0041	-119.8472	x147y1550	LSR3
24	GENOA	39.0041	-119.8472	x144y1542	LSR3
24	GENOA	39.0041	-119.8472	x144y1544	LSR3
24	GENOA	39.0041	-119.8472	x144y1548	LSR3
24	GENOA	39.0041	-119.8472	x144y1552	LSR3

24	GENOA	39.0041	-119.8472	x147y1548	LSR3
24	GENOA	39.0041	-119.8472	x150y1548	LSR3
24	GENOA	39.0041	-119.8472	x153y1548	LSR3
24	GENOA	39.0041	-119.8472	x156y1548	LSR3
27	HAZEN	39.5652	-119.0463	x369y1728	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x108y1644	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x105y1642	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x108y1642	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x111y1642	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x111y1644	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x117y1632	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x117y1634	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x117y1636	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x117y1638	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x117y1640	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x117y1642	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x120y1636	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x120y1640	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x120y1642	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x120y1644	LSR1
23	INCLINE VILLAGE	39.2497	-119.9527	x102y1640	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x102y1642	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x102y1644	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x102y1646	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x105y1640	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x105y1644	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x105y1646	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x105y1648	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x108y1648	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x114y1634	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x114y1636	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x114y1638	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x114y1640	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x114y1642	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x114y1644	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x117y1644	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x99y1636	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x99y1638	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x99y1640	LSR2
23	INCLINE VILLAGE	39.2497	-119.9527	x108y1638	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x108y1640	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x108y1646	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x111y1640	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x111y1646	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x111y1648	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x111y1650	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x111y1636	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x111y1638	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x114y1646	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x114y1648	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x114y1650	LSR3
23	INCLINE VILLAGE	39.2497	-119.9527	x117y1646	LSR3
27	LOVELOCK	40.1794	-118.4735	x528y1976	LSR1
27	LOVELOCK	40.1794	-118.4735	x528y1978	LSR1
27	LOVELOCK	40.1794	-118.4735	x528y1980	LSR1

27	LOVELOCK	40.1794	-118.4735	x528y1982	LSR1
27	LOVELOCK	40.1794	-118.4735	x528y1984	LSR1
27	LOVELOCK	40.1794	-118.4735	x528y1986	LSR1
27	LOVELOCK	40.1794	-118.4735	x531y1978	LSR1
27	LOVELOCK	40.1794	-118.4735	x528y1988	LSR2
27	LOVELOCK	40.1794	-118.4735	x528y1990	LSR2
27	LOVELOCK	40.1794	-118.4735	x531y1976	LSR2
27	LOVELOCK	40.1794	-118.4735	x531y1986	LSR2
27	LOVELOCK	40.1794	-118.4735	x543y2004	LSR2
27	LOVELOCK	40.1794	-118.4735	x546y2004	LSR2
27	LOVELOCK	40.1794	-118.4735	x549y1994	LSR2
27	LOVELOCK	40.1794	-118.4735	x549y1996	LSR2
27	LOVELOCK	40.1794	-118.4735	x549y1998	LSR2
27	LOVELOCK	40.1794	-118.4735	x552y1994	LSR2
27	LOVELOCK	40.1794	-118.4735	x552y1998	LSR2
27	LOVELOCK	40.1794	-118.4735	x552y2000	LSR2
27	LOVELOCK	40.1794	-118.4735	x555y1992	LSR2
27	LOVELOCK	40.1794	-118.4735	x555y1994	LSR2
27	LOVELOCK	40.1794	-118.4735	x591y2130	LSR2
27	LOVELOCK	40.1794	-118.4735	x519y1976	LSR3
27	LOVELOCK	40.1794	-118.4735	x522y1976	LSR3
27	LOVELOCK	40.1794	-118.4735	x525y1972	LSR3
27	LOVELOCK	40.1794	-118.4735	x525y1974	LSR3
27	LOVELOCK	40.1794	-118.4735	x525y1976	LSR3
27	LOVELOCK	40.1794	-118.4735	x528y1966	LSR3
27	LOVELOCK	40.1794	-118.4735	x528y1968	LSR3
27	LOVELOCK	40.1794	-118.4735	x528y1970	LSR3
27	LOVELOCK	40.1794	-118.4735	x528y1972	LSR3
27	LOVELOCK	40.1794	-118.4735	x528y1974	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1526	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1510	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1520	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1530	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1534	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1518	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1520	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1522	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1524	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1526	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1528	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1530	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1532	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1534	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1536	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1518	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1520	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1522	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1524	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1512	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1514	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1522	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1524	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1540	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1510	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1512	LSR1

24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1514	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1512	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1514	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1532	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1534	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1536	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1508	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1510	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1512	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1514	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1516	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1532	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1534	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1538	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1540	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1504	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1506	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1508	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1510	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1532	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1538	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1540	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1504	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1506	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1508	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1510	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1512	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x189y1506	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x189y1508	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x189y1510	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x189y1512	LSR1
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1508	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1510	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1512	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1514	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1516	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1508	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1512	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1514	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1516	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1514	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1530	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1534	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1528	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1536	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1528	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1530	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1532	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1510	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1512	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1516	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1526	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1528	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1526	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1534	LSR2

24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1516	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1534	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1536	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1516	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1518	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1520	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1518	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1520	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1514	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1516	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1518	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1520	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1522	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1524	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1518	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1520	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1522	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1524	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x189y1518	LSR2
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x156y1532	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x156y1534	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x156y1536	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x156y1538	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x159y1530	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x159y1538	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x159y1540	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1536	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1538	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1506	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1508	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1504	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1506	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1516	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1518	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1526	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1526	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1528	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x177y1530	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1526	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1528	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1516	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x159y1532	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x159y1534	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x159y1536	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1532	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x162y1540	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x165y1540	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x168y1510	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x171y1508	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1506	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1508	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1518	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1520	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1522	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x174y1524	LSR3

24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x180y1530	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1526	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1528	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x183y1530	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1526	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1528	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x186y1530	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x189y1526	LSR3
24	MINDEN / GARDNERVILLE	38.9541	-119.7657	x189y1528	LSR3
24	MOUNDHOUSE	39.2136	-119.6759	x186y1622	LSR1
24	MOUNDHOUSE	39.2136	-119.6759	x186y1624	LSR1
24	MOUNDHOUSE	39.2136	-119.6759	x189y1624	LSR1
24	MOUNDHOUSE	39.2136	-119.6759	x189y1626	LSR1
24	MOUNDHOUSE	39.2136	-119.6759	x192y1624	LSR1
24	MOUNDHOUSE	39.2136	-119.6759	x192y1626	LSR1
24	MOUNDHOUSE	39.2136	-119.6759	x195y1624	LSR1
24	MOUNDHOUSE	39.2136	-119.6759	x192y1628	LSR2
24	MOUNDHOUSE	39.2136	-119.6759	x192y1630	LSR2
24	MOUNDHOUSE	39.2136	-119.6759	x195y1626	LSR2
24	MOUNDHOUSE	39.2136	-119.6759	x195y1628	LSR2
24	MOUNDHOUSE	39.2136	-119.6759	x195y1630	LSR2
24	MOUNDHOUSE	39.2136	-119.6759	x198y1624	LSR2
24	MOUNDHOUSE	39.2136	-119.6759	x198y1626	LSR2
24	MOUNDHOUSE	39.2136	-119.6759	x198y1628	LSR2
24	MOUNDHOUSE	39.2136	-119.6759	x198y1630	LSR2
24	MOUNDHOUSE	39.2136	-119.6759	x198y1632	LSR2
24	MOUNDHOUSE	39.2136	-119.6759	x186y1630	LSR3
24	MOUNDHOUSE	39.2136	-119.6759	x186y1632	LSR3
24	MOUNDHOUSE	39.2136	-119.6759	x189y1630	LSR3
24	MOUNDHOUSE	39.2136	-119.6759	x189y1628	LSR3
24	MOUNDHOUSE	39.2136	-119.6759	x192y1632	LSR3
24	MOUNDHOUSE	39.2136	-119.6759	x192y1634	LSR3
24	MOUNDHOUSE	39.2136	-119.6759	x195y1632	LSR3
24	MOUNDHOUSE	39.2136	-119.6759	x195y1634	LSR3
24	MOUNDHOUSE	39.2136	-119.6759	x198y1634	LSR3
27	SILVER SPRINGS	39.4155	-119.2246	x312y1688	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x312y1694	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x315y1688	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x315y1690	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x315y1692	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x315y1694	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x315y1696	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x315y1698	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x318y1698	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x318y1700	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x321y1698	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x321y1700	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x324y1700	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x324y1702	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x324y1704	LSR1
27	SILVER SPRINGS	39.4155	-119.2246	x279y1658	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x282y1658	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x294y1684	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x294y1686	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x297y1684	LSR2

27	SILVER SPRINGS	39.4155	-119.2246	x297y1686	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x297y1688	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x297y1690	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x300y1688	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x300y1690	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x300y1692	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x303y1688	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x303y1690	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x303y1692	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x306y1688	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x306y1690	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x309y1688	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x309y1690	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x309y1692	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x312y1690	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x312y1692	LSR2
27	SILVER SPRINGS	39.4155	-119.2246	x318y1688	LSR3
27	SILVER SPRINGS	39.4155	-119.2246	x318y1690	LSR3
27	SILVER SPRINGS	39.4155	-119.2246	x318y1692	LSR3
27	SILVER SPRINGS	39.4155	-119.2246	x318y1694	LSR3
27	SILVER SPRINGS	39.4155	-119.2246	x318y1696	LSR3
27	SILVER SPRINGS	39.4155	-119.2246	x321y1692	LSR3
27	SILVER SPRINGS	39.4155	-119.2246	x321y1694	LSR3
27	SILVER SPRINGS	39.4155	-119.2246	x321y1696	LSR3
28	SPRING CREEK	40.7266	-115.5859	x1287y2224	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1287y2226	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1287y2228	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1290y2220	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1290y2222	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1290y2224	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1296y2210	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1296y2212	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1296y2214	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1299y2210	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1302y2210	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1305y2210	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1305y2212	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1308y2208	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1308y2210	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1308y2212	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1311y2206	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1311y2208	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1311y2210	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1314y2192	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1314y2200	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1314y2202	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1314y2204	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1314y2206	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1314y2208	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1317y2190	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1317y2192	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1317y2194	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1317y2196	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1317y2198	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1317y2200	LSR1

28	SPRING CREEK	40.7266	-115.5859	x1320y2192	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1320y2194	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1320y2196	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1323y2188	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1323y2190	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1323y2192	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1323y2194	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1323y2196	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1326y2188	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1326y2196	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1326y2198	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1329y2184	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1329y2186	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1329y2188	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1329y2190	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1329y2192	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1329y2194	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1329y2196	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1329y2198	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1332y2182	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1332y2184	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1332y2188	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1332y2192	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1332y2194	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1332y2196	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1335y2180	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1335y2182	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1338y2178	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1338y2180	LSR1
28	SPRING CREEK	40.7266	-115.5859	x1284y2226	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1287y2210	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1287y2212	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1287y2214	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1287y2216	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1287y2218	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1290y2210	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1290y2212	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1290y2214	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1290y2216	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1290y2218	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1293y2212	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1293y2214	LSR2
28	SPRING CREEK	40.7266	-115.5859	x1293y2216	LSR2
24	STAGECOACH	39.3738	-119.3741	x267y1676	LSR1
24	STAGECOACH	39.3738	-119.3741	x267y1678	LSR1
24	STAGECOACH	39.3738	-119.3741	x270y1676	LSR1
24	STAGECOACH	39.3738	-119.3741	x270y1678	LSR1
24	STAGECOACH	39.3738	-119.3741	x270y1680	LSR1
24	STAGECOACH	39.3738	-119.3741	x270y1682	LSR1
24	STAGECOACH	39.3738	-119.3741	x273y1676	LSR1
24	STAGECOACH	39.3738	-119.3741	x273y1678	LSR1
24	STAGECOACH	39.3738	-119.3741	x276y1674	LSR1
24	STAGECOACH	39.3738	-119.3741	x276y1676	LSR1
24	STAGECOACH	39.3738	-119.3741	x276y1678	LSR1
24	STAGECOACH	39.3738	-119.3741	x279y1674	LSR1

24	STAGECOACH	39.3738	-119.3741	x279y1676	LSR1
24	STAGECOACH	39.3738	-119.3741	x279y1678	LSR1
24	STAGECOACH	39.3738	-119.3741	x273y1680	LSR2
24	STAGECOACH	39.3738	-119.3741	x273y1682	LSR2
24	STAGECOACH	39.3738	-119.3741	x273y1684	LSR2
24	STAGECOACH	39.3738	-119.3741	x276y1680	LSR2
24	STAGECOACH	39.3738	-119.3741	x276y1682	LSR2
24	STAGECOACH	39.3738	-119.3741	x276y1684	LSR2
24	STAGECOACH	39.3738	-119.3741	x276y1686	LSR2
24	STAGECOACH	39.3738	-119.3741	x279y1680	LSR3
24	STAGECOACH	39.3738	-119.3741	x279y1682	LSR3
24	STAGECOACH	39.3738	-119.3741	x279y1684	LSR3
24	STAGECOACH	39.3738	-119.3741	x279y1686	LSR3
24	STAGECOACH	39.3738	-119.3741	x282y1682	LSR3
24	STAGECOACH	39.3738	-119.3741	x282y1684	LSR3
24	STAGECOACH	39.3738	-119.3741	x282y1686	LSR3
23	STATELINE	38.9624	-119.9399	x108y1548	LSR1
23	STATELINE	38.9624	-119.9399	x108y1550	LSR1
23	STATELINE	38.9624	-119.9399	x108y1556	LSR1
23	STATELINE	38.9624	-119.9399	x111y1534	LSR1
23	STATELINE	38.9624	-119.9399	x111y1536	LSR1
23	STATELINE	38.9624	-119.9399	x111y1550	LSR1
23	STATELINE	38.9624	-119.9399	x111y1552	LSR1
23	STATELINE	38.9624	-119.9399	x111y1554	LSR1
23	STATELINE	38.9624	-119.9399	x111y1556	LSR1
23	STATELINE	38.9624	-119.9399	x111y1558	LSR1
23	STATELINE	38.9624	-119.9399	x111y1560	LSR1
23	STATELINE	38.9624	-119.9399	x111y1562	LSR1
23	STATELINE	38.9624	-119.9399	x111y1564	LSR1
23	STATELINE	38.9624	-119.9399	x114y1534	LSR1
23	STATELINE	38.9624	-119.9399	x114y1536	LSR1
23	STATELINE	38.9624	-119.9399	x114y1554	LSR1
23	STATELINE	38.9624	-119.9399	x114y1562	LSR1
23	STATELINE	38.9624	-119.9399	x117y1536	LSR1
23	STATELINE	38.9624	-119.9399	x108y1546	LSR2
23	STATELINE	38.9624	-119.9399	x111y1548	LSR2
23	STATELINE	38.9624	-119.9399	x114y1548	LSR2
23	STATELINE	38.9624	-119.9399	x117y1538	LSR2
23	STATELINE	38.9624	-119.9399	x120y1536	LSR2
23	STATELINE	38.9624	-119.9399	x120y1538	LSR2
23	STATELINE	38.9624	-119.9399	x123y1538	LSR2
23	STATELINE	38.9624	-119.9399	x123y1540	LSR2
23	STATELINE	38.9624	-119.9399	x126y1538	LSR2
23	STATELINE	38.9624	-119.9399	x126y1540	LSR2
23	STATELINE	38.9624	-119.9399	x126y1542	LSR2
23	STATELINE	38.9624	-119.9399	x126y1544	LSR2
23	STATELINE	38.9624	-119.9399	x126y1546	LSR2
23	STATELINE	38.9624	-119.9399	x129y1540	LSR2
23	STATELINE	38.9624	-119.9399	x108y1542	LSR3
23	STATELINE	38.9624	-119.9399	x108y1544	LSR3
23	STATELINE	38.9624	-119.9399	x111y1540	LSR3
23	STATELINE	38.9624	-119.9399	x111y1542	LSR3
23	STATELINE	38.9624	-119.9399	x111y1544	LSR3
23	STATELINE	38.9624	-119.9399	x111y1546	LSR3
23	STATELINE	38.9624	-119.9399	x114y1540	LSR3

23	STATELINE	38.9624	-119.9399	x114y1542	LSR3
23	STATELINE	38.9624	-119.9399	x114y1544	LSR3
23	STATELINE	38.9624	-119.9399	x114y1546	LSR3
23	STATELINE	38.9624	-119.9399	x114y1538	LSR3
23	STATELINE	38.9624	-119.9399	x117y1540	LSR3
23	STATELINE	38.9624	-119.9399	x117y1542	LSR3
23	STATELINE	38.9624	-119.9399	x120y1540	LSR3
23	STATELINE	38.9624	-119.9399	x120y1542	LSR3
23	STATELINE	38.9624	-119.9399	x123y1526	LSR3
23	STATELINE	38.9624	-119.9399	x123y1528	LSR3
23	STATELINE	38.9624	-119.9399	x126y1528	LSR3
23	STATELINE	38.9624	-119.9399	x126y1530	LSR3
23	STATELINE	38.9624	-119.9399	x126y1532	LSR3
23	STATELINE	38.9624	-119.9399	x126y1534	LSR3
23	STATELINE	38.9624	-119.9399	x126y1536	LSR3
23	STATELINE	38.9624	-119.9399	x129y1530	LSR3
23	STATELINE	38.9624	-119.9399	x129y1534	LSR3
23	STATELINE	38.9624	-119.9399	x129y1536	LSR3
23	STATELINE	38.9624	-119.9399	x129y1538	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x132y1618	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x132y1620	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x132y1622	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x132y1624	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x132y1626	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x132y1628	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x135y1622	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x135y1624	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1628	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1630	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1632	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1634	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1636	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1638	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1640	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1642	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1644	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1646	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1648	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x141y1650	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x144y1632	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x144y1634	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x144y1636	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x144y1638	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x144y1646	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x144y1648	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x144y1650	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x147y1632	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x147y1634	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x147y1636	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x147y1638	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x147y1640	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x150y1626	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x150y1628	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x150y1630	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x150y1632	LSR1

24	WASHOE VALLEY	39.2963	-119.7761	x150y1634	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x150y1636	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x150y1638	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x150y1640	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x153y1626	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x153y1628	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x153y1630	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x153y1632	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x156y1630	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x156y1632	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x159y1632	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x159y1634	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x162y1634	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x162y1636	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x165y1636	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x165y1638	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x165y1640	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x165y1642	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x168y1638	LSR1
24	WASHOE VALLEY	39.2963	-119.7761	x162y1648	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x162y1652	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x165y1648	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x165y1658	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x168y1652	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x168y1654	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x162y1650	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x162y1654	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x165y1650	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x165y1652	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x165y1654	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x165y1656	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x168y1642	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x168y1644	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x168y1646	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x168y1648	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x168y1650	LSR2
24	WASHOE VALLEY	39.2963	-119.7761	x153y1666	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x153y1668	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x156y1662	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x156y1664	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x156y1666	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x156y1668	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x156y1670	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x159y1648	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x159y1650	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x159y1652	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x159y1654	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x159y1656	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x159y1658	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x159y1660	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x159y1664	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x159y1666	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x162y1658	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x159y1662	LSR3
24	WASHOE VALLEY	39.2963	-119.7761	x162y1656	LSR3

26	WINNEMUCCA	40.973	-117.7357	x720y2248	LSR1
26	WINNEMUCCA	40.973	-117.7357	x723y2248	LSR1
26	WINNEMUCCA	40.973	-117.7357	x723y2250	LSR1
26	WINNEMUCCA	40.973	-117.7357	x726y2244	LSR1
26	WINNEMUCCA	40.973	-117.7357	x726y2246	LSR1
26	WINNEMUCCA	40.973	-117.7357	x726y2248	LSR1
26	WINNEMUCCA	40.973	-117.7357	x726y2250	LSR1
26	WINNEMUCCA	40.973	-117.7357	x726y2252	LSR1
26	WINNEMUCCA	40.973	-117.7357	x726y2264	LSR1
26	WINNEMUCCA	40.973	-117.7357	x726y2266	LSR1
26	WINNEMUCCA	40.973	-117.7357	x729y2252	LSR1
26	WINNEMUCCA	40.973	-117.7357	x729y2254	LSR1
26	WINNEMUCCA	40.973	-117.7357	x729y2256	LSR1
26	WINNEMUCCA	40.973	-117.7357	x729y2258	LSR1
26	WINNEMUCCA	40.973	-117.7357	x729y2260	LSR1
26	WINNEMUCCA	40.973	-117.7357	x729y2262	LSR1
26	WINNEMUCCA	40.973	-117.7357	x729y2266	LSR1
26	WINNEMUCCA	40.973	-117.7357	x732y2260	LSR1
26	WINNEMUCCA	40.973	-117.7357	x738y2264	LSR1
26	WINNEMUCCA	40.973	-117.7357	x738y2266	LSR1
26	WINNEMUCCA	40.973	-117.7357	x738y2268	LSR1
26	WINNEMUCCA	40.973	-117.7357	x738y2270	LSR1
26	WINNEMUCCA	40.973	-117.7357	x738y2272	LSR1
26	WINNEMUCCA	40.973	-117.7357	x738y2274	LSR1
26	WINNEMUCCA	40.973	-117.7357	x741y2262	LSR1
26	WINNEMUCCA	40.973	-117.7357	x741y2264	LSR1
26	WINNEMUCCA	40.973	-117.7357	x741y2266	LSR1
26	WINNEMUCCA	40.973	-117.7357	x741y2268	LSR1
26	WINNEMUCCA	40.973	-117.7357	x741y2270	LSR1
26	WINNEMUCCA	40.973	-117.7357	x741y2274	LSR1
26	WINNEMUCCA	40.973	-117.7357	x744y2264	LSR1
26	WINNEMUCCA	40.973	-117.7357	x744y2266	LSR1
26	WINNEMUCCA	40.973	-117.7357	x744y2270	LSR1
26	WINNEMUCCA	40.973	-117.7357	x756y2368	LSR1
26	WINNEMUCCA	40.973	-117.7357	x786y2428	LSR1
26	WINNEMUCCA	40.973	-117.7357	x789y2426	LSR1
26	WINNEMUCCA	40.973	-117.7357	x789y2428	LSR1
26	WINNEMUCCA	40.973	-117.7357	x624y2194	LSR2
26	WINNEMUCCA	40.973	-117.7357	x624y2196	LSR2
26	WINNEMUCCA	40.973	-117.7357	x627y2194	LSR2
26	WINNEMUCCA	40.973	-117.7357	x630y2194	LSR2
26	WINNEMUCCA	40.973	-117.7357	x633y2194	LSR2
26	WINNEMUCCA	40.973	-117.7357	x636y2194	LSR2
26	WINNEMUCCA	40.973	-117.7357	x690y2262	LSR2
26	WINNEMUCCA	40.973	-117.7357	x690y2264	LSR2
26	WINNEMUCCA	40.973	-117.7357	x693y2258	LSR2
26	WINNEMUCCA	40.973	-117.7357	x693y2260	LSR2
26	WINNEMUCCA	40.973	-117.7357	x693y2262	LSR2
26	WINNEMUCCA	40.973	-117.7357	x696y2254	LSR2
26	WINNEMUCCA	40.973	-117.7357	x696y2256	LSR2
26	WINNEMUCCA	40.973	-117.7357	x696y2258	LSR2
26	WINNEMUCCA	40.973	-117.7357	x699y2254	LSR2
26	WINNEMUCCA	40.973	-117.7357	x711y2248	LSR2
26	WINNEMUCCA	40.973	-117.7357	x711y2258	LSR2
26	WINNEMUCCA	40.973	-117.7357	x711y2262	LSR2

26	WINNEMUCCA	40.973	-117.7357	x714y2240	LSR2
26	WINNEMUCCA	40.973	-117.7357	x714y2242	LSR2
26	WINNEMUCCA	40.973	-117.7357	x714y2258	LSR2
26	WINNEMUCCA	40.973	-117.7357	x714y2262	LSR2
26	WINNEMUCCA	40.973	-117.7357	x717y2240	LSR2
26	WINNEMUCCA	40.973	-117.7357	x717y2242	LSR2
26	WINNEMUCCA	40.973	-117.7357	x717y2244	LSR2
26	WINNEMUCCA	40.973	-117.7357	x717y2246	LSR2
26	WINNEMUCCA	40.973	-117.7357	x717y2262	LSR2
26	WINNEMUCCA	40.973	-117.7357	x717y2264	LSR2
26	WINNEMUCCA	40.973	-117.7357	x720y2242	LSR2
26	WINNEMUCCA	40.973	-117.7357	x720y2244	LSR2
26	WINNEMUCCA	40.973	-117.7357	x720y2246	LSR2
26	WINNEMUCCA	40.973	-117.7357	x720y2262	LSR2
26	WINNEMUCCA	40.973	-117.7357	x720y2264	LSR2
26	WINNEMUCCA	40.973	-117.7357	x723y2264	LSR2
26	WINNEMUCCA	40.973	-117.7357	x732y2258	LSR2
26	WINNEMUCCA	40.973	-117.7357	x732y2262	LSR2
26	WINNEMUCCA	40.973	-117.7357	x735y2258	LSR2
26	WINNEMUCCA	40.973	-117.7357	x735y2260	LSR2
26	WINNEMUCCA	40.973	-117.7357	x735y2262	LSR2
26	WINNEMUCCA	40.973	-117.7357	x735y2264	LSR2
26	WINNEMUCCA	40.973	-117.7357	x738y2260	LSR2
26	WINNEMUCCA	40.973	-117.7357	x738y2262	LSR2
26	WINNEMUCCA	40.973	-117.7357	x741y2256	LSR2
26	WINNEMUCCA	40.973	-117.7357	x741y2258	LSR2
26	WINNEMUCCA	40.973	-117.7357	x741y2260	LSR2
26	WINNEMUCCA	40.973	-117.7357	x744y2256	LSR2
26	WINNEMUCCA	40.973	-117.7357	x744y2258	LSR2
26	WINNEMUCCA	40.973	-117.7357	x717y2234	LSR3
26	WINNEMUCCA	40.973	-117.7357	x717y2236	LSR3
26	WINNEMUCCA	40.973	-117.7357	x717y2238	LSR3
26	WINNEMUCCA	40.973	-117.7357	x720y2232	LSR3
26	WINNEMUCCA	40.973	-117.7357	x720y2234	LSR3
26	WINNEMUCCA	40.973	-117.7357	x720y2236	LSR3
26	WINNEMUCCA	40.973	-117.7357	x720y2238	LSR3
26	WINNEMUCCA	40.973	-117.7357	x720y2240	LSR3
26	WINNEMUCCA	40.973	-117.7357	x723y2234	LSR3
26	WINNEMUCCA	40.973	-117.7357	x723y2236	LSR3
26	WINNEMUCCA	40.973	-117.7357	x723y2238	LSR3
26	WINNEMUCCA	40.973	-117.7357	x723y2240	LSR3
26	WINNEMUCCA	40.973	-117.7357	x723y2242	LSR3
26	WINNEMUCCA	40.973	-117.7357	x723y2244	LSR3
26	WINNEMUCCA	40.973	-117.7357	x723y2246	LSR3
26	WINNEMUCCA	40.973	-117.7357	x726y2226	LSR3
26	WINNEMUCCA	40.973	-117.7357	x726y2228	LSR3
26	WINNEMUCCA	40.973	-117.7357	x726y2230	LSR3
26	WINNEMUCCA	40.973	-117.7357	x726y2232	LSR3
26	WINNEMUCCA	40.973	-117.7357	x726y2234	LSR3
26	WINNEMUCCA	40.973	-117.7357	x726y2236	LSR3
26	WINNEMUCCA	40.973	-117.7357	x726y2242	LSR3
26	WINNEMUCCA	40.973	-117.7357	x729y2230	LSR3
26	WINNEMUCCA	40.973	-117.7357	x729y2244	LSR3
26	WINNEMUCCA	40.973	-117.7357	x729y2246	LSR3
26	WINNEMUCCA	40.973	-117.7357	x729y2268	LSR3

26	WINNEMUCCA	40.973	-117.7357	x729y2270	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2224	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2226	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2228	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2230	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2232	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2264	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2266	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2268	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2270	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2272	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2274	LSR3
26	WINNEMUCCA	40.973	-117.7357	x732y2276	LSR3
26	WINNEMUCCA	40.973	-117.7357	x735y2202	LSR3
26	WINNEMUCCA	40.973	-117.7357	x735y2204	LSR3
26	WINNEMUCCA	40.973	-117.7357	x735y2266	LSR3
26	WINNEMUCCA	40.973	-117.7357	x735y2268	LSR3
26	WINNEMUCCA	40.973	-117.7357	x735y2270	LSR3
26	WINNEMUCCA	40.973	-117.7357	x735y2272	LSR3
26	WINNEMUCCA	40.973	-117.7357	x738y2198	LSR3
26	WINNEMUCCA	40.973	-117.7357	x738y2200	LSR3
26	WINNEMUCCA	40.973	-117.7357	x738y2202	LSR3
26	WINNEMUCCA	40.973	-117.7357	x738y2204	LSR3
27	YERINGTON	38.9858	-119.1629	x318y1574	LSR1
27	YERINGTON	38.9858	-119.1629	x318y1576	LSR1
27	YERINGTON	38.9858	-119.1629	x318y1578	LSR1
27	YERINGTON	38.9858	-119.1629	x321y1540	LSR1
27	YERINGTON	38.9858	-119.1629	x321y1542	LSR1
27	YERINGTON	38.9858	-119.1629	x321y1544	LSR1
27	YERINGTON	38.9858	-119.1629	x321y1562	LSR1
27	YERINGTON	38.9858	-119.1629	x321y1564	LSR1
27	YERINGTON	38.9858	-119.1629	x321y1570	LSR1
27	YERINGTON	38.9858	-119.1629	x324y1544	LSR1
27	YERINGTON	38.9858	-119.1629	x324y1546	LSR1
27	YERINGTON	38.9858	-119.1629	x324y1564	LSR1
27	YERINGTON	38.9858	-119.1629	x327y1544	LSR1
27	YERINGTON	38.9858	-119.1629	x327y1546	LSR1
27	YERINGTON	38.9858	-119.1629	x327y1548	LSR1
27	YERINGTON	38.9858	-119.1629	x330y1544	LSR1
27	YERINGTON	38.9858	-119.1629	x330y1546	LSR1
27	YERINGTON	38.9858	-119.1629	x330y1548	LSR1
27	YERINGTON	38.9858	-119.1629	x330y1550	LSR1
27	YERINGTON	38.9858	-119.1629	x330y1600	LSR1
27	YERINGTON	38.9858	-119.1629	x333y1544	LSR1
27	YERINGTON	38.9858	-119.1629	x333y1546	LSR1
27	YERINGTON	38.9858	-119.1629	x336y1544	LSR1
27	YERINGTON	38.9858	-119.1629	x336y1546	LSR1
27	YERINGTON	38.9858	-119.1629	x336y1548	LSR1
27	YERINGTON	38.9858	-119.1629	x321y1572	LSR2
27	YERINGTON	38.9858	-119.1629	x321y1574	LSR2
27	YERINGTON	38.9858	-119.1629	x321y1576	LSR2
27	YERINGTON	38.9858	-119.1629	x321y1578	LSR2
27	YERINGTON	38.9858	-119.1629	x324y1522	LSR2
27	YERINGTON	38.9858	-119.1629	x324y1524	LSR2
27	YERINGTON	38.9858	-119.1629	x324y1526	LSR2

27	YERINGTON	38.9858	-119.1629	x324y1528	LSR2
27	YERINGTON	38.9858	-119.1629	x324y1530	LSR2
27	YERINGTON	38.9858	-119.1629	x324y1532	LSR2
27	YERINGTON	38.9858	-119.1629	x324y1572	LSR2
27	YERINGTON	38.9858	-119.1629	x324y1574	LSR2
27	YERINGTON	38.9858	-119.1629	x327y1522	LSR2
27	YERINGTON	38.9858	-119.1629	x327y1524	LSR2
27	YERINGTON	38.9858	-119.1629	x327y1526	LSR2
27	YERINGTON	38.9858	-119.1629	x327y1528	LSR2
27	YERINGTON	38.9858	-119.1629	x327y1530	LSR2
27	YERINGTON	38.9858	-119.1629	x327y1532	LSR2
27	YERINGTON	38.9858	-119.1629	x327y1534	LSR2
27	YERINGTON	38.9858	-119.1629	x327y1536	LSR2
27	YERINGTON	38.9858	-119.1629	x330y1530	LSR2
27	YERINGTON	38.9858	-119.1629	x330y1534	LSR2
27	YERINGTON	38.9858	-119.1629	x333y1528	LSR2
27	YERINGTON	38.9858	-119.1629	x333y1530	LSR2
27	YERINGTON	38.9858	-119.1629	x333y1532	LSR2
27	YERINGTON	38.9858	-119.1629	x333y1534	LSR2
27	YERINGTON	38.9858	-119.1629	x333y1536	LSR2
27	YERINGTON	38.9858	-119.1629	x333y1538	LSR2
27	YERINGTON	38.9858	-119.1629	x327y1538	LSR3
27	YERINGTON	38.9858	-119.1629	x327y1540	LSR3
27	YERINGTON	38.9858	-119.1629	x327y1542	LSR3
27	YERINGTON	38.9858	-119.1629	x330y1536	LSR3
27	YERINGTON	38.9858	-119.1629	x330y1538	LSR3
27	YERINGTON	38.9858	-119.1629	x330y1540	LSR3
27	YERINGTON	38.9858	-119.1629	x330y1542	LSR3
27	YERINGTON	38.9858	-119.1629	x333y1540	LSR3
27	YERINGTON	38.9858	-119.1629	x333y1542	LSR3
27	YERINGTON	38.9858	-119.1629	x336y1540	LSR3
27	YERINGTON	38.9858	-119.1629	x336y1542	LSR3

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
OPERATIONS-RELATED WORK ORDERS GREATER THAN $100,000 IN TOTAL COST
CLOSED TO PLANT IN SERVICE DECEMBER 2021 - MAY 2023

Line No.	Work Order Number		Work Order Description	Date First Transferred to Plant	Total Amount Excluding CIAC	CIAC	AFUDC	Line No.
	(a)		(b)	(c)	(d)	(e)	(f)	
1	0028W4103285	[1]	SPCRK - SPRING CREEK HP MAIN P	Dec-21	9,626,248.32	0.00	25,308.12	1
2	0028CB043000		Bwo - New Random Svc-Swg Trnch		2,709,162.02	0.00	4,147.27	2
3	0024CB030000		Bwo - New Meters		1,751,172.56	0.00	2,950.94	3
4	0024CB043000		Bwo - New Random Svc-Swg Trnch		1,676,845.72	(278,435.54)	1,723.69	4
5	0024CB041000		Bwo - New Service Subdivision		1,352,132.36	0.00	2,217.62	5
6	0024CB035000		Bwo - Replc Meters		1,054,051.89	0.00	2,021.81	6
7	0024CB044000		Bwo-New Random Svc-Cust Trench		986,224.11	0.00	1,481.96	7
8	0028W4102121	[1]	SPCRK 2021 - LICHT PKWY	Oct-22	978,020.80	0.00	3,867.90	8
9	0028W4277836	[1]	SPCRK 2022 - PALACE PKWY PH 5	Mar-23	809,158.42	0.00	11,155.47	9
10	0028W4102316	[1]	SPCRK 2021 - SPRING CREEK PARK	Apr-22	797,431.08	0.00	3,201.24	10
11	0028W4102400	[1]	SPCRK 2021 - COUNTRY CLUB PKWY	Oct-22	708,835.47	0.00	1,552.58	11
12	0028W4102060	[1]	SPCRK 2021 - PALACE PARKWAY PH	Aug-22	680,350.04	0.00	1,079.49	12
13	0028W4276324	[1]	SPCRK 2022 - SPRING CREEK PKWY	Feb-23	676,347.02	0.00	3,160.00	13
14	0028W4102752	[1]	SPCRK 2021 - BOYD-KENNEDY RD P	Dec-21	658,043.86	0.00	443.31	14
15	0024W4487580		SI WINNIE LANE VSP REPLACEMENT	May-23	643,250.42	0.00	2,184.30	15
16	0028W4277815	[1]	SPCRK 2022 - PALACE PKWY PH 4	Oct-22	583,137.93	0.00	1,199.28	16
17	0024W4387275		SI - FLOWERY LN REPLACEMENT	Feb-23	561,906.17	0.00	769.68	17
18	0024CB025000		Bwo - Replc Services		560,118.07	0.00	1,042.12	18
19	0024W4332030		NBMS ANDERSEN RANCH ESTATES	Sep-22	551,609.43	0.00	350.17	19
20	0028W4102200	[1]	SPCRK 2021 - SPRING CREEK PARK	Mar-22	526,893.46	0.00	776.35	20
21	0028W4102809	[1]	SPCRK 2021 - SPRING VALLEY CT	Dec-21	493,849.34	0.00	368.98	21
22	0028W4276403	[1]	SPRCK 2022 - SPRING CREEK LANE	Mar-23	466,265.73	0.00	1,210.87	22
23	0024W4401883		NBMR RIDERS AVE REINFORCEMENT	Feb-23	458,284.96	0.00	2,009.33	23
24	0023CB025000		Bwo - Replc Services		453,582.18	0.00	496.45	24
25	0027CB043000		Bwo - New Random Svc-Swg Trnch		451,005.47	(3,499.00)	574.91	25
26	0028W4102788	[1]	SPCRK 2021 - VALLEY VISTA DRIV	Dec-21	436,355.82	0.00	534.16	26
27	0028W4102499	[1]	SPCRK 2021 - SPRING CREEK PKWY	Mar-22	405,601.17	0.00	553.66	27
28	0028W4102694	[1]	SPCRK 2021 - PALACE PARKWAY PH	Oct-22	402,808.02	0.00	658.31	28
29	0028W4102456	[1]	SPCRK 2021 - COUNTRY CLUB PKWY	Oct-22	401,849.61	0.00	225.48	29
30	0028W4102384	[1]	SPCRK 2021 - COUNTRY CLUB PKWY	Sep-22	400,965.40	0.00	443.09	30
31	0027W4167492		DRS - DESERT HILLS DAIRY TAP	Aug-22	400,563.26	0.00	7,017.83	31
32	0024CB010000		Bwo - New Mains		389,305.34	0.00	681.53	32
33	0028W4293534	[1]	SPCRK - 2021 LANDMARK LANE	May-22	371,633.93	0.00	506.48	33
34	0028W4102677	[1]	SPCRK 2021 - PALACE PARKWAY PH	Oct-22	370,923.96	0.00	740.70	34
35	0025W0006614		PROJECT #E25-01-21	Apr-22	352,945.00	0.00	0.00	35
36	0028W4276808	[1]	SPCRK 2022 - BLACK OAK DRIVE	Nov-22	310,196.82	0.00	597.46	36
37	0028W4276382	[1]	SPRCK 2022 - SPRING CREEK PKWY	Apr-23	309,272.78	0.00	1,689.90	37
38	0024W0006508		Field Rugged MWS Replacement-NNV	Jul-22	308,200.14	0.00	0.00	38
39	0024W4229040		NBMS CLEAR CREEK @ TAHOE PHASE	Dec-22	291,693.69	0.00	1,706.55	39
40	0027CB030000		Bwo - New Meters		285,135.76	0.00	494.78	40
41	0028W4277444	[1]	SPCK 2022 - CRIPPLE CREEK DRIV	Oct-22	284,706.11	0.00	702.37	41
42	0025CB030000		Bwo - New Meters		281,804.26	0.00	695.74	42
43	0026W4202388		SI CHUKAR HILLS MHP REPLACEMEN	Nov-22	279,556.46	0.00	916.85	43
44	0028W4367347	[1]	SPCRK 2022 - BELLWOOD DRIVE	May-23	278,025.60	0.00	600.41	44
45	0028W4276786	[1]	SPCRK 2022 - WHITE OAK DRIVE	Oct-22	274,871.99	0.00	747.14	45
46	0027W4175852		NBMS FRIENDLY RANCH PHASE 1	Dec-22	268,685.10	0.00	1,084.01	46
47	0028W4102801	[1]	SPCRK 2021 - EDGEWATER DRIVE	Dec-21	256,834.37	0.00	363.92	47
48	0024W4470085		NBMS TRADITIONS VILLAGE BACKBO	Jan-23	254,959.74	0.00	644.99	48
49	0024W0006198		PROJECT #24-01-21	Oct-22	254,790.75	0.00	0.00	49
50	0026CB025120		BWO - COYL		240,579.32	0.00	263.43	50
51	0028W4277398	[1]	SPCRK 2022 - BLUE JAY DRIVE	Nov-22	221,391.73	0.00	406.92	51
52	0024W4115879		SI - DAYTON DRS 1 REBUILD	Dec-22	218,238.04	0.00	776.13	52
53	0028W4277820	[1]	SPCRK 2022 - THORPE DRIVE	Nov-22	202,953.70	0.00	268.43	53
54	0024W0007067		Carson-GPS Devices & Base Stations	Nov-22	199,732.76	0.00	0.00	54
55	0027W4145927		SI - SHECKLER MAIN REINFORCEME	Jan-22	197,621.16	0.00	213.37	55
56	0024W0006203		PROJECT #29-01-21	May-22	197,174.00	0.00	0.00	56
57	0028W4102762	[1]	SPCRK 2021 - BOYD KENNEDY RD P	Dec-21	191,941.69	0.00	288.25	57
58	0028W4277391	[1]	SPCRK 2022 - OAKMONT PH 1	Oct-22	188,837.24	0.00	816.06	58
59	0028W4276814	[1]	SPCRK 2022 - ROYAL OAK DRIVE	Oct-22	183,852.08	0.00	596.94	59
60	0028W4102410	[1]	SPCRK 2021 - FAIRWAY BLVD	Oct-22	182,322.95	0.00	346.89	60
61	0027W3943521		SI - SILVER SPRINGS DRS	Sep-22	181,305.42	0.00	3,982.57	61
62	0028W4276428	[1]	SPCRK 2022 - FAIRGROVE DRIVE	Dec-22	179,942.40	0.00	450.63	62
63	0024CB042000		Bwo - New Service Commercial		170,699.39	0.00	240.83	63
64	0023CB010000		Bwo - New Mains		169,785.53	0.00	202.00	64

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
OPERATIONS-RELATED WORK ORDERS GREATER THAN $100,000 IN TOTAL COST
CLOSED TO PLANT IN SERVICE DECEMBER 2021 - MAY 2023

Line No.	Work Order Number (a)		Work Order Description (b)	Date First Transferred to Plant (c)	Total Amount Excluding CIAC (d)	CIAC (e)	AFUDC (f)	Line No.
65	0024W4001101		NBMS TRADITIONS VILLAGE BACKBO	Jan-22	160,978.78	0.00	772.47	65
66	0028W4277395	[1]	SPCRK 2022 - OAKMONT PH 2	Nov-22	160,634.57	0.00	529.45	66
67	0028W4277454	[1]	SPCRK 2022 - WOLF CREEK DRIVE	Oct-22	159,304.02	0.00	210.05	67
68	0028W4107034	[1]	SPCRK - SPRING CREEK DRS #2	Mar-22	154,995.33	0.00	542.84	68
69	0024W4401990		NBMS LITTLE LANE VILLAGE PHASE	Oct-22	152,332.34	0.00	65.67	69
70	0026W3943530		SI - NEWMONT PHOENIX MINE DRS	Apr-22	151,706.88	0.00	918.02	70
71	0027CB044000		Bwo-New Random Svc-Cust Trench		151,112.22	(771.00)	189.96	71
72	0028W4107033	[1]	SPCRK - SPRING CREEK DRS #1	Dec-21	149,987.25	0.00	357.29	72
73	0024W4393387		NBMS VALLEY KNOLLS PHASE 2 REV	Aug-22	146,934.84	0.00	365.08	73
74	0027W4308685		NBMS COOK RANCH ESTATES PH 3	Oct-22	146,612.51	0.00	196.39	74
75	0024CB025120		BWO - COYL		137,827.22	0.00	154.79	75
76	0028W4107035	[1]	SPCRK - SPRING CREEK DRS #3	Mar-22	136,153.99	0.00	499.89	76
77	0024CB015000		Bwo - Replc Mains		130,014.55	0.00	182.06	77
78	0028W4082575	[1]	SPCRK - SPRING CREEK HP PHASE	Jan-21	126,870.46	0.00	0.00	78
79	0027W4519719		NBMC COMMERCE CENTER	May-23	126,686.23	0.00	129.42	79
80	0027CB035000		Bwo - Replc Meters		126,035.99	0.00	241.29	80
81	0024W4258451		NBMS - PRISON FARM MAIN	Feb-22	118,514.34	0.00	47.16	81
82	0024W0006866		Carson Leak Survey Equipment	Dec-21	111,137.97	0.00	0.00	82
83	0024W4428638		SI - CARSON VALLEY MIDDLE SCHO	Jul-22	108,929.48	0.00	0.00	83
84	0024W3857795		NBMS PARKHAVEN ESTATES	Aug-22	106,611.94	0.00	326.28	84
85	0024W3903276		NBMS TRADITIONS VILLAGE PH 5	Jun-22	106,224.53	0.00	464.18	85
86	0024W0006262		PROJECT #E24-01-20	Aug-22	103,889.73	0.00	0.00	86
87	0028W4107959	[1]	SPCRK - 6 INCH PE HDD BORE @ L	Mar-22	103,204.93	0.00	351.99	87
88	0023W4366512		SI 4H CAMP COYL REPLACEMENT	May-22	102,159.68	0.00	151.55	88
89	0028CB030000		Bwo - New Meters		101,187.38	0.00	140.21	89

[1] Spring Creek Expansion Area projects removed from rate under test year adjustment No. 25.

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
GAS INFRASTRUCTURE REPLACEMENT PROJECTS
PLANT IN SERVICE FOR ACCELERATED RECOVERY
FOR THE PERIOD BEGINNING DECEMBER 1, 2021 THROUGH JULY 31, 2022 [1]

Line No.	Description	WR#	Total Additions [2][3]	Line No.
	(a)	(b)	(c)	
	Projects Approved in Docket Nos. 16-06001, 17-05027 and 18-06004			
1	Customer Owned Yard Line (COYL)	Multiple	$ 8,263	1
2	Total		$ 8,263	2

[1] Represents the period beginning after the certification period in the Company's last General Rate Case Docket No. 21-09001 through the period of the final GIR Rate Application Docket No. 22-09024.

[2] Additions for December 2021 only as the GIR COYL program ended December 31, 2021.

[3] In the Order for Docket No. 22-09024 the charges recovered through the GIR mechanism ended July 31, 2021 thus these additions were never included in a GIR rate.

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
GAS INFRASTRUCTURE REPLACEMENT
PRUDENCY REVIEW PACKAGE

WORK ORDER 0023CB025120

Exhibit No.__(MAH-4)
SHEET 2 OF 19

Work Order Charges

Southwest Gas Corporation

Company	Major Location		
Funding Project	**Asset Location**	**Months: Dec 2021**	**to Dec 2021**
Southwest Gas Corporation	**Northern Nevada Rate Juris. 0860**		
COYL	**Tahoe District : 0023 : TAHO**		

Work Order Number: 0023CB025120

Charge Type	Expenditure Type	Util Acct	Quantity	Amount
Admin and General Overhead	Additions		0.00	9.24
AFUDC Debt	Additions		0.00	0.63
Capitalized Property Tax	Additions		0.00	1.43
Construction Overhead	Additions		0.00	837.20
Contractor	Additions		0.00	725.61
Sum Amount	**Additions**		**0.00**	**1,574.11**
Sum Amount for WO Number		**0023CB025120**		**1,574.11**

Exhibit No.__(MAH-4)
SHEET 3 OF 19

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
GAS INFRASTRUCTURE REPLACEMENT
INVOICES BY COST CATEGORY
CUSTOMER OWNED YARD LINE (COYL)
0023CB025120

Line No.	PO of Voucher Number and Cost Category (1)	Mains	Services	Subtotal	Cost of Removal	Invoice Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Contractor						
1	922029	$ 0.00	$ 725.61	$ 725.61	$ 0.00	$ 725.61	1

(1) The voucher number is the internal Southwest Gas control number assigned through the Oracle Accounts Payable vouching process.

Exhibit No. __(MAH-4)
SHEET 4 OF 19

Southwest Gas Corporation
Attention: Chris Couture
5241 Spring Mountain Rd.
Las Vegas, NV 89105-0002

P.O. Box 603663
Charlotte, NC 28260-3663
(336) 992-5420
(336) 992-5421 Fax

Invoice #: 211204NNV-COYL
Invoice Date: 12/09/2021

922029

Contract #	PO #	LMR #	Date Performed
3020	RC 14360	211204-SWG-NNV-COYL	12/4/2021
Location			
COYL			

Unit #	Quantity	Description	Unit Price	Extended
LINE_LOC_TECH_NNV	14.25	Line Locate Tech - Hrly - Reg	$50.92	$725.61
			Total	$725.61

Explanation: NNV COYL INVOICE FOR WE 12/04/2021
COYL CB 025120
WR#4305064

Exhibit No.__(MAH-4)
SHEET 5 OF 19

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
GAS INFRASTRUCTURE REPLACEMENT
PRUDENCY REVIEW PACKAGE

WORK ORDER 0024CB025120

Exhibit No. (MAH-4)
SHEET 6 OF 19

Work Order Charges

Southwest Gas Corporation

Company	Major Location			
Funding Project	**Asset Location**	**Months:**	**Dec 2021**	**to Dec 2021**
Southwest Gas Corporation	**Northern Nevada Rate Juris. 0860**			
COYL	**Carson District : 0024 : CARS**			

Work Order Number: 0024CB025120

Charge Type	Expenditure Type	Util Acct	Quantity	Amount
Admin and General Overhead	Additions		0.00	24.56
AFUDC Debt	Additions		0.00	1.02
Capitalized Property Tax	Additions		0.00	3.79
Construction Overhead	Additions		0.00	584.10
Contractor	Additions		0.00	1,317.40
Labor	Additions		5.00	204.05
Labor Loadings	Additions		0.00	145.81
Materials	Additions		22.00	98.31
Materials Loadings	Additions		0.00	116.50
Pipe	Additions		12.00	6.00
Tools Loadings	Additions		0.00	15.00
Transportation Loadings	Additions		0.00	25.00
Sum Amount	**Additions**		**39.00**	**2,541.54**
Sum Amount for WO Number		**0024CB025120**		**2,541.54**

Exhibit No.__(MAH-4)
SHEET 7 OF 19

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
GAS INFRASTRUCTURE REPLACEMENT
INVOICES BY COST CATEGORY
CUSTOMER OWNED YARD LINE (COYL)
0024CB025120

Line No.	PO of Voucher Number and Cost Category (1)	Mains	Services	Subtotal	Cost of Removal	Invoice Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Contractor						
1	919976	$ 0.00	$ 1317.4	$ 1317.40	$ 0.00	$ 1317.40	1

(1) The voucher number is the internal Southwest Gas control number assigned through the Oracle Accounts Payable vouching process.

SHEET 8 OF 19

919976

ARIZONA PIPELINE CO.

P.O. BOX 401865 - HESPERIA, CALIFORNIA 92340-1865 - TELEPHONE (760) 244-8212

INVOICE

SOUTHWEST GAS CORP
400 EAGLE STATION LANE
CARSON CITY, NV 89701
ATTN:COYL

Invoice No: 08121000152961
Invoice Date: 11/24/2021
APL Invoice No: 91472
APL Job No: 108011

Contract #: CAR/FALL 13558

Ticket Number	DESCRIPTION	WO#	WR#	UNITS	UM	RATE	AMOUNT
79159	2 MAN CREW W/O BACKHOE	CB025120	4192163	5	HR	$179.46	$897.30
79159	PLUMBER W/TRUCK	CB025120	4192163	5	HR	$84.02	$420.10

Angelica Blade

Approved By

Approved By

TOTAL: $1,317.40

SHEET 9 OF 19

79159

ARIZONA PIPELINE CO.
2670 LOCKHEED WAY
CARSON CITY, NV 89706

CREW DAY
Daily Progress Report

Bill to Customer Supervisor: D-24 / C041

Foreman Brian Kemp | Day Wednesday | Date 11-17-21 | Job # 108011.

City Washoe Valley | County Washoe | State NV | Foreman Sub Job #

CODE	DESCRIPTION	REG. TIME HRS	WO#	WR#	ADDRESS	CODE	OVERTIME HRS
412	2 MAN CREW W/BKH					414	
413	2 MAN CREW NO/BKH	5	CB025120	4192163	2120 Beaver Dr.	415	
416	3 MAN CREW W/BKH					418	
417	3 MAN CREW NO/BKH					419	
448	TRUCK DRIVER					449	
442	OPERATOR					443	
438	LABORER 1					439	
444	PLUMBER W/TRK	5	CB025120	4192163	2120 Beaver Dr.	445	
446	PLUMBER II W/TRK					447	
424	CONSTR. ASSISTANT					425	
450	WELDER W/TRUCK					451	
458	DIG & INSPECT CREW					459	

	DESCRIPTION	UNIT#	HOURS	SIZE PE / STL	FT INSTALL	CREW NAMES
470	BORE MACHINE					Brian Kemp
480	EXTRA 310 BACKHOE					Devin Fernandez
503	VAC TRAILER					Abraham Botello
475	1/2-3/4 TON PICK TRUCK					
490	5-10 TON DUMP TRUCK					
491	11-15 TON DUMP TRUCK					
478	WATER TRUCK					
498	6" COIL PIPE TRAILER W/TAMER					
499	40 PIPE TRAILER					
508	MINI EX			TARE		TOTAL DPR
474	MAIN CREW TRUCK			PIPE/PARTS	SIZE	AMT
						$1,317.40

COMMENTS: Potholed Service, open trenched 12' to meters new location. Potholed at Edge of property Squeezed and Installed 1/2" EFV.

FOREMAN	DATE	APL SIGNATURE	DATE	CUSTOMER SIGNATURE
Brian Kemp	11-17-21	[signature] 11/18/21		[signature]

AzP-CD2 9/

Exhibit No.__(MAH-4)
SHEET 10 OF 19

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
GAS INFRASTRUCTURE REPLACEMENT
PRUDENCY REVIEW PACKAGE

WORK ORDER 0026CB025120

Work Order Charges

Southwest Gas Corporation

Company	Major Location		
Funding Project	Asset Location	Months: Dec 2021	to Dec 2021
Southwest Gas Corporation	**Northern Nevada Rate Juris. 0860**		
COYL	**Winnemucca District : 0026 : WINN**		

Work Order Number: 0026CB025120

Charge Type	Expenditure Type	Util Acct	Quantity	Amount
Admin and General Overhead	Additions		0.00	14.97
AFUDC Debt	Additions		0.00	0.55
Capitalized Property Tax	Additions		0.00	2.31
Construction Overhead	Additions		0.00	170.49
Labor	Additions		17.95	627.88
Labor Loadings	Additions		0.00	448.68
Tools Loadings	Additions		0.00	53.85
Transportation Loadings	Additions		0.00	44.75
Sum Amount	**Additions**		**17.95**	**1,363.48**
Sum Amount for WO Number		**0026CB025120**		**1,363.48**

Exhibit No.__(MAH-4)
SHEET 12 OF 19

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
GAS INFRASTRUCTURE REPLACEMENT
PRUDENCY REVIEW PACKAGE

WORK ORDER 0027CB025120

Exhibit No.__(MAH-4)
SHEET 13 OF 19

Work Order Charges

Southwest Gas Corporation

Company	Major Location		
Funding Project	**Asset Location**	**Months: Dec 2021**	**to Dec 2021**
Southwest Gas Corporation	**Northern Nevada Rate Juris. 0860**		
COYL	**Fallon District : 0027 : FALL**		

Work Order Number: 0027CB025120

Charge Type	Expenditure Type	Util Acct	Quantity	Amount
Admin and General Overhead	Additions		0.00	34.57
AFUDC Debt	Additions		0.00	1.11
Capitalized Property Tax	Additions		0.00	5.33
Construction Overhead	Additions		0.00	28.95
Contractor	Additions		0.00	2,714.09
Sum Amount	**Additions**		**0.00**	**2,784.05**
Sum Amount for WO Number		**0027CB025120**		**2,784.05**

Exhibit No.__(MAH-4)
SHEET 14 OF 19

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
GAS INFRASTRUCTURE REPLACEMENT
INVOICES BY COST CATEGORY
CUSTOMER OWNED YARD LINE (COYL)
0027CB025120

Line No.	PO of Voucher Number and Cost Category (1)	Mains	Services	Subtotal	Cost of Removal	Invoice Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Contractor						
1	922528	$ 0.00	$ 1,829.52	$ 1829.52	$ 0.00	$ 1,829.52	1
2	922532	0.00	884.57	884.57	0.00	884.57	2
3	Subtotal - Contractor	$ 0.00	$ 2714.09	$ 2714.09	$ 0.00	$ 2,714.09	3
4	**Total Invoices**	**$ 0.00**	**$ 2,714.09**	**$ 2714.09**	**$ 0.00**	**$ 2,714.09**	4

(1) The voucher number is the internal Southwest Gas control number assigned through the Oracle Accounts Payable vouching process.

SHEET 15 OF 19

922528

ARIZONA
PIPELINE CO.

P.O. BOX 401865 - HESPERIA, CALIFORNIA 92340-1865 - TELEPHONE (760) 244-8212

INVOICE

SOUTHWEST GAS CORP
400 EAGLE STATION LANE
CARSON CITY, NV 89701
ATTN:COYL

Invoice No: 08121000153600
Invoice Date: 12/13/2021
APL Invoice No: 92069
APL Job No: 108004 02

Contract #: 13558

Ticket Number	DESCRIPTION	WO#	WR#	UNITS	UM	RATE	AMOUNT
93297	ASP ADDT'L 2" LIFT 26-100 S/F	CB025120	4249374	84	FT	$3.63	$304.92
93297	REPL ASP 0-4" 26-100 S/F	CB025120	4249374	84	FT	$18.15	$1,524.60

Angelica Blade
Approved By

Approved By

TOTAL: $1,829.52

Exhibit No. (MAH-4)
SHEET 16 OF 19

93297
Coyl

ARIZONA PIPELINE CO.
2670 LOCKHEED WAY
CARSON CITY, NV 89706

PAVING & CONCRETE FOOTAGE SHEET

FOREMAN: Jose L. Chairez
LOCATION: 355 Fremont St. Fernley NV
APL JOB#: 108004-02

DATE: 12-02-21
WO#: CB025120
WR#: 4249374
SWG DISTRICT: 27

ASPHALT

	0 - 25	26 - 100	101 - 500	500+	
0 - 4"		84			504
EXTRA 2" LIFT		84			568

EXTRA COST EVERY 2" OVER 4"

SLURRY SEAL

	SQ. YARD:

CONCRETE

0 - 4"	
EXTRA 1"	

EXTRA COST EVERY 1" OVER 4"

NOTES: 5" Deep $1,829.92

AzP-P&C 06

Exhibit No. __(MAH-4)
SHEET 17 OF 19

SOUTHWEST GAS CORPORATION

PAVEMENT REPAIR RECORD

No.

Division: Carson City	Town: Fernley	Atlas #	Date: 12-02-21
Address: 355 Fremont St.	Subdivision	Block No.	Lot No.
Prepared By	Crew Leader	Supervisor Ext.	Contractor Needed? ☐ Yes ☐ No / Saw Cut Needed? ☐ Yes ☐ No
Size of Cut	Thickness of Cut	Type of Paving ☐ Curb ☐ Sidewalk ☐ Concrete ☑ Asphalt ☐ Other	
Claim No.	Permit No.	W.O. Job Account # CB025120 / WR # 4249374	Asphalt (cold mix) Installed? ☑ Yes ☐ No / A.B.C. or Type II Needed? ☑ Yes ☐ No
Customer Name	Customer Phone # Home Work	Remarks: 5" Deep	

Form 231.0 (07 1992) 650 **Distribution:** White & Canary - Paving Repair Pink - Originator

DOCKET NO. 23-09XXX
EXHIBIT NO.__(MAH-4)
SHEET 18 OF 19
922532

ARIZONA
PIPELINE CO.

P.O. BOX 401865 - HESPERIA, CALIFORNIA 92340-1865 - TELEPHONE (760) 244-8212

INVOICE

SOUTHWEST GAS CORP
400 EAGLE STATION LANE
CARSON CITY, NV 89701
ATTN:COYL

Invoice No: 08121000153613
Invoice Date: 12/13/2021
APL Invoice No: 92082
APL Job No: 108005 02

Contract #: 13558

Ticket Number	DESCRIPTION	WO#	WR#	UNITS	UM	RATE	AMOUNT
88495	COORDINATOR	CB025120	4249374	2	HR	$50.72	$101.44
88495	FLAGGER	CB025120	4249374	16	HR	$45.64	$730.24
88495	PICKUP TRUCK 1/2-3/4 TON	CB025120	4249374	3	HR	$17.63	$52.89

Angelica Black

Approved By

Approved By

TOTAL: $884.57

DOCKET NO. 23-09XXX
EXHIBIT NO. (MAH-4)
SHEET 19 OF 19

Traffic Control Daily

ARIZONA PIPELINE CO.
2670 Lockheed Way, Carson City, NV 89706
775-515-7017

88495

Date: 12/2/21
Job Number: 108005-02
Foreman #: JJ Pavers
WR/WO: 4249374
Vendor Invoice #: CBD25120
Address: 355 Fremont St
City: Fernley NV

DIST 27

$884.57

RENTAL EQUIPMENT | **QUANTITY**

RENTAL EQUIPMENT	QUANTITY

CLOSURES / SETUP / REMOVAL	QUANTITY

MISCELLANEOUS CHARGES	QUANTITY
Cord Truck 20641	475 3

428.2

422

LABOR / FLAGGERS	HOURS	OT	DT
Tech Tony Russo	2		
Flagger DAN Gordon	8		
Flagger Jeremy Peterson	8		

Traffic Control Tech/Supervisor	Superintendent	Date	Inspector	Date
[signature]	[signature]		Complete By Rusty Mclaughlin Date 12/07/21	

AFFIRMATION OF MATTHEW A. HELMERS

Pursuant to NAC 703.710, Matthew A. Helmers affirms and declares the following:

1. I am over 18 years of age and am competent to testify to facts stated below which are based upon my personal knowledge.
2. That I am the person identified in the foregoing prepared testimony, including, where applicable, any exhibits.
3. That such testimony and exhibits were prepared by me or under my direction.
4. That the information appearing in my testimony and exhibits are true to the best of my knowledge and belief and that if I were asked the questions stated therein under oath, my answers would be the same.
5. Pursuant to NRS 53.045, I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

EXECUTED and DATED this 24th day of August, 2023

Matthew A. Helmers