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. 21-08___

VOLUME 6 of 34

Prepared Direct Testimony of Dylan W. D'Ascendis
Prepared Direct Testimony of Carla Ayala
Prepared Direct Testimony of Timothy Lyons
Prepared Direct Testimony of Raied Stanley

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IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. 21-08___

PREPARED DIRECT TESTIMONY
OF
DYLAN W. D’ASCENDIS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

AUGUST 31, 2021

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of
Dylan W. D'Ascendis

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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
Exhibit No.__(DWD-3)	Application of the Discounted Cash Flow Model
Exhibit No.__(DWD-4)	Application of the Risk Premium Model
Exhibit No.__(DWD-5)	Application of the Capital Asset Pricing Model
Exhibit No.__(DWD-6)	Basis of Selection for the Non-Price Regulated Companies Comparable in Total Risk to the Utility Proxy Group
Exhibit No.__(DWD-7)	Application of Cost of Common Equity Models to the Non-Price Regulated Proxy Group
Exhibit No.__(DWD-8)	Derivation of the Indicated Size Premium for Southwest Gas Corporation Relative to the Utility Proxy Group
Exhibit No.__(DWD-9)	Regulatory Assessment of Southwest Gas Corporation and the Utility Proxy Group
Exhibit No.__(DWD-10)	Summary of Decoupling Mechanisms in Place at the Utility Proxy Group
Exhibit No.__(DWD-11)	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 241, 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 30 state regulatory commissions in the United States, the Federal Energy Regulatory Commission (FERC), the Alberta Utility Commission, and one American Arbitration Association panel 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 B.

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

A. 5 The purpose of my Direct Testimony is to 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 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-11) were prepared by me or under my direction.

II. SUMMARY

Q. 8 What are your recommended WACCs for Southwest Gas' Southern and Northern rate jurisdictions?

A. 8 I recommend that the Commission authorize Southwest Gas the opportunity to earn WACCs of 6.57% and 6.82% on its Southern and Northern Nevada jurisdictional rate bases, respectively. The Company's ratemaking capital structure applicable to both the Southern and Northern Nevada jurisdictional rate bases consists of 49.00% total debt,[1] at an embedded debt cost rates of 3.10% (Southern) and 3.61% (Northern), and 51.00% common equity at my recommended ROE of 9.90%. My recommended WACC for each rate jurisdiction is summarized on page 1 of Exhibit No.___(DWD-1) and in Tables 1 and 2 below:

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

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	49.00%	3.11%	1.52%
Common Equity	51.00%	9.90%	5.05%
Total	100.00%		6.57%

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	49.00%	3.61%	1.77%
Common Equity	51.00%	9.90%	5.05%
Total	100.00%		6.82%

Q. 9 Please summarize your recommended ROE.

A. 9 My recommended ROE of 9.90% 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 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

[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*).

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 the 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)	9.59%
Risk Premium Model (RPM)	10.66%
Capital Asset Pricing Model (CAPM)	11.71%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.52%
Indicated Range of Common Equity Cost Rates Before Adjustments	9.59% - 12.52%
Business Risk Adjustment	0.10%
Credit Risk Adjustment	0.13%
Flotation Cost Adjustment	0.07%
Indicated Range of Common Equity Cost Rates After Adjustment	9.89% - 12.82%
Recommended Cost of Common Equity	9.90%

The indicated range of common equity cost rates applicable to the Utility Proxy Group is between 9.59% and 12.52% 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 0.13% 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 0.07% to account for flotation costs. These adjustments resulted in a Company-specific indicated range of common equity cost rates between 9.89% and 12.82%.

The wide range of model results may reflect increased uncertainty related to the COVID-19 pandemic and unknown timeframe for when economic conditions will normalize as vaccinations ramp up and the public health crises subsides. I conservatively recommend an ROE for the Company of 9.90%, which is toward the low end of my Company-specific range, but still reasonable.

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 49.00% debt (including short-term debt and customer deposits) and 51.00% common equity. The target capital structure requested in this proceeding is consistent with the Company's long-term plan, 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 3.11% and 3.61% 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 costs 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;
- Section X – Presents my conclusions; and
- Appendix A – Discusses factors temporarily impacting the Company's capital structure.

III. GENERAL PRINCIPALS

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, 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 affirmed 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 has found 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.

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

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

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.

Q. 19 Do rating agencies account for company size in their bond ratings?

A. 19 No. Neither Standard & Poor's (S&P) nor Moody's Investors Service, Inc. (Moody's) have minimum company size requirements for any given rating level. This means, all else equal, a relative size analysis must be conducted for equity investments in companies with similar bond ratings.

IV. SOUTHWEST GAS AND THE UTILITY PROXY GROUP

Q. 20 Why is it necessary to develop a proxy group when estimating the ROE for the Company?

A. 20 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

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[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.

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: 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. 21 Are you familiar with Southwest Gas' operations?

A. 21 Yes. Southwest Gas provides natural gas distribution services to approximately 790,000 customers.[7] Southwest Gas has long-term issuer ratings of Baa1 from Moody's, A- from S&P, and A from Fitch Ratings (Fitch). 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. 22 Please explain how you chose the companies in the Utility Proxy Group.

A. 22 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 28, 2021) (*Value Line*);

(ii) They have 60% or greater of fiscal year 2020 total operating income derived from, and 60% or greater of fiscal year 2020 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 2020 or through the time of preparation of this testimony;

[7] Southwest Gas Holdings, Inc. SEC Form 10-K, Exhibit 13.01 (December 31, 2020) at 2.

(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 seven companies met these criteria:

Table 4: Utility Proxy Group Companies

Company Name	Ticker Symbol
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Holdings, Inc.	SWX
Spire Inc.	SR

V. CAPITAL STRUCTURE

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 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]

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[8] *See,* Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 45-46. (Morin).
[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).

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

A. 25 The Company's proposed capital structure used to determine the WACCs consists of 49.00% debt and 51.00% percent common equity. The recommended capital structure is a target capital structure the Company reasonably expects to achieve and is more representative than its current capital structure of how it will finance rate base assets longer-term.[12] The Company's proposed revenue requirement reflects WACCs of 6.57% and 6.82% for the Southern and Northern rate jurisdictions, respectively, as shown on Page 1 of Exhibit No.__(DWD-1) and Tables 1 and 2, above.

Q. 26 Why are you recommending the Company's target capital structure instead of its actual capital structure?

A. 26 I am recommending the use of the Company's target capital structure in the

[11] Communications Satellite Corp. et. al. v. FCC, 198 U.S. App. D.C. 60, 63-64611 F.2d 883.

[12] The Company's 2021-2023 Three-Year Plan projects an increasing common equity ratio, achieving a common equity ratio of approximately 51% in 2023.

proceeding because recent events out of the control of the Company's management have temporarily lowered Southwest Gas' common equity ratio. These events are discussed further in Appendix A to this Direct Testimony.

Q. 27 Is the actual capital structure, at any point in time, solely determined by a firm's management?

A. 27 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 financings, and dividends. The existence of actual and target capital structures, and the speed of adjustment back to the target capital structure, has been observed and is the focus of numerous empirical studies on the capital structure decisions of firms.[13]

Q. 28 Has SWX demonstrated a commitment to issue additional common equity to maintain the Company's strong investment grade credit ratings?

A. 28 Yes. Southwest Gas is committed to maintaining an appropriate capital structure to support its strong investment grade credit ratings. This commitment has been demonstrated by SWX's willingness to continue to issue new equity to finance the Company's investment in utility plant and improve its capital structure. New equity issuances to support Southwest Gas' capital structure have come primarily from the establishment of a $300 million Equity Shelf Program (ESP)[14] and a $500

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[13] 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

[14] On May 8, 2019, Southwest Gas Holdings, Inc. filed with the Securities and Exchange Commission (SEC) an automatic shelf registration statement on Form S-3 (File No. 333-231297), which became effective upon

million ESP.[15] At the end of the test period ended May 31, 2021, the entirety of the $300 million ESP and $40 million of the $500 million ESP have been issued, all being allocated to the Company.

Going forward, SWX disclosed that it anticipates additional common stock issuance of $600 million to $800 million over the three-year period ended December 31, 2023. SWX has clearly demonstrated that it has and will continue to issue additional common stock to fund capital expenditures by the Company, which are required to maintain a strong credit rating, which provides long-term cost benefits to customers.

Q. 29 How does the Company's recommended common equity ratio of 51.00% compare with the common equity ratios maintained by the Utility Proxy Group?

A. 29 The Company's requested ratemaking common equity ratio of 51.00% 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 31.86% to 59.68% for fiscal year end 2020, and 32.91% to 57.36% for the five-quarter average ending March 31, 2021.

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filing, for the offer and sale of up to $300 million of common stock from time to time in at-the-market offerings under the prospectus included therein and in accordance with the Sales Agency Agreement, dated May 8, 2019, between the Company and BNY Mellon Capital Markets, LLC.

[15] On December 2, 2020, Southwest Gas Holdings, Inc. filed with the SEC an automatic shelf registration statement on Form S-3 (File No. 333-251074), which became effective upon filing, and included, among other registered securities, for the offer and sale of up to $500 million of common stock from time to time in at-the-market offerings under the prospectus included therein. On April 8, 2021, Southwest Gas Holdings, Inc. entered into a Sales Agency Agreement, with BNY Mellon Capital Markets, LLC and J.P. Morgan Securities LLC.

I also considered *Value Line's* projected capital structures for the Utility Proxy Group for 2023-2025. That analysis shows a range of projected common equity ratios between 39.50% and 60.00%.

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 42.10% to 59.68% for fiscal year end 2020 and 42.46% to 58.22% for the five-quarter average ending March 31, 2021.

Q. 30 Is the Company's proposed common equity ratio of 51.00% appropriate for ratemaking purposes?

A. 30 Yes, it is. The Company's proposed common equity ratio of 51.00% is appropriate for ratemaking purposes in the current proceeding because it represents the common equity ratio the Company is projected to obtain while rates from this proceeding will be in effect.[16] It also aligns with 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 for the benefit of all of its stakeholders, including Nevada customers.

[16] The Company's 2021-2023 Three-Year Plan projects achieving a common equity ratio of approximately 51% in 2023.

VI. ENBEDDED COST OF DEBT

Q. 31 Have you determined the appropriate projected cost rate for debt capital for the certification period?

A. 31 Yes. An overall embedded cost of debt of 3.11% for the Southern Nevada rate jurisdiction and 3.61% 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, 2021.

Q. 32 Please describe the development of the cost rates of debentures and notes.

A. 32 The Company will have nine outstanding debenture and note issues totaling $2.350 billion of gross principal at the end of the certification period (November 30, 2021). The debentures and notes have a weighted average cost of 4.03% as shown on line 10, column (e), of Schedule F-1, Sheet 3 of 12.

Q. 33 Please describe the cost rate of the medium-term notes.

A. 33 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 expects to have three remaining outstanding medium-term note issues totaling $57.5 million of gross principal at November 30, 2021. The medium-term notes had a weighted average effective cost of 7.79% as shown on line 14, column (e), of Schedule F-1, Sheet 3 of 12.

Q. 34 Please describe and discuss the cost of unamortized loss on reacquired debt.

A. 34 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, ($3,752,316) as shown on line 15, column (f) and column (d), of Schedule F-1, Sheet 3 of 12.

Q. 35 Please describe and discuss the amortization of the gains and losses on the retirement of fixed-rate Clark County IDRBs.

A. 35 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 26, column (f), of Schedule F-1, Sheet 3 of 12.

Q. 36 Please describe and discuss development of the cost of the variable-rate IDRBs for Southern Nevada.

A. 36 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 1.04% as shown on line 31, 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. 37 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. 37 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. 38 How have Southwest Gas' regulatory bodies treated the cost of IDRBs in past regulatory proceedings?

A. 38 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. 39 Please describe and discuss the development of the cost rate for the variable-rate term facility debt.

A. 39 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 London Interbank Offered Rate (LIBOR) 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 LIBOR 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 1.00% as shown on line 1, column (c), of Schedule F-1, Sheet 7 of 12, based on the expectation of having approximately $150 million in outstanding LIBOR loans.

Q. 40 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. 40 As discussed previously, $250 million of the revolving credit bank facility is classified as short-term debt. Additionally, in March of 2021, the Company established a $250 million, 364-day Term Loan facility which is classified as short-term debt. At the end of the test period, the Company had $285 million of short-term debt outstanding ($250 million of Term Loan debt and $35 million of revolving credit bank facility). For the certification period, the Company anticipates having $309 million in 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 $211 million, with an effective cost rate of 1.11% as shown on line 1, column (c), of Schedule F-1, Sheet 9 of 12.

Q. 41 Please describe and discuss the development of the cost of customer deposits.

A. 41 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, 2021) is 0.035% as shown on line 3 of Statement F, Sheet 1 of 4. The 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, 2021, effective for the period July 1 to December 31, 2021. The customer deposit balances and costs by state regulatory jurisdiction are displayed on Schedule F-1, Sheet 11 of 12.

Q. 42 Please explain how the overall cost of debt specific to the Southern Nevada jurisdiction was derived.

A. 42 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 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 = Debt to Capital Ratio X Southern Nevada Rate Base

  = 49.00% X $1,541,455,182

  = $755,313,039

- 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	$15,676,004
Clark County Variable-Rate IDRBs	$145,382,598
Clark County Fixed-Rate IDRBs	$1,841,824
= Total Jurisdictional Allocated Debt	$162,900,426

- 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	$755,313,039
Less Jurisdiction-Specific Debt	$162,900,426
= Other Debt	$592,412,613

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

A. 43 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 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 = Debt to Capital Ratio X Northern Nevada Rate Base

= 49.00% X $187,778,659

= $92,011,543

- 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	$ 3,152,577

- 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	$ 92,115,543
Less Jurisdiction-Specific Debt	$ 3,152,577
= Other Debt	$ 88,858,966

- 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. 44 Please provide an overview of the VIER mechanism.

A. 44 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.[17] 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.

Q. 45 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, 2021.

A. 45 For the certification period ended November 30, 2021, the projected 12-month weighted AVIR for the Clark County variable rate IDRBs was 0.0981%. The calculation of the estimated new AVIR is as follows:

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

X Embedded Cost of Clark County Variable Rate IDRB

= ($145,382,598/$1,541,455,182) X 1.04%

= 0.0981%

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 1.04% for the certification period ended November 30, 2021. The AVIR will be updated in the Company's certification filing.

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

Q. 46 Please summarize your recommendations regarding capital structure and debt cost rates.

A. 46 I recommend the use of the Company's target capital structure consisting of 49.00% debt and 51.00% common equity at embedded debt cost rates of 3.11% and 3.61% for the Southern and Northern rate jurisdictions, respectively.

<u>VII. COMMON EQUITY COST RATE</u>

Q. 47 Is it important that cost of common equity models be market based?

A. 47 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. 48 Are your cost of common equity models market based?

A. 48 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. 49 What analytical approaches did you use to determine the Company's ROE?

A. 49 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. 50 Has the PUCN recognized the importance of considering multiple cost of common equity models in arriving at an ROE recommendation?

A. 50 Yes. For example, in the order in Southwest Gas' most recent 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).[18]

A. Discounted Cash Flow Model

Q. 51 What is the theoretical basis of the DCF model?

A. 51 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 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. 52 Which version of the DCF model did you use?

A. 52 I used the single-stage constant growth DCF model in my analyses.

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[18] *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.

Q. 53 Please describe the dividend yield you used in applying the constant growth DCF model.

A. 53 The unadjusted dividend yields are based on the proxy companies' dividends as of July 30, 2021, divided by the average closing market price for the 60 trading days ended July 30, 2021.[19]

Q. 54 Please explain your adjustment to the dividend yield.

A. 54 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 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-3) have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

Q. 55 Please explain the basis for the growth rates you apply to the Utility Proxy Group in your constant growth DCF model.

A. 55 Investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, Yahoo! Finance, and Bloomberg. Investors realize that analysts have significant insight into the dynamics of the industries and individual

[19] *See,* Column 1, page 1 of Exhibit No.___(DWD-3).

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. 56 Please summarize the constant growth DCF model results.

A. 56 As shown on page 1 of Exhibit No.___(DWD-3), for the Utility Proxy Group, the mean result of applying the single-stage DCF model is 9.65%, the median result is 9.53%, and the average of the two is 9.59%. 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. 57 Please describe the theoretical basis of the RPM.

A. 57 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. 58 Please explain how you derived your indicated cost of common equity based on the RPM.

A. 58 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. 59 Please explain the PRPM

A. 59 The PRPM, published in the *Journal of Regulatory Economics*,[20] 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.[21] 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

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[20] 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.
[21] Autoregressive conditional heteroscedasticity; *see also* www.nobelprize.org.

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 July 2021. Using a generalized form of ARCH, 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[22] and a GARCH coefficient.[23] Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[24] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 2.74%[25] 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*).[26] The mean PRPM indicated common equity cost rate for the Utility Proxy Group is 10.92%, the median is 10.94%, and the average of the two is 10.93%. Consistent with my reliance on the average of the median and mean results of the DCF

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[22] Illustrated on Columns 1 and 2, page 2 of Exhibit No.___(DWD-4).
[23] Illustrated on Column 4, page 2 of Exhibit No.___(DWD-4).
[24] Annualized Return = (1 + Monthly Return) ^12 - 1.
[25] *See,* Column 6, page 2 of Exhibit No.___(DWD-4).
[26] *See,* Blue Chip Financial Forecasts, August 3, 2021 at page 2; June 1, 2021 at page 14.

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 10.93%.

Q. 60 Please explain the total market approach RPM.

A. 60 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. 61 Please explain the basis of the expected bond yield of 3.90% applicable to the Utility Proxy Group.

A. 61 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 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the fourth calendar quarter of 2022, and *Blue Chip's* long-term projections for 2023 to 2027, and 2028 to 2032. As shown on line 1, page 3 of Exhibit No.___(DWD-4), the average expected yield on Moody's Aaa-rated corporate bonds is 3.48%. 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 0.38%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[27] Adding that recent 0.38% spread to the expected Aaa-rated corporate bond yield of 3.48% results in

[27] As shown on line 2 and explained in note 2, page 3 of Exhibit No.___(DWD-4).

an expected A2-rated public utility bond yield of 3.86%. Since the Utility Proxy Group's average Moody's long-term issuer rating is A2/A3, another adjustment to the expected A2-rated public utility bond is needed to reflect the difference in bond ratings. An upward adjustment of 0.04%, which represents one-sixth of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the prospective bond yield applicable to an A2/A3-rated public utility bond.[28] Adding the 0.04% to the 3.86% prospective A2-rated public utility bond yield results in a 3.90% expected bond yield applicable to the Utility Proxy Group.

Table 5: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[29]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip*)	3.48%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.38%
Adjustment to Reflect the Utility Proxy Group's Average Moody's Bond Rating of A2/A3	0.04%
Prospective Bond Yield Applicable to the Utility Proxy Group	3.90%

Q. 62 Please explain how the beta-derived equity risk premium is determined.

A. 62 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-4). 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

[28] As shown on line 4 and explained in note 3, page 3 of Exhibit No.___(DWD-4).
[29] As shown on page 3 of Exhibit No.___(DWD-4).

premiums, and a Bloomberg-based equity risk premium. Each of these is described below.

Q. 63 How did you derive a market equity risk premium based on long-term historical data?

A. 63 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 2021 (SBBI - 2021)[30] less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2020. 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 11.94% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 6.02%.[31] As shown on line 1, page 8 of Exhibit No.___(DWD-4), subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.92%.

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 - 2021.[32] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide

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[30] *See,* SBBI-2021 Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2020.
[31] As explained in note 1, page 9 of Exhibit No.___(DWD-4).
[32] *See,* SBBI - 2021, at 10-22 and 10-23.

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

A. 64 To derive the regression-based market equity risk premium of 8.79% shown on line 2, page 8 of Exhibit No.___(DWD-4), 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 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. 65 Please explain the derivation of the PRPM equity risk premium.

A. 65 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 July 2021.[33] 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 8.16%.[34]

Q. 66 Please explain the derivation of a projected equity risk premium based on *Value Line* data for your RPM analysis.

A. 66 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-4). 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 30, 2021, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line* (Standard Edition).[35]

The average median expected price appreciation is 28%, which translates to a 6.78% annual appreciation, and when added to the average of *Value Line's* median expected dividend yields of 1.73%, equates to a forecasted annual total return rate on the market of 8.51%. The forecasted Moody's Aaa-rated corporate bond yield of 3.48% is deducted from the total market return of 8.51%, resulting in an equity risk premium of 5.03%, as shown on line 4, page 8 of Exhibit No.___(DWD-4).

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[33] Data from January 1926 to December 2020 is from SBBI - 2021. Data from January 2021 to July 2021 is from Bloomberg.
[34] Shown on line 3, page 8 of Exhibit No.___(DWD-4).
[35] As explained in detail in note 1, page 2 of Exhibit No.___(DWD-5).

Q. 67 Please explain the derivation of an equity risk premium based on the S&P 500 companies.

A. 67 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 14.68%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.48% results in an 11.20% projected equity risk premium.

Q. 68 Please explain the derivation of an equity risk premium based on Bloomberg Data.

A. 68 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 16.56%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.48% results in a 13.08% projected equity risk premium.

Q. 69 What is your conclusion of a beta-derived equity risk premium for use in your RPM analysis?

A. 69 I gave equal weight to all six equity risk premiums based on each source – historical, *Value Line*, and Bloomberg – in arriving at an 8.70% equity risk premium.

Table 6: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[36]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa-Rated Corporate Bond Yields (1928 – 2020)	5.92%
Regression Analysis on Historical Data	8.79%
PRPM Analysis on Historical Data	8.16%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	5.03%
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	11.20%
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	13.08%
Average	8.70%

After calculating the average market equity risk premium of 8.70%, 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-5), the average of the mean and median beta for the Utility Proxy Group is 0.93. Multiplying the 0.93 average beta by the market equity risk premium of 8.70% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 8.09%.

[36] As shown on page 8 of Exhibit No.___(DWD-4).

Q. 70 How did you derive the equity risk premium based on the S&P Utility Index and Moody's A2-rated public utility bonds?

A. 70 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 10.65% and monthly Moody's A2-rated public utility bond yields of 6.49% from 1928 to 2020, to arrive at an equity risk premium of 4.16%.[37] I then used the same historical data to derive an equity risk premium of 6.45% 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 July 2021 to arrive at a PRPM-derived equity risk premium of 5.04% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 11.23% and 9.24% using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 3.86%,[38] which resulted in equity risk premiums of 7.37% and 5.38%, respectively. As with the market equity risk premiums, I averaged each risk premium based on each source (*i.e.*, historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 5.68%.

[37] As shown on line 1, page 12 of Exhibit No.___(DWD-4).
[38] Derived on line 3, page 3 of Exhibit No.___(DWD-4).

Table 7: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[39]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2020)	4.16%
Regression Analysis on Historical Data	6.45%
PRPM Analysis on Historical Data	5.04%
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	7.37%
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	5.38%
Average	5.68%

Q. 71 How did you derive an equity risk premium of 5.64% based on authorized ROEs for natural gas distribution utilities?

A. 71 The equity risk premium of 5.69% shown on line 3, page 7 of Exhibit No.___(DWD-4) 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-4) which contains the graphical results of a regression analysis of 800 rate cases for natural gas distribution utilities, which were fully litigated during the period from January 1, 1980 through July 30, 2021. 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

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[39] As shown on page 12 of Exhibit No.___(DWD-4).

financial literature on the subject.[40] 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 3.86%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 5.69%, which is shown on line 3, page 7 of Exhibit No.___(DWD-4).

Q. 72 What is your conclusion of an equity risk premium for use in your total market approach RPM analysis?

A. 72 The equity risk premium I apply to the Utility Proxy Group is 6.49%, 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 8.09%, 5.68%, and 5.69%, respectively.[41]

Q. 73 What is the indicated RPM common equity cost rate based on the total market approach?

A. 73 As shown on line 7, page 3 of Exhibit DWD-3, and shown on Table 8, below, I calculated a common equity cost rate of 10.39% for the Utility Proxy Group based on the total market approach RPM.

Table 8: Summary of the Total Market Return Risk Premium Model[42]

Prospective Moody's A2/A3-Rated Utility Bond Applicable to the Utility Proxy Group	3.90%
Prospective Equity Risk Premium	6.49%
Indicated Cost of Common Equity	10.39%

[40] *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.
[41] As shown on page 7 of Exhibit No.___(DWD-4).
[42] As shown on page 3 of Exhibit No.___(DWD-4).

Q. 74 What are the results of your application of the PRPM and the total market approach RPM?

A. 74 As shown on page 1 of Exhibit No.___(DWD-4), the indicated RPM-derived common equity cost rate is 10.66%, which gives equal weight to the PRPM (10.93%) and the adjusted-market approach results (10.39%).

C. The Capital Asset Pricing Model

Q. 75 Please explain the theoretical basis of the CAPM.

A. 75 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

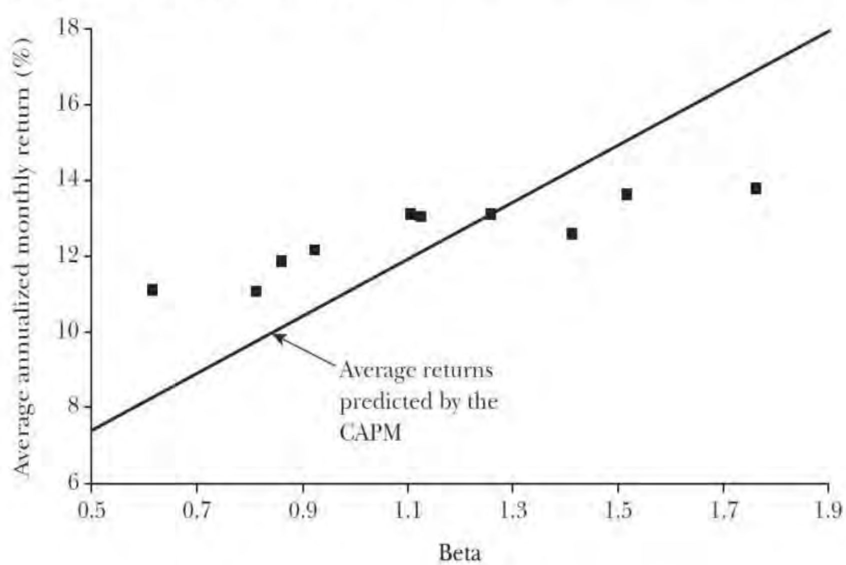
β = Adjusted beta (volatility of the security relative to the market as a whole)

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.[43]

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."[44]

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



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[43] Morin, at page 175.

[44] 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.[45]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = RF + x\,(RM - RF) + (1\text{-}x)\ \beta(RM - RF)$$
>
> 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:
>
> $$K = RF + 0.25(RM - RF) + 0.75\ \beta(RM - RF)$$[46]

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).[47]

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.[48]

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[45] Morin, at 175.
[46] Morin, at 190.
[47] Fama & French, at 32.
[48] 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. 76 What betas did you use in your CAPM analysis?

A. 76 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. 77 Please describe your selection of a risk-free rate of return.

A. 77 As shown in Column 5, page 1 of Exhibit No.___(DWD-5), the risk-free rate adopted for both applications of the CAPM is 2.74%. 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 2022, and long-term projections for the years 2023 to 2027, and 2028 to 2032.

Q. 78 Why is the yield on long-term U.S. Treasury bonds appropriate for use as the risk-free rate?

A. 78 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. 79 Please explain the estimation of the expected risk premium for the market used in your CAPM analyses.

A. 79 The basis of the market risk premium is explained in detail in note 1 on Exhibit No.___(DWD-5). 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 5.05% was deducted from the SBBI - 2021 monthly historical total market return of 12.20%, which results in an historical market equity risk premium of 7.15%.[49] 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 - 2021. That regression analysis yielded a market equity risk premium of 9.53%. The PRPM market equity risk premium is 9.08%, and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through July 2021.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 2.74%, discussed above, from the *Value Line* projected total annual market return of 8.51%, resulting in a forecasted total market equity risk premium of 5.77%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the

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[49] SBBI - 2021, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

projected risk-free rate of 2.74% from the projected total return of the S&P 500 of 14.68%. The resulting market equity risk premium is 11.94%.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 2.74% from the projected total return of the S&P 500 of 16.56%. The resulting market equity risk premium is 13.82%. These six measures, when averaged, result in an average total market equity risk premium of 9.55%.

Table 9: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[50]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2020)	7.15%
Regression Analysis on Historical Data	9.53%
PRPM Analysis on Historical Data	9.08%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	5.77%
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	11.94%
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	13.82%
Average	9.55%

Q. 80 What are the results of your application of the traditional and empirical CAPM to the Utility Proxy Group?

A. 80 As shown on page 1 of Exhibit No.___(DWD-5), the mean result of my CAPM/ECAPM analyses is 11.79%, the median is 11.62%, and the average of the

[50] As shown on page 2 of Exhibit No.___(DWD-5).

two is 11.71%. 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 11.71%.

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

Q. 81 Why do you also consider a proxy group of domestic, non-price regulated companies?

A. 81 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. 82 How did you select non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. 82 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 43 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 and similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. 83 Have you prepared an exhibit which shows the data from which you selected the 43 domestic, non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. 83 Yes, the basis of my selection and both proxy groups' regression statistics are shown in Exhibit No.___(DWD-6).

Q. 84 Did you calculate common equity cost rates using the DCF model, RPM, and CAPM for the non-price regulated proxy group?

A. 84 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-7) 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 13.38%.

Pages 3 through 5 of Exhibit No.___(DWD-7) contain the data and calculations that support the 12.49% RPM common equity cost rate. As shown on line 1, page 3 of Exhibit No.___(DWD-7), the consensus prospective yield on Moody's Baa2-rated corporate bonds for the six quarters ending in the fourth quarter of 2022, and for the years 2023 to 2027 and 2028 to 2032, is 4.31%.[51] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of Baa2, no adjustment of the projected Baa2-rated corporate bond yield is necessary to reflect a difference in ratings.

When the beta-adjusted risk premium of 8.18%[52] relative to the Non-Price Regulated Proxy Group is added to the prospective Baa2-rated corporate bond yield of 4.31%, the indicated RPM common equity cost rate is 12.49%.

Page 6 of Exhibit No.___(DWD-7) contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 11.76%.

Q. 85 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. 85 As shown on page 1 of Exhibit No.___(DWD-7), 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: 13.38% (DCF),

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[51] Blue Chip Financial Forecasts, August 3, 2021, at page 2; June 1, 2021, at page 14.
[52] Derived on page 5 of Exhibit No.___(DWD-7).

12.49% (RPM), and 11.76% (CAPM). The average of the mean and median of these models is 12.52%, 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. 86 What is the range of indicated common equity cost rates produced by your ROE models?

A. 86 The range of indicated ROEs is from 9.59% (DCF model) to 12.52% (Non-Price Regulated Market Models), which is applicable to the Utility Proxy Group. The spread between the high and low values in the range (293 basis points) indicates that there is still a fair amount of uncertainty around the recovery from the COVID-19 pandemic. 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. 87 What Company-specific business risks did you consider for your relative risk analysis?

A. 87 As detailed below, I have considered Southwest Gas' size, its regulatory environment, and its regulatory mechanisms relative to those in the Utility Proxy Group.

1. Size Comparison

Q. 88 Please compare Southwest Gas' size with that of the Utility Proxy Group.

A. 88 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	$1,548,633	
Utility Proxy Group	$3,695.963	2.4x
*From page 1 of Exhibit No.___(DWD-8).		

Southwest Gas' estimated market capitalization was $1,549 million as of July 30, 2021, compared with the market capitalization of the median company in the Utility Proxy Group of $3,696 million as of July 30, 2021. The median company in the Utility Proxy Group has a market capitalization 2.4 times the size of Southwest Gas' estimated market capitalization.

Q. 89 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. 89 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 combination of operations in each state, and that each state's operations experience the operating risks specific to their jurisdiction. The market's expectation of SWX return is commensurate with the realities of the Company's composite operations in each of the states in which it operates.

Q. 90 Does Southwest Gas' smaller size relative to the Utility Proxy Group companies increase its business risk?

A. 90 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 small 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. Duff & Phelps' 2020 Valuation Handbook – U.S. Guide to Cost of Capital (D&P – 2020) 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 Returns," D&P – 2020 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).[53]

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.[54]

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.[55] 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).[56]

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

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[53] Duff & Phelps Valuation Handbook – U.S. Guide to Cost of Capital, Wiley 2020, at 4-1.
[54] Fama & French, at 25-43.
[55] Richard A. Brealey and Steward C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.
[56] 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.

2. Regulatory Risk

Q. 91 Is the regulatory environment in which a utility operates an important consideration in determining an appropriate ROE?

A. 91 The regulatory environment is one of the most important issues considered by both debt and equity investors in assessing the risks and prospects of utility companies. Moody's finds the regulatory environment to be so important that 50.00% of the factors that weigh in the Company's ratings determination are determined by the nature of regulation.[57] Similarly, S&P has noted that:

> The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most.[58]

Q. 92 Have ratings agencies commented on Southwest Gas' regulatory environment recently?

A. 92 Yes, they have. In comments by Moody's for their rationale for the Company's downgrade in January 2021, commenting on the outcome of the Company's most recent Arizona general rate case, Moody's states:

> However, the utility's allowed return on equity (ROE) was lowered to a below-industry average 9.1% from 9.5% and equity

[57] *See,* Moody's Investors Service, *Rating Methodology; Regulated Gas and Electric Utilities*, June 23, 2017, at 4.
[58] Standard & Poor's, *Utilities: Assessing U.S. Utility Regulatory Environments*, November 15, 2011.

> capitalization was lowered to 51.1% from 51.7%, both credit negatives.[59]

Moody's also comments on the Company's last Nevada general rate case as follows:

> In September 2020, the PUCN approved a $23.5 million rate increase in Nevada based on an ROE of 9.25% and equity layer of 49.26%. The authorized ROE, unchanged from the utility's previously allowed ROE and equity layer slightly lower than the previous case of 49.66%, are below industry averages.[60]

Moreover, the Company's credit metrics have declined since the Company's last general rate case, with Fitch revising the Company's credit rating outlook to "Negative" on June 4, 2021. Fitch stated the following rationale for the change in the outlook:

> The Negative Outlook at SWG reflects expected credit metrics that are outside of stated Fitch's downgrade threshold over Fitch's forecast period following another round of rate case filings in Arizona and Nevada expected later this year. Recent rate cases decisions in both states, and in particular in Arizona, were modestly disappointing and do not provide sufficient cash flow to keep leverage below negative sensitivity threshold.
>
> Absent additional equity funding or better than projected resolution of the upcoming rate cases that would return metrics to within the stated threshold by 2023, negative rating action is likely.[61]

Q. 93 Are you aware of services that rate regulatory environments?

A. 93 Yes, I am. Regulatory Research Associates (RRA) provides an assessment of the degree to which regulatory jurisdictions are constructive, or not. As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average,

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[59] Moody's Investors Service, Ratings Action: *Moody's Downgrades Southwest Gas Corporation and Southwest Gas Holdings; outlooks stable*, January 29, 2021, p. 1.
[60] Moody's Investors Service, Credit Opinion: Southwest Gas Corporation, February 4, 2021, p.5.
[61] Fitch Ratings, *Fitch Affirms SWX and SWG at 'BBB+' and 'A-'; SWG Outlook Revised to Negative from Stable*, June 4, 2021, p. 1.

> Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate. Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger or more constructive rating from an investor viewpoint; 2, a mid-range rating; and, 3, a less constructive rating within each higher-level category. Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."[62]

UBS Securities LLC (UBS), which is a sell-side analyst that covers Southwest Gas Holdings, Inc., also ranks state regulatory jurisdictions to better evaluate differences between them for an investor viewpoint.

Moody's also assesses regulatory risk when assigning ratings to utilities they cover. Moody's is a National Recognized Statistical Rating Organization by the SEC, and is relied on by investors for their investment decisions. While Moody's provides assessments of regulatory risk for the Utility Proxy Group companies, they do not rank individual regulatory jurisdictions.

Q. 94 How does the Nevada regulatory jurisdiction rank using RRA and UBS criteria?

A. 94 According to RRA, the Nevada regulatory climate is ranked as Average/2, the midpoint of RRA's rating scale, and UBS ranks it the 50th best regulatory jurisdiction.[63]

[62] Regulatory Research Associates, *Regulatory Focus*, State Regulatory Evaluations - Energy, December 9, 2019, at 7.
[63] UBS Global Research, Gas Distribution 2021 Outlook, December 8, 2020.

Q. 95 Does UBS measure the risk of specific gas distribution utilities?

A. 95 Yes, they do. UBS ranks each regulatory jurisdiction and then weights each jurisdiction by its rate base, creating a weighted average regulatory environment for each company.

Q. 96 Did you conduct a similar study using RRA jurisdictional rankings?

A. 96 Yes, I did.

Q. 97 Did you conduct any additional comparative analyses?

A. 97 Yes, I did. I reviewed the Moody's Ratings Methodology and Scorecard Factors 1 (Regulatory Framework) and 2 (Ability to Recover Costs and Earn Returns) from credit opinions for each Utility Proxy Group Company. Regarding the importance of these factors, Moody's notes:

> For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.[64]

As noted previously, Moody's is widely respected and relied on by capital market participants. As such, I find its assessment of the Company's regulatory risk to be an important consideration for equity risk.

Q. 98 What did those analyses reveal?

A. 98 As shown on page 1 of Exhibit No.___(DWD-9), the UBS regulatory ranking study showed that the weighted average regulatory risk ranking was approximately 18

[64] Moody's Investor Service, Rating Methodology, Regulated Electric and Gas Utilities, June 23, 2017.

compared to Southwest Gas' Nevada regulatory risk ranking of 50. The RRA regulatory ranking study showed that the weighted average regulatory risk ranking was Average/3 compared to the Nevada ranking of Average/2. Finally, as shown on page 2 of Exhibit No.___(DWD-9), the Moody's regulatory ranking study showed that SWX (Moody's does not rank individual state jurisdictions) was the riskiest company in the Utility Proxy Group based on its regulatory risk.

Q. 99 What do you conclude from these relative risk studies regarding regulatory risk?

A. 99 Out of the three independent ranking services, two show that Southwest Gas is riskier than the Utility Proxy Group based on regulatory risk factors. As such, their increased relative risk should be considered when determining the ROE for the Company in this proceeding.

3. Rate Mechanisms

Q. 100 Have you also reviewed the regulatory mechanisms in place at the Company and the Utility Proxy Group as it relates to the Company's regulatory risk compared to the Utility Proxy Group?

A. 100 Yes, I have. It is important to remember that the cost of capital is a comparative exercise, so if the mechanism is common throughout the companies on which one bases their analyses, the comparative risk is zero, because any impact of the perceived reduced risk (if any) of the mechanism(s) by investors would be reflected in the market data of the proxy group. To that point, as shown on Exhibit No.___(DWD-10) every single one of the proxy companies has rate stabilization mechanisms in at least one of their jurisdictions. As such, the presence of Southwest Gas' General Revenues Adjustment (GRA) is not indicative of a reduction in risk for investors as compared to the Utility Proxy Group.

Q. 101 Are you aware of any studies that have addressed the relationship between rate stabilization mechanisms, generally, and ROE?

A. 101 Yes. I, along with Richard A. Michelfelder of Rutgers University, and my colleague at ScottMadden, Pauline M. Ahern, examined the relationship between rate stabilization mechanisms and ROE among electric, gas, and water utilities. Using the generalized consumption asset pricing model, also known as the PRPM (discussed above), we found decoupling and infrastructure rider mechanisms to have no statistically significant effect on investor perceived risk, and hence, ROE.[65]

Also, in March 2014, The Brattle Group (Brattle) published a study addressing the effect of revenue decoupling structures on the cost of capital for electric utilities.[66] In its report, which extended a prior analysis focused on natural gas distribution utilities, Brattle pointed out that although decoupling structures may affect revenues, net income still can vary. Brattle further noted that the distinction between diversifiable and non-diversifiable risk is important to equity investors, and the relationship between decoupling and ROE should be examined in that context. Further, Brattle noted that although reductions in total risk may be important to bondholders, only reductions in non-diversifiable business risk would justify a reduction to the ROE. In November 2016, the Brattle study was updated based on data through the fourth quarter of 2015.[67]

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[65] Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, The Impact of Decoupling on The Cost of Capital of Public Utilities, *Energy Policy* 130 (2019), at 311-319.
[66] The Brattle Group, The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation, Prepared for the Energy Foundation, March 20, 2014.
[67] Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang and James Hall, Effect on the Cost of Capital of Innovative Ratemaking that Relaxes the Linkage between Revenue and kWh Sales – An Updated Empirical Investigation, November 2016.

Brattle's empirical analysis examined the relationship between decoupling and the After-Tax WACC for a group of electric utilities that had implemented decoupling structures in various jurisdictions throughout the United States. As with Brattle's 2014 study, the updated study found no statistically significant link between the cost of capital and revenue decoupling structures.[68]

Q. 102 What is your conclusion regarding the Company's relative risk as compared to the Utility Proxy Group?

A. 102 In view of all of the above, the Company is smaller and riskier (as measured by regulatory risk) than the Utility Proxy Group. Since the cost of capital is a comparative exercise, and the Utility Proxy Group has decoupling mechanisms in their market data, the Company's GRA should not be considered unique or risk reducing compared to the Utility Proxy Group.

Q. 103 Is there a way to quantify a relative risk adjustment due to Southwest Gas' greater business risk when compared to the Utility Proxy Group?

A. 103 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 <u>SBBI-2021</u> 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 2020 period. The median size premium for the Utility Proxy Group with a market capitalization of $3,696 million falls in the fifth decile, while the Company's estimated market capitalization of $1,549 million places it in the seventh decile. The size premium spread between the fifth decile and the seventh decile is 0.45%. Even though an 0.45% upward size adjustment

[68] *Ibid.*

is indicated, I applied a size premium of 0.10% to the Company's indicated common equity cost rate.

B. Credit Risk Adjustment

Q. 104 Please discuss your proposed credit risk adjustment.

A. 104 Southwest Gas' long-term issuer ratings are Baa1 and A- from Moody's Investors Services 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.[69]

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/A3 is one-half of a recent three-month average spread between Moody's A2 and Baa2-rated public utility bond yields of 0.25%, shown on page 4 of Exhibit No.___(DWD-4), or 0.13%.[70]

C. Flotation Costs

Q. 105 What are flotation costs?

A. 105 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. 106 Why is it important to recognize flotation costs in the allowed common equity cost rate?

A. 106 It is important because there is no other mechanism in the ratemaking paradigm

[69] Source: S&P Global Market Intelligence.
[70] 0.13% = 0.25% * (1/2); differences due to rounding.

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 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.[71]

Q. 107 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. 107 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

[71] Morin, at p. 321.

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

A. 108 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.[72] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[73] 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. 109 How did you calculate the flotation cost allowance?

A. 109 I modified the DCF calculation to provide a dividend yield that would reimburse

[72] Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at 342.
[73] Morin, at 327-330.

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-11), an adjustment of 0.07% is required to reflect the flotation costs applicable to the Utility Proxy Group.

Q. 110 What is the indicated cost of common equity after your company-specific adjustments?

A. 110 Applying the 0.10% size adjustment, the 0.13% credit risk adjustment, and the 0.07% flotation cost adjustment to the indicated range of common equity cost rates between 9.59% and 12.52% results in a Company-specific range of common equity rates between 9.89% and 12.82%. In consideration of the wide range of potential outcomes surrounding the recovery of the economy from the COVID-19 pandemic, I conservatively recommend an ROE toward the bottom of the indicated range, or 9.90%, for Southwest Gas in this proceeding.

X. CONCLUSION

Q. 111 What is your recommended ROE for the company?

A. 111 Given the discussion above and the results from the analyses, I recommend that an ROE of 9.90% is appropriate for the Company at this time.

Q. 112 In your opinion, is your proposed ROE of 9.90% fair and reasonable to Southwest Gas and its customers?

A. 112 Yes, it is.

Q. 113 In your opinion, is Southwest Gas' proposed capital structure consisting of 49.00% long-term debt and 51.00% common equity fair and reasonable?

A. 113 Yes, it is.

Q. 114 In your opinion, is Southwest Gas' proposed costs of debt of 3.11% (Southern) and 3.61% (Northern) fair and reasonable?

A. 114 Yes, it is.

Q. 115 Does this conclude your Direct Testimony?

A. 115 Yes, it does.

APPENDIX A: FACTORS TEMPORARILY IMPACTING SOUTHWEST GAS' CAPITAL STRUCTURE

Q. 116 What factors have negatively impacted the Company's capital structure, moving it away from its target capital structure?

A. 116 The key contributing factors that have pressured the Company's capital structure and credit metrics are the Company's elevated capital expenditures, in combination with the negative cash flow impacts of tax reform and below average authorized ROEs in two of its regulatory jurisdictions.[74,75] Also impacting the capital structure was the lack of any equity issuances by SWX during the first quarter of 2020. This was due to the capital market volatility resulting from the COVID-19 pandemic, which created unfavorable conditions for SWX to issue common stock through its ESP. During the test period in this proceeding, the capital structure was negatively impacted by Winter Storm Uri in February 2021 that significantly impacted natural gas costs which resulted in higher outstanding short-term debt balances.

Southwest Gas anticipates that capital expenditures will level off at current levels over the 2021-2023 period and that the common equity ratio will improve, through retained earnings and periodic equity contributions from SWX through the proceeds of additional common stock issuances. The common equity ratio will also improve as the Company collects the purchased gas adjustment (PGA) receivable balances and pays down the short-term debt resulting from Winter Storm Uri. As of June 30, 2021, the PGA receivable balance was $235.1 million.

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[74] S&P Global Market Intelligence, RRA Regulatory Focus, *Nevada commission adopts below-average ROE for Southwest Gas*, September 30, 2020.
[75] S&P Global Market Intelligence, RRA Regulatory Focus, Ariz. regulators render decision in Southwest Gas rate case, December 10, 2020.

Q. 117 Please discuss the negative capital structure impacts from Winter Storm Uri.

A. 117 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 caused daily natural gas prices to reach unprecedented levels. During this time, the Company secured natural gas supplies, albeit at substantially higher prices, maintaining service to its customers. The incremental cost for these supplies was approximately $250 million (companywide), funded using a 364-day $250 million Bank Term Loan executed in March 2021. The incremental gas costs are expected to be collected from customers through the existing PGA mechanisms.76 The detrimental impact of this weather event on the Company's common equity ratio is estimated to be 1.5 percentage points, as absent the incremental $250 million term loan required to fund the change in the PGA balance, the projected actual common equity ratio at certification would have been 47.40% instead of 45.90%. The debt incurred due to Winter Storm Uri is transitory, in which the Company expects to repay the debt in the short to medium term, as it collects the outstanding PGA balances.

[76] Southwest Gas Holding, Inc., SEC Form 10-Q, For the quarterly period ended March 31, 2021, p. 23.

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). He has served as a consultant for investor-owned and municipal utilities and authorities for 12 years. Dylan has extensive experience in rate of return analyses, class cost of service, rate design, and valuation for regulated public utilities. He has testified as an expert witness in the subjects of rate of return, cost of service, rate design, and valuation before 30 regulatory commissions in the U.S., one Canadian province, and an American Arbitration Association panel.

He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured.

Areas of Specialization

- Regulation and Rates
- Utilities
- Mutual Fund Benchmarking
- Capital Market Risk
- Financial Modeling
- Valuation
- Regulatory Strategy
- Rate Case Support
- Rate of Return
- Cost of Service
- Rate Design

Recent Expert Testimony Submission/Appearances

Jurisdiction	***Topic***
Massachusetts Department of Public Utilities	Rate of Return
New Jersey Board of Public Utilities	Rate of Return
Hawaii Public Utilities Commission	Cost of Service, Rate Design
South Carolina Public Service Commission	Return on Common Equity
American Arbitration Association	Valuation

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- 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 Publications 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

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
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.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
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				
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
Colorado Public Utilities Commission				
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
Delaware Public Service Commission				
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	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System	09/20	Peoples Gas System	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				
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

Sponsor	Date	Case/Applicant	Docket No.	Subject
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	07/19	Atmos Energy	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
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				
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
Maryland Public Service Commission				
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	Docket No. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Rate of Return
Mississippi Public Service Commission				
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				
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.	Docket No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
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	05/21	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

Sponsor	Date	Case/Applicant	Docket No.	Subject
FirstEnergy	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
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 Company	01/21	Southwestern Public Service Company	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
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	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Docket No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
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
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

Sponsor	Date	Case/Applicant	Docket No.	Subject
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
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 Company	02/21	Southwestern Public Service Company	Docket No. 51802	Return on Equity
Southwestern Electric Power Company	10/20	Southwestern Electric Power Company	Docket No. 51415	Rate of Return
Virginia State Corporation Commission				
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

Southwest Gas Corporation
Recommended Capital Structure and Cost Rates for Ratemaking Purposes at July 30, 2021

Southern Nevada Rate Jurisdiction

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	49.00%	3.11%	(1)	1.52%
Common Equity	51.00%	9.90%	(2)	5.05%
Total	100.00%			6.57%

Northern Nevada Rate Jurisdiction

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	49.00%	3.61%	(1)	1.77%
Common Equity	51.00%	9.90%	(2)	5.05%
Total	100.00%			6.82%

(1) See page 1 of Statement F for the respective rate jurisdictions.
(2) From page 2 of this Exhibit.

Southwest Gas Corporation
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Seven Natural Gas Distribution Companies
1.	Discounted Cash Flow Model (DCF) (1)	9.59%
2.	Risk Premium Model (RPM) (2)	10.66%
3.	Capital Asset Pricing Model (CAPM) (3)	11.71%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	12.52%
5.	Range of Common Equity Model Results	9.59% - 12.52%
6.	Business Risk Adjustment (5)	0.10%
7.	Credit Risk Adjustment (6)	0.13%
8.	Flotation Cost Adjustment (7)	0.07%
9.	Indicated Range of Common Equity Cost Rates after Adjustment	9.89% - 12.82%
10.	Recommended Common Equity Cost Rate	9.90%

Notes:
(1) From page 1 of Exhibit No.___(DWD-3).
(2) From page 1 of Exhibit No.___(DWD-4).
(3) From page 1 of Exhibit No.___(DWD-5).
(4) From page 1 of Exhibit No.___(DWD-7).
(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-11).

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

Common Equity Ratio

Company	2021Q1	2020Q4	2020Q3	2020Q2	2020Q1	FY 2020	5Q average ending Q1 2021
Atmos Energy Corporation	51.67%	58.46%	59.68%	58.78%	58.19%	59.68%	57.36%
New Jersey Resources Corporation	44.02%	40.85%	43.07%	44.82%	47.54%	43.07%	44.06%
Northwest Natural Holding Company	43.99%	41.36%	41.98%	42.68%	37.48%	41.36%	41.50%
ONE Gas, Inc.	33.36%	51.91%	53.07%	53.97%	54.61%	51.91%	49.39%
South Jersey Industries, Inc.	33.77%	31.86%	32.97%	34.48%	31.46%	31.86%	32.91%
Southwest Gas Holdings, Inc.	46.90%	47.58%	47.86%	47.05%	48.49%	47.58%	47.57%
Spire Inc.	39.96%	39.18%	39.79%	41.53%	42.05%	39.79%	40.50%
					Minimum	31.86%	32.91%
					Maximum	59.68%	57.36%

Total Debt Ratio

Company	2021Q1	2020Q4	2020Q3	2020Q2	2020Q1	FY 2020	5Q average ending Q1 2021
Atmos Energy Corporation	48.33%	41.54%	40.32%	41.22%	41.81%	40.32%	42.64%
New Jersey Resources Corporation	55.98%	59.15%	56.93%	55.18%	52.46%	56.93%	55.94%
Northwest Natural Holding Company	56.01%	58.64%	58.02%	57.32%	62.52%	58.64%	58.50%
ONE Gas, Inc.	66.64%	48.09%	46.93%	46.03%	45.39%	48.09%	50.61%
South Jersey Industries, Inc.	66.23%	68.14%	67.03%	65.52%	68.54%	68.14%	67.09%
Southwest Gas Holdings, Inc.	53.10%	52.42%	52.14%	52.95%	51.51%	52.42%	52.43%
Spire Inc.	56.15%	56.78%	55.98%	54.13%	53.75%	55.98%	55.36%
					Minimum	40.32%	42.64%
					Maximum	68.14%	67.09%

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 Seven Natural Gas Distribution Companies at the Operating Company Level

Common Equity Ratio

Company	2021Q1	2020Q4	2020Q3	2020Q2	2020Q1	FY 2020	5Q average ending Q1 2021
Atmos Energy Corporation	51.67%	58.46%	59.68%	58.78%	58.19%	59.68%	57.36%
New Jersey Natural Gas Company	55.14%	53.13%	52.55%	57.16%	58.14%	52.55%	55.22%
Northwest Natural Gas Company	44.66%	42.10%	43.01%	43.96%	38.55%	42.10%	42.46%
ONE Gas, Inc.	33.36%	51.91%	53.07%	53.97%	54.61%	51.91%	49.39%
South Jersey Gas Company	56.14%	53.34%	53.77%	50.68%	50.78%	53.34%	52.95%
Southwest Gas Corporation	46.13%	46.59%	47.03%	46.44%	48.08%	46.59%	46.85%
Spire Alabama Inc.	58.12%	55.53%	57.74%	59.74%	59.98%	57.74%	58.22%
Spire Missouri Inc.	47.93%	49.45%	50.00%	51.74%	51.75%	50.00%	50.17%
					Minimum	42.10%	42.46%
					Maximum	59.68%	58.22%

Total Debt Ratio

Company	2021Q1	2020Q4	2020Q3	2020Q2	2020Q1	FY 2020	5Q average ending Q1 2021
Atmos Energy Corporation	48.33%	41.54%	40.32%	41.22%	41.81%	40.32%	42.64%
New Jersey Natural Gas Company	44.86%	46.87%	47.45%	42.84%	41.86%	47.45%	44.78%
Northwest Natural Gas Company	55.34%	57.90%	56.99%	56.04%	61.45%	57.90%	57.54%
ONE Gas, Inc.	66.64%	48.09%	46.93%	46.03%	45.39%	48.09%	50.61%
South Jersey Gas Company	43.86%	46.66%	46.23%	49.32%	49.22%	46.66%	47.05%
Southwest Gas Corporation	53.87%	53.41%	52.97%	53.56%	51.92%	53.41%	53.15%
Spire Alabama Inc.	41.88%	44.47%	42.26%	40.26%	40.02%	42.26%	41.78%
Spire Missouri Inc.	52.07%	50.55%	50.00%	48.26%	48.25%	50.00%	49.83%
					Minimum	40.32%	41.78%
					Maximum	57.90%	57.54%

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

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

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seven 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	Bloomberg'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	2.51 %	7.00 %	7.34 %	7.43 %	7.17 %	7.24 %	2.60 %	9.84 %
New Jersey Resources Corporation	3.21	2.00	7.10	7.55	6.00	5.66	3.30	8.96
Northwest Natural Holding Company	3.60	5.50	4.93	4.73	3.80	4.74	3.69	8.43
ONE Gas, Inc.	3.09	6.50	5.00	5.00	5.00	5.38	3.17	8.55
South Jersey Industries, Inc.	4.61	11.50	5.43	4.76	4.80	6.62	4.76	11.38
Southwest Gas Holdings, Inc.	3.51	9.00	5.50	5.17	4.00	5.92	3.61	9.53
Spire Inc.	3.56	10.00	5.49	6.00	7.31	7.20	3.69	10.89
							Average	9.65 %
							Median	9.53 %
							Average of Mean and Median	9.59 %

NA= Not Available
NMF= Not Meaningful Figure

Notes:
(1) Indicated dividend at 07/30/2021 divided by the average closing price of the last 60 trading days ending 07/30/2021 for each company.
(2) From pages 2 through 8 of this Exhibit.
(3) Average of columns 2 through 5 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 6) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.51% x (1+(1/2 x 7.24%)) = 2.60%.
(5) Column 6 + column 7.

Source of Information:
Value Line Investment Survey
www.zacks.com Downloaded on 07/30/2021
www.yahoo.com Downloaded on 07/30/2021
Bloomberg Professional Services

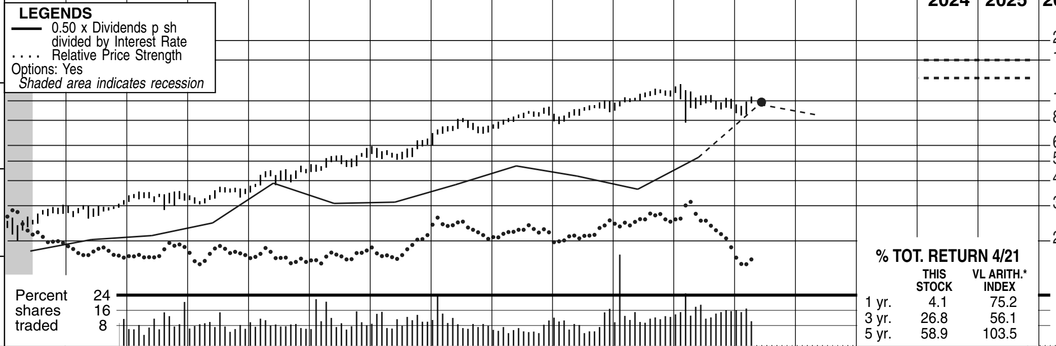
ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 98.51 | P/E RATIO 18.9 (Trailing: 18.5 Median: 19.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 3 Lowered 4/2/21
SAFETY 1 Raised 6/6/14
TECHNICAL 5 Lowered 4/9/21
BETA .80 (1.00 = Market)

High:	32.0	35.6	37.3	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.0
Low:	25.9	28.5	30.4	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6

LEGENDS
— 0.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2024 | 2025 | 2026
200 / 160 / 100 / 80 / 60 / 50 / 40 / 30 / 20

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$75-$159	$117 (20%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+60%)	15%
Low	130	(+30%)	10%

Institutional Decisions

	2Q2020	3Q2020	4Q2020
to Buy	233	256	280
to Sell	262	231	228
Hld's(000)	108597	108898	107949

Percent shares traded 24 / 16 / 8

% TOT. RETURN 4/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.1	75.2
3 yr.	26.8	56.1
5 yr.	58.9	103.5

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
61.75	75.27	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	*24.50*	*25.05*	Revenues per sh A	*35.50*
3.90	4.26	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	*8.55*	*9.10*	"Cash Flow" per sh	*10.25*
1.72	2.00	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	*5.10*	*5.45*	Earnings per sh AB	*6.50*
1.24	1.26	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*	*2.70*	Div'ds Decl'd per sh C■	*3.30*
4.14	5.20	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	*15.80*	*15.75*	Cap'l Spending per sh	*15.15*
19.90	20.16	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	*62.15*	*70.25*	Book Value per sh	*87.85*
80.54	81.74	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	*133.00*	*137.00*	Common Shs Outst'g D	*155.00*
16.1	13.5	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	*Bold figures are*		Avg Ann'l P/E Ratio	*22.5*
.86	.73	.84	.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.13	*Value Line*		Relative P/E Ratio	*1.25*
4.5%	4.7%	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%	*estimates*		Avg Ann'l Div'd Yield	*2.3%*

CAPITAL STRUCTURE as of 3/31/21
Total Debt $7316.6 mill. **Due in 5 Yrs** $410.0 mill.
LT Debt $7316.4 mill. **LT Interest** $370.0 mill.
(LT interest earned: 9.5x; total interest coverage: 9.5x)
Leases, Uncapitalized Annual rentals $20.4 mill.

Pfd Stock None

Pension Assets-9/20 $528.9 mill.
Oblig. $604.2 mill.
Common Stock 130,671,944 shs.
as of 4/30/21

MARKET CAP: $12.9 billion (Large Cap)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
4347.6	3438.5	3886.3	4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	*3260*	*3430*	Revenues ($mill) A	*5500*
199.3	192.2	230.7	289.8	315.1	350.1	382.7	444.3	511.4	580.5	*665*	*735*	Net Profit ($mill)	*1000*
36.4%	33.8%	38.2%	39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	*20.5%*	*21.5%*	Income Tax Rate	*25.0%*
4.6%	5.6%	5.9%	5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	*20.4%*	*21.4%*	Net Profit Margin	*18.2%*
49.4%	45.3%	48.8%	44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	*48.0%*	*45.0%*	Long-Term Debt Ratio	*40.0%*
50.6%	54.7%	51.2%	55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	*52.0%*	*55.0%*	Common Equity Ratio	*60.0%*
4461.5	4315.5	5036.1	5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	*15900*	*17500*	Total Capital ($mill)	*22700*
5147.9	5475.6	6030.7	6725.9	7430.6	8280.5	9259.2	10371	11788	13355	*14500*	*15650*	Net Plant ($mill)	*19100*
6.1%	6.1%	5.9%	6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.6%	*8.0%*	*7.5%*	Return on Shr. Equity	*7.5%*
8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.6%	*8.0%*	*7.5%*	Return on Com Equity	*7.5%*
3.3%	2.8%	4.0%	4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	*4.0%*	*4.0%*	Retained to Com Eq	*3.5%*
62%	65%	56%	50%	51%	50%	50%	48%	48%	49%	*50%*	*50%*	All Div'ds to Net Prof	*51%*

CURRENT POSITION ($MILL.)	2019	2020	3/31/21
Cash Assets	24.5	20.8	865.3
Other	433.5	450.5	755.1
Current Assets	458.0	471.3	1620.4
Accts Payable	265.0	235.8	263.6
Debt Due	464.9	.2	.2
Other	479.5	546.4	607.5
Current Liab.	1209.4	782.4	871.3
Fix. Chg. Cov.	990%	1306%	1320%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	-8.5%	-11.0%	*6.0%*
"Cash Flow"	5.5%	7.0%	*5.0%*
Earnings	8.0%	9.0%	*7.0%*
Dividends	5.0%	7.5%	*7.5%*
Book Value	7.5%	10.0%	*10.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	889.2	1219.4	562.2	444.7	3115.5
2019	877.8	1094.6	485.7	443.7	2901.8
2020	875.6	977.6	493.0	474.9	2821.1
2021	914.5	1319.1	*525.9*	*500.5*	*3260*
2022	*960*	*1405*	*545*	*520*	*3430*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	1.40	1.57	.64	.41	4.00
2019	1.38	1.82	.68	.49	4.35
2020	1.47	1.95	.79	.53	4.72
2021	1.71	2.30	*.67*	*.42*	*5.10*
2022	*1.82*	*2.27*	*.80*	*.56*	*5.45*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.45	.45	.45	.485	1.84
2018	.485	.485	.485	.525	1.98
2019	.525	.525	.525	.575	2.15
2020	.575	.575	.575	.625	2.35
2021	.625	.625			

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 2020: 68.6%, residential; 26.2%, commercial; 3.6%, industrial; and 1.6% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately 1.2% of common stock (12/20 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.

Atmos Energy shined during the first half of fiscal 2021 (which concludes on September 30th). Earnings per share jumped 17%, to $4.01, relative to the previous-year total of $3.42. One contributor was the natural gas distribution unit, which benefited from higher rates, primarily in the Mid-Tex, Mississippi, Louisiana, and West Texas divisions. Customer growth, mainly in the Mid-Tex unit, and a decrease in operating expenses also helped. Meanwhile, the performance of the pipeline and storage business got a lift from a GRIP filing approved in May, 2020 plus diminished system maintenance costs. Although the coronavirus has not gone away, full-year profits might increase around 8%, to $5.10 a share, compared to last year's $4.72 figure. Regarding fiscal 2022, we look for share net to rise at a similar percentage rate, to $5.45, assuming that operating margins widen further.

A powerful storm hit the service area, particularly Texas, in February. Consequently, the company experienced unprecedented market pricing for natural gas costs, resulting in total gas purchases during that month of $2.3 billion. To help pay for those expenses, it issued $2.2 billion in long-term debt. Leadership adds that it is working with regulators to recover these costs. Even though finances are now more leveraged, we believe these actions make sense.

Good things appear to be in store over the 2024-2026 time frame. Atmos ranks as one of the country's largest natural gas-only distributors, boasting more than three million customers across several states, including Texas, Louisiana, and Mississippi. Furthermore, it appears that the pipeline and storage unit has promising overall expansion opportunities, since it operates in one of the most-active drilling regions in the world. Finally, the balance sheet remains adequate. In the company's present configuration, annual earnings advances might be between 6% and 8% during the 3- to 5-year period.

The stock holds decent, risk-adjusted total return potential. Long-term capital appreciation possibilities are solid, even after taking recent price strength into account. Consider, too, the healthy dividend growth prospects.

Frederick L. Harris, III *May 28, 2021*

(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 egs. rpt. 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	90
Earnings Predictability	100

NEW JERSEY RES. NYSE-NJR

RECENT PRICE **42.59** | P/E RATIO **19.4** (Trailing: 15.5 Median: 17.0) | RELATIVE P/E RATIO **0.89** | DIV'D YLD **3.1%** | VALUE LINE

TIMELINESS 3 Raised 5/21/21
SAFETY 2 Lowered 4/17/20
TECHNICAL 3 Raised 4/16/21
BETA 1.00 (1.00 = Market)

High:	22.0	25.2	25.1	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	43.9
Low:	16.7	19.8	19.3	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3

Target Price Range
2024 | 2025 | 2026

18-Month Target Price Range

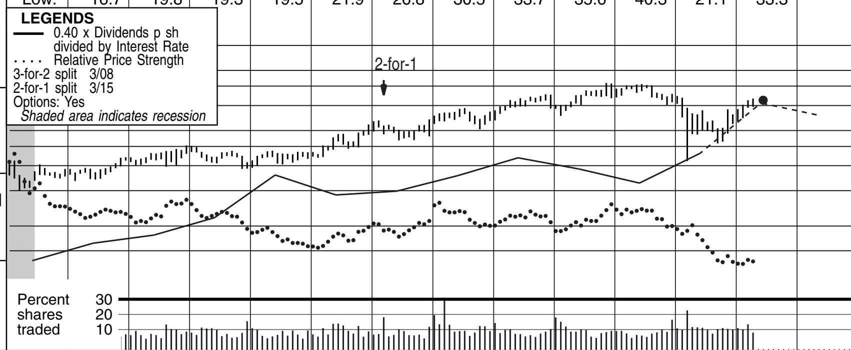
Low-High	Midpoint (% to Mid)
$16-$52	$34 (-20%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	7%
Low	35	(-20%)	-1%

Institutional Decisions

	2Q2020	3Q2020	4Q2020
to Buy	139	129	132
to Sell	97	105	118
Hld's(000)	67573	69155	71013



% TOT. RETURN 4/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	29.2	75.2
3 yr.	11.6	56.1
5 yr.	36.4	103.5

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
38.10	39.81	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	**24.75**	**26.55**	Revenues per sh A	**28.40**
1.31	1.37	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	**3.45**	**3.75**	"Cash Flow" per sh	**4.00**
.88	.93	.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	**2.15**	**2.40**	Earnings per sh B	**2.55**
.45	.48	.51	.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	**1.34**	**1.42**	Div'ds Decl'd per sh C ■	**1.65**
.64	.64	.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	**4.10**	**4.10**	Cap'l Spending per sh	**4.00**
5.30	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	**20.30**	**21.50**	Book Value per sh D	**24.60**
82.64	82.88	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	**97.00**	**98.00**	Common Shs Outst'g E	**100.00**
16.8	16.1	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	*Bold figures are*		Avg Ann'l P/E Ratio	**17.0**
.89	.87	1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	*Value Line*		Relative P/E Ratio	**.95**
3.1%	3.2%	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%	*estimates*		Avg Ann'l Div'd Yield	**3.7%**

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
3009.2	2248.9	3198.1	3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	**2400**	**2600**	Revenues ($mill) A	**2840**
106.5	112.4	113.7	176.9	153.7	138.1	149.4	240.5	175.0	196.2	**210**	**235**	Net Profit ($mill)	**260**
30.2%	7.1%	25.4%	30.2%	26.3%	15.5%	17.2%	- -	NMF	5.0%	**5.0%**	**5.0%**	Income Tax Rate	**5.0%**
3.5%	5.0%	3.6%	4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	**8.7%**	**9.1%**	Net Profit Margin	**9.1%**
35.5%	39.2%	36.6%	38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	**54.0%**	**54.5%**	Long-Term Debt Ratio	**53.0%**
64.5%	60.8%	63.4%	61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	**46.0%**	**45.5%**	Common Equity Ratio	**47.0%**
1203.1	1339.0	1400.3	1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	**4270**	**4605**	Total Capital ($mill)	**5260**
1295.9	1484.9	1643.1	1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	**4065**	**4145**	Net Plant ($mill)	**4400**
9.7%	9.2%	9.0%	12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.0%**
13.7%	13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	**10.5%**	**11.0%**	Return on Shr. Equity	**10.5%**
13.7%	13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	**10.5%**	**11.0%**	Return on Com Equity	**10.5%**
6.2%	6.2%	5.2%	11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	**4.0%**	**4.5%**	Retained to Com Eq	**3.5%**
55%	55%	59%	40%	50%	60%	59%	40%	59%	60%	**62%**	**59%**	All Div'ds to Net Prof	**64%**

CAPITAL STRUCTURE as of 3/31/21
Total Debt $2296.3 mill. **Due in 5 Yrs** $420.5 mill.
LT Debt $2265.2 mill. **LT Interest** $47.1 mill.
Incl. $54.9 mill. capitalized leases.
(LT interest earned: 5.0x; total interest coverage: 5.0x)
Pension Assets-9/20 $404.4 mill.
Oblig. $643.0 mill.
Pfd Stock None

Common Stock 96,339,849 shs.
as of 5/3/21
MARKET CAP: $4.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	3/31/21
Cash Assets	2.7	117.0	57.7
Other	508.9	505.3	477.5
Current Assets	511.6	622.3	535.2
Accts Payable	295.9	270.1	288.2
Debt Due	46.9	152.6	31.1
Other	103.6	111.0	96.8
Current Liab.	446.4	533.7	416.1
Fix. Chg. Cov.	545%	545%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	-2.5%	-6.5%	*.5%*
"Cash Flow"	7.0%	7.0%	*3.0%*
Earnings	6.0%	5.5%	*2.0%*
Dividends	7.0%	6.5%	*5.5%*
Book Value	7.5%	8.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	705.3	1019.1	543.4	647.3	2915.1
2019	811.8	866.2	434.9	479.1	2592.0
2020	615.0	639.6	299.0	400.1	1953.7
2021	454.3	802.2	***525***	***618.5***	***2400***
2022	***505***	***850***	***575***	***670***	***2600***

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	1.53	1.61	d.09	d.33	2.72
2019	.61	1.27	d.20	.29	1.96
2020	.44	1.12	d.06	.57	2.07
2021	.46	1.77	***d.20***	***.12***	***2.15***
2022	***.50***	***1.85***	***d.13***	***.18***	***2.40***

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.255	.255	.255	.273	1.04
2018	.273	.273	.273	.2925	1.11
2019	.2925	.2925	.2925	.3125	1.19
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325			

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 558,000 cust. at 9/30/20. Fiscal 2020 volume: 215 bill. cu. ft. (14% interruptible, 21% res., 10% commercial & elec. utility, 55% capacity release programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2020 dep. rate: 2.8%. Has 1,156 empls. Off./dir. own 1.3% of common; BlackRock, 14.3%; Vanguard, 10.6% (12/20 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.

Since our February review, shares of New Jersey Resources have advanced nicely. The company's stock price increased about 15% over that time frame. This uptick likely reflected the better-than-expected financial results, of late.

The retailer and wholesaler of energy services posted solid results for the March quarter. To that point, revenues increased 25.4%, to $802.2 million, thanks to double-digit gains of nonutility volumes of nearly 44% and to a lesser extent a 4% rise in utility volumes. Meanwhile, on the profitability front, overall expenses fell 970 basis points, as a percentage of the top line. All told, these factors drove the bottom line 58% higher, to $1.77 per share. This was markedly better than our call for earnings of $0.90.

We have raised our fiscal 2021 (ends September 30th) share-net estimate by $0.50, bringing that figure to $2.15. Our revised figure would represent a year-over-year gain of about 4%, and falls at the top end of management's recently increased guidance range of $2.05 to $2.15. The primary driver of this year's results will largely be the Energy Services division that has been able to take advantage of the increased volatility affecting commodity prices these days. At the same time, the New Jersey Natural Gas (NJNG) regulated utility segment has added roughly 3,700 new customer accounts in the first six months of this year. Combined, we look for New Jersey Resources annual revenues to advance more than 20% this year, to $2.4 billion. That said, the industry's operating environment has been experiencing elevated uncertainty due to the COVID-19 pandemic; volatility surrounding commodity prices; a slump in end-user demand; and now fossil fuels transportation factors.

We look for this steady momentum to continue into next year, as well. The NJNG unit is on pace to add 28,000-30,000 new customers from 2021-2023. At the same time, the regulated utility business filed for a base rate case increase of about $165 million, which would help to return some of its investments in capital expansion projects.

Steady dividend growth aside, these shares appear richly valued.

Bryan J. Fong *May 28, 2021*

(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 Aug.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2020: $527.5 million, $5.51/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	80
Price Growth Persistence	60
Earnings Predictability	55

N.W. NATURAL NYSE-NWN

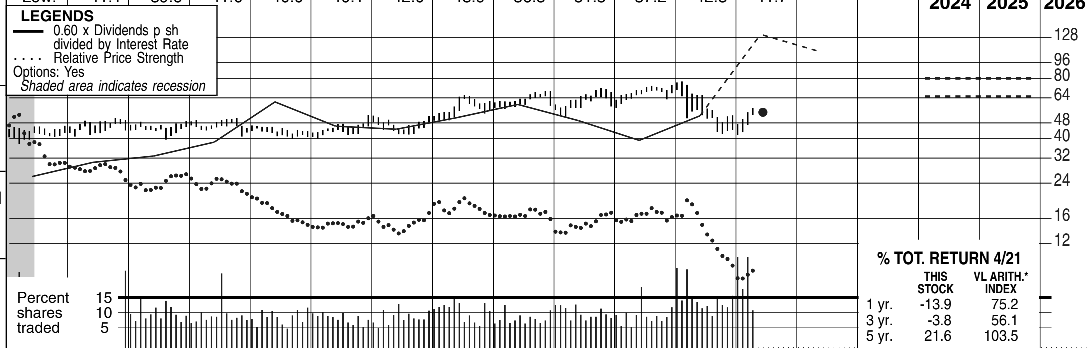
RECENT PRICE 54.22 | P/E RATIO 21.3 (Trailing: 20.4 Median: 24.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS	3	Raised 11/20/20
SAFETY	3	Lowered 3/19/21
TECHNICAL	4	Raised 5/7/21

BETA .85 (1.00 = Market)

High:	50.9	49.0	50.8	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8
Low:	41.1	39.6	41.0	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7

LEGENDS
— 0.60 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2024 | 2025 | 2026

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$27-$71	$49 (-10%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+65%)	15%
Low	60	(+10%)	6%

Institutional Decisions

	2Q2020	3Q2020	4Q2020
to Buy	73	92	99
to Sell	103	94	85
Hld's(000)	21936	21896	22201

Percent shares traded 15 10 5

% TOT. RETURN 4/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-13.9	75.2
3 yr.	-3.8	56.1
5 yr.	21.6	103.5

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
33.01	37.20	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	26.80	27.80	Revenues per sh	31.05
4.34	4.76	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	5.80	6.05	"Cash Flow" per sh	6.85
2.11	2.35	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	2.55	2.65	Earnings per sh A	3.10
1.32	1.39	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	Div'ds Decl'd per sh B■	1.96
3.48	3.56	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	8.40	8.70	Cap'l Spending per sh	9.40
21.28	22.01	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	33.85	37.10	Book Value per sh D	45.30
27.58	27.24	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	31.00	31.00	Common Shs Outst'g C	32.00
17.0	15.9	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	Bold figures are		Avg Ann'l P/E Ratio	24.0
.91	.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.30	Value Line		Relative P/E Ratio	1.35
3.7%	3.7%	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%	estimates		Avg Ann'l Div'd Yield	2.6%

CAPITAL STRUCTURE as of 3/31/21
Total Debt $1192.2 mill. **Due in 5 Yrs** $360.2 mill.
LT Debt $860.7 mill. **LT Interest** $43.1 mill.

(Total interest coverage: 3.1x)

Pension Assets-12/20 $373.9 mill.
Oblig. $595.2 mill.

Pfd Stock None

Common Stock 30,656,006 shares
as of 4/26/21

MARKET CAP $1.7 billion (Mid Cap)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
848.8	730.6	758.5	754.0	723.8	676.0	762.2	706.1	746.4	773.7	830	860	Revenues ($mill)	995
63.9	59.9	60.5	58.7	53.7	58.9	d55.6	67.3	65.3	70.3	79.0	82.0	Net Profit ($mill)	120
40.4%	42.4%	40.8%	41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	21.0%	21.0%	Income Tax Rate	21.0%
7.5%	8.2%	8.0%	7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.5%	9.5%	Net Profit Margin	10.0%
47.3%	48.5%	47.6%	44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	49.0%	46.5%	Long-Term Debt Ratio	43.0%
52.7%	51.5%	52.4%	55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	51.0%	53.5%	Common Equity Ratio	57.0%
1356.2	1424.7	1433.6	1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	2050	2150	Total Capital ($mill)	2550
1893.9	1973.6	2062.9	2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2640	2750	Net Plant ($mill)	3105
6.2%	5.7%	5.8%	5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	4.0%	4.0%	Return on Total Cap'l	4.0%
8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	7.5%	7.0%	Return on Shr. Equity	7.0%
8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	7.5%	7.0%	Return on Com Equity	7.0%
2.4%	1.6%	1.5%	1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.0%	2.0%	Retained to Com Eq	2.5%
73%	80%	81%	85%	92%	87%	NMF	76%	82%	79%	75%	73%	All Div'ds to Net Prof	63%

CURRENT POSITION ($MILL.)	2019	2020	3/31/21
Cash Assets	9.6	30.2	17.9
Other	284.1	293.0	284.9
Current Assets	293.7	323.2	302.8
Accts Payable	113.4	97.9	88.6
Debt Due	224.2	399.9	331.5
Other	144.6	129.3	165.6
Current Liab.	482.2	627.1	585.7
Fix. Chg. Cov.	336%	335%	312%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	-3.5%	-2.0%	4.0%
"Cash Flow"	0.5%	1.5%	4.0%
Earnings	-1.5%	1.5%	5.5%
Dividends	1.5%	0.5%	.5%
Book Value	1.0%	- -	8.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	264.7	124.6	91.2	226.7	706.1
2019	285.4	123.4	90.3	247.3	746.4
2020	285.2	135.0	93.3	260.2	773.7
2021	315.9	145	110	259.1	830
2022	320	150	120	270	860

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.46	d.01	d.39	1.27	2.33
2019	1.50	.07	d.61	1.26	2.19
2020	1.58	d.17	d.61	1.50	2.30
2021	1.94	d.10	d.60	1.31	2.55
2022	1.96	d.08	d.58	1.35	2.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.47	.47	.47	.4725	1.88
2018	.4725	.4725	.4725	.475	1.89
2019	.475	.475	.475	.4775	1.90
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48			

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1000 communities, 775,000 customers, in Oregon (89% 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 1,167. BlackRock Inc. owns 16.4% of shares; State Street, 15.4%; Off./Dir., 1.03% (4/21 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Since our February review, shares of Northwest Natural Holding Co. are trading markedly higher. In fact, over that time frame, the stock's price climbed approximately 17%. While this is encouraging, investors should recall that NWN shares did sell off from the highs experienced in 2020. In fact, the stock lost more than 45% of its value through the lows that were hit earlier this year.

Meanwhile, the company posted solid financial results for the March quarter. This is evident in revenues advancing 10.8%, to $315.9 million, thanks to new rate increases in Oregon, customer growth, and asset management benefits. In fact, the regulated utility business added 11,000 natural gas meters over the past 12 months. Additionally, the colder-than-normal weather patterns across NWN's service territory helped to drive end-use consumer demand. Those benefits were partially offset by ongoing challenges stemming from the COVID-19 pandemic. However, with vaccines rolling out, it appears that there is a light at the end of that tunnel. On the margin front, overall expenses decreased 320 basis points, as a percentage of the top line. Combined, these factors drove the bottom line 22.8% higher, to $1.94 a share. This bested our call of $1.60.

We have raised our 2021 revenue and earnings estimate by $10 million and $0.05, to $830 million and $2.55 a share, respectively. Our revised figure would represent a more-than-10% year-over-year share-net advance. This should be supported by an estimated 7.5% rise in sales, thanks to new customer accounts at the Natural Gas Distribution business. At the same time, the Other business segment has been getting a boost from acquisitions. The NW Natural Water Company continues to purchase water and waste water utilities, thereby expanding its geographic footprint and providing clean, reliable service to its customers.

Neutrally ranked shares of Northwest Natural may appeal to income-seeking patient investors. Indeed, the stock's above-average dividend yield is enticing and well covered. What's more, NWN offers worthwhile recovery potential for the pull to 2024-2026.

Bryan J. Fong *May 28, 2021*

(A) Diluted earnings per share. Excludes nonrecurring items: '06, ($0.06); '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early Aug.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2020: $69.2 million, $2.26/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	30
Earnings Predictability	5

ONE GAS, INC. NYSE-OGS

RECENT PRICE 74.20 | P/E RATIO 19.5 (Trailing: 19.8 Median: NMF) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Raised 3/26/21
SAFETY 2 New 6/2/17
TECHNICAL 4 Raised 5/28/21
BETA .80 (1.00 = Market)

	2014	2015	2016	2017	2018	2019	2020	2021
High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	66.8

18-Month Target Price Range

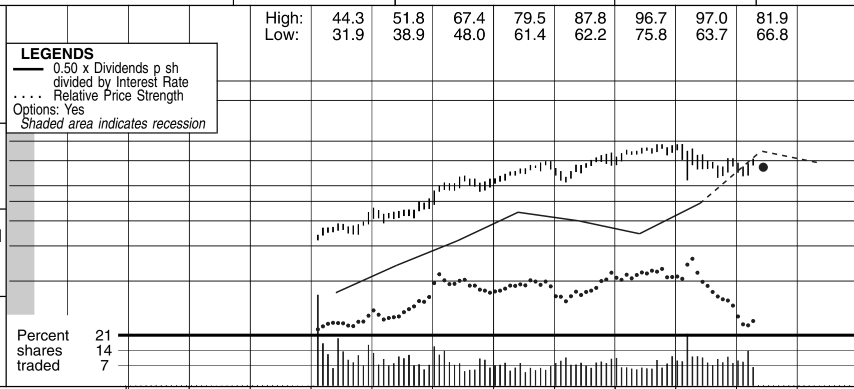
Low-High	Midpoint (% to Mid)
\$60-\$121	\$91 (20%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+95%)	20%
Low	105	(+40%)	12%

Institutional Decisions

	2Q2020	3Q2020	4Q2020
to Buy	142	130	123
to Sell	137	151	163
Hld's(000)	42060	42057	42726



Target Price Range
2024 | 2025 | 2026

% TOT. RETURN 4/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.9	75.2
3 yr.	23.8	56.1
5 yr.	54.8	103.5

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.

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
--	--	--	34.92	29.62	27.30	29.43	31.08	31.32	28.78	**31.30**	**33.85**	Revenues per sh	**43.00**
--	--	--	4.52	4.82	5.43	5.96	6.32	6.96	7.36	**7.75**	**8.20**	"Cash Flow" per sh	**9.75**
--	--	--	2.07	2.24	2.65	3.02	3.25	3.51	3.68	**3.80**	**4.00**	Earnings per sh A	**5.00**
--	--	--	.84	1.20	1.40	1.68	1.84	2.00	2.16	**2.32**	**2.48**	Div'ds Decl'd per sh B■	**2.95**
--	--	--	5.70	5.63	5.91	6.81	7.50	7.91	8.87	**9.00**	**9.20**	Cap'l Spending per sh	**9.75**
--	--	--	34.45	35.24	36.12	37.47	38.86	40.35	42.01	**44.40**	**48.45**	Book Value per sh	**74.40**
--	--	--	52.08	52.26	52.28	52.31	52.57	52.77	53.17	**53.50**	**53.50**	Common Shs Outst'g C	**57.00**
--	--	--	17.8	19.8	22.7	23.5	23.1	25.3	21.7	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**25.0**
--	--	--	.94	1.00	1.19	1.18	1.25	1.35	1.11			Relative P/E Ratio	**1.40**
--	--	--	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%			Avg Ann'l Div'd Yield	**2.4%**
--	--	--	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	**1675**	**1810**	Revenues (\$mill)	**2450**
--	--	--	109.8	119.0	140.1	159.9	172.2	186.7	196.4	**205**	**215**	Net Profit (\$mill)	**285**
--	--	--	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	**17.0%**	**17.5%**	Income Tax Rate	**22.0%**
--	--	--	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	**12.2%**	**11.9%**	Net Profit Margin	**11.6%**
--	--	--	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	**64.0%**	**62.0%**	Long-Term Debt Ratio	**47.0%**
--	--	--	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	**36.0%**	**38.0%**	Common Equity Ratio	**53.0%**
--	--	--	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	**6600**	**6820**	Total Capital (\$mill)	**8000**
--	--	--	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	**5100**	**5330**	Net Plant (\$mill)	**6000**
--	--	--	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	**5.0%**	**5.0%**	Return on Total Cap'l	**5.0%**
--	--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	**8.5%**	**8.5%**	Return on Shr. Equity	**6.5%**
--	--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	**8.5%**	**8.5%**	Return on Com Equity	**6.5%**
--	--	--	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	**3.5%**	**3.0%**	Retained to Com Eq	**3.0%**
--	--	--	40%	53%	52%	55%	56%	56%	58%	**61%**	**62%**	All Div'ds to Net Prof	**59%**

CAPITAL STRUCTURE as of 3/31/21
Total Debt \$4529.7 mill. **Due in 5 Yrs** \$1020.0 mill.
LT Debt \$4082.7 mill. **LT Interest** \$150.0 mill.
(LT interest earned: 4.8x; total interest coverage: 4.8x)
Leases, Uncapitalized Annual rentals \$7.9 mill.
Pfd Stock None
Pension Assets-12/20 \$987.6 mill.
Oblig. \$1077.6 mill.
Common Stock 53,245,144 shs.
as of 4/26/21
MARKET CAP: \$4.0 billion (Mid Cap)

CURRENT POSITION (\$MILL.)	2019	2020	3/31/21
Cash Assets	17.9	8.0	704.9
Other	488.3	531.9	453.8
Current Assets	506.2	539.9	1158.7
Accts Payable	120.5	152.3	228.0
Debt Due	516.5	418.2	447.0
Other	235.7	226.6	204.0
Current Liab.	872.7	797.1	879.0
Fix. Chg. Cov.	567%	587%	595%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	--	-1.0%	6.0%
"Cash Flow"	--	8.0%	6.0%
Earnings	--	10.0%	6.5%
Dividends	--	14.5%	7.0%
Book Value	--	3.0%	10.5%

Cal-endar	QUARTERLY REVENUES (\$ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	638.5	292.5	238.3	464.4	1633.7
2019	661.0	290.6	248.6	452.5	1652.7
2020	528.2	273.3	244.6	484.2	1530.3
2021	625.3	**320**	**257**	**472.7**	**1675**
2022	**650**	**355**	**300**	**505**	**1810**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.72	.39	.31	.83	3.25
2019	1.76	.46	.33	.96	3.51
2020	1.72	.48	.39	1.09	3.68
2021	1.79	**.51**	**.42**	**1.08**	**3.80**
2022	**1.85**	**.55**	**.47**	**1.13**	**4.00**

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.42	.42	.42	.42	1.68
2018	.46	.46	.46	.46	1.84
2019	.50	.50	.50	.50	2.00
2020	.54	.54	.54	.54	2.16
2021	.58	.58			

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 153 Bcf of natural gas supply in 2020, compared to 174 Bcf in 2019. Total volumes delivered by customer (fiscal 2020): transportation, 58.3%; residential, 31.7%; commercial & industrial, 9.4%; other, .6%. ONE Gas has around 3,600 employees. BlackRock owns 11.9% of common stock; The Vanguard Group, 9.7%; American Century Investment, 7.6%; officers and directors, 1.9% (4/21 Proxy). CEO: Pierce H. Norton II. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas' bottom line exhibited some improvement in the opening quarter of 2021. Share net of \$1.79 was 4% higher than the prior-year total of \$1.72. That partially reflected benefits from new rates, primarily in Texas and Oklahoma. Another contributing factor was an expanded customer base in Oklahoma and Texas. The effective income tax rate decreased, as well. The company adds that there was only a small number of outages across the service area despite the severe storm that occurred there in February (see below for more details). Although the effects of the coronavirus have continued, we believe that full-year earnings will increase around 3%, to \$3.80 a share. Assuming further growth of operating margins in 2022, share net might advance another 5%, to \$4.00.

Winter Storm Uri prompted leadership to take certain actions. Given that event, ONE Gas experienced unprecedented market pricing for gas costs in its Kansas, Oklahoma, and Texas territories, which resulted in aggregated natural gas purchases for February of approximately \$2.1 billion. To pay for these expenses, the company issued \$1 billion of 0.85 percent senior notes due 2023, \$700 million of 1.10 percent senior notes due 2024, and \$800 million of floating-rate senior notes due 2023. It should also be stated that ONE Gas seeks to recover those costs through future rate filings. Still, since the balance sheet is now more leveraged, we lowered the Financial Strength rating one notch, to B++.

Business prospects over the 2024-2026 span seem promising. The company remains the leading natural gas distributor (as measured by customer count) in both Oklahoma and Kansas, and holds the number-three position in Texas. Moreover, these markets seem to have decent growth possibilities and are located in one of the most active drilling regions in the United States. Also, ONE Gas seems capable of satisfying its working capital requirements, capital expenditures, and other commitments for a while.

These shares, although just an Average (3) selection for Timeliness, possess solid long-term total return potential.

Frederick L. Harris, III *May 28, 2021*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, \$0.06. Next earnings report due early Aug. Quarterly EPS for 2018 don't add up 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	95
Price Growth Persistence	80
Earnings Predictability	100

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE **25.66** | P/E RATIO **14.3** (Trailing: 14.2 / Median: 19.0) | RELATIVE P/E RATIO **0.66** | DIV'D YLD **5.0%** | VALUE LINE

TIMELINESS **5** Lowered 5/28/21
SAFETY **3** Lowered 8/28/20
TECHNICAL **5** Lowered 5/21/21
BETA 1.05 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	27.1	29.0	29.0	31.1	30.6	30.4	34.8	38.4	36.7	34.5	33.4	29.2
Low:	18.6	21.4	22.9	25.3	25.9	21.2	22.1	30.8	26.0	26.6	18.2	20.8

Target Price Range 2024 | 2025 | 2026

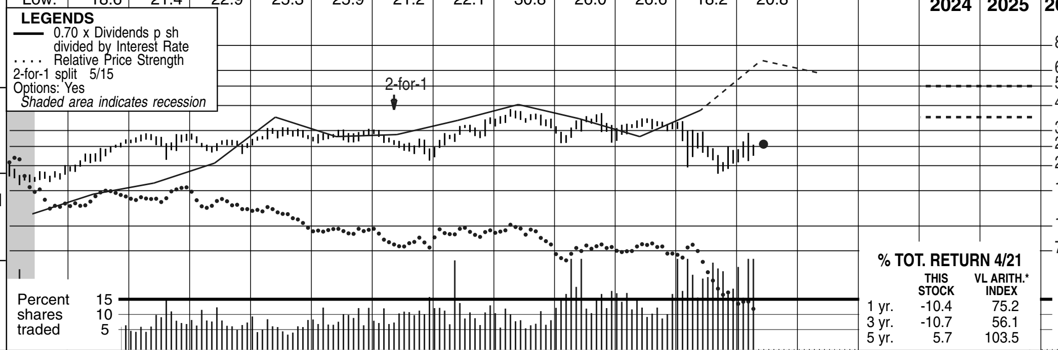
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$18-$51 $35 (35%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+95%)	21%
Low	35	(+35%)	12%

Institutional Decisions

	2Q2020	3Q2020	4Q2020
to Buy	88	132	110
to Sell	110	64	91
Hld's(000)	83521	85672	110377



% TOT. RETURN 4/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-10.4	75.2
3 yr.	-10.7	56.1
5 yr.	5.7	103.5

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
15.89	15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	13.04	15.63	19.20	17.63	15.32	*17.25*	*18.10*	Revenues per sh	*21.75*
1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.42	2.67	2.79	2.91	2.56	3.32	*2.95*	*3.25*	"Cash Flow" per sh	*4.15*
.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.44	1.34	1.23	1.38	1.12	1.68	*1.80*	*1.95*	Earnings per sh A	*2.70*
.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.06	1.10	1.13	1.16	1.19	*1.25*	*1.32*	Div'ds Decl'd per sh B ■	*1.50*
1.60	1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	4.87	3.50	3.43	3.99	5.46	4.84	*5.85*	*6.65*	Cap'l Spending per sh	*7.85*
6.75	7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	14.62	16.22	14.99	14.82	15.41	16.51	*18.20*	*18.85*	Book Value per sh C	*22.60*
57.96	58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.97	79.48	79.55	85.51	92.39	100.59	*103.00*	*105.00*	Common Shs Outst'g D	*115.00*
16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.9	21.7	27.9	22.6	28.3	14.9	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.90	1.14	1.40	1.22	1.51	.77	*Value Line*		Relative P/E Ratio	*.90*
3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.9%	3.6%	3.2%	3.6%	3.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/21
Total Debt $3377.5 mill. **Due in 5 Yrs** $380.1 mill.
LT Debt $3063.4 mill. **LT Interest** $100 mill.

Leases, Uncapitalized Annual rentals $1.2 mill.
Pension Assets-12/20 $331 mill.
Oblig. $481.8 mill.
Pfd Stock None

Common Stock 112,421,394 shs.
as of 5/1/21

MARKET CAP: $2.9 billion (Mid Cap)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
828.6	706.3	731.4	887.0	959.6	1036.5	1243.1	1641.3	1628.6	1541.4	*1775*	*1900*	Revenues ($mill)	*2500*
87.0	93.3	97.1	104.0	99.0	102.8	98.1	116.2	103.0	163.0	*185*	*205*	Net Profit ($mill)	*300*
22.4%	10.8%	- -	- -	5.9%	42.0%	- -	- -	- -	9.9%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
10.5%	13.2%	13.3%	11.7%	10.3%	9.9%	7.9%	7.1%	6.3%	10.6%	*10.4%*	*10.8%*	Net Profit Margin	*12.0%*
40.5%	45.0%	45.1%	48.0%	49.2%	38.5%	48.5%	62.4%	59.2%	62.6%	*63.0%*	*63.0%*	Long-Term Debt Ratio	*60.5%*
59.5%	55.0%	54.9%	52.0%	50.8%	61.5%	51.5%	37.6%	40.8%	37.4%	*37.0%*	*37.0%*	Common Equity Ratio	*39.5%*
1048.3	1337.6	1507.4	1791.9	2043.9	2097.2	2315.4	3373.9	3493.9	4437.3	*5075*	*5380*	Total Capital ($mill)	*6600*
1352.4	1578.0	1859.1	2134.1	2448.1	2623.8	2700.2	3653.5	4073.5	4464.2	*4800*	*5150*	Net Plant ($mill)	*5800*
8.9%	7.4%	6.8%	6.4%	5.4%	5.4%	5.1%	4.4%	4.0%	4.8%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	*10.0%*	*10.5%*	Return on Shr. Equity	*11.5%*
13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	*10.0%*	*10.5%*	Return on Com Equity	*11.5%*
6.7%	5.8%	4.8%	4.3%	2.8%	1.6%	.9%	1.7%	NMF	2.9%	*3.0%*	*3.5%*	Retained to Com Eq	*5.0%*
52%	55%	59%	61%	71%	80%	89%	82%	104%	70%	*70%*	*68%*	All Div'ds to Net Prof	*58%*

CURRENT POSITION ($MILL.)	2019	2020	3/31/21
Cash Assets	6.4	34.0	30.4
Other	646.1	472.8	458.5
Current Assets	652.5	506.8	488.9
Accts Payable	232.2	256.6	218.1
Debt Due	1316.6	739.2	314.1
Other	183.1	167.8	220.5
Current Liab.	1731.9	1163.6	752.7
Fix. Chg. Cov.	176%	238%	333%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	1.5%	6.5%	*4.0%*
"Cash Flow"	4.5%	3.0%	*6.0%*
Earnings	1.5%	-1.5%	*11.5%*
Dividends	6.5%	4.0%	*4.5%*
Book Value	5.5%	2.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	521.9	227.3	302.5	589.6	1641.3
2019	637.3	266.9	261.2	463.2	1628.6
2020	534.1	260.0	261.5	485.8	1541.4
2021	674.3	*285*	*285*	*530.7*	*1775*
2022	*640*	*320*	*320*	*620*	*1900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.19	.07	d.27	.39	1.38
2019	1.09	d.13	d.30	.46	1.12
2020	1.15	d.01	d.06	.62	1.68
2021	1.26	*.01*	*d.05*	*.58*	*1.80*
2022	*1.32*	*.02*	*d.02*	*.63*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	- -	.273	.273	.553	1.10
2018	- -	.280	.280	.567	1.13
2019	- -	.287	.287	.582	1.16
2020	- -	.295	.295	.598	1.19
2021	- -	.303			

BUSINESS: South Jersey Industries, Inc. is a holding company. The company distributes natural gas in New Jersey and Maryland. South Jersey Gas rev. mix '20: residential, 48%; commercial, 23%; cogen. and electric gen., 9%; industrial, 20%. Acq. Elizabethtown Gas and Elkton Gas, 7/18. Nonutil. oper. incl. South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 1,130 empl. Off./dir. own less than 1% of common; BlackRock, 14.4%; State Street Corporation, 13.9%; The Vanguard Group, 10.8% (3/21 proxy). Pres. & CEO: Michael J. Renna. Chairman: Joseph M. Rigby. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.

South Jersey Industries has recently completed two concurrent registered public offerings. This included $228 million in shares of common stock and $300 million in equity units. The equity units were also listed on the New York Stock Exchange. Net proceeds from these offerings will be used to reduce leverage and for general purposes, as well as for capital expenditures mainly for its regulated businesses, such as infrastructure investments. Investors were not pleased by this development and the shares fell on the news. This issuance of additional shares drives down the price of a security and dilutes the ownership interest of existing stockholders.

But the equity has staged a partial rebound lately. The company posted good results for the March quarter. The top line increased roughly 26%, year over year, to $674.3 million. Adjusted earnings per share of $1.26 compared favorably with the prior-year tally. The company's utility and nonutility operations both fared well in the recent period.

Prospects for the coming years appear favorable here. The company's utility businesses should continue to benefit from solid customer growth, rate relief, and infrastructure modernization programs that allow South Jersey to enhance the reliability of its systems and earn an authorized return on these investments. Elsewhere, we expect favorable results on the nonutility side. The Energy Management segment's Wholesale Services line should continue to benefit from improved asset optimization opportunities and additional fuel management contracts. Earnings from fuel cell and solar investments ought to support performance at the Energy Production segment.

This stock is ranked to trail the broader market averages for the coming six to 12 months. Looking further out, we anticipate increasing revenue and healthy growth in earnings per share for the company over the pull to mid-decade. From the recent quotation, this equity offers attractive long-term total return potential. This is helped by a relatively generous dividend yield. All told, patient, income-oriented accounts may find something to like here.

Michael Napoli, CFA *May 28, 2021*

(A) Based on economic egs. from 2007. GAAP EPS: '10, $1.11; '11, $1.49; '12, $1.49; '13, $1.28; '14, $1.46; '15, $1.52; '16, $1.56; '17, ($0.04); '18, $0.21; '19, $0.84; '20, $1.62. Excl. nonrecur. gain (loss): '10, ($0.24); '11, $0.04; '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08; '16, $0.22; '17, ($1.27); '18, ($1.17); '19, ($0.28); '20, ($0.06). Next egs. rpt. due early August. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2020: $674.0 mill., $6.70 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	60
Price Growth Persistence	15
Earnings Predictability	65

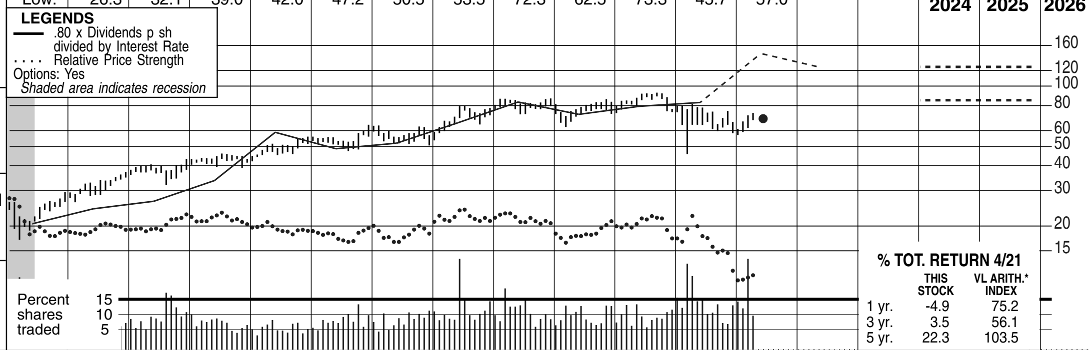
SOUTHWEST GAS NYSE-SWX

RECENT PRICE **68.88** | P/E RATIO **15.3** (Trailing: 14.2 / Median: 19.0) | RELATIVE P/E RATIO **0.71** | DIV'D YLD **3.5%** | VALUE LINE

TIMELINESS **3** Lowered 1/8/21
SAFETY **3** Lowered 1/4/91
TECHNICAL **4** Raised 5/28/21
BETA .95 (1.00 = Market)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	37.3	43.2	46.1	56.0	64.2	63.7	79.6	86.9	86.0	92.9	81.6	73.5
Low:	26.3	32.1	39.0	42.0	47.2	50.5	53.5	72.3	62.5	73.3	45.7	57.0

Target Price Range 2024 | 2025 | 2026



% TOT. RETURN 4/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.9	75.2
3 yr.	3.5	56.1
5 yr.	22.3	103.5

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$48-$119	$84 (20%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	125	(+80%)	18%
Low	85	(+25%)	9%

Institutional Decisions

	2Q2020	3Q2020	4Q2020
to Buy	130	116	140
to Sell	123	137	123
Hld's(000)	48082	46991	48058

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
43.59	48.47	50.28	48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	57.68	59.30	60.65	Revenues per sh	67.70
5.20	5.97	6.21	5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	10.50	11.05	"Cash Flow" per sh	14.00
1.25	1.98	1.95	1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	4.50	4.75	Earnings per sh A	6.50
.82	.82	.86	.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.37	2.48	Div'ds Decl'd per sh B■†	2.80
7.49	8.27	7.96	6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	13.55	16.40	Cap'l Spending per sh	24.60
19.10	21.58	22.98	23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	50.00	52.85	Book Value per sh	63.10
39.33	41.77	42.81	44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	59.00	61.00	Common Shs Outst'g C	65.00
20.6	15.9	17.3	20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	16.0
1.10	.86	.92	1.22	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.87			Relative P/E Ratio	.90
3.2%	2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%			Avg Ann'l Div'd Yield	2.7%

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
1887.2	1927.8	1950.8	2121.7	2463.6	2460.5	2548.8	2880.0	3119.9	3298.9	3500	3700	Revenues ($mill)	4400
112.3	133.3	145.3	141.1	138.3	152.0	173.8	182.3	213.9	232.3	260	285	Net Profit ($mill)	410
36.2%	36.2%	35.0%	35.7%	36.4%	33.9%	32.8%	25.3%	20.5%	21.6%	21.0%	21.0%	Income Tax Rate	21.0%
6.0%	6.9%	7.4%	6.7%	5.6%	6.2%	6.8%	6.3%	6.9%	7.0%	7.4%	7.7%	Net Profit Margin	9.3%
43.2%	49.2%	49.4%	52.4%	49.3%	48.2%	49.8%	48.3%	47.9%	50.5%	50.5%	50.0%	Long-Term Debt Ratio	48.0%
56.8%	50.8%	50.6%	47.6%	50.7%	51.8%	50.2%	51.7%	52.1%	49.5%	49.5%	50.0%	Common Equity Ratio	52.0%
2155.9	2576.9	2793.7	3123.9	3143.5	3213.5	3613.3	4359.3	4806.4	5407.2	5950	6425	Total Capital ($mill)	7850
3218.9	3343.8	3486.1	3658.4	3891.1	4132.0	4523.7	5093.2	5685.2	6176.1	6400	6750	Net Plant ($mill)	8000
6.4%	6.4%	6.3%	5.7%	5.5%	5.8%	5.8%	5.2%	5.4%	5.3%	5.0%	5.5%	Return on Total Cap'l	6.0%
9.2%	10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	9.0%	9.0%	Return on Shr. Equity	10.0%
9.2%	10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	9.0%	9.0%	Return on Com Equity	10.0%
5.3%	6.1%	6.1%	5.0%	4.0%	4.1%	4.5%	3.6%	3.9%	4.0%	4.0%	4.0%	Retained to Com Eq	5.5%
43%	40%	41%	47%	54%	55%	53%	55%	54%	54%	54%	53%	All Div'ds to Net Prof	44%

CAPITAL STRUCTURE as of 3/31/21
Total Debt $3073.9 mill. **Due in 5 Yrs** $750.9 mill.
LT Debt $2696.6 mill. **LT Interest** $100.0 mill.
(Total interest coverage: 4.3x) (48% of Cap'l)
Leases, Uncapitalized Annual rentals $13.9 mill.
Pension Assets-12/20 $1238.7 mill. **Oblig.** $1581.4 mill.

Pfd Stock None

Common Stock 58,001,396 shs. **as of 4/30/21**

MARKET CAP: $4.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	3/31/21
Cash Assets	49.5	83.4	92.3
Other	810.4	787.6	908.6
Current Assets	859.9	871.0	1000.9
Accts Payable	238.9	231.3	182.8
Debt Due	374.5	147.4	377.3
Other	466.5	533.3	475.9
Current Liab.	1079.9	912.0	1036.0
Fix. Chg. Cov.	340%	379%	419%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	2.5%	4.0%	3.0%
"Cash Flow"	4.0%	1.5%	7.5%
Earnings	7.5%	5.5%	9.0%
Dividends	8.5%	8.0%	4.5%
Book Value	6.0%	7.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	754.3	670.9	668.1	786.7	2880.0
2019	833.6	713.0	725.2	848.1	3119.9
2020	836.3	757.2	791.2	914.2	3298.9
2021	885.9	825	840	949.1	3500
2022	925	875	900	1000	3700

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.63	.44	.25	1.36	3.68
2019	1.77	.41	.10	1.67	3.94
2020	1.31	.68	.32	1.82	4.14
2021	2.03	.50	.25	1.72	4.50
2022	1.95	.60	.35	1.85	4.75

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.450	.495	.495	.495	1.94
2018	.495	.520	.520	.520	2.06
2019	.520	.545	.545	.545	2.16
2020	.545	.570	.570	.570	2.26
2021	.570	.595			

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas and Centuri Group. Southwest Gas is a regulated gas distributor serving 2.1 million customers in Arizona, Nevada, and California. Centuri provides construction services. 2020 margin mix: residential and small commercial, 85%; large commercial and industrial, 3%; transportation, 12%. Total throughput: 2.2 billion therms. Has 11,149 employees. Off. & dir. own .8% of common; BlackRock, Inc., 12.3%; The Vanguard Group, Inc., 9.8%; Lazard Asset Management LLC, 9.4% (3/21 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: John P. Hester. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Tel.: 702-876-7237. Web: www.swgas.com.

Shares of Southwest Gas have moved higher in price in the current year. The company reported favorable results for the March period. The top line increased roughly 6%, year to year, to $885.9 million. Earnings per share of $2.03 marked a considerable improvement over the prior-year tally. The utility business benefited from favorable rulings in several rate cases. Its territories in Arizona, California, and Nevada have all experienced significant growth, driving increased demand for new homes, and natural gas services in general. Many of the communities that the company serves have benefited in recent times from the easing of pandemic-related restrictions. The infrastructure services operation, Centuri, also fared well. This business continues to gain as its regulated utility customers modernize their energy infrastructure.

We anticipate solid operating results going forward. Southwest's utility operation ought to further benefit from healthy growth in the customer base. Infrastructure investments by the utility should also pay off in the years ahead. Rate relief will likely continue to benefit performance, too. The company depends on such approved revenue increases to offset increasing expenses and allow it to earn an acceptable return on investment. Elsewhere, Centuri, the company's infrastructure services business, should also perform fairly well. This line derives its revenue from the installation, replacement, repair, and maintenance of energy distribution systems. Centuri has a robust client base, and ought to benefit from the ongoing need of utilities to replace aging infrastructure. Measures by the company to control costs should also pay off.

This stock is ranked to track the broader market averages for the coming six to 12 months. Looking further out, we anticipate solid growth in revenues and earnings for the company over the pull to mid-decade. From the recent quotation, this stock offers attractive long-term total return potential. The dividend should continue to increase at a steady rate in the coming years. In addition, Southwest Gas earns good marks for Financial Strength, Price Stability, and Earnings Predictability. Volatility is subdued, too.

Michael Napoli, CFA *May 28, 2021*

(A) Diluted earnings. Excl. nonrec. gains (losses): '05, (11¢); '06, 7¢. Next egs. report due early August. (B) Dividends historically paid early March, June, September, and December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions. (D) Totals may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	60
Earnings Predictability	100

SPIRE INC. NYSE-SR

RECENT PRICE **74.48** | P/E RATIO **14.6** (Trailing: 25.9 / Median: 19.0) | RELATIVE P/E RATIO **0.67** | DIV'D YLD **3.6%** | VALUE LINE

TIMELINESS 3 Raised 5/21/21
SAFETY 2 Raised 6/20/03
TECHNICAL 2 Raised 5/28/21
BETA .85 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	37.8	42.8	44.0	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9
Low:	30.8	32.9	36.5	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3

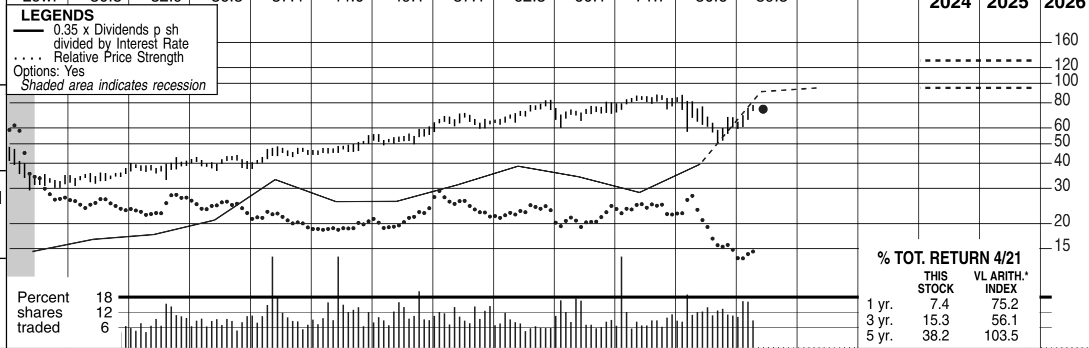
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$37-$92 $65 (-15%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+75%)	18%
Low	95	(+30%)	10%

Institutional Decisions

	2Q2020	3Q2020	4Q2020
to Buy	127	145	131
to Sell	130	121	148
Hld's(000)	40679	40642	41028



% TOT. RETURN 4/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.4	75.2
3 yr.	15.3	56.1
5 yr.	38.2	103.5

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
75.43	93.51	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	**42.85**	**36.90**	Revenues per sh A	**58.20**
2.98	3.81	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	**9.10**	**8.55**	"Cash Flow" per sh	**10.50**
1.90	2.37	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	**5.00**	**4.30**	Earnings per sh A B	**5.50**
1.37	1.40	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**	**2.72**	Div'ds Decl'd per sh C■	**3.10**
2.84	2.97	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	**11.25**	**10.85**	Cap'l Spending per sh	**11.45**
17.31	18.85	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	**54.40**	**56.25**	Book Value per sh D	**75.00**
21.17	21.36	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	**52.50**	**53.50**	Common Shs Outst'g E	**55.00**
16.2	13.6	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	NMF	*Bold figures are*		Avg Ann'l P/E Ratio	**20.5**
.86	.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	NMF	*Value Line*		Relative P/E Ratio	**1.15**
4.4%	4.3%	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%	*estimates*		Avg Ann'l Div'd Yield	**2.8%**

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
1603.3	1125.5	1017.0	1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	**2250**	**1975**	Revenues ($mill) A	**3200**
63.8	62.6	52.8	84.6	136.9	144.2	161.6	214.2	184.6	88.6	**265**	**230**	Net Profit ($mill)	**300**
31.4%	29.6%	25.0%	27.6%	31.2%	32.5%	32.4%	32.4%	15.7%	12.3%	**20.0%**	**21.0%**	Income Tax Rate	**23.5%**
4.0%	5.6%	5.2%	5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	**11.8%**	**11.6%**	Net Profit Margin	**9.4%**
38.9%	36.1%	46.6%	55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	**49.0%**	**49.0%**	Long-Term Debt Ratio	**45.0%**
61.1%	63.9%	53.4%	44.9%	47.0%	49.1%	50.0%	54.3%	55.0%	51.0%	**51.0%**	**51.0%**	Common Equity Ratio	**55.0%**
937.7	941.0	1959.0	3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	**5600**	**5900**	Total Capital ($mill)	**7500**
928.7	1019.3	1776.6	2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	**5100**	**5400**	Net Plant ($mill)	**6800**
8.1%	7.9%	3.3%	3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	**6.0%**	**5.5%**	Return on Total Cap'l	**5.5%**
11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	**9.5%**	**7.5%**	Return on Shr. Equity	**7.5%**
11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	**9.5%**	**7.5%**	Return on Com Equity	**7.5%**
4.9%	4.3%	1.0%	1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	**4.0%**	**2.5%**	Retained to Com Eq	**3.0%**
56%	59%	81%	73%	58%	59%	60%	51%	66%	NMF	**57%**	**70%**	All Div'ds to Net Prof	**62%**

CAPITAL STRUCTURE as of 3/31/21
Total Debt $3456.8 mill. **Due in 5 Yrs** $1690.0 mill.
LT Debt $2692.5 mill. **LT Interest** $130.0 mill.
(Total interest coverage: 2.0x)

Leases, Uncapitalized Annual rentals $8.8 mill.
Pension Assets-9/20 $897.9 mill. **Oblig.** $1401.3 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 51,679,561 shs. as of 4/30/21

MARKET CAP: $3.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	3/31/21
Cash Assets	5.8	4.1	104.0
Other	608.7	586.5	936.0
Current Assets	614.5	590.6	1040.0
Accts Payable	301.5	243.3	352.1
Debt Due	783.2	708.4	764.3
Other	384.1	497.5	391.1
Current Liab.	1468.8	1449.2	1507.5
Fix. Chg. Cov.	272%	373%	385%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	-8.0%	- -	7.5%
"Cash Flow"	4.5%	8.5%	8.0%
Earnings	1.5%	4.5%	10.0%
Dividends	4.5%	6.0%	4.5%
Book Value	7.0%	5.5%	9.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	561.8	813.4	350.6	239.2	1965.0
2019	602.0	803.5	321.3	225.6	1952.4
2020	566.9	715.5	321.1	251.9	1855.4
2021	512.6	1104.9	**377.5**	**255**	**2250**
2022	**530**	**803**	**376**	**266**	**1975**

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	2.39	2.03	.52	d.51	4.33
2019	1.32	3.04	d.09	d.74	3.52
2020	1.24	2.54	d1.87	d.45	1.44
2021	1.65	3.55	**.48**	**d.68**	**5.00**
2022	**1.75**	**2.74**	**.45**	**d.64**	**4.30**

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.525	.525	.525	.525	2.10
2018	.5625	.5625	.5625	.5625	2.25
2019	.5925	.5925	.5925	.5925	2.37
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65			

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 2020: 3.3 bill. Revenue mix for regulated operations: residential, 68%; commercial and industrial, 22%; transportation, 6%; other, 4%. Has about 3,583 employees. Officers and directors own 3.0% of common shares; BlackRock, 12.0% (1/21 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 registered impressive numbers during the first half of fiscal 2021 (concludes September 30th). Share net of $5.20 surged around 38%, compared to the prior-year total of $3.78. This was made possible partially by the Gas Utility division, helped by increased Infrastructure System Replacement Surcharge (ISRS) revenues, the effects of colder temperatures, plus diminished operating costs. Moreover, favorable market conditions, especially in February when Winter Storm Uri struck parts of the U.S., drove the performance of the Gas Marketing unit. Given that the company faces an easy bottom-line comparison in the third quarter, it appears that full-year share net will jump nearly 3.5 times, to $5.00, versus the uninspiring fiscal 2020 tally of $1.44 (which was crushed by the impact of COVID-19). Turning to next year, we expect lower, though still respectable, earnings of $4.30 a share, since the second-quarter matchup will be challenging.

***Value Line* is optimistic about the company's prospects over the 2024-2026 period.** The gas utilities boast 1.7 million customers in Mississippi, Alabama, and Missouri, providing a measure of regional diversity. Furthermore, the other operations, particularly pipelines, hold promise. Additional expansionary projects and technological enhancements in customer service and elsewhere ought to assist Spire, too. Finally, the balance sheet (see below) is healthy.

The Financial Strength rating resides at B++. When March ended, there was around $675 million of available liquidity partly via a revolving credit facility. Too, long-term debt was a manageable 49.6% of total capital, and short-term commitments did not seem to be a major hurdle. So, the company ought to be able to meet its various obligations (including interest payments, capital expenditures, and dividends) with relative ease. Acquisitions are also plausible.

These good-quality shares have risen greatly in value in recent months. It appears that Spire's strong results of late are a driving force behind that movement. Also, long-term total return potential is solid. Meanwhile, the stock is neutrally ranked for Timeliness.

Frederick L. Harris, III *May 28, 2021*

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. 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 '20: $1,171.6 mill., $22.71/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	55
Earnings Predictability	50

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

	Proxy Group of Seven Natural Gas Distribution Companies
Predictive Risk Premium Model (PRPM) (1)	10.93 %
Risk Premium Using an Adjusted Total Market Approach (2)	10.39
Average	10.66 %

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 Seven 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)	[7] Indicated ROE (5)
Atmos Energy Corporation	0.33%	0.41%	0.37%	2.2493	10.46%	2.74%	13.20%
New Jersey Resources Corporation	0.38%	0.38%	0.38%	2.0290	9.65%	2.74%	12.39%
Northwest Natural Holding Company	0.32%	0.29%	0.31%	1.5450	5.90%	2.74%	8.64%
ONE Gas, Inc.	0.29%	0.35%	0.32%	3.8153	15.68%	2.74%	NMF
South Jersey Industries, Inc.	0.39%	0.55%	0.47%	1.6294	9.59%	2.74%	12.33%
Southwest Gas Holdings, Inc.	0.43%	0.34%	0.39%	1.3833	6.67%	2.74%	9.41%
Spire Inc.	0.71%	0.45%	0.58%	0.9478	6.80%	2.74%	9.54%
						Average	10.92%
						Median	10.94%
						Average of Mean and Median	10.93%

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 the long-term average and spot predicted variance.
(3) (1+(Column [3] * Column [4])^12) - 1.
(4) From note 2 on page 2 of Exhibit No.___(DWD-5).
(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 Seven Natural Gas Distribution Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	3.48 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds	0.38 (2)
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	3.86 %
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group	0.04 (3)
5.	Adjusted Prospective Bond Yield	3.90 %
6.	Equity Risk Premium (4)	6.49
7.	Risk Premium Derived Common Equity Cost Rate	10.39 %

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 0.38% from page 4 of this Exhibit.
(3) Adjustment to reflect the A2/A3 Moody's LT issuer rating of the Utility Proxy Group as shown on page 5 of this Exhibit. The 0.04% upward adjustment is derived by taking 1/6 of the spread between A2 and Baa2 Public Utility Bonds (1/6 * 0.25% = 0.04%) as derived from page 4 of this Exhibit.
(4) 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
Jul-2021	2.57 %	2.95 %	3.20 %
Jun-2021	2.79	3.16	3.41
May-2021	2.96	3.33	3.58
Average	2.77 %	3.15 %	3.40 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:
0.38 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:
0.25 % (2)

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

Source of Information:
Bloomberg Professional Service

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

	Moody's Long-Term Issuer Rating July 2021		Standard & Poor's Long-Term Issuer Rating July 2021	
Proxy Group of Seven 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	- -
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	BBB+	8.0
South Jersey Industries, Inc.	A3	7.0	BBB	9.0
Southwest Gas Holdings, Inc.	Baa1	8.0	A-	7.0
Spire Inc.	A1/A2	5.5	A-	7.0
Average	A2/A3	6.5	A-	7.2

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 Seven Natural Gas Distribution Companies

Line No.		Proxy Group of Seven Natural Gas Distribution Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	8.09 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	5.68
3.	Predicted Equity Risk Premium Based on Regression Analysis of 803 Fully-Litigated Natural Gas Utility Rate Cases (3)	5.69
4.	Average equity risk premium	6.49 %

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 Seven Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Seven Natural Gas Distribution Companies
	Ibbotson-Based Equity Risk Premiums:	
1.	Ibbotson Equity Risk Premium (1)	5.92 %
2.	Regression on Ibbotson Risk Premium Data (2)	8.79
3.	Ibbotson Equity Risk Premium based on PRPM (3)	8.16
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	5.03
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	11.20
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	13.08
7.	Conclusion of Equity Risk Premium	8.70 %
8.	Adjusted Beta (7)	0.93
9.	Forecasted Equity Risk Premium	8.09 %

Notes provided on page 9 of this Schedule.

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

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Ibbotson® SBBI® 2021 Market Report minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1928-2020.

(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 Aa rated corporate bond yields from 1928-2020 referenced in Note 1 above.

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson 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 July 2021.

(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 3.48% (from page 3 of this Exhibit) from the projected 3-5 year total annual market return of 8.51% (described fully in note 1 on page 2 of Exhibit No.___(DWD-5)).

(5) Using data from Value Line for the S&P 500, an expected total return of 14.68% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 3.48% results in an expected equity risk premium of 11.20%.

(6) Using data from the Bloomberg Professional Service for the S&P 500, an expected total return of 16.56% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 3.48% results in an expected equity risk premium of 13.08%.

(7) Average of mean and median beta from Exhibit No.___(DWD-5).

Sources of Information:

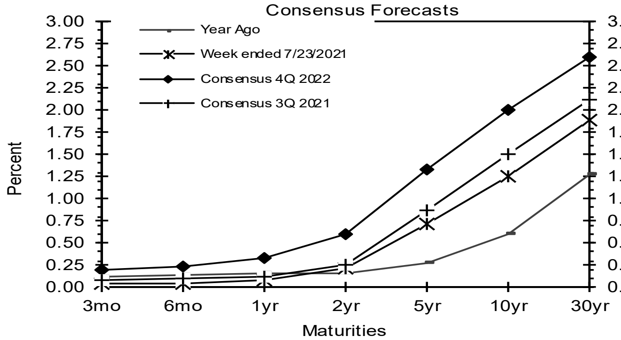
Stocks, Bonds, Bills, and Inflation - 2020 SBBI Yearbook, John Wiley & Sons, Inc.
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, August 3, 2021 and June 1, 2021
Bloomberg Professional Service

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

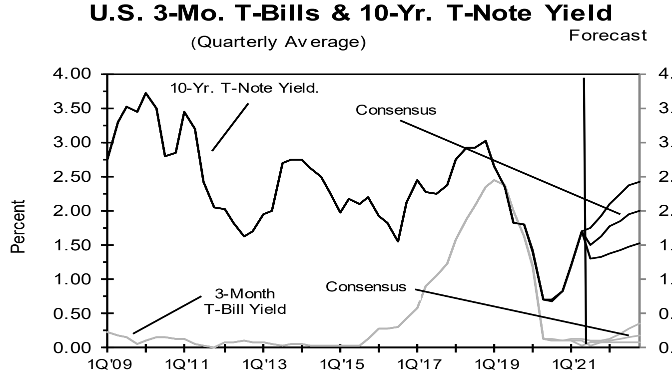
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	3Q	4Q	1Q	2Q	3Q	4Q
Interest Rates	Jul 23	Jul 16	Jul 9	Jul 2	Jun	May	Apr	2Q 2021	**2021**	**2021**	**2022**	**2022**	**2022**	**2022**
Federal Funds Rate	0.10	0.10	0.10	0.10	0.08	0.06	0.07	0.07	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
LIBOR, 3-mo.	0.13	0.13	0.13	0.14	0.13	0.15	0.18	0.16	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**
Commercial Paper, 1-mo.	0.05	0.06	0.06	0.05	0.04	0.10	0.04	0.06	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**
Treasury bill, 3-mo.	0.05	0.05	0.06	0.05	0.04	0.02	0.02	0.03	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**
Treasury bill, 6-mo.	0.05	0.05	0.06	0.06	0.05	0.04	0.04	0.04	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**
Treasury bill, 1 yr.	0.07	0.08	0.08	0.08	0.07	0.05	0.06	0.06	**0.1**	**0.1**	**0.2**	**0.2**	**0.3**	**0.3**
Treasury note, 2 yr.	0.21	0.24	0.22	0.25	0.20	0.16	0.16	0.17	**0.2**	**0.3**	**0.4**	**0.5**	**0.5**	**0.6**
Treasury note, 5 yr.	0.71	0.81	0.78	0.88	0.84	0.82	0.86	0.84	**0.9**	**1.0**	**1.1**	**1.2**	**1.3**	**1.3**
Treasury note, 10 yr.	1.26	1.36	1.34	1.47	1.52	1.62	1.64	1.59	**1.5**	**1.6**	**1.8**	**1.9**	**1.9**	**2.0**
Treasury note, 30 yr.	1.89	1.97	1.96	2.08	2.16	2.32	2.30	2.26	**2.1**	**2.3**	**2.4**	**2.5**	**2.6**	**2.6**
Corporate Aaa bond	2.69	2.74	2.74	2.81	2.91	3.06	3.04	3.00	**2.8**	**3.0**	**3.1**	**3.2**	**3.3**	**3.3**
Corporate Baa bond	3.13	3.19	3.19	3.26	3.35	3.52	3.51	3.46	**3.5**	**3.7**	**3.9**	**4.0**	**4.1**	**4.2**
State & Local bonds	2.59	2.60	2.63	2.66	2.64	2.64	2.66	2.65	**2.4**	**2.5**	**2.6**	**2.6**	**2.7**	**2.7**
Home mortgage rate	2.78	2.88	2.90	2.98	2.98	2.96	3.06	3.00	**3.0**	**3.2**	**3.3**	**3.4**	**3.5**	**3.5**
	History								**Consensus Forecasts-Quarterly**					
	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	**3Q**	**4Q**	**1Q**	**2Q**	**3Q**	**4Q**
Key Assumptions	2019	2019	2020	2020	2020	2020	2021	2021	**2021**	**2021**	**2022**	**2022**	**2022**	**2022**
Fed's AFE $ Index	110.6	110.5	111.4	112.4	107.3	105.2	103.4	102.9	**104.5**	**104.4**	**104.0**	**103.9**	**103.9**	**104.0**
Real GDP	2.8	1.9	-5.1	-31.2	33.8	4.5	6.3	6.5	**7.2**	**5.5**	**4.0**	**3.3**	**2.7**	**2.3**
GDP Price Index	1.4	1.5	1.6	-1.5	3.6	2.2	4.3	6.0	**3.7**	**2.5**	**2.4**	**2.3**	**2.3**	**2.3**
Consumer Price Index	1.3	2.6	1.0	-3.1	4.7	2.4	3.7	8.4	**4.7**	**2.4**	**2.2**	**2.4**	**2.4**	**2.2**
PCE Price Index	1.1	1.7	1.3	-1.6	3.7	1.5	3.8	6.4	**3.7**	**2.2**	**2.1**	**2.3**	**2.2**	**2.2**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, PCE Price Index and Consumer 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; LIBOR quotes from Intercontinental Exchange. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).

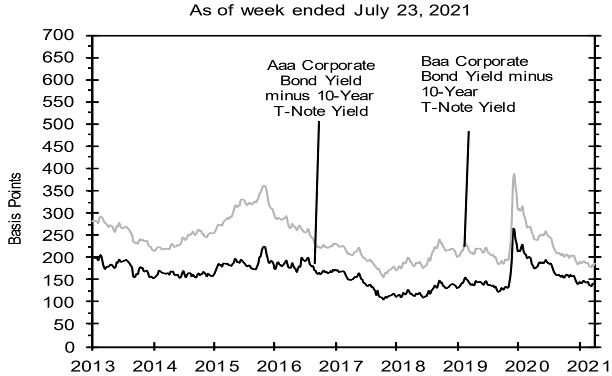
U.S. Treasury Yield Curve
Week ended July 23, 2021 & Year Ago vs. 3Q 2021 & 4Q 2022 Consensus Forecasts



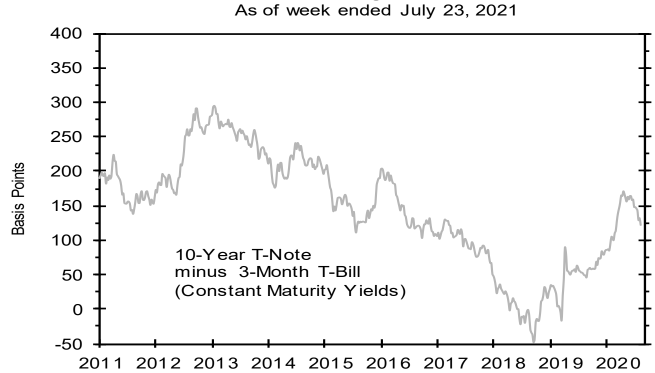
U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield
(Quarterly Average)



Corporate Bond Spreads
As of week ended July 23, 2021



U.S. Treasury Yield Curve
As of week ended July 23, 2021



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 2022 through 2027 and averages for the five-year periods 2023-2027 and 2028-2032. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

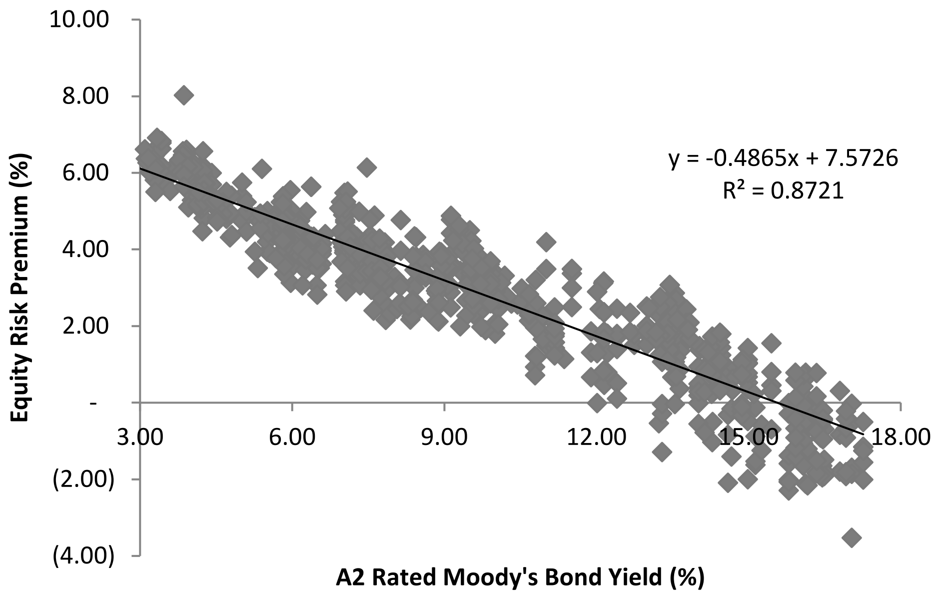
		Average For The Year						Five-Year Averages	
		2022	2023	2024	2025	2026	2027	2023-2027	2028-2032
1. Federal Funds Rate	CONSENSUS	**0.1**	**0.4**	**1.0**	**1.6**	**1.9**	**2.1**	**1.4**	**2.2**
	Top 10 Average	0.2	0.7	1.6	2.4	2.6	2.7	2.0	2.7
	Bottom 10 Average	0.1	0.1	0.5	0.9	1.3	1.5	0.9	1.6
2. Prime Rate	CONSENSUS	**3.3**	**3.5**	**4.2**	**4.7**	**5.0**	**5.2**	**4.5**	**5.2**
	Top 10 Average	3.4	3.8	4.7	5.4	5.7	5.8	5.1	5.8
	Bottom 10 Average	3.2	3.3	3.7	4.0	4.4	4.6	4.0	4.7
3. LIBOR, 3-Mo.	CONSENSUS	**0.4**	**0.6**	**1.3**	**1.8**	**2.1**	**2.3**	**1.6**	**2.4**
	Top 10 Average	0.5	1.0	1.8	2.4	2.7	2.9	2.2	3.0
	Bottom 10 Average	0.2	0.4	0.8	1.2	1.6	1.7	1.1	1.8
4. Commercial Paper, 1-Mo	CONSENSUS	**0.2**	**0.6**	**1.3**	**1.8**	**2.1**	**2.3**	**1.6**	**2.4**
	Top 10 Average	0.4	0.9	1.6	2.3	2.6	2.8	2.0	2.8
	Bottom 10 Average	0.1	0.3	0.9	1.3	1.8	1.9	1.2	2.0
5. Treasury Bill Yield, 3-Mo	CONSENSUS	**0.2**	**0.5**	**1.0**	**1.6**	**1.9**	**2.1**	**1.4**	**2.2**
	Top 10 Average	0.3	0.8	1.6	2.2	2.5	2.7	1.9	2.7
	Bottom 10 Average	0.1	0.2	0.6	0.9	1.3	1.5	0.9	1.6
6. Treasury Bill Yield, 6-Mo	CONSENSUS	**0.2**	**0.5**	**1.1**	**1.6**	**2.0**	**2.2**	**1.5**	**2.3**
	Top 10 Average	0.3	0.8	1.7	2.3	2.6	2.7	2.0	2.8
	Bottom 10 Average	0.1	0.3	0.6	1.0	1.4	1.6	1.0	1.7
7. Treasury Bill Yield, 1-Yr	CONSENSUS	**0.3**	**0.7**	**1.2**	**1.8**	**2.1**	**2.3**	**1.6**	**2.4**
	Top 10 Average	0.5	1.0	1.8	2.4	2.8	2.9	2.2	3.0
	Bottom 10 Average	0.2	0.3	0.7	1.1	1.5	1.7	1.1	1.8
8. Treasury Note Yield, 2-Yr	CONSENSUS	**0.5**	**0.9**	**1.5**	**2.0**	**2.3**	**2.5**	**1.8**	**2.6**
	Top 10 Average	0.7	1.3	2.1	2.7	3.0	3.1	2.5	3.3
	Bottom 10 Average	0.3	0.5	0.9	1.3	1.6	1.8	1.2	1.9
9. Treasury Note Yield, 5-Yr	CONSENSUS	**1.2**	**1.6**	**2.1**	**2.5**	**2.8**	**2.8**	**2.4**	**3.0**
	Top 10 Average	1.5	2.0	2.8	3.3	3.5	3.5	3.0	3.6
	Bottom 10 Average	0.9	1.2	1.5	1.8	2.0	2.2	1.7	2.3
10. Treasury Note Yield, 10-Yr	CONSENSUS	**2.0**	**2.4**	**2.7**	**3.0**	**3.2**	**3.3**	**2.9**	**3.3**
	Top 10 Average	2.3	2.8	3.4	3.8	4.0	3.9	3.6	4.0
	Bottom 10 Average	1.7	1.9	2.1	2.3	2.5	2.6	2.3	2.7
11. Treasury Bond Yield, 30-Yr	CONSENSUS	**2.6**	**2.9**	**3.3**	**3.6**	**3.8**	**3.8**	**3.5**	**3.9**
	Top 10 Average	3.0	3.5	4.0	4.5	4.6	4.5	4.2	4.6
	Bottom 10 Average	2.3	2.4	2.5	2.7	2.9	3.1	2.7	3.2
12. Corporate Aaa Bond Yield	CONSENSUS	**3.3**	**3.7**	**4.1**	**4.5**	**4.7**	**4.7**	**4.3**	**4.8**
	Top 10 Average	3.6	4.2	4.7	5.2	5.4	5.4	5.0	5.4
	Bottom 10 Average	3.1	3.2	3.4	3.7	3.9	4.1	3.7	4.2
13. Corporate Baa Bond Yield	CONSENSUS	**4.3**	**4.7**	**5.1**	**5.4**	**5.6**	**5.7**	**5.3**	**5.8**
	Top 10 Average	4.6	5.1	5.6	6.1	6.3	6.2	5.9	6.4
	Bottom 10 Average	4.0	4.3	4.5	4.7	4.9	5.2	4.7	5.2
14. State & Local Bonds Yield	CONSENSUS	**2.9**	**3.2**	**3.6**	**3.9**	**4.1**	**4.2**	**3.8**	**4.2**
	Top 10 Average	3.2	3.5	4.1	4.5	4.7	4.7	4.3	4.8
	Bottom 10 Average	2.6	2.9	3.1	3.4	3.7	3.7	3.3	3.8
15. Home Mortgage Rate	CONSENSUS	**3.6**	**4.0**	**4.4**	**4.7**	**4.9**	**5.0**	**4.6**	**5.0**
	Top 10 Average	4.0	4.5	5.0	5.5	5.6	5.6	5.2	5.7
	Bottom 10 Average	3.2	3.6	3.8	4.0	4.2	4.3	4.0	4.4
A. Fed's AFE Nominal $ Index	CONSENSUS	**103.7**	**103.7**	**104.0**	**103.7**	**103.6**	**103.3**	**103.7**	**103.1**
	Top 10 Average	105.3	106.0	106.8	107.0	107.3	107.5	106.9	107.9
	Bottom 10 Average	102.0	101.5	101.4	100.8	100.4	100.0	100.8	99.4
		Year-Over-Year, % Change						Five-Year Averages	
		2022	2023	2024	2025	2026	2027	2023-2027	2028-2032
B. Real GDP	CONSENSUS	**4.2**	**2.6**	**2.3**	**2.2**	**2.1**	**2.1**	**2.2**	**2.1**
	Top 10 Average	5.3	3.3	2.7	2.5	2.4	2.4	2.7	2.5
	Bottom 10 Average	2.9	2.0	1.9	1.8	1.8	1.7	1.8	1.7
C. GDP Chained Price Index	CONSENSUS	**2.3**	**2.3**	**2.2**	**2.1**	**2.2**	**2.1**	**2.2**	**2.1**
	Top 10 Average	2.6	2.6	2.4	2.4	2.4	2.4	2.4	2.3
	Bottom 10 Average	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9
D. Consumer Price Index	CONSENSUS	**2.4**	**2.4**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.8	2.7	2.5	2.5	2.5	2.4	2.5	2.4
	Bottom 10 Average	2.1	2.1	1.9	1.9	2.0	1.9	2.0	1.9
E. PCE Price Index	CONSENSUS	**2.3**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.7	2.5	2.4	2.4	2.4	2.4	2.4	2.3
	Bottom 10 Average	1.9	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.		Implied Equity Risk Premium
	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1):	
1.	Historical Equity Risk Premium	4.16 %
2.	Regression of Historical Equity Risk Premium (2)	6.45
3.	Forecasted Equity Risk Premium Based on PRPM (3)	5.04
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	7.37
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	5.38
6.	Average Equity Risk Premium (6)	5.68 %

Notes:
(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2020. 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 - 2020 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 - July 2021.
(4) Using data from Value Line for the S&P Utilities Index, an expected return of 11.23% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 3.86%, calculated on line 3 of page 3 of this Exhibit results in an equity risk premium of 7.37%. (11.23% - 3.86% = 7.37%)
(5) Using data from Bloomberg Professional Service for the S&P Utilities Index, an expected return of 9.24% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 3.86%, calculated on line 3 of page 3 of this Exhibit results in an equity risk premium of 5.38%. (9.24% - 3.86% = 5.38%)
(6) Average of lines 1 through 5.

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



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.572627 %	-0.48654	3.86 %	5.69 %

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

Source of Information:
Regulatory Research Associates
Bloomberg Professional Services

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 Seven 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	0.80	0.92	0.86	9.55 %	2.74 %	10.95 %	11.29 %	11.12 %
New Jersey Resources Corporation	1.00	0.98	0.99	9.55	2.74	12.19	12.22	12.21
Northwest Natural Holding Company	0.85	0.86	0.86	9.55	2.74	10.95	11.29	11.12
ONE Gas, Inc.	0.80	1.00	0.90	9.55	2.74	11.33	11.57	11.45
South Jersey Industries, Inc.	1.05	1.00	1.03	9.55	2.74	12.58	12.50	12.54
Southwest Gas Holdings, Inc.	0.95	1.10	1.02	9.55	2.74	12.48	12.43	12.46
Spire Inc.	0.85	0.99	0.92	9.55	2.74	11.53	11.72	11.62
Mean			0.94			11.72 %	11.86 %	11.79 %
Median			0.92			11.53 %	11.72 %	11.62 %
Average of Mean and Median			0.93			11.63 %	11.79 %	11.71 %

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 (1926-2020)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2020:	12.20	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.05	
MRP based on Ibbotson Historical Data:	7.15	%

Measure 2: Application of a Regression Analysis to Ibbotson Historical Data (1926-2020)	9.53	%
Measure 3: Application of the PRPM to Ibbotson Historical Data: (January 1926 - July 2021)	9.08	%

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP (Thirteen weeks ending July 30, 2021)

Total projected return on the market 3-5 years hence*:	8.51	%
Projected Risk-Free Rate (see note 2):	2.74	
MRP based on Value Line Summary & Index:	5.77	%

*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:	14.68	%
Projected Risk-Free Rate (see note 2):	2.74	
MRP based on Value Line data	11.94	%

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	16.56	%
Projected Risk-Free Rate (see note 2):	2.74	
MRP based on Bloomberg data	13.82	%
Average of Value Line, Ibbotson, and Bloomberg MRP:	9.55	%

(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 Exhbit No.___(DWD-4).) The projection of the risk-free rate is illustrated below:

Third Quarter 2021	2.10	%
Fourth Quarter 2021	2.30	
First Quarter 2022	2.40	
Second Quarter 2022	2.50	
Third Quarter 2022	2.60	
Fourth Quarter 2022	2.60	
2023-2027	3.50	
2028-2032	3.90	
	2.74	%

(3) Average of Column 6 and Column 7.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, August 3, 2021 and June 1, 2021
Stocks, Bonds, Bills, and Inflation - 2020 SBBI Yearbook, John Wiley & Sons, Inc.
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-three 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 0.65 – 0.95 and residual standard error of the regression range of 2.8123 – 3.3543 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 0.1355. 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

$$\text{Thus, } 0.1355 = \frac{3.0833}{\sqrt{518}} = \frac{3.0833}{22.7596}$$

Source of Information: Value Line, Inc., June 2021
Value Line Investment Survey (Standard Edition)

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

Proxy Group of Seven Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Atmos Energy Corporation	0.80	0.67	2.7774	0.0693
New Jersey Resources Corporation	1.00	0.93	3.0337	0.0757
Northwest Natural Holding Company	0.85	0.70	3.2144	0.0802
ONE Gas, Inc.	0.80	0.68	2.7447	0.0685
South Jersey Industries, Inc.	1.05	1.01	3.7945	0.0947
Southwest Gas Holdings, Inc.	0.95	0.86	3.1572	0.0788
Spire Inc.	0.85	0.73	2.8613	0.0714
Average	0.90	0.80	3.0833	0.0769

Beta Range (+/- 2 std. Devs. of Beta)	0.65	0.95
2 std. Devs. of Beta	0.15	
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.8123	3.3543
Std. dev. of the Res. Std. Err.	0.1355	
2 std. devs. of the Res. Std. Err.	0.2710	

Source of Information: Valueline Proprietary Database, June 2021

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

	[1]	[2]	[3]	[4]
Proxy Group of Forty-Three Non-Price Regulated Companies	VL Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Apple Inc.	0.90	0.83	3.2843	0.0819
Assurant Inc.	0.90	0.84	2.8245	0.0705
ANSYS, Inc.	0.85	0.77	3.1971	0.0798
Booz Allen Hamilton	0.90	0.84	3.1767	0.0793
Bristol-Myers Squibb	0.85	0.75	3.3304	0.0831
Brady Corp.	1.00	0.94	2.9465	0.0735
CACI Int'l	0.95	0.89	2.9930	0.0747
Casey's Gen'l Stores	0.90	0.81	3.2028	0.0799
Quest Diagnostics	0.80	0.69	2.9288	0.0731
Lauder (Estee)	0.95	0.91	2.8562	0.0713
Exponent, Inc.	0.90	0.81	2.9605	0.0739
Fastenal Co.	0.95	0.88	3.2005	0.0799
FirstCash, Inc.	0.90	0.79	3.2437	0.0809
Franklin Electric	0.95	0.89	3.2374	0.0808
GATX Corp.	1.00	0.92	3.1223	0.0779
Gorman-Rupp Co.	1.00	0.93	3.2972	0.0823
Int'l Flavors & Frag	0.95	0.85	3.3168	0.0828
Ingredion Inc.	0.90	0.84	2.8771	0.0718
Iron Mountain	0.90	0.78	3.1699	0.0791
Hunt (J.B.)	0.95	0.87	2.8702	0.0716
J&J Snack Foods	0.95	0.86	2.9559	0.0738
Henry (Jack) & Assoc	0.85	0.71	2.8328	0.0707
ManTech Int'l 'A'	0.85	0.77	3.1011	0.0774
Monster Beverage	0.85	0.76	3.0195	0.0753
Altria Group	0.95	0.86	2.9525	0.0737
MSA Safety	1.00	0.94	3.0342	0.0757
MSCI Inc.	0.95	0.87	2.9742	0.0742
Vail Resorts	0.95	0.88	3.2995	0.0823
Maxim Integrated	0.95	0.87	3.0073	0.0750
Northrop Grumman	0.85	0.72	2.8865	0.0720
Old Dominion Freight	0.95	0.86	2.9913	0.0746
Packaging Corp.	1.00	0.92	2.8690	0.0716
PerkinElmer Inc.	0.90	0.82	3.0422	0.0759
Philip Morris Int'l	0.95	0.91	3.2461	0.0810
Pool Corp.	0.85	0.74	3.2969	0.0823
Post Holdings	0.95	0.87	2.9481	0.0736
RLI Corp.	0.80	0.67	3.0423	0.0759
Rollins, Inc.	0.85	0.73	2.9580	0.0738
Selective Ins. Group	0.90	0.80	2.9918	0.0746
Sirius XM Holdings	0.95	0.88	2.8551	0.0712
Synopsys, Inc.	0.95	0.91	2.8936	0.0722
Tetra Tech	0.95	0.88	3.2523	0.0811
West Pharmac. Svcs.	0.80	0.69	3.2862	0.0820
Average	0.92	0.83	3.0645	0.0765
Proxy Group of Seven Natural Gas Distribution Companies	0.90	0.80	3.0833	0.0769

Source of Information: Valueline Proprietary Database, June 2021

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

Principal Methods	Proxy Group of Forty-Three Non-Price Regulated Companies
Discounted Cash Flow Model (DCF) (1)	13.38 %
Risk Premium Model (RPM) (2)	12.49
Capital Asset Pricing Model (CAPM) (3)	11.76
Mean	12.54 %
Median	12.49 %
Average of Mean and Median	12.52 %

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 Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Three Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Bloomberg'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)
Apple Inc.	0.66 %	14.50 %	12.70 %	12.80 %	17.93 %	14.48 %	0.71 %	15.19 %
Assurant Inc.	1.67	11.50	17.80	17.78	17.80	16.22	1.81	18.03
ANSYS, Inc.	-	8.00	12.30	12.12	11.52	10.99	-	NA
Booz Allen Hamilton	1.71	10.50	11.00	13.00	9.83	11.08	1.80	12.88
Bristol-Myers Squibb	2.95	12.50	7.00	5.53	7.95	8.25	3.07	11.32
Brady Corp.	1.57	7.50	7.00	9.00	7.00	7.63	1.63	9.26
CACI Int'l	-	13.50	13.10	12.06	13.68	13.08	-	NA
Casey's Gen'l Stores	0.66	10.50	NA	13.75	7.50	10.58	0.69	11.27
Quest Diagnostics	1.86	7.00	26.50	(4.96)	(8.66)	16.75	2.02	18.77
Lauder (Estee)	0.68	11.00	10.70	18.25	26.73	16.67	0.74	17.41
Exponent, Inc.	0.88	12.50	NA	NA	15.00	13.75	0.94	14.69
Fastenal Co.	2.12	9.00	9.00	7.85	7.17	8.26	2.21	10.47
FirstCash, Inc.	1.53	9.50	NA	NA	23.00	16.25	1.65	17.90
Franklin Electric	0.86	10.00	NA	15.00	13.40	12.80	0.92	13.72
GATX Corp.	2.14	6.00	NA	3.00	12.00	7.00	2.21	9.21
Gorman-Rupp Co.	1.76	8.50	NA	13.00	15.00	12.17	1.87	14.04
Int'l Flavors & Frag	2.12	7.50	9.80	15.99	7.72	10.25	2.23	12.48
Ingredion Inc.	2.77	7.50	NA	11.00	1.90	6.80	2.86	9.66
Iron Mountain	5.66	11.50	1.70	0.66	1.70	3.89	5.77	9.66
Hunt (J.B.)	0.72	8.00	15.00	14.65	21.53	14.80	0.77	15.57
J&J Snack Foods	1.47	10.00	NA	NA	6.00	8.00	1.53	9.53
Henry (Jack) & Assoc	1.13	9.00	14.00	12.47	10.64	11.53	1.20	12.73
ManTech Int'l 'A'	1.75	9.00	5.10	5.53	3.87	5.88	1.80	7.68
Monster Beverage	-	11.50	13.30	11.48	14.86	12.78	-	NA
Altria Group	7.10	6.00	4.00	4.25	4.54	4.70	7.27	11.97
MSA Safety	1.07	6.50	NA	9.00	18.00	11.17	1.13	12.30
MSCI Inc.	0.81	16.00	NA	14.95	15.31	15.42	0.87	16.29
Vail Resorts	-	7.50	NA	65.25	56.46	43.07	-	NA
Maxim Integrated	-	11.00	10.00	9.25	21.91	13.04	-	NA
Northrop Grumman	1.71	7.00	8.70	5.53	5.77	6.75	1.77	8.52
Old Dominion Freight	0.31	9.00	22.70	20.51	19.83	18.01	0.34	18.35
Packaging Corp.	2.82	5.00	5.00	3.00	13.06	6.52	2.91	9.43
PerkinElmer Inc.	0.19	11.00	37.90	(5.71)	37.90	28.93	0.22	29.15
Philip Morris Int'l	4.88	7.00	8.80	10.85	13.30	9.99	5.12	15.11
Pool Corp.	0.71	15.00	NA	17.00	17.00	16.33	0.77	17.10
Post Holdings	-	9.50	NA	20.30	31.20	20.33	-	NA
RLI Corp.	0.95	12.00	NA	NA	9.80	10.90	1.00	11.90
Rollins, Inc.	0.91	11.50	NA	NA	8.20	9.85	0.95	10.80
Selective Ins. Group	1.29	9.50	9.50	10.17	5.10	8.57	1.35	9.92
Sirius XM Holdings	0.92	31.50	12.20	28.98	10.10	20.69	1.02	21.71
Synopsys, Inc.	-	12.50	14.60	15.18	14.70	14.25	-	NA
Tetra Tech	0.65	13.50	15.00	16.00	15.00	14.88	0.70	15.58
West Pharmac. Svcs.	0.19	17.00	25.80	19.46	25.80	22.01	0.21	22.22
							Mean	13.94 %
							Median	12.81 %
							Average of Mean and Median	13.38 %

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 30, 2021. 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, Bloomberg Professional Services, 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 07/30/2021
www.yahoo.com Downloaded on 07/30/2021
Bloomberg Professional Services

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-Three Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	4.31 %
2.	Equity Risk Premium (2)	8.18
3.	Risk Premium Derived Common Equity Cost Rate	12.49 %

Notes: (1) Average forecast of Baa2 corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated August 3, 2021 and June 1, 2021 (see pages 10 and 11 of Exhibit No.___(DWD-4)). The estimates are detailed below.

Third Quarter 2021	3.50 %
Fourth Quarter 2021	3.70
First Quarter 2022	3.90
Second Quarter 2022	4.00
Third Quarter 2022	4.10
Fourth Quarter 2022	4.20
2023-2027	5.30
2028-2032	5.80
Average	4.31 %

(2) From page 5 of this Exhibit.

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

	Moody's Long-Term Issuer Rating July 2021		Standard & Poor's Long-Term Issuer Rating July 2021	
Proxy Group of Forty-Three Non-Price Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Apple Inc.	Aa1	2.0	AA+	2.0
Assurant Inc.	Baa3	10.0	BBB	9.0
ANSYS, Inc.	NA	--	NA	--
Booz Allen Hamilton	NA	--	NA	--
Bristol-Myers Squibb	A2	6.0	A+	5.0
Brady Corp.	NA	--	NA	--
CACI Int'l	NA	--	BB+	11.0
Casey's Gen'l Stores	NA	--	NA	--
Quest Diagnostics	Baa2	9.0	BBB+	8.0
Lauder (Estee)	A1	5.0	A+	5.0
Exponent, Inc.	NA	--	NA	--
Fastenal Co.	NA	--	NA	--
FirstCash, Inc.	Ba1	11.0	BB	12.0
Franklin Electric	NA	--	NA	--
GATX Corp.	Baa2	9.0	BBB	9.0
Gorman-Rupp Co.	NA	--	NA	--
Int'l Flavors & Frag	Baa3	10.0	BBB	9.0
Ingredion Inc.	Baa1	8.0	BBB	9.0
Iron Mountain	Ba3	13.0	BB-	13.0
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
J&J Snack Foods	NA	--	NA	--
Henry (Jack) & Assoc	NA	--	NA	--
ManTech Int'l 'A'	WR	--	BB+	11.0
Monster Beverage	NA	--	NA	--
Altria Group	A3	7.0	BBB	9.0
MSA Safety	NA	--	NA	--
MSCI Inc.	Ba1	11.0	BB+	11.0
Vail Resorts	B2	15.0	BB	12.0
Maxim Integrated	Baa1	8.0	BBB+	8.0
Northrop Grumman	Baa2	9.0	BBB+	8.0
Old Dominion Freight	NA	--	NA	--
Packaging Corp.	Baa2	9.0	BBB	9.0
PerkinElmer Inc.	Baa3	10.0	BBB	9.0
Philip Morris Int'l	A2	6.0	A	6.0
Pool Corp.	NA	--	NA	--
Post Holdings	B2	15.0	B+	14.0
RLI Corp.	Baa2	9.0	BBB	9.0
Rollins, Inc.	NA	--	NA	--
Selective Ins. Group	Baa2	9.0	BBB	9.0
Sirius XM Holdings	NA	--	BB	12.0
Synopsys, Inc.	NA	--	NA	--
Tetra Tech	NA	--	NA	--
West Pharmac. Svcs.	NA	--	NA	--
Average	Baa2	9.0	BBB	9.1

Notes:
(1) From page 6 of Exhibit No.___(DWD-4).

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-Three Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Seven Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Forty-Three Non-Price Regulated Companies
	Ibbotson-Based Equity Risk Premiums:	
1.	Ibbotson Equity Risk Premium (1)	5.92 %
2.	Regression on Ibbotson Risk Premium Data (2)	8.79
3.	Ibbotson Equity Risk Premium based on PRPM (3)	8.16
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	5.03
5	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	11.20
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	13.08
7.	Conclusion of Equity Risk Premium	8.70 %
8.	Adjusted Beta (7)	0.94
9.	Forecasted Equity Risk Premium	8.18 %

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

Sources of Information:
Stocks, Bonds, Bills, and Inflation - 2020 SBBI Yearbook, John Wiley & Sons, Inc.
Value Line Summary and Index
Blue Chip Financial Forecasts, August 3, 2021 and June 1, 2021
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 Seven Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Three 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)
Apple Inc.	0.90	1.00	0.95	9.55 %	2.74 %	11.81 %	11.93 %	11.87 %
Assurant Inc.	0.90	1.00	0.95	9.55	2.74	11.81	11.93	11.87
ANSYS, Inc.	0.85	0.95	0.90	9.55	2.74	11.33	11.57	11.45
Booz Allen Hamilton	0.90	0.91	0.91	9.55	2.74	11.43	11.64	11.54
Bristol-Myers Squibb	0.85	0.80	0.82	9.55	2.74	10.57	11.00	10.79
Brady Corp.	1.00	1.08	1.04	9.55	2.74	12.67	12.58	12.62
CACI Int'l	0.95	1.01	0.98	9.55	2.74	12.10	12.15	12.12
Casey's Gen'l Stores	0.90	0.92	0.91	9.55	2.74	11.43	11.64	11.54
Quest Diagnostics	0.80	0.96	0.88	9.55	2.74	11.14	11.43	11.29
Lauder (Estee)	0.95	1.00	0.97	9.55	2.74	12.00	12.07	12.04
Exponent, Inc.	0.90	0.96	0.93	9.55	2.74	11.62	11.79	11.70
Fastenal Co.	0.95	0.94	0.94	9.55	2.74	11.72	11.86	11.79
FirstCash, Inc.	0.85	0.94	0.90	9.55	2.74	11.33	11.57	11.45
Franklin Electric	0.95	0.99	0.97	9.55	2.74	12.00	12.07	12.04
GATX Corp.	1.00	1.00	1.00	9.55	2.74	12.29	12.29	12.29
Gorman-Rupp Co.	1.00	1.06	1.03	9.55	2.74	12.58	12.50	12.54
Int'l Flavors & Frag	0.95	1.08	1.01	9.55	2.74	12.38	12.36	12.37
Ingredion Inc.	0.90	0.93	0.91	9.55	2.74	11.43	11.64	11.54
Iron Mountain	0.90	1.04	0.97	9.55	2.74	12.00	12.07	12.04
Hunt (J.B.)	0.95	0.94	0.95	9.55	2.74	11.81	11.93	11.87
J&J Snack Foods	0.95	0.81	0.88	9.55	2.74	11.14	11.43	11.29
Henry (Jack) & Assoc	0.85	0.89	0.87	9.55	2.74	11.05	11.36	11.20
ManTech Int'l 'A'	0.85	1.12	0.99	9.55	2.74	12.19	12.22	12.21
Monster Beverage	0.85	0.97	0.91	9.55	2.74	11.43	11.64	11.54
Altria Group	0.95	0.89	0.92	9.55	2.74	11.53	11.72	11.62
MSA Safety	1.00	1.01	1.01	9.55	2.74	12.38	12.36	12.37
MSCI Inc.	0.95	0.91	0.93	9.55	2.74	11.62	11.79	11.70
Vail Resorts	0.95	1.13	1.04	9.55	2.74	12.67	12.58	12.62
Maxim Integrated	0.95	0.96	0.95	9.55	2.74	11.81	11.93	11.87
Northrop Grumman	0.85	0.78	0.82	9.55	2.74	10.57	11.00	10.79
Old Dominion Freight	0.95	0.99	0.97	9.55	2.74	12.00	12.07	12.04
Packaging Corp.	1.00	0.79	0.90	9.55	2.74	11.33	11.57	11.45
PerkinElmer Inc.	0.90	0.80	0.85	9.55	2.74	10.86	11.21	11.04
Philip Morris Int'l	0.95	0.92	0.94	9.55	2.74	11.72	11.86	11.79
Pool Corp.	0.85	0.95	0.90	9.55	2.74	11.33	11.57	11.45
Post Holdings	0.95	0.90	0.93	9.55	2.74	11.62	11.79	11.70
RLI Corp.	0.80	0.91	0.85	9.55	2.74	10.86	11.21	11.04
Rollins, Inc.	0.85	0.70	0.77	9.55	2.74	10.09	10.64	10.37
Selective Ins. Group	0.90	0.99	0.94	9.55	2.74	11.72	11.86	11.79
Sirius XM Holdings	0.95	1.13	1.04	9.55	2.74	12.67	12.58	12.62
Synopsys, Inc.	0.95	1.02	0.98	9.55	2.74	12.10	12.15	12.12
Tetra Tech	0.95	1.06	1.00	9.55	2.74	12.29	12.29	12.29
West Pharmac. Svcs.	0.80	0.74	0.77	9.55	2.74	10.09	10.64	10.37
		Mean	0.93			11.64 %	11.80 %	11.72 %
		Median	0.94			11.72 %	11.86 %	11.79 %
	Average of Mean and Median		0.94			11.68 %	11.83 %	11.76 %

Notes:
(1) From note 1 of page 2 of Exhibit No.___(DWD-5).
(2) From note 2 of page 2 of Exhibit No.___(DWD-5).
(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 30, 2021 (1) (millions)	(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	$ 1,548.633		7	1.54%	
2.	Proxy Group of Seven Natural Gas Distribution Companies	$ 3,695.963	2.4 x	5	1.09%	0.45%

	[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	$ 29,025.803	$ 1,966,078.882	-0.22%
	2	13,178.743	28,808.073	0.49%
	3	6,743.361	13,177.828	0.71%
	4	3,861.858	6,710.676	0.75%
	5	2,445.693	3,836.536	1.09%
	6	1,591.865	2,444.745	1.37%
	7	911.586	1,591.765	1.54%
	8	451.955	911.103	1.46%
	9	190.019	451.800	2.29%
Smallest	10	2.194	189.831	5.01%

*From 2021 Duff & Phelps 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 0.45% in Column [4], Line No. 2 is derived as follows 0.45% = 1.54% - 1.09%.

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

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2020 (millions)	[2] Book Value per Share at Fiscal Year End 2020 (1)	[3] Total Common Equity at Fiscal Year End 2020 (millions)	[4] Closing Stock Market Price on July 30, 2021	[5] Market-to-Book Ratio on July 30, 2021 (2)	[6] Market Capitalization on July 30, 2021 (3) (millions)
Southwest Gas Corporation		NA		881.909 (4)	NA		
Based upon Proxy Group of Seven Natural Gas Distribution Companies						175.6 (5)	$ 1,548.633 (6)
Proxy Group of Seven Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	125.882	$ 53.949	$ 6,791.203	$ 98.590	182.7 %	$ 12,410.753
New Jersey Resources Corporation	NYSE	95.949	19.226	1,844.692	38.520	200.4	3,695.963
Northwest Natural Holding Company	NYSE	30.589	29.054	888.733	52.290	180.0	1,599.499
ONE Gas, Inc.	NYSE	53.167	42.006	2,233.311	73.780	175.6	3,922.642
South Jersey Industries, Inc.	NYSE	100.592	16.571	1,666.876	25.170	151.9	2,531.899
Southwest Gas Holdings, Inc.	NYSE	57.193	46.771	2,674.953	69.930	149.5	3,999.501
Spire Inc.	NYSE	51.612	44.182	2,280.300	70.950	160.6	3,661.856
Median		57.193	42.006	2,233.311	69.930	175.600 %	3,695.963

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 30, 2021 is assumed to be equal to the market-to-book ratio of Proxy Group of Seven Natural Gas Distribution Companies on July 30, 2021 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2020 Annual Forms 10K
yahoo.finance.com
Bloomberg Professional

Southwest Gas Corporation
UBS and RRA Regulatory Rankings for the
Proxy Group of Seven Natural Gas Distribution Companies

Operating Company	Parent	State	UBS Gas Utility Regulatory Ranking [1]	RRA Regulatory Ranking [2]	RRA Regulatory Ranking [2]	Rate Base %	Rate Base weighted UBS Ranking	Rate Base weighted RRA Ranking
Atmos Energy	ATO	Colorado	38	Average / 1	6	2%	0.76	0.12
Atmos Energy	ATO	Kansas	16	Below Average / 1	3	3%	0.48	0.09
Atmos Energy	ATO	Kentucky	4	Average / 1	6	5%	0.20	0.30
Atmos Energy	ATO	Louisiana	13	Average / 2	5	8%	1.04	0.40
Atmos Energy	ATO	Mississippi	38	Above Average / 3	7	6%	2.28	0.42
Atmos Energy	ATO	Tennessee	26	Above Average / 3	7	4%	1.04	0.28
Atmos Energy	ATO	Texas	11	Average / 2	5	71%	7.81	3.55
Atmos Energy	ATO	Virginia	43	Average / 1	6	1%	0.43	0.06
New Jersey Natural Gas	NJR	New Jersey	NA	Below Average / 1	3	100%	NA	3.00
Northwest Natural Gas	NWN	Oregon	20	Average / 2	5	88%	17.60	4.40
Northwest Natural Gas	NWN	Washington	31	Average / 3	4	13%	4.03	0.52
Kansas Gas Service	OGS	Kansas	16	Below Average / 1	3	29%	4.64	0.87
Oklahoma Natural Gas	OGS	Oklahoma	20	Average / 2	5	42%	8.40	2.10
Texas Gas Service	OGS	Texas	11	Average / 2	5	29%	3.19	1.45
Elizabethtown Gas	SJI	New Jersey	NA	Below Average / 1	3	50%	NA	1.50
South Jersey Gas	SJI	New Jersey	NA	Below Average / 1	3	50%	NA	1.50
Southwest Gas Corporation	SWX	Arizona	19	Below Average / 1	3	46%	8.74	1.38
Southwest Gas Corporation	SWX	California	23	Average / 2	5	9%	2.07	0.45
Southwest Gas Corporation	SWX	Nevada	50	Average / 2	5	43%	21.50	2.15
Spire Alabama Inc.	SR	Alabama	1	Above Average / 1	9	10%	0.10	0.90
Spire Gulf Inc.	SR	Alabama	1	Above Average / 1	9	10%	0.10	0.90
Spire Mississippi Inc.	SR	Mississippi	38	Above Average / 3	7	1%	0.38	0.07
Spire Missouri East	SR	Missouri	6	Average / 3	4	40%	2.37	1.58
Spire Missouri West	SR	Missouri	6	Average / 3	4	40%	2.37	1.58
Proxy Group Company								
Atmos Energy Corporation	ATO			Average / 2			14.04	5.22
New Jersey Resources Corporation	NJR			Below Average / 1			NA	3.00
Northwest Natural Gas Company	NWN			Average / 2			21.63	4.92
ONE Gas, Inc.	OGS			Average / 3			16.23	4.42
South Jersey Industries, Inc.	SJI			Below Average / 1			NA	3.00
Southwest Gas Holdings, Inc.	SWX			Average / 3			32.31	3.98
Spire Inc.	SR			Average / 2			5.32	5.03
Proxy Group Average				Average / 3			17.91	4.22

Sources:
[1] UBS Gas Distribution 2021 Outlook, December 8, 2020
[2] Regulatory Research Associates, as of July 30, 2021

Southwest Gas Corporation
Moody's Iinvestors Service - Assessment of Regulatory Risk for the
Proxy Group of Seven Natural Gas Distribution Companies

	ATO	NJR	NWN	OGS	SJI	SR	SWX	Average	SWX
Factor 1: Regulatory Framework									
Legislative and Judicial Underpinnings of Regulatory Framework	A	A	A	A	A	A	A	A	A
Consistency and Predictability of Regulation	Aa	Aa	A	A	Aa	A	A	A	A
Factor 2: Ability to Recover Costs and Earn Returns									
Timeliness of Recovery of Operating and Capital Costs	Aa	A	Aa	A	A	A	Baa	A	Baa
Sufficiency of Rates and Returns	A	A	A	Baa	A	A	Baa	A	Baa
Factor 1: Regulatory Framework									
Legislative and Judicial Underpinnings of Regulatory Framework	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Consistency and Predictability of Regulation	3.00	3.00	2.00	2.00	3.00	2.00	2.00	2.43	2.00
Factor 2: Ability to Recover Costs and Earn Returns									
Timeliness of Recovery of Operating and Capital Costs	3.00	2.00	3.00	2.00	2.00	2.00	1.00	2.14	1.00
Sufficiency of Rates and Returns	2.00	2.00	2.00	1.00	2.00	2.00	1.00	1.71	1.00
Average	2.50	2.25	2.25	1.75	2.25	2.00	1.50	2.07	1.50

Source: Moody's Investors Service Credit Opinions Publications

Southwest Gas Corporation
Comparison of Regulatory Mechanisms for
Proxy Group of Seven Natural Gas Distribution Companies

Company (bold if parent)	State	Full or Partial Decoupling
Atmos Energy Corporation		
Atmos Energy Holdings, Inc.	CO	
Atmos Energy Holdings, Inc.	KS	Partial Decoupling
Atmos Energy Holdings, Inc.	KY	Partial Decoupling
Atmos Energy Holdings, Inc.	LA	Partial Decoupling
Atmos Energy Holdings, Inc.	MS	Partial Decoupling
Atmos Energy Holdings, Inc.	TN	Partial Decoupling
Atmos Energy Holdings, Inc.	TX	Partial Decoupling
Atmos Energy Holdings, Inc.	VA	Partial Decoupling
New Jersey Resources Corporation		
New Jersey Natural Gas Co.		Full Decoupling
Northwest Natural Holding Company		
Northwest Natural Gas	OR	Partial Decoupling
Northwest Natural Gas	WA	
ONE Gas, Inc.		
ONE Gas, Inc.	KS	Partial Decoupling
ONE Gas, Inc.	OK	Partial Decoupling
ONE Gas, Inc.	TX	Partial Decoupling
South Jersey Industries, Inc.		
Elizabethtown Gas Co.	NJ	Partial Decoupling
South Jersey Gas Co.	NJ	Full Decoupling
Southwest Gas Holdings, Inc.		
Southwest Gas Corporation	AZ	Full Decoupling
Southwest Gas Corporation	CA	Full Decoupling
Southwest Gas Corporation	NV	Full Decoupling
Spire Inc.		
Spire Alabama Inc.	AL	Partial Decoupling
Spire Gulf Inc.	AL	Partial Decoupling
Spire Mississippi Inc.	MS	Partial Decoupling
Spire Missouri East	MO	Partial Decoupling
Spire Missouri West	MO	Partial Decoupling

Source: S&P Global Market Intelligence, Company Financial Statements, Company Tariffs

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

Equity Issuances since 2010

		[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)
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%
						$ 778,592,134	$ 763,813,902	$ 14,778,233	1.90%

Flotation Cost Adjustment

	Average Dividend Yield	Average Projected EPS Growth Rate	Adjusted Dividend Yield	Average DCF Cost Rate Unadjusted for Flotation (8)	DCF Cost Rate Adjusted for Flotation (9)	Flotation Cost Adjustment (10)
Proxy Group of Seven Natural Gas Distribution Companies	3.44 %	6.11 %	3.55 %	9.66 %	9.73 %	0.07 %

See page 2 of this Exhibit for notes.

Source of Information: Company SEC filings

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

(1) Company SEC Filings.

(2) Column 2 – Column 3.

(3) Column 1 * Column 2.

(4) Column1 * Column 4.

(5) Column 1 * Column 3.

(6) Column 5 – Column 6

(7) (Column 5 – Column 6) divided by Column 5.

(8) Using the average growth rate from page 1 of Exhibit No.___(DWD-3).

(9) Adjustment for flotation costs based on adjusting the average DCF constant growth cost rate in accordance with the following:

$$K = \frac{D(1+0.5g)}{P(1-F)} + g\,,$$

where g is the growth factor and F is the percentage of flotation costs.

(10) Flotation cost adjustment of 0.07% equals the difference between the flotation adjusted average DCF cost rate of 9.73% and the unadjusted average DCF cost rate of 9.66% of the Utility Proxy Group.

Source of Information:

Company SEC Filings.

AFFIRMATION

STATE OF NEW JERSEY)

: ss.

COUNTY OF Burlington)

Dylan W. D'Ascendis being first duly sworn, deposes and says:

That I am the person identified in the Prepared Direct Testimony, and the exhibits applicable to my testimony; that such testimony and exhibits were prepared by me or under my direction; that the answers and information set forth therein are true to the best of my own knowledge and belief.

Dylan W. D'Ascendis

Signed and sworn to before me on

this 26th day of August, 2021.

Heather N. Fulmer

Notary Public

HEATHER N. FULMER
NOTARY PUBLIC OF NEW JERSEY
Commission # 50115526
My Commission Expires 10/25/2024

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. 21-08XXX

PREPARED DIRECT TESTIMONY
CARLA AYALA

ON BEHALF OF
SOUTHWEST GAS CORPORATION

AUGUST 31, 2021

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Prepared Direct Testimony
of
Carla Ayala

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Appendix A – Summary of Qualifications of Carla Ayala

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Prepared Direct Testimony
of
Carla Ayala

I. INTRODUCTION

Q. 1 Please state your name and business address.

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

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

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

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

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

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

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

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

A. 5 I sponsor the Company's billing determinants (number of bills and therms) for both the test period and certification period as well as the associated adjustments to the recorded bills and therms for both the Southern and Northern Nevada rate jurisdictions.

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

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

- The methodology used to develop the billing determinants for the test year under present rates.
- The five adjustments made by Southwest Gas to the recorded number of bills and therms.
- The methodology used to develop the annualized billing determinants for the certification period.

II. METHODOLOGY USED TO DEVELOP BILLING DETERMINANTS

Q. 7 Please describe the methodology Southwest Gas utilized to develop the billing determinants for the test year under present rates.

A. 7 The development of the billing determinants commenced with the compilation of the monthly recorded number of bills and therms by rate schedule for the 12-month period ended May 31, 2021. Certain adjustments were made to the recorded information to derive the adjusted test year billing determinants. Those adjustments include: (1) billing adjustments; (2) customer-specific volume annualizations; (3) customer reclassifications; (4) weather normalization; and (5) customer annualizations. The details of the adjustments are discussed below and presented in the Statement J Schedule J-1 Workpapers: Book 2 of Northern Nevada and Book 2 of Southern Nevada.

Q. 8 Why were the adjustments made to the test year billing determinants?

A. 8 The purpose of the adjustments is to ensure that the test year number of bills and volumes accurately reflect a full 12 months of consumption under normal weather conditions for each active customer billed at the end of the test year.

Adjustments to test year billing determinants have been made pursuant to Section 703.2355 (2) of Nevada Administration Code, which states: “Jurisdictional operating revenues must be adjusted to show the annual effect of changes occurring during the period of testing.”

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

A. 9 No. In fact, Southwest Gas has utilized the same general methodology to develop the billing determinants since 2001.

III. ADJUSTMENTS TO BILLING DETERMINANTS

Q. 10 Please explain Southwest Gas’ billing adjustments.

A. 10 After compiling recorded test year billing determinants, significant billing anomalies were investigated to ensure that the correct consumption level is reflected for each month in the test year. Most of the corrections for billing adjustments involved restating the monthly consumption levels for customer bills to reflect actual monthly usage with no impact upon the total test year sales. This adjustment is necessary to ensure that the monthly adjusted volumes accurately reflect actual test year consumption. Otherwise, distorted monthly values would reduce the reliability of the regression analysis associated with the weather normalization adjustments, which is addressed later in my testimony.

Q. 11 Please explain Southwest Gas’ customer-specific volume annualization adjustments.

A. 11 After completing the corrections for billing adjustments, customer-specific volume annualization adjustments were performed to reflect a full year of consumption for active customers billed during May 2021. This process involves estimating additional consumption for months during the test year where a new customer was not on-line or was clearly in a start-up phase, as well as removing consumption attributable to specific customers who discontinued service during the test year.

Q. 12 Please explain the purpose of Southwest Gas' customer reclassification adjustments.

A. 12 Customer reclassification adjustments move customers within or between rate schedules. These adjustments are performed to ensure that customer-specific consumption reflects a full 12 months of usage under the correct rate schedule at the end of the test year. Reclassification adjustments do not impact the overall number of bills or volumes for the test year.

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

A. 13 Weather normalization adjustments provide an accurate depiction of monthly test year volumes under normal (average) weather conditions. To the extent that weather for the test year deviates from normal weather conditions, heat-sensitive consumption per customer should be adjusted to provide an accurate representation of monthly test year volumes under normal weather conditions.

For the test year in this case, actual billing cycle heating degree days were approximately 9.5 percent colder than normal in Southern Nevada and approximately 1.5 percent warmer than normal in Northern Nevada. As a result of these deviations from normal weather, adjustments to test year volumes were computed to reflect anticipated volumes under normal weather conditions.

Q. 14 What rate schedules received weather normalization adjustments in Southern Nevada and Northern Nevada?

A. 14 In both Southern Nevada and Northern Nevada, weather normalization adjustments were completed for the single-family residential rate schedule; the multi-family residential rate schedule; the residential air conditioning rate schedule; and the apartment, small commercial, large commercial and armed forces categories within the general service rate schedules.

Q. 15 How many years of historical weather data were utilized to calculate the normal (average) heating degree days used to weather normalize the heat-sensitive volumes for the test year?

A. 15 Southwest Gas utilized ten years (120 months ended May 2021) of historical weather data to calculate normal (average) heating degree days.

Q. 16 Is the use of ten-year average heating degree days to weather normalize the heat-sensitive volumes consistent with Southwest Gas' prior practices for general rate cases in Nevada?

A. 16 Yes. Southwest Gas has consistently utilized ten-year average heating degree days to weather normalize test year volumes in every general rate case filed in Nevada since 1985.

Q. 17 Please explain Southwest Gas' procedure for calculating the weather normalization adjustments.

A. 17 Southwest Gas conducted regression analyses to quantify the historical relationships between actual monthly consumption per customer and heating degree day for each heat-sensitive customer class. The monthly consumption per heating degree days factors (regression coefficients) quantified in the regression analyses were then applied to monthly heating degree day deviations from normal to quantify the corresponding monthly adjustments to consumption per customer.

The Southern Nevada District Large Commercial rate schedules: G2, G3 and G4 Annual Demand, were weather normalized by applying the percent change factor calculated from a percent change between the monthly actual and weather normalized sales volumes from similar rate schedules. The G2-LC rate schedule utilized the percent change factor from the G2-SC rate schedule, the G3-LC rate schedule utilized the percent change factor from the G3-SC rate schedule and the G4-LC Annual Demand rate schedule utilized the percent change factor from the G4-LC Monthly Demand rate schedule.

The Mesquite District Single Family Residential and General Service Small Commercial rate schedules were weather normalized by utilizing the regression coefficients and heating degree days for the same rate schedules in the Southern Nevada District. The General Service Large Commercial rate schedule was weather normalized by applying the percent change factor calculated from a percent change between the monthly actual and weather normalized sales volumes for the General Service Small Commercial (G2) rate schedule in the Mesquite District.

The Spring Creek District Single-Family Residential rate schedule was weather normalized by utilizing the regression coefficients and heating degree days for the same rate schedule in the Elko District.

The methodologies utilized to develop the weather normalization adjustments for the Mesquite and Spring Creek Districts as well as the Large Commercial customers in Southern Nevada were based on a lack of historical data to develop regression equation coefficients.

Q. 18 What was the impact of the weather normalization adjustments upon test year volumes?

A. 18 The net result of the weather normalization adjustments was a decrease in test year volumes of 16,431,011 therms in Southern Nevada, and an increase in test year volumes of 634,646 therms in Northern Nevada.

Q. 19 Please explain Southwest Gas' customer annualization adjustments.

A. 19 Customer annualization adjustments were made to annualize the number of bills and volumes based upon the number of active customers billed during the last month of the test year.

Q. 20 Why were customer annualization adjustments performed for these customers?

A. 20 In reference to test year volumes, Section 703.2355 (2) of the Nevada Administrative Code states,

> "Adjusted sales for each rate schedule to show the annual effect of increases or decreases in the number of customers during such a period may be computed using the number of customers at the end of the period and the average annual usage and demand per customer, except where the applicant can attribute changes in sales directly to changes in the usage or demand of individual customers."

With the exception of the single-family and multi-family residential rate schedules, the small commercial customers within the general service rate schedules, the SG-G1 apartment customers, and the SG-L customers all rate schedules have been annualized by individual customer, based upon customer-specific information. These customer-specific annualization adjustments were covered under the "volume annualization" adjustments previously discussed in my testimony. Because of the sheer magnitude of customers in the rate schedules listed above, tracking billing histories to perform customer specific billing or annualization adjustments was impractical. Accordingly, annualization adjustments were performed using the number of customers at the end of the test period and the weather normalized average consumption per customer.

Q. 21 Please summarize the impact of the adjustments for the preparation of the annualized number of bills and therms for the test year under present rates.

A. 21 The impacts of each of the adjustments upon the number of bills and volumes for the test year are indicated by rate schedule in the supporting schedules Northern Nevada Schedule J-1, sheets 12 through 14 and the Southern Nevada Schedule J-1, sheets 12 through 14. All adjustments (billing adjustments, customer-specific volume annualizations, and customer annualizations) were made to ensure the accuracy and propriety of the number of bills and therms used to establish rates.

IV. CERTIFICATION PERIOD BILLING DETERMINANTS

Q. 22 Please describe the methodology used to develop the annualized billing determinants for the certification period in this filing.

A. 22 The certification billing determinants for this filing were developed by calculating volumes for the certification period ended November 2021 from the consumption per customer derived from the test year ended May 2021 and a customer forecast at November 2021 for the Single-Family and Multi-Family residential rate schedules; the small commercial customers within the general service rate schedules; and the apartment customers within the SG-G1 rate schedule. A customer annualization adjustment, as mentioned earlier in my testimony, was then performed on these rate schedules to calculate the annualized bills and volumes for the certification period. All other customers were held constant to the May 2021 test period. A subsequent certification filing will be made with updated actual customers for the annualized customers through November 2021.

Q. 23 Why does Southwest Gas forecast customers for the above-mentioned rate schedules?

A. 23 Southwest Gas forecasts the Single-Family and Multi-Family residential rate schedules; the small commercial customers within the general service rate schedules; and the apartment customers within the SG-G1 rate schedule to accurately reflect expected customer growth between the test period and certification filing.

Q. 24 How would you characterize the customer growth Southwest Gas has experienced in Nevada over the last couple of years?

A. 24 Southwest Gas has experienced robust customer growth over the last five years; Northern Nevada's growth rate has averaged 1.24 percent annually and Southern Nevada's growth rate has averaged 2.06 percent annually. The Company expects continued robust customer growth for the foreseeable future.

Q. 25 Does this conclude your prepared direct testimony?

A. 25 Yes.

SUMMARY OF QUALIFICATIONS
CARLA AYALA

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

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

AFFIRMATION

STATE OF NEVADA)

: ss.

COUNTY OF CLARK)

Carla Ayala being first duly sworn, deposes and says:

That I am the person identified in the Prepared Direct Testimony, and the exhibits applicable to my testimony; that such testimony and exhibits were prepared by me or under my direction; that the answers and information set forth therein are true to the best of my own knowledge and belief.

Carla Ayala

Carla Ayala

Signed and sworn to before me on this 23rd day of August , 2021.

Stella Meneses

Notary Public

NOTARY PUBLIC
STATE OF NEVADA
County of Clark
STELLA MENESES
Appt. No. 99-51091-1
My Appt. Expires Dec. 8, 2022

SUMMARY OF QUALIFICATIONS
CARLA AYALA

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

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

AFFIRMATION

STATE OF NEVADA)

: ss.

COUNTY OF CLARK)

Carla Ayala being first duly sworn, deposes and says:

That I am the person identified in the Prepared Direct Testimony, and the exhibits applicable to my testimony; that such testimony and exhibits were prepared by me or under my direction; that the answers and information set forth therein are true to the best of my own knowledge and belief.

Carla Ayala

Carla Ayala

Signed and sworn to before me on this 23rd day of August , 2021.

Stella Meneses

Notary Public

NOTARY PUBLIC
STATE OF NEVADA
County of Clark
STELLA MENESES
Appt. No. 99-51091-1
My Appt. Expires Dec. 8, 2022

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 21-08-____

PREPARED DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

ON BEHALF OF

SOUTHWEST GAS CORPORATION

AUGUST 31, 2021

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of
Timothy S. Lyons

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Appendix A – Summary of Qualifications of Timothy S. Lyons

Exhibit No. ___(TSL-1)

Exhibit No. ___(TSL-2)

Exhibit No. ___(TSL-3)

BEFORE THE STATE OF NEVADA PUBLIC UTILITIES COMMISSION

Prepared Direct Testimony

of

Timothy S. Lyons

I. INTRODUCTION

Q. 1 Please state your name and business address.

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

Q. 2 Please describe your current position.

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

Q. 3 Please summarize your educational background and professional experience.

A. 3 My educational background and professional experience is summarized in Appendix A to this testimony.

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

A. 4 Yes, I have previously sponsored testimony before 20 regulatory commissions, including the Public Utilities Commission of Nevada (Commission). A summary of my qualifications is included in Appendix A.

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

A. 5 The purpose of my pre-filed direct testimony is to sponsor Southwest Gas's (Southwest Gas or Company) proposed rates for the Company's two Nevada rate jurisdictions: Southern Nevada and Northern Nevada. Each rate jurisdiction has its own set of statements and schedules. Furthermore, each statement and schedule discussed in this testimony is applicable to the Southern Nevada and Northern Nevada rate jurisdictions, unless otherwise indicated.

The testimony includes:

- Description of the Company's compliance with two Commission Class Cost of Service Study (CCOSS) directives from the Company's most recent rate case proceeding in Docket No. 20-02023.
- Description of the Company's compliance with a Commission directive in Docket No. 19-02024 regarding special contract rates.
- Development of two CCOSS for each rate jurisdiction.
    - The first CCOSS (Version 1) allocates the Company's overall cost of service to each of the Company's tariff rate classes, except "recourse" rate classes SG-G5, SG-G6, SG-G7 and NG-G5.[1]
    - The second CCOSS (Version 2) is generally consistent with the first CCOSS (Version 1) except the second CCOSS (Version 2) allocates the Company's overall cost of service to each of the Company's tariff rate classes including the recourse rate classes.
- Development of the proposed tariff rates for the non-recourse rate classes based on the results of the CCOSS (Version 1). The testimony also includes a bill comparison between the proposed and current tariff rates for the non-recourse rate classes.

---

[1] CCOSS (Version 1) excludes Schedules SG-G5. SG-G6, SG-G7 and NG-G5 since those Schedules reflect "recourse" rates that are based on the cost of serving negotiated rate customers. Presently, there is a customer taking service under the recourse rates (Schedule SG-G6). The proposed change in recourse rate SG-G6 is reflected in CCOSS (Version 1) since it has an impact on development of the non-recourse rates. The customer taking service under SG-G6 was formerly taking service under Schedule SG-G4.

- Development of the proposed tariff rates for the recourse rate classes based on the results of the CCOSS (Version 2). The proposed recourse rates represent the otherwise applicable cost of service rates for negotiated rate customers.
- The revenue adjustment associated with certain negotiated rate customers, as discussed by Company witness Amy L Timperley.
- Development of the lead lag study used to support the cash working capital requirement.

Q. 6 Please summarize your testimony.

A. 6 First, the testimony describes the Company's compliance with two Commission directives from the Company's most recent rate case proceeding and one Commission directive from a Special Contracts proceeding.

In addition, the testimony describes the results of the Company's CCOSS (Version 1) that shows the current rate design produces a disparity in class rates of return ("ROR") for the Southern and Northern Nevada rate jurisdictions, as shown respectively in Figures 1 and 2 (below). The Figures summarize each rate class's "unit" ROR (where "unit" ROR is the class ROR as a factor of the system or overall ROR).

Figure 1: Class ROR vs. System ROR (Southern Nevada)

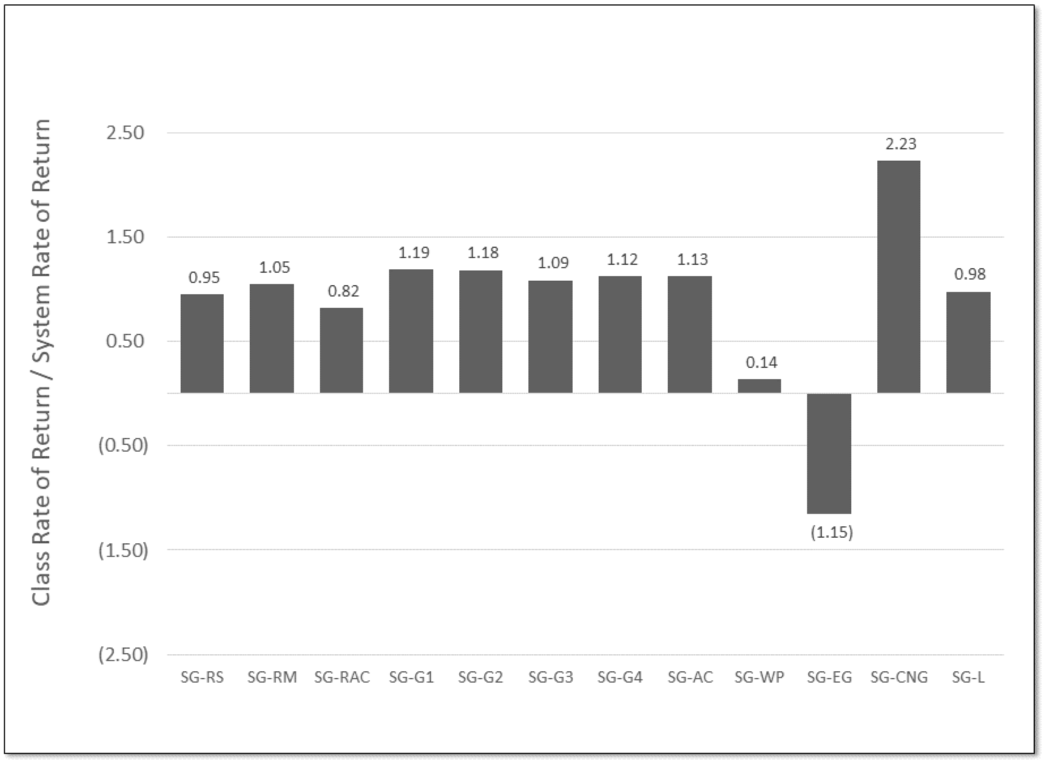

Figure 1 (Southern Nevada) shows that some of the rate classes produce RORs at current rates that are less than the system ROR (i.e., the unit ROR is less than 1.00), indicating the current rates recover less than their cost of service. The remaining rate classes produce RORs that are higher than the system ROR (i.e., the unit ROR is greater than 1.00), indicating the current rates recover more than their cost of service.

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

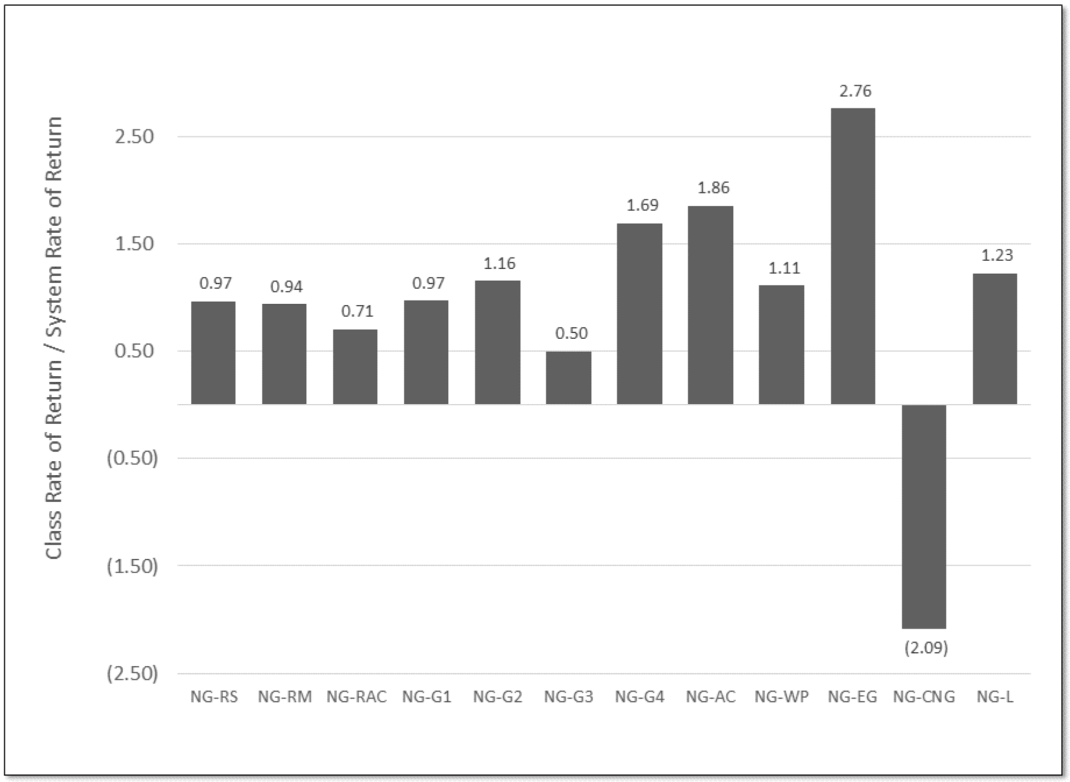

Figure 2 (Northern Nevada) also shows that some of the rate classes produce RORs at current rates that are lower than the system ROR (i.e., the unit ROR is lower than 1.00), indicating the rates recover less than their cost of service. The remaining rate classes produce RORs that are higher than the system ROR (i.e., the unit ROR is more than 1.00), indicating the current rates recover more than their cost of service.

The CCOSS was developed by identifying the relationship between the service requirements for each rate class and their respective cost drivers. This approach is well established in industry literature. Except as described in my prepared direct testimony, the CCOSS was developed consistent with the methodologies approved by the Commission in the Company's most recent general rate case filing in Docket No. 20-02023.

The results of the Company's CCOSS were used to evaluate the extent to which the current rates are fair and equitable, that is, when class RORs are equal to the system ROR. The results of the CCOSS were then used to inform the proposed rates.

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

The Company prepared a bill impact analysis to evaluate the impact of the proposed rate changes. The bill impact analysis compares the impacts of the proposed rate changes on customer bills during an average summer and an average winter month. The analysis also compares bills at 50.0 percent of average monthly summer and winter use and 150.0 percent of average monthly summer and winter use.

The impact of the proposed rate increase on Residential monthly bills varies depending on jurisdiction and season, as shown in Figure 3 (below).

Figure 3: Comparison of Proposed Residential Bill vs. Current Bill

Bill Impact Analysis: Single-Family Residential Gas Service	Monthly Consumption (Therms)	Month Bill ($) Proposed Rates	Month Bill ($) Current Rates	Increase / (Decrease) Dollars ($)	Increase / (Decrease) Percent (%)
Southern Nevada					
50 Percent of Average Use	11	$ 20.90	$ 19.87	$ 1.03	5.18%
Average <u>Summer</u> Use	21	30.26	28.28	1.98	7.00%
150 Percent of Average Use	32	40.18	37.19	2.99	8.04%
50 Percent of Average Use	31	$ 39.26	$ 36.36	$ 2.90	7.98%
Average <u>Winter</u> Use	62	67.65	61.86	5.79	9.36%
150 Percent of Average Use	93	96.19	87.48	8.71	9.96%
Northern Nevada					
50 Percent of Average Use	12	$ 24.22	$ 23.37	$ 0.85	3.64%
Average <u>Summer</u> Use	25	38.25	36.51	1.74	4.77%
150 Percent of Average Use	37	52.18	49.55	2.63	5.31%
50 Percent of Average Use	50	$ 66.72	$ 63.17	$ 3.55	5.62%
Average <u>Winter</u> Use	100	122.09	115.03	7.06	6.14%
150 Percent of Average Use	149	177.43	166.85	10.58	6.34%

Figure 3 shows the proposed residential rates will increase winter bills for the average Southern Nevada customer using 62 therms in a winter month by $5.79 per month, or 9.36 percent, and for an average Northern Nevada customer using 100 therms in a winter month by $7.06 per month, or 6.14 percent. The bills reflect the currently effective Tariff rate.

The Company also developed a second CCOSS (Version 2) for each jurisdiction that includes the recourse rate classes. The proposed recourse rates were based on the results of the CCOSS (Version 2). The recourse rates represent otherwise applicable cost of service rates for the negotiated rate customers.

II. COMPLIANCE WITH COMMISSION DIRECTIVES

Q. 7 Please describe the Commission's CCOSS directives from the Company's most recent rate case proceeding in Docket No. 20-02023.

A. 7 The Commission's two CCOSS directives from the Company's most recent rate case are stated below.

1. "The Commission also directs SWG to coordinate with BCP and Staff, to the extent practicable, to develop and provide a zero-intercept CCOSS in its next GRC as recommended by BCP."[2]

2. "The Commission directs SWG to study BCP's proposal related to Allocator #5 and present the findings of this study prior to filing its next GRC, as proposed by BCP and agreed to by SWG in rebuttal testimony."[3]

Q. 8 Has the Company complied with the Commission's directives?

A. 8 Yes. First, the Company prepared a zero-intercept CCOSS for this filing. The classification approach and findings are discussed below. The Company shared the classification approach, initial findings and workpapers related to the zero-intercept with BCP and Staff prior to the rate case filing.

The Company also prepared a study of BCP's proposal related to Allocator #5. The allocator approach and findings are discussed below. The Company also shared the allocator approach, initial findings and workpapers related to Allocator #5 with BCP and Staff prior to the rate case filing.

Q. 9 Please describe the Commission's directive in Docket No. 19-02024 regarding special contracts.

---

[2] Order in Docket No. 20-02023 at paragraph 495.
[3] Order in Docket No. 20-02023 at paragraph 494.

A. 9 The Commission's directive is provided below.

"8. …Southwest Gas…shall file, in their next general rate cases, otherwise applicable rate schedules that include minimum and maximum rates (for all variable commodity or demand charge rate components and the non-discountable basic service charge applicable to each customer's otherwise applicable rate class) for customers taking service pursuant to a discounted rate contract, a contract for an alternative fuel capable customer, or a contract for special services.

9. In their next general rate case, in the rate design or cost of service study section of the filing, Southwest Gas…shall also identify any customer-specific facilities whose costs are not yet fully depreciated that are allocable to each contract customer."[4]

Q. 10 Has the Company complied with the Commission's directives?

A. 10 Yes. First, the Company prepared minimum and maximum rates in this filing. The proposed rates are discussed below.

In addition, the Company identified in its workpapers customer-specific facilities whose costs are not yet fully depreciated that are allocated to negotiated rate or contract customers.

<u>III. OVERVIEW OF THE CCOSS</u>

Q. 11 Please describe the purpose of a CCOSS.

A. 11 The purpose of a CCOSS is to allocate a utility's overall cost of service to each rate class in a manner that reflects its underlying cost of service. The CCOSS sponsored in this testimony was developed by identifying the relationship

---

[4] Order in Docket No. 19-02024 at 16.

between the service requirements for each rate class and their respective cost drivers. This approach is well established in industry literature[5] and is consistent with the Company's approach adopted by the Commission in Docket No. 20-02023.

Q. 12 How was the CCOSS developed?

A. 12 The CCOSS was developed utilizing models adopted by the Commission in Docket No. 20-02023. Each rate base and expense item in the CCOSS was assigned to a rate class based on the three-step process described below. Two CCOSS studies were developed for each of the Company's two rate jurisdictions: Southern and Northern Nevada. The first CCOSS (Version 1) was used to develop non-recourse tariff rates while the second CCOSS (Version 2) was used to develop recourse tariff rates.

Q. 13 Please describe the approach used to develop the CCOSS.

A. 13 The approach used to develop the CCOSS consisted of a three step process: (1) functionalization, or cost assignment into functional categories, largely related to production, storage, transmission and distribution; (2) classification, or cost assignment according to whether costs are related to serving peak demands, customer service requirements, or commodity demands; and (3) allocation, or cost assignment to rate classes consistent with the functionalization and classification steps described above.

. . .

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

Q. 14 Please describe the data used to prepare the CCOSS.

A. 14 The CCOSS was based on data for the period December 1, 2020 through November 30, 2021.[6] The CCOSS includes the number of customers, usage and revenues by rate class. Usage reflects normal weather conditions. Revenues at present rates reflect the Company's current margin rates. The CCOSS also includes rate base items, including intangible plant, distribution, and general plant-in-service as well as (a) additions to rate base, including cash working capital, and materials and supplies, and (b) reductions to rate base, including deferred income taxes, accumulated deferred income taxes, and customer deposits. The CCOSS also includes operations and maintenance (O&M) expenses, including distribution, customer service, customer account, sales, and administrative and general expenses as well as taxes other than income, such as payroll and property taxes, and income taxes.

Q. 15 What is Functionalization?

A. 15 Functionalization consists of separating rate base and expense items into operational components that include production, storage, transmission, and distribution.

Q. 16 Please describe the functionalization process used to develop the CCOSS.

A. 16 The functionalization process used to develop the CCOSS followed the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts. Southwest Gas does not have production or storage facilities in its Nevada service areas but has transmission facilities in its Southern Nevada service area.

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[6] The period June 1, 2021 through November 30, 2021 represents the "Certification" period.

Gas commodity costs, which include production and pipeline charges and related costs, are recovered through the Base Tariff Energy Rate (BTER) and are not included in the CCOSS.

Q. 17 What is Classification?

A. 17 Classification consists of separating rate base and expense items into categories based on cost drivers.

Q. 18 Please describe the classification process used to develop the CCOSS.

A. 18 The CCOSS classified costs into one of three categories:

- Customer – costs that vary with customer access to the natural gas system as well as on-going customer services, such as meter reading and billing services.
- Demand – costs that vary with customer peak demand requirements
- Commodity – costs that vary with customer commodity requirements.

In some cases, costs were classified into only one of the three categories. The cost of meter reading, for example, was classified as customer. Meter reading costs vary with the number of customers. In other cases, costs were classified into more than one category. The cost of distribution mains, for example, was classified as both customer and demand. Distribution main costs vary with the number of customers and peak day demands.

Q. 19 Please describe the classification of distribution mains.

A. 19 Distribution mains typically represent the largest plant investment for a natural gas utility. The classification of distribution mains reflects two cost drivers. The first driver is the number of customers. Distribution mains are designed to provide customer access to the natural gas system. The second driver is peak day demand. Distribution mains are designed to meet customer demands on the design day.[7]

The classification of distribution mains in the CCOSS is consistent with the Company's approach approved by the Commission in Docket No. 20-02023, which classifies distribution mains as 50 percent customer and 50 percent demand.

Q. 20 Did the Company evaluate other approaches to classify distribution mains?

A. 20 Yes. The Company considered two other approaches to classify distribution mains: (1) the zero-inch or zero-intercept method, consistent with the Commission's directive discussed earlier; and (2) the minimum system method. Both methods are recognized by the National Association of Regulated Utility Commissions ("NARUC"). NARUC states,

> "One argument for inclusion of distribution related items in the customer cost classification is the 'zero or minimize size main theory.' This theory assumes that there is a zero or minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service as he so desires.
>
> Under the minimum size main theory, all distribution mains are priced out at the historical unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution

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[7] Design day demand is the highest estimated gas demand for a 24-hour period and is used as a basis for designing the capacity of the transmission and distribution system.

mains is assigned to demand. The zero-inch main method would allocate the cost of a theoretical main of zero-inch diameter to the customer function, and allocate the remaining costs associated with mains to demand"[8]

Q. 21 What is the zero-inch or zero-intercept method?

A. 21 The zero-inch or zero-intercept method represents the cost of connecting customers to the distribution system with a hypothetical "zero-size" main. The method is based on a regression analysis that examines the relationship between distribution main sizes and their average costs. The regression analysis produces an intercept that represents the average cost of a theoretical zero-inch distribution main, or a distribution main that serves no demand. The zero-inch main costs are classified as customer, while costs in excess of the zero-inch main cost are classified as demand.

Q. 22 How was the estimated cost of a zero-inch main determined?

A. 22 The estimated cost of a zero-inch main was based on a regression analysis of distribution main sizes and their average costs. The regression analysis produced an intercept that represented the average cost ($ per foot) of a theoretical zero-inch distribution main. Multiplying the average cost of a zero-inch main by the actual number of feet in the system yielded a theoretical cost of a system comprised of zero-inch mains. The customer portion of distribution mains was calculated as the ratio of the cost of a zero-inch main to the total cost of the mains system.

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[8] NARUC Gas Distribution Rate Design Manual. Pg. 22-23

Q. 23 What were the results of the zero-inch method?

A. 23 The results of the zero-inch method show the customer portion of the mains investment is 41.93 percent and 41.94 percent, respectively, for Southern and Northern Nevada, as shown in Figures 4 and 5 (below).

Figure 4: Results of Zero-Inch Analysis (Southern Nevada)

Southern Nevada Zero-Intercept Analysis		
Total Quantity (Plastic)		33,271,456
Zero-Intercept Unit (Plastic)	$	17.55
Total Quantity (Steel)		1,961,773
Zero-Intercept Unit (Steel)	$	36.58
Zero-Intercept System	$	655,669,919
Total System Costs	$	1,563,606,861
Customer-Related		41.93%

Figure 4 shows for Southern Nevada the estimated cost of a zero-inch plastic and steel main was $17.55 per foot and $36.58 per foot, respectively. Multiplying the estimated cost of a zero-inch main by the actual number of feet in the system yielded a theoretical cost of a system comprised of zero-inch mains of $655.7 million. The customer portion of distribution mains of 41.93 percent was calculated as the ratio of the cost of zero-inch mains of $655.7 million to the total cost of the mains system of $1.6 billion. The demand portion of the total cost of the mains system was 58.07 percent.

Figure 5: Results of Zero-Inch Analysis (Northern Nevada)

Northern Nevada Zero-Intercept Analysis		
Total Quantity (Plastic)		9,183,760
Zero-Intercept Unit (Plastic)	$	10.01
Total Quantity (Steel)		892,094
Zero-Intercept Unit (Steel)	$	18.31
Zero-Intercept System	$	108,231,971
Total System Costs	$	258,065,488
Customer-Related		41.94%

Figure 5 shows for NNV the estimated cost of a zero-inch plastic and steel main was $10.01 per foot and $18.31 per foot, respectively. Multiplying the estimated cost of a zero-inch main by the actual number of feet in the system yielded a theoretical cost of a system comprised of zero-inch mains of $108.2 million. The customer portion of distribution mains of 41.94 percent was calculated as the ratio of the cost of zero-inch mains of $108.2 million to the total cost of the mains of $258.1 million. The demand portion of the mains investment was 58.06 percent.

Q. 24 How was the estimated cost of a minimum size main determined?

A. 24 The estimated cost of a minimum size main was based on a two-inch plastic main, which is the smallest main commonly installed by the Company. Multiplying the estimated cost of two-inch plastic main by the actual number of feet in the system yielded the theoretical cost of a system comprised of two-inch mains. The customer portion of distribution mains was calculated as the ratio of the cost of a two-inch mains system to the cost of the total mains system.

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Q. 25 What were the results of the minimum size main method?

A. 25 The results of the minimum size main method show the customer portion of the mains investment is 70.21 percent and 71.33 percent, respectively, for Southern and Northern Nevada, as shown in Figures 6 and 7 (below).

Figure 6: Results of Minimum Size Main Method (Southern Nevada)

Southern Nevada Minimum System Analysis		
Total Quantity		35,234,968
Min-System Unit Costs	$	31.51
Min-System Costs	$	1,110,291,459
Total System Costs	$	1,581,460,677
Customer-Related		70.21%

Figure 6 shows for Southern Nevada the estimated cost of a minimum size main is $1.1 billion, which is based on the estimated cost of a two-inch plastic main and the actual number of feet in the system. The customer portion of distribution mains of 70.21 percent was calculated as the ratio of the cost of minimum size main of $1.1 billion to the total cost of the mains of $1.6 billion. The demand portion of the mains investment was 29.79 percent.

Figure 7: Results of Zero-Inch Analysis (Northern Nevada)

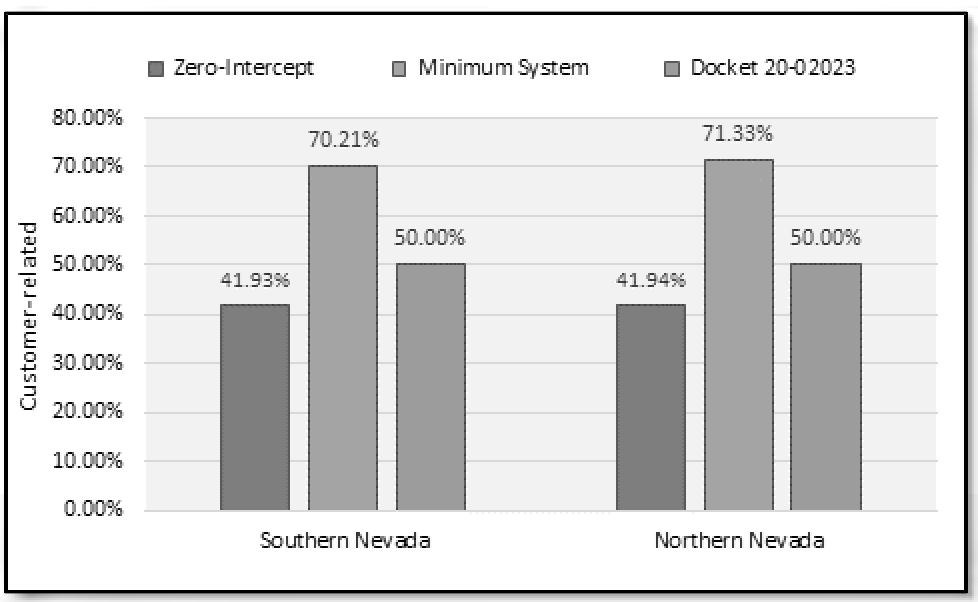
Northern Nevada Minimum System Analysis		
Total Quantity		10,078,010
Min-System Unit Costs	$	18.27
Min-System Costs	$	184,092,872
Total System Costs	$	258,095,019
Customer-Related		71.33%

Figure 7 shows for Northern Nevada the estimated cost of a minimum size main is $184.1 million and is based on the estimated cost of a two-inch plastic main and the actual number of feet in the system. The customer portion of distribution mains of 71.33 percent was calculated as the ratio of the cost of minimize size main of $184.1 million to the total cost of the mains of $258.1 million. The demand portion of the mains investment was 28.67 percent.

Q. 26 What is the Company's recommendation regarding the classification of distribution main?

A. 26 The Company recommends classifying distribution mains in this proceeding as 50.00 percent customer and 50.00 percent demand (50/50). First, the 50/50 approach is consistent with the approach approved by the Commission in the most recent rate case proceeding. The approach has been in place for many years. Second, the 50/50 approach is between the results of the zero-inch and minimum size system methods, as shown in Figure 8 (below). As discussed earlier, the zero-inch and minimum size system methods are recognized in the industry as approaches for classifying distribution main.

Figure 8: Summary of Distribution Mains Classification Methods



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Q. 27 Please discuss the classification of other rate base items.

A. 27 Other rate base items were similarly classified based on their underlying cost drivers. For example, meter cost, meter installation, service cost, and regulator investments were classified as customer since they provide customer access to the natural gas system. Rate base items not directly associated with one of the classification categories, such as general plant, were classified through a composite classifier based on the related costs.

Q. 28 Please discuss classification of operations and maintenance (O&M) expenses.

A. 28 O&M expenses were classified similar to their respective plant items. For example, Maintenance of Services (Account 892) was allocated based on the allocation of Services plant (Account 380).

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

Q. 29 What is Allocation?

A. 29 Allocation consists of assigning rate base and expense items to individual rate classes based on allocators that reflect their underlying cost of service.

Q. 30 Please describe the allocation process used to develop the CCOSS.

A. 30 Costs were allocated to each rate class based on the costs incurred to serve that rate class. In short, cost allocation follows cost causation. This is an established industry approach and is consistent with the Company’s approach in Docket No. 20-02023. This approach requires development of cost allocators that reflect the design of the natural gas system.

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

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

Q. 31 Please describe the process used to develop the demand allocator.

A. 31 The demand allocator is based on peak month (January) sales. The allocator reflects each rate class's responsibility to peak month sales. The approach is consistent with the method approved by the Commission in the Company's most recent rate case proceeding.

Q. 32 Does the Company suggest evaluation of an alternative demand allocator should the Commission have concerns with using peak month (January) sales?

A. 32 Yes. The Company suggests evaluation of the Average and Peak (A&P) method for the demand allocator should the Commission have concerns with using peak month (January) sales. The Average and Peak (A&P) method is a generally accepted method for a demand allocator for natural gas utilities.[9] The allocator is based on a weighted average of each rate classes' responsibility to the average day and peak day (or design day) demands of the system.

The average day portion of the allocator is based on each rate class's responsibility to the average daily demands on the system. The "Peak" portion

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[9] National Association of Regulatory Utility Commissioners, Staff Subcommittee on Gas. "Gas Distribution Rate Design Manual", p. 27 (June 1989).

of the allocator is based on each rate class's responsibility to the peak day (or design day) demands of the system. The "Average" portion is weighted by the system's load factor to arrive at the portion of costs attributable to average use and thus assigned to customers based on class contributions to average daily demands. The remaining portion (1 minus the system's load factor) is considered attributable to peak use and thus is assigned to customers based on class contributions to peak day (or design day) demands.

Q. 33 Please describe the process used to develop the special studies allocators.

A. 33 There were three special studies developed to allocate meter investments, meter installations, service investments, regulators, and industrial customer investments. The allocators were developed separately for each of the Company's rate jurisdictions.

- Meters and Meter Installation investments were allocated to each rate class based on the average installed cost of a meter in each rate class.
- Service investments were allocated to each rate class based on the average installed cost of a service line in each rate class.
- Industrial customer investments were allocated to the large industrial rate classes since the investments are used to serve those customers.

Q. 34 Has the Company made enhancements to its Meters study?

A. 34 Yes. The Company conducted a more comprehensive study of the Company's meters that added more precision to the allocator. The current study was based on a full population of the Company's meters while the prior study was based on a sample of the Company's meters. The current study consisted of four steps.

In the first step, the Company identified the number of active meters by meter type installed for each rate class. In the second step, the Company identified the average cost of meter equipment and meter installation by meter type. In the third step, the Company calculated the total cost of installed meters by rate class based on the number of meters by type (determined in step 1) and meter installation costs (determined in step 2). In the fourth and final step, the Company calculated the average installed meter cost by rate class.

Q. 35 Did the Company evaluate an alternative method to allocate the customer portion of distribution mains?

A. 35 Yes. Consistent with the Commission's directive discussed earlier, the Company prepared analysis related to Allocator #5, which allocates the customer portion of distribution mains, as shown in Figure 9 (below).

Figure 9: Summary of Allocator #5 Analysis

	Recent Projects	Housing Units	Main Footage	Main Footage per Housing Unit	Average Main Footage
1	Oquendo Apartments	244	4,144	17	13.3
2	Seven Hills Apartments	286	3,285	11	13.3
3	North 5th & Rome Phase I Apartments	176	1,984	11	13.3
4	Rise Apartments	122	2,065	17	13.3
5	Core Apartments	320	1,901	6	13.3
6	Solana Apartments	204	1,598	8	13.3
7	Jardin Gardens Apartments	80	2,272	28	13.3
8	The Gallery Apartment Homes	325	2,019	6	13.3
9	Elysian at Flamingo Apartments	360	2,035	6	13.3
10	Rome Pines Phase II Apartments	116	1,984	17	13.3
11	Espinoza Terrace Apartments	100	2,283	23	13.3
12	Level 25 @ Cactus Apartments	320	5,664	18	13.3
13	Level 25 @ Oquendo Apartments Phase II	59	4,144	70	13.3
14	Wardell Townhomes	65	2,174	33	13.3
15	Arista Apartments	220	2,300	10	13.3
	Total	2,997	39,852	13.3	
1	Highlands Single Family	165	5,967	36	37.9
2	Parcel D Single Family	156	6,032	39	37.9
3	Cadence Single Family	150	5,703	38	37.9
4	Saguaro Single Family	126	4,000	32	37.9
5	Binion 80 Single Family	126	4,793	38	37.9
6	Valley Vista 1.2 Single Family	138	5,078	37	37.9
7	Palmer Ranch Single Family	224	9,845	44	37.9
8	Silverado Ranch and Arville Single Family	189	11,472	61	37.9
9	Valley Vista 2.2 Single Family	135	5,150	38	37.9
10	Ascent Single Family	137	3,398	25	37.9
11	Cassia Single Family	207	6,747	33	37.9
12	Highland Village 21 Single Family	246	5,421	22	37.9
13	Ann and Hualapia Single Family	218	11,297	52	37.9
14	Desert Skies Single Family	179	5,881	33	37.9
	Total	2,396	90,784	37.9	
	Total	5,393	130,636	24.2	
	Ratio of Single-Family to Multi-Family			2.8	

The Figure shows main footage per housing unit of 29 recent multifamily and single-family projects. The Figure shows main footage per multifamily unit of 13.3 feet and main footage per single-family unit of 37.9 feet.

Q. 36 Does the Company propose using the analysis to allocate the customer portion of distribution mains?

A. 36 No. The Company does not propose to use the analysis for several reasons. First, the analysis is limited to a certain sample of units over a limited period. Second, the analysis is based only on the mains needed to serve a specific project without consideration for the larger network. In other words, the analysis does not evaluate how might the main extensions for other projects have had an impact on the 29 projects. Third, the Company believes a better approach is to compare the relationship between miles of distribution main and customers. The Company prepared such a comparison with distribution main and customer data from 2010 to 2020. The Company found a strong statistical relationship between the miles of distribution main and number of customers. The data and regression equations for Southern and Northern Nevada, respectively, are shown in Figures 10 and 11 (below).

Figure 10: Customers and Miles of Distribution Main (Southern Nevada)

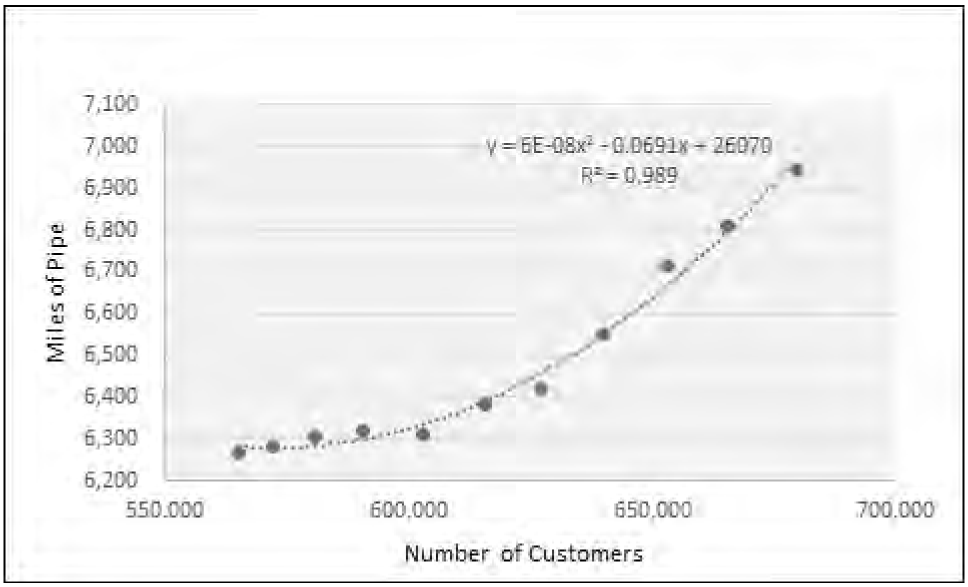

Figure 10 shows an r-square of 0.9890, which indicates 98.90 percent of the increase in distribution mains for Southern Nevada can be explained by increases in the number of customers.

Figure 11: Customers and Miles of Distribution Main (Northern Nevada)

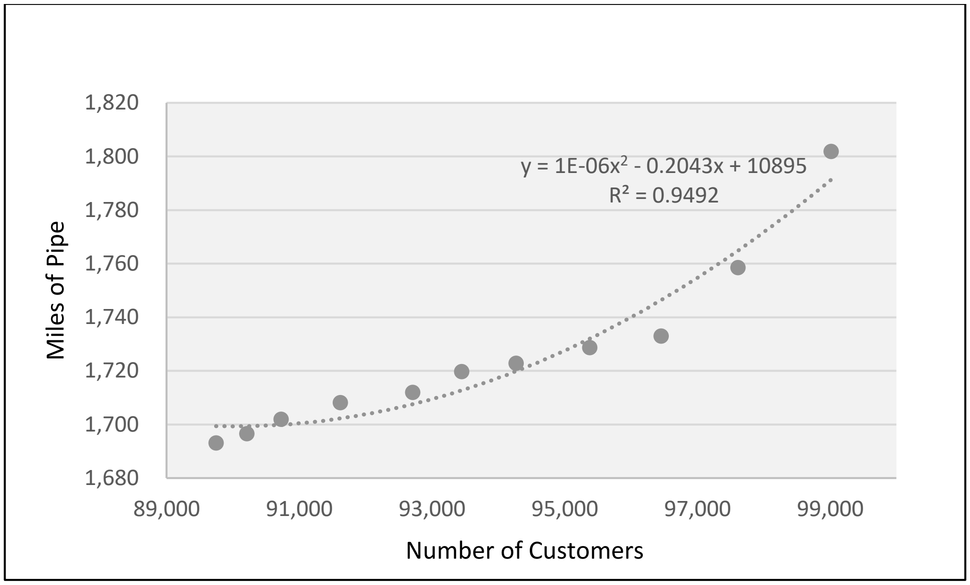

Figure 11 shows an r-square of 0.9492, which indicates 94.92 percent of the increase in distribution mains for Northern Nevada can be explained by increases in the number of customers.

Q. 37 Please describe the process to allocate rate base items to each rate class.

A. 37 The allocation of rate base to each rate class is summarized in the filed Statement N schedules. Plant investment by individual FERC account was allocated to each rate class based on an allocator that most closely reflects the underlying cost driver. Additions and deductions to net plant investment were allocated to each rate class based on an allocator that most closely reflects the underlying cost driver to form rate base.

In general, the Company's allocation methodologies were consistent with those adopted by the Commission in Docket No. 20-02023.

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Q. 38 Please describe allocation of O&M expenses to the customer classes.

A. 38 The allocation of O&M expenses to each rate class is summarized in the filed Statement N schedules. As discussed earlier, the special studies were used in some cases to allocate certain costs to each rate class.

In general, the Company's allocation methodologies were consistent with those adopted by the Commission in Docket No. 20-02023., including allocation of Other Gas Supply Expenses (FERC Account 813) and Distribution System Load Dispatching Expenses (FERC Account 871) based on rate class throughput.[10]

IV. RESULTS OF THE CCOSS (VERSION 1)

Q. 39 Please summarize the results of the Company's CCOSS (Version 1).

A. 39 The results of CCOSS (Version 1) are shown in Figures 1 and 2 (above). The Figures compared the calculated ROR for each rate class based on current rates to the system or overall ROR.

Q. 40 What conclusions can be reached when a rate class ROR is higher or lower than the system ROR?

A. 40 If a rate class produces a ROR that is lower than the system ROR, then the revenues recovered from the rate class are less than the cost of service. Conversely, if a rate class produces a ROR that is higher than the system ROR, then the revenues recovered from the rate class are more than the cost of service. As discussed below, the CCOSS (Version 1) results were used to inform the proposed rate design for each rate class.

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[10] Order in Docket No. 20-02023, paragraph 501 and paragraph 510.

V. DEVELOPMENT OF THE RATE DESIGN

Q. 41 Please provide an overview of the Company's rates.

A. 41 Customers are presently served under rate classes based on the type of service and load characteristics. The Company's current rate structure consists of delivery charges that recover delivery costs, and gas cost charges that recover purchased gas costs and several surcharges. The delivery charges include a monthly Basic Service Charge and commodity charge per Therm. The General Service-4 also includes a demand charge that recovers the delivery cost of service.

Q. 42 Please describe the principles used to guide the proposed rate design.

A. 42 The proposed rate design was guided by several principles common throughout the industry, including: (a) rates should recover the overall cost of providing service; (b) rates should be fair, minimizing inequities to the maximum extent possible; and (c) rate changes should be tempered by rate continuity concerns.[11]

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

Q. 43 How were the principles applied to the proposed rate design?

A. 43 First, rates were designed to recover the overall cost of service. This was done by developing customer and usage charges based on test year bills and usage. In addition, rates were designed to be fair and equitable. This was done by setting revenue targets that reflect each rate class's cost of service subject to rate continuity considerations. As discussed earlier, the results of the CCOSS

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

show that some rate classes produce less than the overall ROR. The goal of the proposed rate design was to eliminate that deficiency, subject to rate continuity considerations.

Q. 44 What is the total revenue requirement that you used as a starting point for the rate design?

A. 44 The total revenue requirement used as a starting point for the rate design is described in the testimony of Company Witness Greg Waller.

Q. 45 Please describe the process used to set the revenue targets for each rate class.

A. 45 The proposed revenue targets for each rate class were based on the results of the CCOSS, adjusted to reflect a 10.0 percent cap on cost allocation changes to address rate continuity consideration. The 10.0 percent cap is consistent with the cap used in the Company's most recent rate case as well.

Q. 46 Please describe the proposed rate design for each rate class.

A. 46 The proposed rate design for each rate class is provided in the filed Statement J-1 schedules. The proposed Residential rate design is described below.

Basic Service Charge

The Company proposes to maintain the current residential basic service charge. The current single-family basic service charge is $10.80 per month, and the current multifamily basic service charge is $9.00 per month. The charges are the same for customers in the Southern and Northern Nevada jurisdictions.

Commodity Charges

The Company proposes a residential commodity charge that recovers delivery costs not recovered through the Basic Service Charge. The Company proposes a commodity charge of $0.48645 per therm for single family residential customers and $0.51356 per therm for multi-family residential customers in Southern Nevada. In Northern Nevada, the Company proposes a commodity charge of $0.39209 per therm for single family residential customers and $0.42499 per therm for multi-family residential customers.

Q. 47 What rate structure is the Company proposing for the general service customers?

A. 47 The Company proposes to retain its existing rate structure for the general service customers. The three General Service rate classes (G1, G2 and G3) have a two-part rate structure, consisting of a monthly Basic Service Charge and a single commodity charge. The remaining General Service rate classes (G4, G5 and G6) have a three-part rate structure, consisting of a monthly Basic Service Charge, a single commodity charge, and a demand charge based on the customers' highest monthly gas demand in the past 12 months.

Q. 48 Which schedules evaluate the impact of the proposed rate design on customers?

A. 48 Statement O schedules evaluate the impact of the proposed rate design on customers. The schedules compare average customer bills at the present and proposed base rates. The impact of the proposed base rate increases on residential monthly bills varies depending on jurisdiction and season, as shown in Figure 3 (above).

Q. 49 Has Southwest Gas included schedules showing the proposed revenue changes by rate schedule?

A. 49 Yes. Statement J schedules show the proposed revenue changes by rate schedule.

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Q. 50 Has the Company prepared CCOSS results based on alternative cost allocation methods?

A. 50 Yes. The Company prepared CCOSS results based on alternative cost allocation methods, as summarized in Figures 12 and 13 (below). The Figures show changes in rate class ROR under four cost allocation methods: (1) the Company's approach; (2) classification of distribution mains based on the zero-inch or zero-intercept method; (3) classification of distribution mains based on the minimum system method; and (4) allocation of the customer portion of distribution mains based on a 3:1 customer ratio for multi-family customers.

Figure 12: Summary of Alternative Cost Allocations (Southern Nevada)

Alternative Cost Allocations ROR Comparison	Company Proposed	Zero Intercept	Minimum System	Allocator #5 3:1 Ratio
SG-RS	5.07%	5.20%	4.76%	4.57%
SG-RM	5.60%	6.34%	4.10%	11.78%
SG-RAC	4.36%	3.55%	7.18%	4.23%
SG-G1	6.35%	6.16%	6.87%	6.12%
SG-G2	6.30%	5.43%	9.19%	6.24%
SG-G3	5.80%	4.64%	10.29%	5.78%
SG-G4	5.99%	4.74%	11.00%	5.99%
SG-AC	6.00%	5.22%	8.52%	5.90%
SG-WP	0.73%	0.07%	3.29%	0.72%
SG-EG	-6.14%	-6.09%	-6.32%	-6.14%
SG-CNG	11.90%	10.16%	18.55%	11.86%
SG-L	5.22%	5.85%	3.92%	4.50%
System Rate of Return	5.33%	5.33%	5.33%	5.33%

Figure 12 shows for Southern Nevada, for example, single-family ROR of 5.07 percent, 5.20 percent, 4.76 percent, and 4.57 percent, respectively, under the four cost allocation options as compared to the overall or system ROR of 5.33 percent. The multi-family ROR increases from 5.60 percent to 11.78 percent under the 3:1 customer ratio.

Figure 12 also shows for Southern Nevada SG-G4 ROR of 5.99 percent, 4.74 percent, 11.00 percent, and 5.99 percent, respectively, under the four cost allocation options.

Figure 13: Summary of Alternative Cost Allocations (Northern Nevada)

Alternative Cost Allocations ROR Comparison	Company Proposed	Zero Intercept	Minimum System	Allocator #5 3:1 Ratio
NG-RS	4.81%	5.12%	4.13%	3.83%
NG-RM	4.67%	5.39%	3.35%	16.23%
NG-RAC	3.51%	3.69%	3.12%	2.73%
NG-G1	5.74%	5.37%	6.53%	5.62%
NG-G2	2.47%	1.98%	3.54%	2.45%
NG-G3	8.40%	7.89%	9.51%	8.39%
NG-AC	9.22%	9.15%	9.25%	8.64%
NG-WP	5.53%	5.67%	5.17%	4.81%
NG-EG	13.71%	13.69%	13.69%	13.38%
NG-CNG	-10.37%	-10.59%	-9.84%	-10.44%
NG-L	6.10%	7.24%	4.13%	4.26%
System Rate of Return	4.96%	4.96%	4.96%	4.96%

Figure 13 shows for Northern Nevada, for example, single-family ROR of 4.81 percent, 5.12 percent, 4.13 percent, and 3.83 percent, respectively, under the four cost allocation options as compared to the overall or system ROR of 4.96 percent. The multi-family ROR increases from 4.67 percent to 16.23 percent under the 3:1 customer ratio.

Figure 13 also shows for Northern Nevada NG-G3 ROR of 8.40 percent, 7.89 percent, 9.51 percent, and 8.39 percent, respectively, under the four cost allocation options.

VI. DEVELOPMENT OF THE CCOSS (VERSION 2)

Q. 51 Please describe the overall development of the CCOSS (Version 2).

A. 51 The CCOSS (Version 2) is generally consistent with the CCOSS (Version 1) except CCOSS (Version 1) allocated the Company's overall cost of service to only the Company's non-recourse rates while the CCOSS (Version 2) allocated the Company's overall cost of service to the Company's non-recourse and recourse rates. The CCOSS (Version 2) followed the same three-step process as the CCOSS (Version 1) for both the Southern Nevada and Northern Nevada rate jurisdictions.

Q. 52 Please describe the CCOSS (Version 2) for the Southern Nevada rate jurisdiction.

A. 52 The CCOSS (Version 2) for the Southern Nevada rate jurisdiction included six negotiated rate customers and one existing GS-G6 customer. The CCOSS (Version 2) was developed based on the methodologies adopted by the Commission in Docket No. 20-02023. Specifically, the CCOSS (Version 2) includes allocation of system distribution costs, consistent with the Commission's Order in Docket No. 20-02023.[12]

Q. 53 Please describe the development of the CCOSS (Version 2) for Northern Nevada rate jurisdiction.

A. 53 The CCOSS (Version 2) for the Northern Nevada rate jurisdiction included one negotiated rate customer.[13] The CCOSS (Version 2) was developed based on the methodologies adopted by the Commission in Docket No. 20-02023. Specifically, the CCOSS (Version 2) includes allocation of system distribution costs, consistent with the Commission's Order in Docket No. 20-02023.

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[12] Order in Docket No. 20-02023, paragraphs 562 through 575.

[13] In Docket No. 20-02023, the Company also included five Direct Connect customers to the Northern Nevada CCOSS (Version 2). The Company discontinued service to these customers in compliance with the Commission Order in Docket 20-02023, paragraph 464.

Q. 54 Please describe the overall results of the Company's CCOSS (Version 2).

A. 54 Summaries of the allocation of rate base, expenses, and the resulting overall cost of service to the recourse rates are shown in Exhibit No. __(TSL-1) to my direct testimony, Sheets 1 and 2 for Southern Nevada and Northern Nevada respectively.

<u>VII. DEVELOPMENT OF PROPOSED RECOURSE RATES</u>

Q. 55 Please describe development of the proposed recourse rates.

A. 55 First, the Company proposes one change to the recourse rate tariff schedules: to combine Schedules SG-G6 and SG-G7. Presently, Schedule SG-G6 is applicable to customers whose winter use (December through March) is at least twenty percent but less than fifty percent of their annual use, while Schedule SG-G7 is applicable to customers whose winter use is less than twenty percent of their annual use. The negotiated rate customer used as the basis for the SG-G7 recourse rate in the last rate case is no longer eligible for SG-G7 based on their current consumption. Instead, the customer is now eligible for Schedule SG-G6.

The Company's proposed solution to this change is to expand eligibility of Schedule SG-G6 to include customers whose winter use is less than twenty percent. Thus, Schedule SG-G6 eligibility would be expanded to include those customers currently eligible for Schedule SG-G7.

Presently, the SG-G6 demand change is approximately 6.0 percent higher than the SG-G7 demand charge; thus, combining the rate classes should not result in substantial rate continuity considerations.

The overall approach to develop the recourse rates was consistent with the methodologies adopted by the Commission in Docket No. 20-02023. In addition, the Company prepared minimum and maximum rates for the recourse rate schedules in this filing, in compliance with Commission directive in Special Contract proceeding (Docket No. 19-02024) discussed earlier.

Q. 56 Please describe development of the proposed minimum and maximum rates for recourse rates SG-G5, SG-G6 and NG-G5.

A. 56 The proposed minimum rates for recourse rates SG-G5, SG-G6 and NG-G5 were based on the results of the CCOSS (Version 2) and reflect demand and commodity charges that recover O&M-related costs, as shown in Figure 14 (below). The proposed maximum rates were based on the proposed rates.

Figure 14: Minimum Rates for SG-G5, SG-G6 and NG-G5

Minimum and Maximum Rates ($ per Therm)	Minimum Rates	Maximum Rates
Southern Nevada		
SG-G5		
Basic Service Charge	$ 1,000.00	$ 1,000.00
Transportation Charge	500.00	500.00
Demand Charge	$ 0.00061	$ 0.00485
Commodity Charge	0.00242	0.00433
SG-G6		
Basic Service Charge	$ 1,000.00	$ 1,000.00
Transportation Charge	500.00	500.00
Demand Charge	$ 0.00500	$ 0.02855
Commodity Charge	0.00242	0.00966
Northern Nevada		
NG-G5		
Basic Service Charge	$ 1,000.00	$ 1,000.00
Transportation Charge	500.00	500.00
Demand Charge	$ 0.00620	$ 0.01361
Commodity Charge	0.00250	0.00411

The Figure shows for Southern Nevada, for example, the SG-G5 minimum demand and commodity charges are, respectively, $0.00061 per therm and $0.00242 per therm.

VIII. CONTRACT TRANSITION ADJUSTMENT PROVISION

Q. 57 Does the Company propose to continue the Contract Transition Adjustment Provision (CTAP) mechanism approved by the Commission in Docket No. 20-02023?

A. 57 Yes. The Company proposes to continue the Contract Transition Adjustment Provision ("CTAP") mechanism approved by the Commission in Docket No. 20-02023.[14] The CTAP mechanism addresses Company's concerns that if the negotiated contract customers decide to move to the proposed recourse rates, there may be a difference in revenues associated with such transition. The CTAP is a two-way balancing account through which any such loss or gain in revenues will be recovered or returned from retail customers through a per therm charge until rates can be reset in a general rate case. The CTAP is included in the proposed Tariff Sheets.

IX. GENERAL REVENUES ADJUSTMENT (GRA) PROVISION

Q. 58 What is the Company's proposal regarding the continuation of its GRA provision[15]?

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[14] Order in Docket No. 20-02023, paragraphs 576 through 579.

[15] Nevada Administrative Code (NAC) Section 704.9716 (3), states, "In the initial general rate application requesting approval to decouple general rate revenues and each subsequent general rate application for which the gas utility continues to use the general revenue decoupling methodology, the gas utility must request approval to exempt any customer class from the general revenue decoupling methodology. The gas utility must apply the approved general revenue decoupling methodology to all customer classes not specifically exempted by the Commission.

A. 58 The Company requests authority to continue the GRA provision originally approved by the Commission in Docket No. 09-04003. The GRA provision has performed as designed: (1) benefiting customers by providing credits during times of colder-than-normal weather; and (2) benefiting the Company by recovering revenues generally consistent with the Commission-authorized revenue levels. Consistent with NAC 704.9716, the Company requests approval to continue to track and balance the margins for the Single-Family Residential, Multi-Family Residential, and the General Service rate classes (SG/NG-1; SG/NG-2; and SG/NG-3).

Q. 59 Does the Company propose a change to the GRA Provision?

A. 59 Yes. The Company proposes to include (or not exempt) Schedule No. SG/NG-4 from the GRA provision. Nevada Administrative Code (NAC) Section 704.9716 (3) states:

> "In the initial general rate application requesting approval to decouple general rate revenues and each subsequent general rate application for which the gas utility continues to use the general revenue decoupling methodology, the gas utility must request approval to exempt any customer class from the general revenue decoupling methodology. The gas utility must apply the approved general revenue decoupling methodology to all customer classes not specifically exempted by the Commission."

In past rate cases, the Company proposed to exempt Schedule No. SG/NG-4 from the GRA provision.

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Q. 60 Why is the Company proposing this change?

A. 60 The Company believes the proposed change accomplishes two objectives: (1) better aligns with the purpose of the GRA Provision in ensuring the Company does not over- or under-recover its authorized revenues, and (2) removes the Company's financial disincentive in supporting the State of Nevada's goal of reducing Greenhouse Gas (GHG) emissions since its achievement would include a reduction in natural gas usage.[16]

Q. 61 Why should other rate classes be exempt from the GRA provision?

A. 61 The exclusion of the other rate classes is consistent with the Commission's determination in Docket Nos. 09-04003 and 12-04005, where the Commission recognized that unintended consequences of the GRA provision could be harmful to certain customer classes. See Order, Docket No. 09-04003 at ¶ 228. As noted in Docket No. 09-04003, unintended consequences of the GRA provision could occur where a customer class is not of a sufficient size in the number of customers or where customers of a class do not possess homogeneous consumption characteristics. For those same reasons, the other rate classes should continue to be excluded from the GRA provision.

X. CONTRACT REVENUE ADJUSTMENT

Q. 62 Please describe the Company's proposal to adjust customer rates to refund annually to Northern Nevada customers an overcollection of revenues of $30,775 and recover annually from Southern Nevada customers an undercollection of revenues of $1,636,056.

[16] Senate Bill 245

A. 62 The Company proposes to adjust customer rates to refund annually to Northern Nevada customers an overcollection of revenues of $30,775 and recover annually from Southern Nevada customers an undercollection of revenues of $1,636,056, as explained in the direct testimony of Company witness Amy L. Timperley. The adjustment is shown on Line 13 of Schedule N-2, Sheet 4 of 4

XI. LEAD LAG STUDY

Q. 63 Please describe the development of the lead lag study.

A. 63 The lead-lag study compares differences between the Company's revenue lag and expense leads. The revenue lag measures the number of days from the time natural gas service is provided to customers to the time payment is received from customers. The expense leads measure the number of days from the time goods and services used to provide natural gas service are provided to the Company to the time payments are made by the Company for those goods and services. The lag and leads are measured in days for individual expenses, converted to "dollar-days" that reflect a weighting by expense amount, and then summed across all expenses. Schedule G-5 provides the results of the Company's lead-lag study for the test year.

Q. 64 Does this conclude your prepared direct testimony?

A. 64 Yes, it does.

Summary of Qualifications

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

Tim has sponsored testimony before 20 state regulatory commissions. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

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

Capabilities

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

Articles and Speeches

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

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted and sponsored testimony supporting a lead-lag study for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
California Public Utilities Commission			
Liberty Utilities (CalPeco Electric)	5/21	Docket No. A 21-05-017	Sponsored testimony supporting the lead-lag study/cash working capital, marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation (Southern California, Northern California and South Lake Tahoe jurisdictions)	8/19	Docket No. A.19-08-015	Sponsored testimony on behalf of three separate rate jurisdictions supporting revenue requirements, lead-lag/ cash working capital, and class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Maine Public Utilities Commission			
Maine Water Company	03/21	Docket No. 2021-00053	Sponsored testimony supporting a proposed rate smoothing mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.

Sponsor	Date	Docket No.	Subject
Massachusetts Department of Public Utilities			
Liberty Utilities (New England Gas Company)	08/20	Docket No. DPU 20-92	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2020/2021 through 2024/2025.
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Missouri Public Service Commission			
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting class cost of service, rate design, and lead-lag study proposals for a general rate case proceeding. The testimony also included support for a proposed revenue adjustment mechanism.
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.

Sponsor	Date	Docket No.	Subject
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
New Hampshire Public Utilities Commission			
Unitil (Northern Utilities, Inc.)	8/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	4/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
Nevada Public Utilities Commission			
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
New Jersey Board of Public Utilities			
South Jersey Gas Company	03/20	Docket No. GR20030243	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Corporation Commission of Oklahoma			
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The

Sponsor	Date	Docket No.	Subject
			testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
Texas Gas Service Company – Central Texas and Gulf Coast Service Areas	12/19	GUD No. 10928	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Beaumont/ East Texas Division	11/19	GUD No. 10920	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Virginia State Corporation Commission			
American Electric Power - Appalachian Power Company	3/20	Case No. PUR-2020-00015	Sponsored testimony supporting the Lead/Lag study for the 2020 triennial review of base rates, terms and conditions.

SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
CLASS COST OF SERVICE STUDY SUMMARY - PROPOSED RATES AT SYSTEM RATE OF RETURN
TWELVE MONTHS ENDED MAY 31, 2021 (TEST YEAR)

Line No.	Description	Allocation Factor	General Gas Service - 5	General Gas Service - 6	Line No.
	(a)	(b)	(c)	(d)	
1	Rate Base				
2	Total Direct Net Plant		$ 14,728,369	$ 113,689,884	2
3	Total Common Systems Allocable Net Plant		490,969	3,789,846	3
4	Cash Working Capital	11.2	58,747	453,473	4
5	Materials & Supplies	1.1	66,066	509,971	5
6	Customer Advances	8.0	0	0	6
7	Deferred Taxes	1.1	(2,260,823)	(17,451,542)	7
8	Other Debits and Credits	1.1	223,887	1,728,209	8
9	Total Rate Base		$ 13,307,215	$ 102,719,843	9
10	Margin				10
11	Net Operating Margin	Direct	$ 2,671,467	$ 17,812,796	11
12	Negotiated Contract and Pabco Margin	Net Op Marg	0	0	12
13	Contract Revenue Adjustment		(14,494)	(96,644)	13
14	Other Revenue - Labor	Net Op Marg	10	68	14
15	Other Revenue - Parts & Material	Net Op Marg	1	4	15
16	Other Revenue - Rental Income	Net Op Marg	0	0	16
17	Late Charges	12.0	0	0	17
18	Service Establishment Charges	9.0	0	0	18
19	Reconnect / Reread Charges	9.0	0	0	19
20	Other Revenue	Net Op Marg	0	54	20
21	Other Revenue - Returned Item Fee	13.0	0	4	21
22	Total Revenue		$ 2,656,984	$ 17,716,282	22
23	Operating Deductions				23
24	Operations & Maintenance Expenses		$ (578,483)	$ (2,840,640)	24
25	Incremental Uncollectible Expenses	4.0	(1)	(2)	25
26	Administrative & General Expenses	O&M	(388,223)	(1,906,370)	26
27	Depreciation Expenses		(529,187)	(4,084,891)	27
28	Regulatory Amortization	1.1	(40,797)	(314,914)	28
29	Mill Tax	Net Op Marg	(18,999)	(68,399)	29
30	Modified Business Tax	1.1	2,072	15,995	30
31	Taxes other than Income	1.1	(70,339)	(542,956)	31
32	Total Operating Deductions		$ (1,623,957)	$ (9,742,176)	32
33	State Income Tax				33
34	Taxable Income before Interest Expense		$ 1,033,028	$ 7,974,106	34
35	Interest Expenses	1.1	(195,211)	(1,506,857)	35
36	State Taxable Income		$ 837,816	$ 6,467,249	36
37	State Income Tax	0.00%	$ 0	$	37
38	South Georgia State	1.1	0		38
39	Total State Income Tax		$ 0	$	39
40	Taxable Income				40
41	Taxable Income before Interest Expense		$ 1,033,028	$ 7,974,106	41
42	Interest Expenses		(195,211)	(1,506,857)	42
43	Schedule M Adjustments		(315,397)	(2,434,586)	43
44	Taxable Income		$ 522,419	$ 4,032,664	44
45	Federal Income Tax				45
46	Federal Income Tax	21.00%	$ 109,708	$ 846,859	46
47	Investment Tax Credit (I.T.C.)	1.1	0	0	47
48	Federal Deferred Provision / ARAM	1.1	48,951	377,857	48
49	South Georgia Federal	1.1	0	0	49
50	Total Federal Income Tax		$ 158,659	$ 1,224,716	50
51	Regulatory Amortization CP National	1.1	$ 0	$ 0	51
52	Net Income		$ 874,369	$ 6,749,390	52
53	Rate of Return on Rate Base		6.57%	6.57%	53

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
CLASS COST OF SERVICE STUDY SUMMARY - PROPOSED RATES AT SYSTEM RATE OF RETURN
TWELVE MONTHS ENDED MAY 31, 2021 (TEST YEAR)

Line No.	Description	Allocation Factor		General-5	Line No.
	(a)	(b)		(c)	
1	Rate Base				1
2	Total Direct Net Plant	Various	$	5,394,490	2
3	Total Common Allocable Net Plant	1.1		298,884	3
4	Cash Working Capital	1.1		9,623	4
5	Materials & Supplies	1.1		301,279	5
6	Other Debits and Credits	4		132,513	6
7	Customer Advances	8		0	7
8	Deferred Taxes	1.1		(1,005,625)	8
9	Total Rate Base		$	5,131,164	9
10	Revenue				10
11	Net Operating Margin	Direct	$	1,098,614	11
12	Negotiated Contracts Margin	Net Op Mrg		0	12
13	Contract Revenue Adjustment	Net Op Mrg		705	13
14	Other Revenue - Labor	Net Op Mrg		3	14
15	Other Revenue - Parts & Material	Net Op Mrg		0	15
16	Other Revenue - Rental Income	Net Op Mrg		0	16
17	Late Charges	12		0	17
18	Service Establishment Charges	9		0	18
19	Reconnect / Reread Charges	9		0	19
20	Other Revenue - Field Collection Fee	Net Op Mrg		0	20
21	Other Revenue - Returned Items	13		0	21
22	Total Revenue		$	1,099,322	22
23	Operating Deductions				23
24	Operations & Maintenance Exps	Various	$	(232,360)	24
25	Incremental Uncollectible Exps	4		(0)	25
26	Regulatory Amortization	Depr Exp		(10,455)	26
27	Mill Tax			0	27
28	Modified Business Tax			27	28
29	Administrative & General Exps	O&M		(153,943)	29
30	Depreciation Expenses	1.1		(237,869)	30
31	Taxes Other than Income	1.1		(61,885)	31
32	Total Operating Deductions		$	(696,486)	32
40	Taxable Income				40
41	Taxable Income before Interest Exp	Various	$	402,836	41
42	Interest Expenses	1.1		(88,229)	42
43	Schedule M Adjustments	1.1		(144,487)	43
44	Taxable Income		$	170,120	44
45	Federal Income Tax				
46	Federal Income Tax	21.00%	$	35,725	46
47	Investment Tax Credit (I.T.C.)	1.1		0	47
48	Federal Deferred Provision	1.1		17,345	48
49	South Georgia Amortization - Fed	1.1		0	49
50	Total Federal Income Tax		$	53,070	50
51	Net Income		$	349,766	51
52	Rate of Return on Rate Base			6.82%	52

SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
SUMMARY OF REVENUES AT PROPOSED RATES BY PROPOSED RECOURSE RATE SCHEDULES
TWELVE MONTHS ENDED MAY 31, 2021 (TEST YEAR)

			Billing Determinants		Proposed Margin Rates [1]		Margin at Proposed Rates			Revenue at Proposed Rates		
Line No.	Description	Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Delivery Charge	Basic Service Charge	Delivery Charge	Total Margin	Gas Cost [2]	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g) (c)*(e)	(h) (d)*(f)	(i) (g)+(h)	(j)	(k)	
1	General Gas Service - 5	SG-G5										1
2	Basic Service Charge per Month											2
3	Sales Customers		0		$ 1,000.00		$ 0		$ 0	$ 0	$ 0	3
4	Transportation Customers		24		1,000.00		24,000		24,000	0	24,000	4
5	Transportation Service Charge		0		500.00		0		0	0	0	5
6	Demand Charges											6
7	Sales Customers			0		$ 0.00485		0	0	0	0	7
8	Transportation Customers			440,260,200		$ 0.00485		2,136,996	2,136,996	0	2,136,996	8
9	Commodity Charge per Therm:											9
10	Sales Customers			0		$ 0.00433		0	0	0	0	10
11	Transportation Customers			124,853,643		$ 0.00433		540,249	540,249	0	540,249	11
12	Total General Gas Service - 5		24	124,853,643			$ 24,000	$ 2,677,245	$ 2,701,245	$ 0	$ 2,701,245	12
13												
14	General Gas Service - 6	SG-G6										14
15	Basic Service Charge per Month											15
16	Sales Customers		0		$ 1,000.00		$ 0		$ 0	$ 0	$ 0	16
17	Transportation Customers		72		1,000.00		72,000		72,000	0	72,000	17
18	Transportation Service Charge		0		500.00		0		0	0	0	18
19	Demand Charges											19
20	Sales Customers			0		$ 0.02855		0	0	0	0	20
21	Transportation Customers			413,095,680		$ 0.02855		11,794,568	11,794,568	0	11,794,568	21
22	Commodity Charge per Therm:											22
23	Sales Customers			0		$ 0.00966		0	0	0	0	23
24	Transportation Customers			307,153,579		$ 0.00966		2,966,642	2,966,642	0	2,966,642	24
25	Total General Gas Service - 6		72	307,153,579			$ 72,000	$ 14,761,210	$ 14,833,210	$ 0	$ 14,833,210	25

SOUTHWEST GAS CORPORATION
SOUTHERN NEVADA
DISTRIBUTION OF EXPENSES BY FUNCTION - DATA ENTRY AND CLASSIFICATION OF COSTS
TWELVE MONTHS ENDED MAY 31, 2021 (TEST YEAR)

Line No.	Description		General Gas Service - 5	General Gas Service - 6	Line No.
	(a)		(b)	(c)	
1	Allocated Margin	$	2,671,467	17,812,796	1
2	Present Margin		3,561,937	12,823,343	2
3	Allocated Change in Revenue		(890,470)	4,989,453	3
4	System Average plus 10% Increase Cap		558,280	2,009,867	4
5	Revenue Requirement Capped Schedules (Ln 2 + Ln 4)		n/a	14,833,210	5
6	Increase Amount Exceeding 10% Cap (Ln 3 - Ln 4)		n/a	2,979,586	6
7	Increase Amount Exceeding Full Margin and Negotiated Revenue		n/a	n/a	7
8	Increase Exceeding 10% Cap and Contract Revenue (Ln 6 + Ln 7)		0	2,979,586	8
9	Revenue Requirement Non-Capped Schedules		2,701,245	n/a	9
10	Total Revenue Including Contracts		2,701,245	14,833,210	10

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
SUMMARY OF REVENUES AT PROPOSED RATES BY PROPOSED RATE SCHEDULES
TWELVE MONTHS ENDED MAY 31, 2021 (TEST YEAR)

				Billing Determinants		Proposed Margin Rates [1]		Margin at Proposed Rates			Revenue at Proposed Rates		
Line No.	Description	Reference	Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Delivery Charge	Basic Service Charge	Delivery Charge	Total Margin	Gas Cost [2]	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) (d)*(f)	(i) (e)*(g)	(j) (h)+(i)	(k)	(l) (j)+(k)	
1	General Gas Service - 5		NG-G5										1
2	Basic Service Charge per Month												2
3	Sales Customers	Sch J-1, Sh 14		0		$ 1,000.00		$ 0		$ 0	$ 0	$ 0	3
4	Transportation Customers	WP Sch J-1, Sh 42		12		1,000.00		12,000		12,000	0	12,000	4
5	Transportation Service Charge	WP Sch J-1, Sh 42		12		500.00		6,000		6,000	0	6,000	5
6	Demand Charge												6
7	Sales Customers	WP Sch J-1, Sh 44			0		$ 0.01361		0	0	0	0	7
8	Transportation Customers	WP Sch J-1, Sh 44			26,493,960		0.01361		360,583	360,583	0	360,583	8
9	All Usage												9
10	Sales Customers	Sch J-1, Sh 14			0		$ 0.00411		0	0	0	0	10
11	Transportation Customers	WP Sch J-1, Sh 42			23,007,450		0.00411		94,561	94,561	0	94,561	11
12	Total General Gas Service - 5			12	23,007,450			$ 18,000	$ 455,144	$ 473,144	$ 0	$ 473,144	12

SOUTHWEST GAS CORPORATION
NORTHERN NEVADA
CLASS COST OF SERVICE STUDY SUMMARY - PROPOSED RATES AT SYSTEM RATE OF RETURN
TWELVE MONTHS ENDED MAY 31, 2021 (TEST YEAR)

Line No.	Description (a)	General-5 (b)	Line No.
1	Allocated Margin	$ 1,098,614	1
2	Present Margin	415,637	2
3	Allocated Change in Revenue	682,977	3
4	System Average plus 10% Increase Cap	57,512	4
5	Revenue Requirement Capped Schedules (Ln 2 + Ln 4)	473,149	5
6	Increase Amount Exceeding 10% Cap (Ln 3 - Ln 4)	625,465	6
7	Increase Amount Exceeding Contract Revenue	n/a	7
8	Increase Exceeding 10% Cap and Contract Revenue (Ln 6 + Ln 7)	625,465	8
9	Revenue Requirement Non-Capped Schedules	n/a	9
10	Total Revenue Including Contracts	473,149	10

AFFIRMATION

STATE OF VERMONT

: ss.

Timothy S. Lyons being first duly sworn, deposes and says:

That I am the person identified in the Prepared Direct Testimony, and the exhibits applicable to my testimony; that such testimony and exhibits were prepared by me or under my direction; that the answers and information set forth therein are true to the best of my own knowledge and belief.

Timothy S. Lyons

Timothy S. Lyons

Signed and sworn to before me on

this 31 day of August, 2021.

Notary Public

KEVIN LEMIEUX
Notary Public, State of Vermont
Commission No. 157.0008207
My Commission Expires Jan. 31, 2023

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. 21-08___

PREPARED DIRECT TESTIMONY

RAIED N. STANLEY

ON BEHALF OF

SOUTHWEST GAS CORPORATION

AUGUST 31, 2021

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Prepared Direct Testimony
of
Raied N. Stanley

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Appendix A – Summary of Qualifications of Raied N. Stanley

Exhibit No.__(RNS-1)

Exhibit No.__(RNS-2)

Exhibit No.__(RNS-3)

Exhibit No.__(RNS-4)

Exhibit No.__(RNS-5)

Exhibit No.__(RNS-6)

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 (I/S) 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 No.

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

A. 5 To provide an overview of the project governance and oversight structure for approved technology-related capital projects and 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 discussion on 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' 2020 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, 2021; and
- Support the reasonableness and prudence of severance payments to Information Services department employees.

Q. 7 Please describe why you are the person most knowledgeable 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 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 Portfolio Approval Council (PAC) to centralize the governance of processes, tools, and resources to maximize the business value of these capital projects. 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), used to certify 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 Company executive and typically maintains a governance structure consisting of a Steering Committee, Oversight Committee, a dedicated project manager from the EPMO, and a project team.
- Each project will undertake 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 PAC?

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. The PRB serves the PAC as a technical resource to the council 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 PAC 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 timing to launch new projects and initiatives. The primary purpose of the PAC is to institute portfolio governance and sustain it with disciplined oversight. To that end, the PAC builds and maintains a portfolio based upon corporate strategies/initiatives, risk profile and capital distribution as determined by senior management. In addition, the PAC brings together influential company leaders in conversation with each other to explore and evaluate the business rationale and justification for requested projects. The PAC also evaluates project requests against Company objectives and promotes innovations in project and portfolio management. The PAC has ultimate authority to oversee the management of major capital projects. They promote decision transparency, standardized policies, accountability, and buy-in. A copy of the PRB and PAC charters 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. It frequently uses experienced based contractors for resource flexibility based upon 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 completion date. Consultant invoices and timesheets are ultimately reviewed and validated by internal personnel responsible for the project.

Q. 11 Has the oversight for technology-related capital projects materially changed since the Company's 2020 GRC?

A. 11 No. The Company's EPMO was established on the following principles: 1) established governance mechanisms; 2) dedicated project managers; and 3) developed project management frameworks and processes. The Company has experienced transition, growth, a strong desire to continually improve the customer experience, and a need to upgrade technology that is necessary to serve our customers. The process and framework around technology-related capital projects have remained constant throughout these changes.

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 work orders that closed to plant in service since June 2020, which was the end of the certification period in the Company's last GRC. Attached as Exhibit No. (RNS-03) is a list of all technology-related work orders greater than $100,000 in total costs that closed to plant since June 2020. Below, I provide further discussion on each of the projects or initiatives where the costs incurred were greater than $1 million.

IV. OVERVIEW OF PROJECT HORIZON

Q. 13 Please provide an overview of Project Horizon.

A. 13 Southwest Gas launched Project Horizon in July of 2019 to replace a legacy in-house developed and maintained Customer Service System (CSS), originally implemented in 1990, with a modern Customer Information System (CIS). The CIS is the Company's core meter to cash billing system for over 2-million residential, commercial, and industrial customers across service territories in three states; the CIS is also the hub of critical business processes including customer scheduling, billing and payment processing, tariff rate calculations and rate changes, meter data management, meter performance management, appointment setting, and compliance reporting. The CIS has approximately 1,000 users Companywide and integrates business processes across 12 functional areas throughout the organization.

After conducting a formal Request for Proposal (RFP) process for a CSS Assessment partner in 2016, Southwest Gas selected TMG Consulting (TMG), an industry expert in customer systems and implementation strategies, to review options for modernization of the legacy system. TMG was selected based on specified criteria including industry experience in CIS implementations for companies of similar size, qualifications of dedicated team members, and alignment with organizational culture. Before arriving at the decision to replace CSS with a modern CIS, the Company conducted a thorough analysis of the following alternatives:

1. Continue to maintain the existing CSS (status quo);
2. Perform a major system upgrade of CSS;

3. Revamp the CSS Graphical User Interface (GUI) and provide a new system, front-end to eliminate the "green screen technology" from the legacy system;
4. Implement a new Customer Relationship Management (CRM) system as a front-end to CSS to improve customer communications and transactions;
5. Integrate an enhanced Complex Billing platform to CSS;
6. Create a data warehouse for enhanced analytics;
7. Replace CSS with a new commercial-off-the-shelf and vendor supported CIS; or
8. Replace CSS with a new vendor hosted and supported solution.

After completion of the CSS Assessment, the TMG collaboration continued though the CIS platform selection and procurement stage. The Company selected the SAP Customer Relationship and Billing (CR&B) solution as the preferred solution for the organization after conducting a vigorous RFP process with the top vendors in the industry according to market research. To ensure the procurement of a qualified system implementation (SI) partner with the best experience on the SAP platform and a team with a complimentary culture to the organization, the company conducted a separate RFP for the SI. Southwest Gas selected Accenture as the Project Horizon SI. Additional RFPs were conducted for organizational change management and training and all technology hardware purchases associated with the project. RFPs were conducted for all major expenditures unless a pre-negotiated rate had already been established through a separate procurement process.

TMG remained a partner throughout the CIS implementation to perform quality assurance and to ensure that the replacement project had adequate oversight and project management. The TMG project team members supported the call center and technical support model development in addition to keeping their hand on the pulse of any potential project pitfalls. A monthly assessment was provided to the Project Horizon Executive Governance Board comprised of Company's senior management.

A team comprised of cross-functional subject matter experts from various internal Company departments throughout the service territory was fully dedicated to the SAP CR&B implementation effort. In addition to internal subject matter experts, Southwest Gas enlisted professional expertise from the following implementation partners with a message of "One Team, One Goal" to establish a unified and inclusive team environment to support a successful project delivery:

1. Accenture – system implementation
2. Avertra – exception handling and back-office solution
3. Ernst & Young, LLP (EY) – Organizational Change Management (OCM) and training
4. Infosys – edge systems integration
5. KPMG – Sarbanes Oxley (SOX) compliance and controls
6. SAP – platform partner and Max Attention professional services
7. Smart Energy Water (SEW) Self-Service Accelerator (SSA) – customer self-service platform, mobile application, and agency portal
8. TMG Consulting – procurement and quality assurance

Prior to the global pandemic in early 2020, the Horizon project team planned to co-locate in a project facility in Las Vegas, Nevada, in addition to leveraging software collaboration tools and video-conferencing technology to communicate with team members in different time zones around the globe. The virtual collaboration tools became a necessity with the onset of Coronavirus safety regulations and travel restrictions. Project team members were no longer able to co-locate; however, the project team stayed on schedule. The Project Horizon team was able to transition to a full-functioning remote work environment with laptops readily available and configured for team usage and minimal changes to the technical infrastructure to support application availability and site connectivity. Southwest Gas successfully implemented the SAP CR&B on May 3, 2021. The commitment to this project resulted in the necessary speed and grace to be agile, with all the corresponding and necessary experience. The successful on-time go live of May 3rd was met because the project team carefully and accurately scoped project needs, outcomes and risks were communicated clearly, and progress was monitored throughout. The strong methods, concepts and accelerators ensured that our successful on time go-live date far exceeded the industry average when compared to projects of this magnitude.

Q. 14 What are the expected benefits of Project Horizon?

A. 14 The legacy CSS was over three decades old, and it had become increasingly difficult to maintain, operate, and enhance to meet the ongoing changes in customer and regulatory requirements. Minor system changes required extensive, lengthy, and costly programming efforts due to the complexity and rigidness of the antiquated Common Business-Oriented Language (COBOL) system. COBOL is rarely offered as part of the curriculum for computer science professionals, which made it difficult to attract and retain a skilled workforce. Increased cybersecurity requirements and controls to maintain an effective security posture was more of a challenge in the previous system due to the complexity of the legacy CSS.

Southwest Gas expects to realize benefits in multiple areas as the SAP system stabilizes over time. While productivity typically decreases after a CIS implementation as the end users transition to the new system and process changes, the Company anticipates gaining efficiencies after stabilization in the following areas:

- Enhanced customer experience and satisfaction through improved web and mobile self-service capabilities with functionality to review and analyze customer usage;
- Increased communications and updates on gas service outages through the customers' preferred communication channel (i.e., Email, Text, Interactive Voice Response (IVR) etc.);
- Advanced security and data loss prevention tools for the customers and the Company to reduce potential threats of security breaches by eliminating the presence of Personal Identifying Information (PII) and Payment Card Industry (PCI) information;
- Increased Call Center productivity;

    - Company Witness Michelle Ansani elaborates on the expected benefits in the Call Center and customer response times in her prepared direct testimony.

- Centralized billing engine for residential, commercial, and industrial customers with an emphasis on customer-centric information for better account service and maintenance functionality rather than a premise-based (meter location) system;
- Modernized system that is flexible and expandable to support customer growth, green energy initiatives, enhanced products, programs, and services; and
- Modern programming language to attract and retain skilled technical professionals to support system maintenance and future improvements.

Q. 15 Has this project been previously presented to Commission?

A. 15 This project was the subject of Docket No. 19-03042 in which the Company sought approval from the Commission to establish a regulatory asset to track the capital and operations & maintenance (O&M) expenses related to this multi-year project, however, that request was denied. While the Company was authorized recovery of normalized test year expenses related to the project in the Company's last GRC (Docket No. 20-02023), this is the first time the entire project has been presented to the Commission for a determination of prudence and recovery of the capital-related costs. I support the reasonableness and prudence of the project's capital expenditures, as well as the related O&M expenses. Company witness, Randi L. Cunningham, supports the proposed ratemaking adjustment to reflect ongoing costs for Project Horizon and CSS during the rate effective period. The ongoing cost for Project Horizon and CSS is $7.6 million; and for full recovery of the approximate $9.8 million in O&M expenses incurred during the test year for the successful implementation of

Project Horizon. The specific ongoing cost for CSS is $2.6 million which is vital for the ongoing hyper-care period and for the next 18-24 months as system stabilization continues. The primary reason for the ongoing cost is the nature of the data and the current need for access. The legacy CSS contains historical customer data that was not migrated to the new CIS system. There were also regulatory requirements that dictated those records be readily accessible to end users. The project team determined that archiving the data was easier and more cost-effective than migrating it, based on the recency of the data and how often it needs to be accessed. As a result, the ongoing cost for CSS captures the necessary data model, query, and reporting intelligence required to retain the value of the data. The ongoing cost for Project Horizon is $4.9 million. The costs are related to license fees to maintain the system ($2.8 million) and employee and contractor services ($2.1 million) to ensure all customer defects are resolved and implemented accurately and timely. In addition, adaptive maintenance is imperative as it involves updates/changes made to the new system to match up to current industry standards. No matter how cutting edge, this project will require regular updating to keep up with the latest developments in its field. In turn, we will opt for the most convenient, comprehensive options, which make adaptive maintenance a vital part of the technological upkeep.

Q. 16 What was the total cost for Project Horizon?

A. 16 Project Horizon costs are comprised of project implementation/software and infrastructure costs. The total cost for the Project Horizon implementation/software/infrastructure was approximately $112.8 million in capital, of which approximately $105.3 million (before allocation) was closed to plant in service as of May 31, 2021. The Company anticipates approximately $7.5 million in trailing and hyper care-related charges that will be recorded to the work order during the certification period. The following provides a description of the implementation/software/infrastructure required for the functionality of Project Horizon:

- Project Horizon Implementation (0061W0005095, $103.8 million): Implementation costs for system implementor and all-other solution partners.
- Servers for SAP at H1 (0061W0005393, $1.3 million): Application and database servers for SAP platform, SAP HANA, SAP NetWeaver and SAP S/4HANA solutions. Servers were endorsed by SAP, and helps reduce the risk of service outages, minimize effort during system maintenance, and allows for deployment services faster on-premises or in the cloud.
- Storage for SAP at H1 (0061W0005381, $1.1 million): Storage solution which delivered extreme performance and resiliency demanded by SAP applications. The high-end storage delivered unparalleled simplicity, and reduced storage tasks with self-managing, self-healing storage arrays.
- Servers for SAP at H2 (0061W0005693, $957K): Backup application and database servers for SAP platform, SAP HANA, SAP NetWeaver and SAP S/4HANA solutions. Servers were endorsed by SAP, and helps reduce the risk of service outages, minimize effort during system maintenance, and allows for deployment services faster on-premises or in the cloud. This infrastructure was only for production systems.
- Storage for SAP at H2 (0061W0005692, $594K): Backup storage solution which delivered extreme performance and resiliency demanded by SAP

applications. The high-end storage delivered unparalleled simplicity, and reduced storage tasks with self-managing, self-healing storage arrays. This storage was only for production systems.

- Worksoft Automated Testing Software (0061W0005708, $354K): SAP environments are constantly changing with rapid release cycles and other development changes, each with the potential for massive impact on our critical business processes. Worksoft is a scalable test automation to ensure flawless execution of our SAP platform. It combines deep, SAP testing expertise with industry-leading, code-free continuous automation.
- Core switches for Project Horizon (0061W0005694, $237K): These are high-capacity core switches which played an important role in delivering frames/packets as fast as possible in the center of our SAP network. The contribution was in networks where speed, scalability and reliability are key to users.
- Core switches for Project Horizon (0061W0005407, $235K): Backup switches at H2 data center. These are high-capacity core switches which played an important role in delivering frames/packets as fast as possible in the center of our SAP network. The contribution was in networks where speed, scalability and reliability are key to users.
- SAP non-prod storage at H2 (0061W0005690, $100K): Additional required storage for backup data center.
- Communication Equipment for Project Horizon (0061W0005798, $92K): Miscellaneous equipment for network to ensure proper sizing and security.

- SAP non-prod storage at H1 (0061W0005358, $89K): Additional required storage for primary data center.
- Laptops for Project Horizon (0061W0005893, $100K): Required laptops for project team due to impact of pandemic.
- SAP Non-Production Servers at H1 (0061W0005357, $321K): Preliminary servers for H1 data center for Project Horizon.
- Computer Equipment for Project Horizon (0061W0005497, $164K): Equipment and video conferencing equipment which was leveraged for the satellite project team sites. Used frequently prior to Covid pandemic and vital to support team collaboration during pandemic and in other Operating Divisions.
- SEW Self Accelerator (0061W0005325, $3.24 million): SAP/SEW CX Self-Service for Utilities (SSA) delivers an integrated cross channel digital customer experience for Southwest customers. Deployed, managed, and maintained by SAP, the accelerator integrates customer interactions to provide exceptional customer experience. The software provides channels to customers through MyAccount (typical residential and small business customers, full 360 view of all features for small mass market customer and multi-channel notification preference center via SMS Text, Email, Voice, and Mobile push. The software also provides a mobile app which is approved for both iOS and Android devices.

Q. 17 Why do you believe the costs associated with Project Horizon are reasonable?

A. 17 Southwest Gas takes pride in being among the industry leaders in customer satisfaction and operational excellence. To remain an industry leader, the Company recognizes the importance of the "Plan, Do, Check, Act" quality cycle and the need for continuous enhancements in quality assurance and project delivery. To ensure that the Company, stakeholders, and customers were receiving the best product for the organizational needs at the most competitive pricing, Southwest Gas worked closely with TMG to compare vendor products, project costs, and project resources to other companies of comparable size. This information was for benchmarking purposes. As stated above in Q/A 8, due diligence for product and service procurement was conducted through formalized RFP's, unless otherwise negotiated via a pre-existing contract.

In addition, Southwest Gas dedicated a full time resource to the project whose specific job function was to review and report on the project financials to ensure that all costs were justifiable and allocated appropriately. The project team members received training and reference materials on how to submit and approve project expenditures. All costs were heavily scrutinized, regardless of the amount, and traceable to the established agreements and milestone payments.

Lastly, the Company's internal audit team added another layer of project management and documentation review by conducting regularly scheduled audits throughout the duration of the project implementation. The results from all audits were reported to the project Executive Governance Board. Southwest

Gas is fully confident in the reasonableness and prudency of all costs associated with Project Horizon because of the multiple layers of management review, forensic review, and internal and external audits partners.

V. OVERVIEW OF THE HCM PROJECT

Q. 18 Please provide an overview of the Human Capital Management (HCM) Project.

A. 18 Southwest Gas initiated the HCM Project to digitally transform the applications and tools leveraged by leadership and employees throughout the organization. The on-premises Oracle system had not been upgraded since 2002. The Oracle on-premises solution had integration issues, slow productivity, lagging technology, and was causing stress on business performance to maintain and optimize. A system modernization was necessary to offer paperless transactions, increased flexibility, scalability, mobility, and functionality out of the core systems. The HCM system provides gained efficiencies to allow leaders and employees to spend less time on manually managing their data and provides a more positive employee experience. The HCM Project planned to achieve the following objectives through the delivery of a modernized and integrated end-to-end solution:

- Implement an agile, user-friendly system that could be leveraged to advance Company strategic initiatives,
- Minimize paper-driven and/or manually intensive business processes,
- Provide a comprehensive solution with analytical capabilities to support organizational leadership and employee transactions,

- Improve functionality to support staff, employees, and future applicants by providing a "one-stop shop" experience for all informational needs,
- Provide system expandability and agility based on strategic needs and/or new regulations,
- Leverage mobile capabilities to coincide with increased demand for a remote work environment, and
- Provide an attractive platform to employee applicants to attract and retain a skilled workforce.

The HCM Project was comprised of two (2) separate phases to ensure a successful completion and timely rollout of functionality based upon Company needs and reporting requirements. The company implemented Phase 1 of the project in October of 2020 which included the following Oracle modules:

1. Core HR system
2. Employee Self-Service
3. Manager Self-Service
4. Benefits
5. Absence Management
6. Recruiting and Onboarding
7. Learning Management

Phase 2 of the HCM Project was implemented in June of 2021. The following additional modules were placed in service:

8. Compensation
9. Succession Planning
10. Performance Management

11. Goals Management
12. Career Development
13. HR Helpdesk

The Company incorporated additional resources to support analytics associated with the new system, organizational structure, and an ongoing support model. Efficiency gains are realized through utilization of the new platform.

Q. 19 What are the expected benefits of the HCM Project?

A. 19 As stated above in Q/A 18, the expected benefits of the HCM Project are to implement a fully integrated, end-to-end solution that is scalable and can be leveraged by Company leadership and employees to reduce paper transactions across the organization. The HCM cloud solution is mobile capable which allows employees and leaders to work on the go and at their convenience. These HCM enhancements will improve the employee experience which is expected to increase employee engagement, productivity, and retention. The Cloud HCM supports the development of the organization’s digital culture transformation and aligns the employee experience with the customer experience digitally which supports a technology driven workforce. Oracle HCM Cloud provides a robust database to perform analytics and workforce modeling to enable better forecasting, people cost management and organizational capability modeling to avoid future talent needs. Oracle cloud based HCM is designed to engage employees and track their expertise, certifications, compensation, and interests as well as automated report conversion. With cloud-based solutions, HR teams and leaders can bolster real-time hiring efforts and assess internal talent according to business priorities.

Q. 20 What was the total cost for the HCM Project?

A. 20 The HCM Project implementation costs were allocated to two (2) separate work orders due to changes in federal reporting for cloud solutions in 2020. The overall HCM Project totaled approximately $2.2 million as allocated to the following work orders:

- 0061W0005349: HCM Project
- 0061W0005683: Project HCM 2020 – Cloud Based.

Q. 21 Why do you believe the costs associated with the HCM Project are reasonable?

A. 21 Company management implemented additional administrative procedures and quality assurance checks to ensure all costs allocated to capital work orders are prudent and appropriately categorized. There is a heightened level of scrutiny and multiple layers of review throughout implementation. Additionally, invoice approvers receive training and guidance on how to properly account for all company costs. Vendor rates are researched and negotiated based on information available regarding market pricing and key resource availability to ensure that the Company receives a competitive rate for new initiatives.

VI. OVERVIEW OF THE DTRM PROJECT

Q. 22 Please provide an overview of the DTRM Project.

A. 22 Southwest Gas initiated the DTRM Project in early 2018 to enhance existing Pipeline Integrity Management (PIM) risk models for distribution and transmission pipelines. The DTRM Project planned to purchase, architect, and implement the Synergi Pipeline applications to advance Company core values for safety, excellence, and quality. The Pipeline and Hazardous Materials Safety

Administration (PHMSA) established regulations almost two decades ago for the enforcement of PIM plans for natural gas transmission pipelines, and over a decade ago for the enforcement of PIM plans for natural gas distribution companies to promote the safe operation of pipeline facilities to ensure the protection of the public and property. The DTRM solution is a modernized and centralized platform used to better understand the materials and characteristics of the pipeline system to proactively assess existing and potential issues through the analysis of maintenance information. This type of programmatic PIM algorithm was supported by the Pipeline Safety Staff at the Public Utilities Commission of Nevada (PUCN). The objective of this tool is to identify and remediate any areas that may become problematic if not already appropriately addressed. The project planned to deliver the following objectives:

- Implement a PIM solution to standardize risk modeling methods across all service territories to better align with industry proven practices, standards, and regulations;
- Strengthen risk modeling capabilities in anticipation of federally mandated regulation updates for distribution and transmission integrity management programs;
- Create a central repository for pipeline maintenance history obtained from legacy data sources so that there is a single source of truth for pipeline facility records;
- Integrate pipeline maintenance history with the Geographical Information System (GIS) for enhanced pipeline information and analysis trending; and

- Replace the legacy TRIMP suite solution that was approaching the end of support.

A project team comprised of functional and technical subject matter experts from department areas including but not limited to Engineering Staff, Gas Operations, and Risk Management collaborated to complete the following project deliverables:

- Purchased, configured, and implemented the Synergi Pipeline suite application for the company-wide distribution and transmission integrity management programs;
- Developed and implemented a Leak Analysis Data System with integration to facility GIS; and
- Installed the Synergi Pipeline High Consequence Area application for transmission pipelines to proactively mitigate potential risks in densely populated areas.

Q. 23 What are the expected benefits of the DTRM Project?

A. 23 As stated above in Q/A 22, the DTRM Project established standardized proven practices across all Company service territories for the proactive analysis and mitigation of risks to pipeline distribution and transmission systems. Distribution Integrity Management and Transmission Integrity Management are federally mandated and are essential to protecting the public and property.

Q. 24 What was the total cost for the DTRM Project?

A. 24 All DTRM Project implementation costs were allocated to work order "0061W0004323: DNV GL-DIMP & TRIMP Risk Model Proj" for a cumulative total of approximately $1.2 million.

Q. 25 Why do you believe the costs associated with the DTRM Project are reasonable?

A. 25 As stated above in Q/A 14, the Company has implemented additional training, procedures, and oversight to ensure all expenditures are prudent and accurate. Product costs are researched and compared early on to ensure that the best value product is obtained at a competitive rate.

VII. TRANSFORMATION OF I/S DEPARTMENT RESOURCES

Q. 26 Please provide an overview of the transformation of certain I/S Department resources that took place during the test year.

A. 26 As previously described, the Company implemented a transformational, modernized CIS in May of 2021. Consistent with the need to modernize this critical system, the Company also recognized the need to transform a portion of its workforce to include resources that possess the knowledge and skills of the new SAP-based CIS platform. This program was one mechanism that allowed IS to have greater flexibility with strategic and financial decisions in the longer term. For example, IS will have operational opportunities to examine every vacated position to determine whether the position needs to be refilled or redefined, whether certain positions may remain vacant for some time or whether some positions may be eliminated. In short, this voluntary resignation program will offer IS greater flexibility in making cost reductions and increased opportunities in making strategic staffing decisions moving forward. Furthermore, the department's drive for greater efficacy focused on the following themes: delayering to increase our staff to supervisor ratio; consolidation/reduction of administrative or support functions; restructuring or reducing highly graded supervisory and non-supervisory positions; restructuring to focus on core business functions (innovation support); restructuring to focus on SAP programmatic priorities; and consolidating and streamlining functions, activities and/or reducing the number of our current programs.

Q. 27 Please describe the eligibility requirements and terms for the severance package.

A. 27 Eligibility to participate was limited to Company employees in the I/S department who were at least 55 years of age with at least 10 years of Company service. Employees who elected to voluntarily separate from the Company in conjunction with this offering are not eligible to be rehired by the Company. The severance offering included two components. The first component contemplated a cash payment equal to one week of the participating employee's current salary for every year of service with the Company and the second component was a $10,000 incentive to participate.

Q. 28 How many employees elected to participate?

A. 28 Of the 43 employees that met the eligibility requirements, 22 elected to participate during the test year in 2020. In addition, 12 other employees met the eligibility in 2021, of which 8 elected to participate.

Q. 29 Are the labor costs associated with the employees that volunteered to separate from the Company included in the proposed cost of service?

A. 29 The 22 employees who elected to participate in the transformational opportunity in 2020 retired from the Company effective November 2020, therefore, they were not active employees as of the end of the test period and not included in the Company's Labor Annualization Adjustment No. 3. The cost of the severance payments is included in that adjustment and is fully discussed in the prepared direct testimony of Company witness Nick Liu. The other 8 employees that elected to participate in this opportunity retired from the Company effective June 2021.

Q. 30 Did this transformational initiative result in a cost reduction?

A. 30 Yes. The annualized salaries, including labor loadings, of the 22 employees was approximately $3.7 million, whereas the severance payment total was approximately $1.242 million, and the participation incentive was approximately $220K, for a difference of approximately $2.2 million. The Company believes this offering was prudent and associated cost should be recovered. The annualized salaries, including labor loadings, of the 8 employees was approximately $1.5 million, whereas the severance payment total was approximately $562K, and the participation incentive was approximately $80K, for a difference of approximately $878K. The Company believes this offering was prudent and associated cost should be recovered.

Q. 31 Did the employees who accepted the severance receive any enhanced retirement benefits?

A. 31 No. As discussed in the prepared direct testimony of Company witness Frederica Harvey, the employees who elected to participate in the transformational offering only received the retirement benefits afforded to them under the Company's retirement plan.

VIII. CONCLUSION

Q. 32 Does this conclude your prepared direct testimony?

A 32 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 which 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.

Version 1.7

August 24, 2021

Portfolio Review Board

Charter

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Executive Summary

Customer expectations, industry demands, and technology advancements continue to require the need for agility and responsiveness to organizational changes. The Southwest Gas mission is to enrich the lives of our customers and employees by providing a safe and reliable gas service. Our mission can be achieved through the selection, prioritization, and successful implementation of enterprise projects. A structured and well-defined Project and Portfolio Management (PPM) Governance helps to promote alignment with Company strategic objectives while mitigating financial risk. PPM provides value to the organization by supporting Company core values such as customer service **excellence**, financial **stewardship**, portfolio **quality** assurance, and **safety**. The centralized governance of projects, programs, resources, and processes helps to maximize the business value of the Company enterprise project portfolio. PPM provides the governance and tools to support:

- Demand Management
- Financial Management
- Portfolio Health Management
- Value Management
- Reporting Analytics
- Communication

What is the Portfolio Review Board?

The Portfolio Review Board (PRB) is a resource comprised of cross-functional company stakeholders. The PRB supports the governance and standardization of processes, practices, and tools to facilitate PPM for enterprise capital and O&M projects and/or programs. The PRB serves the Portfolio Approval Council (PAC) as the “Gate Keepers” of proposed projects for the enterprise portfolio.

PRB Mission

The PRB strives to align the enterprise project portfolio with the Company Mission:

…to enrich the lives of customers and employees within our Southwest communities by providing safe and natural gas service.

PRB Authority

The PRB operates under the authority and direction of the PAC. The PAC reserves the right of final approval for decisions and recommendations on the enterprise PPM.

PRB Roles and Responsibilities

Membership

PRB membership is determined by the PAC and should include the Vice President level (or delegate) of the following:

- Accounting – one representative
- Administration – one representative
- Engineering Staff – one representative
- Information Services (IS) – one representative
- Operations – one representative
- Regulatory – one representative
- Member at Large – one representative

The Director of the Enterprise Project Management Office (EPMO) will act as the facilitator, provide portfolio status updates, and post meeting minutes.

With the permission of the membership, others may be invited to attend, observe, or contribute to meetings and activities.

Procedures

The PRB will meet monthly or as needed and agreed to by the membership.

Quorum

- A quorum is required for the membership to hold a meeting.
- A quorum shall be defined as any number greater than ½ of the voting membership.
- To constitute a quorum, one member or proxy in attendance must be from IS.

PRB Attendance

- To vote on project approval, a PRB member must either be present at the meeting or remote via telephone. No proxy votes without attendance are allowed.

Responsibilities - General

The EPMO Director will provide the meeting agenda with input from the CIO. The EPMO Director will arrange meetings and organize materials required to facilitate decision-making by the PRB.

The EPMO Director will record and publish summaries of major issues discussed, decisions, and action items. These meeting minutes will be distributed to all PRB members within 5 days of the meeting.

The CIO and EPMO Director will report updates to the PAC.

Responsibilities - Portfolio

PRB members assume the following portfolio responsibilities:

- Screen proposed projects and determine portfolio eligibility
- Assess proposed project business cases
- Categorize and prioritize new projects
- Periodically review the portfolio
    - Identify project relationships and dependencies

- Work with the PAC and EPMO to assist with project conflict resolution
- Monitor overall progress and key developments of significant projects

- Participate in discussions of portfolio quality assurance
- Reconcile the portfolio project inventory to align with the I/S 3-year budget plan

Version 2.0
August 24, 2021

PORTFOLIO APPROVAL COUNCIL

Charter

This charter establishes the Portfolio Approval Council which serves to lead and promote the Enterprise Portfolio Management Processes of Southwest Gas Corporation.

Purpose of the Portfolio Approval Council

The primary purpose of the Portfolio Approval Council (PAC) is to institute portfolio governance and sustain it with disciplined oversight. To that end, the PAC will build and maintain a portfolio based upon corporate strategies/initiatives, risk profile and capital distribution as determined by senior management.

In addition, the PAC brings together influential company leaders in conversation with each other to explore and promote innovations in project and portfolio management, and to oversee the management of major capital projects. They promote decision transparency, accountability, & buy-in.

The PAC will promote the use of standardized policies, practices, and tools to facilitate the management and prioritization of significant capital and O&M projects within its purview.

Why is a Portfolio Approval Council needed?

Utilities, government agencies, and private and public corporations all face the challenge of meeting numerous high priority needs with constrained resources. Project portfolio management practices provide a methodology for approving and monitoring a portfolio of projects to manage the risk involved in accomplishing the desired objectives and strengthen the alignment of the portfolio to the company's goals.

Faced with growing demands, increasing complexity of implementations, and a diverse array of priorities, the PAC (and the Portfolio Review Board (PRB) under guidance of the PAC) evaluates potential projects in the context of overall strategic priorities.

The PAC supports portfolio management standards, policies and procedures developed and recommended by the Enterprise Project Management Office (EPMO). The PAC provides approval for the overall portfolio that is overseen by the Portfolio Review Board (PRB). With improved portfolio management practices, the Company is better able to produce a portfolio of projects that more effectively, reliably, and efficiently delivers results that optimally address the company's objectives.

Authority

The PAC is a cross-functional, decision-making and oversight group, composed primarily of senior executives. They are the owners of the project portfolio. The PAC operates under the expressed authority of the President, and the PAC operates and exercises its authority. No individual member, committee or task force can act unless authorized by the PAC.

Subordinate to the Portfolio Approval Council is the Portfolio Review Board.

Final approval for decisions and recommendations for major enterprise projects shall reside with the Portfolio Approval Council. The PAC can, and has the authority to, override PRB decisions.

Membership

Membership is by appointment by the CEO or designate, and should include Officers representing the following functional areas:

- Finance or Accounting
- Division Operations
- IS
- Engineering Staff
- Regulatory
- Other functional VPs as needed/appointed

The CIO and EPMO Director participate in the PAC meetings, but do not have voting rights.

The CIO will facilitate the discussion, and the EPMO Director will act as scribe to summarize and post meeting minutes.

With the permission of the membership, others may be invited to attend, observe, or contribute to meetings and activities.

Procedures

The Portfolio Approval Council will meet semi-annually or as needed and agreed to by the membership.

Where voting is required, each member will have one vote, except for the non-voting members as noted.

- Quorum
  - A quorum is required for the membership to hold a meeting; a quorum shall be defined as any number greater than ½ of the voting membership.

- EPMO Leadership
  - The CIO and EPMO Director will develop the meeting agenda.
  - The CIO will act as the meeting facilitator.
  - The EPMO Director will arrange meetings and organize materials required to facilitate decision-making by the PAC.
  - The EPMO Director will record and publish a summary of major issues discussed, decisions, and action items. These meeting minutes will be distributed to all PAC members within five days of the meeting.

PAC Responsibilities - General

Foster a project portfolio management philosophy that is state-of-the-art, comprehensive, and consistently applied; foster a culture of improvement and of candid internal disclosure of project information.

Approve the overall EPMO 3-year plan limits to align with corporate strategic and tactical objectives and optimize the portfolio to ensure maximum utility.

Provide input to the Budget Review Committee.

PAC Responsibilities – Portfolio

Determine standards and parameters by which to assess projects for worthiness and priority.

Set the project portfolio mix/balance based upon the company's planned business strategies.

Provide portfolio policy guidance.

Periodically review the portfolio for:
- Alignment with corporate strategy and goals
- Overall portfolio health
- Viability of each project
- Prioritization of projects
- Resource availability
- Changes to the portfolio since the last review
- Balancing of short term and long-term goals
- Balancing of risk

Work with the Portfolio Review Board to resolve priority, conflicts, and dependency issues.

Consider and resolve appeals to any challenged Portfolio Review Board decisions.

Responsibilities – Projects

Encourage company-wide adherence to repeatable project management processes and standards.

When a qualified project manager is not available, work with the Portfolio Review Board and the project sponsor to determine whether to delay the project, re-prioritize other projects, or to contract for outside project management expertise.

Monitor overall progress and key developments of significant projects.

Intermittently, have the PRB conduct independent reviews of projects and project management processes, and implement changes as required.

Participate in discussions of quality assurance review results with project manager, project sponsor, Oversight Committee, and, if appropriate, the project Steering Committee.

Responsibilities – Communication

The Portfolio Approval Council is responsible for maintaining regular communication with the following:

- Portfolio Review Board – Through the PRB Chairperson, who is a member of the PAC, the PRB can receive regular direction and feedback.

- Sr Management – Through the following:
  - The portfolio dashboard, published periodically
  - Updates, periodically, on:
    - The portfolio mix, heath, risk,
    - Significant projects,
    - Policy and project recommendations, and/or
    - Project or portfolio issues.

- Others – Broad organization presentation of PAC activities, as deemed necessary.

SOUTHWEST GAS CORPORATION
NEVADA
TECHNOLOGY-RELATED WORK ORDERS GREATER THAN $100,000 IN TOTAL COST
CLOSED TO PLANT IN SERVICE JUNE 2020 - MAY 2021

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	0021W0005740	Itron hardware refresh 2020 - SONV	Dec-20	213,029.95	0.00	0.00	1
2	0021W0005456	Plotter/Scanner Refresh Project-SNV	Nov-20	135,944.41	0.00	0.00	2
3	System Allocable						3
4	0061W0005095	Project Horizon Implementation	May-21	96,308,192.43	0.00	4,496,721.15	4
5	0061W0005683	Project HCM 2020 - Cloud Based	Oct-20	1,772,381.61	0.00	14,873.60	5
6	0061W0005393	Servers for SAP at H1	Jun-20	1,272,965.90	0.00	0.00	6
7	0061W0004323	DNV GL-DIMP & TRIMP Risk Model Proj	Jan-21	1,220,414.68	0.00	43,708.40	7
8	0061W0005381	Storage for SAP at H1	Jul-20	1,072,737.86	0.00	0.00	8
9	0061W0005693	Servers for SAP at H2	Aug-20	957,320.86	0.00	0.00	9
10	0061W0003658	Outage Management Project	Nov-20	890,095.09	0.00	0.00	10
11	0061W0005695	Refresh of storage at H2	Jun-20	674,526.57	0.00	0.00	11
12	0061W0005692	Storage for SAP at H2	Aug-20	593,891.26	0.00	0.00	12
13	0061W0005362	Fleet Management System	Jan-21	580,457.79	0.00	0.00	13
14	0061W0005826	SD-WAN for Corporate	Dec-20	471,844.08	0.00	0.00	14
15	0061W0005349	HCM Project	Oct-20	464,225.36	0.00	17,710.36	15
16	0061W0005853	Extrahop Monitoring ApplianceSWITCH	Aug-20	431,994.80	0.00	0.00	16
17	0061W0005052	Risk Management Information System	Oct-20	431,792.76	0.00	0.00	17
18	0061W0004904	Laptops and Tablets	Jul-20	402,684.13	0.00	0.00	18
19	0061W0005708	Worksoft Automated Testing Licenses	Aug-20	353,750.00	0.00	0.00	19
20	0061W0005998	SCADA Upgrade Project Hardware	Jan-21	337,097.49	0.00	0.00	20
21	0061W0005694	Core switches for Project Horizon	Jun-20	236,946.58	0.00	0.00	21
22	0061W0005407	Core switches for Project Horizon -	Jun-20	235,349.48	0.00	0.00	22
23	0061W0005691	Network Attached Storage for H2	Sep-20	208,842.20	0.00	0.00	23
24	0061W0005688	Backup Storage - H1&H2 (Switch)	Dec-20	156,113.81	0.00	0.00	24
25	0061W0005115	K2 Electronic Form Development	Oct-20	150,000.00	0.00	0.00	25
26	0061W0005415	LogRhythm capacity add - SWITCH	Sep-20	140,147.10	0.00	0.00	26
27	0061W0005339	Toughbooks 2019	Nov-20	119,401.30	0.00	0.00	27
28	0061W0005690	SAP non-prod storage at H2	Sep-20	99,930.75	0.00	0.00	28
29	0061W0005798	Communication Equip - Project Horizon	Mar-21	91,568.39	0.00	0.00	29
30	0061W0005358	SAP non-prod storage at H1	Dec-21	89,176.02	0.00	0.00	30
31	0061W0005893	Durango Laptops for Horizon Project	Nov-20	51,207.52	0.00	0.00	31

Customer Systems Modernization (CSM) Program

Business Case

Southwest Gas Corporation
Confidential & Proprietary
Last Updated: [DATE]
Date Created: [DATE]
Version [VERSION]

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Version Control

Date	Revision	Description	Author
11/13/18	Business Case V1	Initial Draft	Sara Avalos
11/20/18	Business Case v2	Draft updates	Sara Avalos
12/26/18	Business Case v3	Draft updates from Jim H.	Sara Avalos
12/27/18	Business Case v5	Revisions	Christine Gonzales
01/04/19	Business Case v.6	Updates - from Christine's revisions	Sara Avalos
02/26/19	Business Case v.7	Jim H. revisions	Sara Avalos

Final Approvals

Final approvals are to be completed after all required participants have reviewed this document and edits have been made.

Approver Name	Title	Signature	Date
Ngoni Murandu	CIO, Program Sponsor		
Jose Esparza	VP Customer Engagement, Program Sponsor		
Keith Sutton	EPMO Manager		
Robin Pierce	EPMO Director		

1 Executive Summary

The Customer Information System (CIS) assessment to replace the existing Customer Service System (CSS) began in 2016 with the engagement of TMG Consulting in collaboration with a core team of SWG user and technical personnel. Beginning in August of 2016 SWG partnered with TMG to perform a 6-month assessment on the current CSS. TMG developed an application plan comprised of alternatives for a potential upgrade, enhancement, migration, or replacement of the CSS application. Extensive research was conducted including: benchmarking with peer utilities, internal interviews, surveys, and review of current processes and systems (functional and business). At the end of the 2016 assessment TMG's final recommendation was to replace the current systems with a new CIS system. Beginning 2017 SWG embarked on the journey to replace the legacy CSS by enlisting specialized program management and quality assurance support to: finalize the preplanning phase, create a sound implementation plan applying industry best practices, develop a budget, direct OCM activities, and drive the platform and system integrator selection initiatives. SWG has named the program – Customer Systems Modernization (CSM). The total projected implementation cost for the CSM program is 144.29M of which $122.5 million is of capital spend and $21.6 million is O&M spend. The implementation cost projections, timeline and staffing plan align with industry standards.

There will be thousands of users impacted in 12 organizational units going from a mainframe green screen to a web-based system. In addition, over 20 critical business processes will be impacted by this program, changing the way SWG does business and interacts with our customers.

1.1 Opportunity

From a technical standpoint, the current CSS is increasingly difficult to operate and enhance. In addition, security vulnerabilities are always challenging with aged system making SWG more susceptible to potential breaches via cyber-attacks and non-compliance with Personal Identifiable Information (PII) laws. SWG workforce have several key legacy support employees retiring within 5 years. This makes tribal knowledge-transfer less viable to maintain the system up and running. The industry workforce pool has less knowledge of Cobol, this will progressively become extinct as it is 70's technology. The future CIS will result in a sustainable system with an internal configurable solution rather than a vendor customized system, minimize SWG's costs of outsourcing for ongoing support. We will gain an expandable system that will support future territories, products, programs, and services, as well as streamline and align manual and automated business processes to make business operations more efficient. The system will provide SWG the ability for enhanced query, extraction, analytical and reporting capabilities with real-time data, as well as necessary integration and interfaces between SWG's automated systems to provide for a single-system of record for the customer thus eliminating redundancies across systems.

1.2 Anticipated Outcomes

Moving forward with a completely new CIS replacement will relief major pain points and issues in technical risk, inflexible technology, and customer experience.
From a technical risk outlook, replacing our aging CIS application architecture and technology will bring us much needed sustainability and scalability -currently missing- with a system that is becoming more difficult to operate and enhance. Our system security will improve, reducing our risk to breaches, and limiting the presence of sensitive customer data. One of our bigger challenges with an aging system is our aging workforce. The new CIS will allow us to capture institutional knowledge as business and technical personnel retire, as well as attract up and coming talent to join SWG as we become a more modernized and innovative company. We will have a modern venue to implement an internal configurable solution that we can own versus a vendor customized system, eliminating extra costs.

From a flexible technology standpoint, a new CIS will afford SWG an expandable new system to support future territories, products, programs, and services as we continue to grow our customer base territories. We will have the ability to streamline and align manual and automated business processes to make business operations more efficient. Another great outcome will be enhanced query, extract, manipulation, and reporting of information from the new CIS solution. We will gain necessary support for integration and interfaces between SWG's automated systems to provide for a single system of record for the customer and eliminate redundancy across systems.

From a customer experience aspect, by implementing a new CIS solution, SWG will be able to provide exceptional levels of customer service by engaging with our customers online and real time; tailoring our product offerings to their immediate needs, just as other peer utilities (who currently have modernized systems in place) are now able to do. A much-anticipated outcome is having one primary billing engine with an emphasis on a customer-centric system rather than a locational (premise) based. This will also allow us to leverage our customer data for future marketing campaigns.

2 Overview

2.1 Background

SWG is a regulated public utility principally engaged in the purchase, transportation and distribution of natural gas; providing service to more than 2 million residential, commercial, and industrial customers throughout Arizona, Nevada, and parts of Northeastern and Southeastern California. SWG employs approximately 2,300 employees. Southwest Gas Corporation is a subsidiary of Southwest Gas Holdings, Inc.; which is a publicly-traded company (NSYE: SWX).

Paiute Pipeline Company, another wholly owned subsidiary of Southwest Gas Corporation, owns and operates an interstate natural gas transmission pipeline system; including a liquefied natural gas storage facility. Paiute is regulated by the Federal Energy Regulatory Commission. Additional company information can be found at https://www.swgas.com and at https://www.swgasholdings.com/.

2.2 History

- Incorporated in Barstow, California in 1931, Southwest Gas began as a liquid petroleum gas (LPG) company serving 160 customers. One year after its incorporation, the company expanded west to Victorville and added 90 customers.
- In 1951, the company moved from an LPG to a natural gas utility when it secured the right to tap one of Pacific Gas & Electric Company's (PG&E) high-pressure natural gas transmission lines to procure natural gas service for Barstow and Victorville.
- Soon afterward, the Company expanded into southern Nevada by acquiring the Nevada Natural Gas Pipe Line Co. (Nevada Natural). In 1953, Nevada Natural built a 110-mile pipeline from Topock, Arizona to Las Vegas and the industrial complex in Henderson. Twelve months later, the Company formed Nevada Southern Gas Company (Nevada Southern) to purchase the existing Las Vegas Gas Company and convert its 3,300 customers from propane to natural gas.
- Over the years, growth continued for Southwest Gas:
  - In 1957, Nevada Southern and Natural Gas Service of Arizona were merged into Southwest Gas. The latter furnished natural gas to Casa Grande and Coolidge, Arizona.
  - In 1958, Southwest Gas moved its corporate headquarters from Los Angeles to Las Vegas and acquired the assets of Big Bear Lake Gas Company.
  - In 1959, the company purchased a small LPG company in Big Bear Lake, California and converted the Big Bear LPG system to natural gas.
  - In 1962, Nevada Natural was merged into Southwest Gas.
  - In 1962, Nevada Northern Gas Company (Nevada Northern), a subsidiary of Southwest Gas began construction of a 250-mile interstate natural gas transmission

line from the Idaho border to the Reno area. The transmission pipeline later expanded to the Carson City, Elko and Lake Tahoe areas.

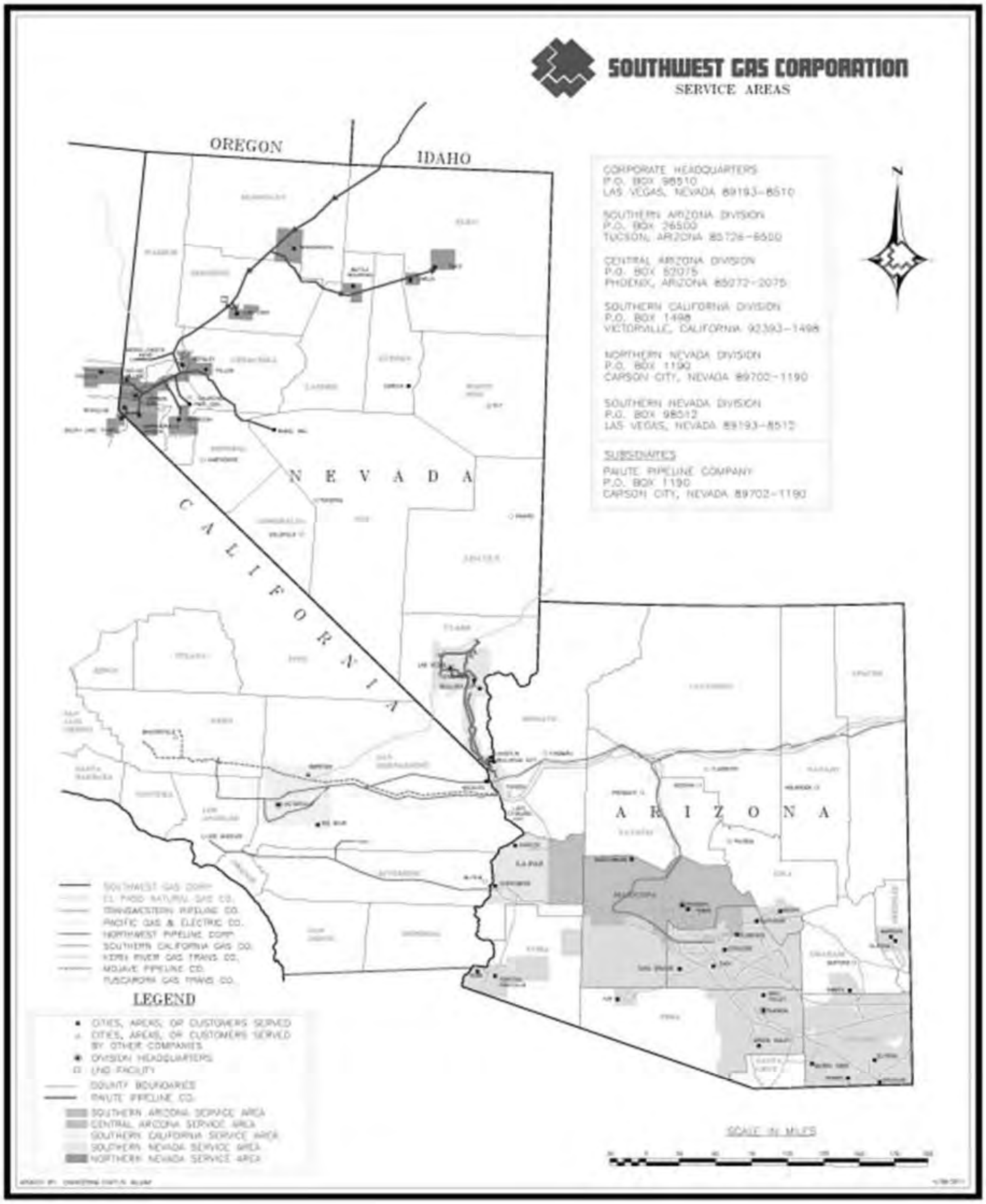
- In 1963, the pipeline was completed, Nevada Northern was merged into Southwest Gas and the assets of Elko Gas Utilities, Inc. (LPG) were acquired.
- In 1964, the assets of Carson City Gas Company (LPG) were acquired and certificates to serve 15 communities in northern Nevada were granted by the Nevada Public Service Commission.
- In 1973, Southwest Gas purchased Boulder Natural Gas, Co., which served about 1,200 customers in Boulder City, Nevada.
- In 1979, the company nearly doubled its size overnight with the acquisition of the gas system owned by Tucson Gas & Electric Company in southern Arizona.
- In 1980, the peak-shaving Joseph H. Gray Propane-Air Natural Gas (PANG) Plant in Reno, Nevada was completed.
- In 1982, the peak-shaving Harold G. Laub Liquefied Natural Gas (LNG) Plant near Lovelock, Nevada was completed.
- In 1984, the company again doubled its size with the purchase of the natural gas properties of Arizona Public Service Company in central Arizona, including metropolitan Phoenix and surrounding communities.
- In 1987, Southwest Gas formed Paiute Pipeline Co., a wholly owned subsidiary, to oversee the operation of northern Nevada's LNG and PANG plants as well as the interstate transmission pipeline.
- In 1991, Southwest purchased the natural gas properties of CP National Corporation in Henderson and Green Valley, Nevada and Needles, California, which added 13,000 customers.
- In 2003, the company purchased Black Mountain Gas serving Cave Creek and Carefree, Arizona.
- In 2005, Southwest acquired Avista Corporation's South Lake Tahoe system.
- In 2007, Southwest Gas surpassed 1.8 million customers.
- In 2011, the company celebrated its 80th anniversary.
- In 2017, Southwest Gas and its subsidiaries become subsidiaries of Southwest Gas Holdings, Inc.
- In 2017, Southwest Gas ends the year with the celebration of a historic milestone as it surpassed 2 million customers.

2.2.1 Service Territories

SWG is regulated by three state commissions and is divided into five operating divisions: Southern Nevada, Northern Nevada, Southern Arizona, Central Arizona, and Southern California, with the corporate headquarters in Las Vegas, Nevada. There are 26 districts locations across the five divisions. The service territory is depicted in the table and figure below:

Division	Geographical Area
Central Arizona Division (CAZ)	Includes the greater Phoenix metro area and Wickenburg, Arizona and surrounding areas
Northern Nevada Division (NNV)	Includes Carson City, Elko, Fallon, Winnemucca, Incline Village, Nevada, and Truckee, South Lake Tahoe, North Tahoe, California, and surrounding areas
Southern Arizona Division (SAZ)	Includes Tucson, Yuma, Sierra Vista, Casa Grande, Douglas, Willcox, Clifton, Morenci, Globe, Arizona and surrounding areas
Southern California Division (SCA)	Includes Victorville, Barstow and Big Bear and surrounding areas of California
Southern Nevada Division (SNV)	Includes Las Vegas and Laughlin, Nevada and surrounding areas, Parker, Ehrenberg, and Bullhead, Arizona, and Needles, California
Paiute Pipeline Company	Includes area in vicinity of Paiute's transmission pipeline, located in northern Nevada

Figure 1 - Service Territory Map



2.3 Current and Future State

The current CSS is used companywide and consists of over 200 screens within 18 subsystems providing an on-line access to current and historical data, there are no preferred methods for interfaces and no design patterns in place. It is also missing standard middleware for standardizing business processes across all systems, most interfaces are flat files without a standard format to send and/or receive data from external systems.

The new CIS will bring a standard service bus for interface and integrations. Common business process interfaces will share a common design pattern for extensibility and code reusability. SWG is converting a file-based data transfer process to an automated interface process for their customers and service partners.

Item	Current State with CSS System	Future State with Future CIS System
Usability	– Difficult to learn and use – High drop rate in training classes	– Intuitive application design – Graphical user interface
Business Flexibility	– System changes are difficult, risky and time consuming – Regulatory changes suppress competing customer and user enhancements	– Technology enables advancements in business process and customer offerings – Configuration rather than hard coding allows quicker response
Customer Expectations	– Very limited ability to deliver omni-service channels and programs	– Ability to add and change customer programs, both within the core platform and through integration – Target service opportunities based on prior experience with that customer
Support Model	– Heavily customized – Full support model “owned’ by SWG, not vendor supported or maintained – Declining resource pool	– Lower business risk through expanded support model – Use of standard API’s, service bus, and integration standards to simplify support
Analytics	– Basic customer data available through traditional reporting tools – Desire additional knowledge of customer attributes and behavior	– Improved understanding of customer expectations and behavior – Enhanced system that can incorporate customer experience directly in the system

2.4 Project Assumptions

2.4.1 Installation

- Staffing plan has been planned for 33 months which encompasses the following categories: 2 months for Startup, 6 months for Analysis, 6 months for Configuration and Development, 9 months for Testing and Acceptance, 1 month for Go-Live, and 9 months for Post Implementation Support.
- Peak staffing occurs in month 20 with 113 FTE. This is broken down into the following categories: 55 FTE for SWG-Functional Personnel, 40 FTE for SWG-Technical Personnel, 87 FTE for SI/Vendor Personnel, and 20 FTE for Third Party Personnel.
- The following staffing rates were applied to each category: $70/hour for SWG-Functional Personnel, $75/hour for SWG-Technical Personnel, $175/hour for SI/Vendor Personnel, and $150/hour for Third Party Personnel.
- This resulted in the following dollars for each category. This totaled $86 million in services for all categories. $16 million in staffing fees for SWG-Functional Personnel, $12.3 million in staffing fees for SWG-Technical Personnel, $49 million in staffing fees for SI/Vendor Personnel, and $**12.7** million in staffing fees for Third Party Personnel.
- Internal Project Expenses totaled approximately $4 million.
- Other implementation costs totaled approximately $89 million inclusive of all hardware, software, and contingency.
- The total implementation cost is $72.14 per customer or a total of $144.29M

2.4.2 Operational

- SWG will not reduce current IT operating and support costs.
- The legacy baseline infrastructure cost as of 2017 was $3.1M annually. This will increase to $4.3M in year 6 and stabilize from that point forward.
- The baseline application support services cost as of 2017 was $1.9M annually. This will grow to $3.3M in year 6 and stabilize from that point forward.
- The incremental Business Technology Support services cost as of 2017 was $1.1M and will grow to $1.5M in year 6 and stabilize from that point forward.
- The incremental infrastructure and related services for the new environment will start at $2,400,000 in year 2018 and will remain in place for the 10-year period.
- The incremental CSR efficiency impact for the new environment will cover a CSR increase of 75 CSR's or $9.2M in total for years 2021, 2022 and 2023.
- The operating costs as of 2017 was $7.0M, this will increase to $9.1 in year 6, stabilize from that point forward.

2.5 Project Constraints

- Legacy support for CSS will be required throughout the CSM implementation and after go-live for historical data access.
- Discretionary changes to CSS will stop as the CSM project moves out of Design and Construction and into Testing and Training. However, data cleansing on CSS will continue to go-live.
- Integration code changes to ancillary systems will intensify as will subsequent data mapping and cleansing exercises.
- Parallel environments with CSS and CSM interfaces will need to be maintained through to go-live.
- Interfaces to external systems will have their own complexities due to CSM-driven changes and lack of timing leverage.
- Knowledge of the data structures and data quality of the legacy source systems will be critical which has a dependency on the new data warehouse.
- CSS will not be the only source system to be sent to CSM. Some or many of those sources may not be electronically suited to transmit their data.
- Common attributes among source systems will need to be considered and decisions about best source will be made.
- Cleansing legacy systems too early comes with the risk of repeat cleansing required later in the project.
- All source systems will need to be validated to the CSM files after the Extract Transform and Load (ETL) have run, which can also be labor intensive until automated.

2.6 Dependencies

The following dependencies have been identified for this project.

2.6.1 Project Dependencies

Bill Print Project completion.
The Enterprise Data Management Project completion.
Nexus Project completion.

2.6.2 System Dependencies

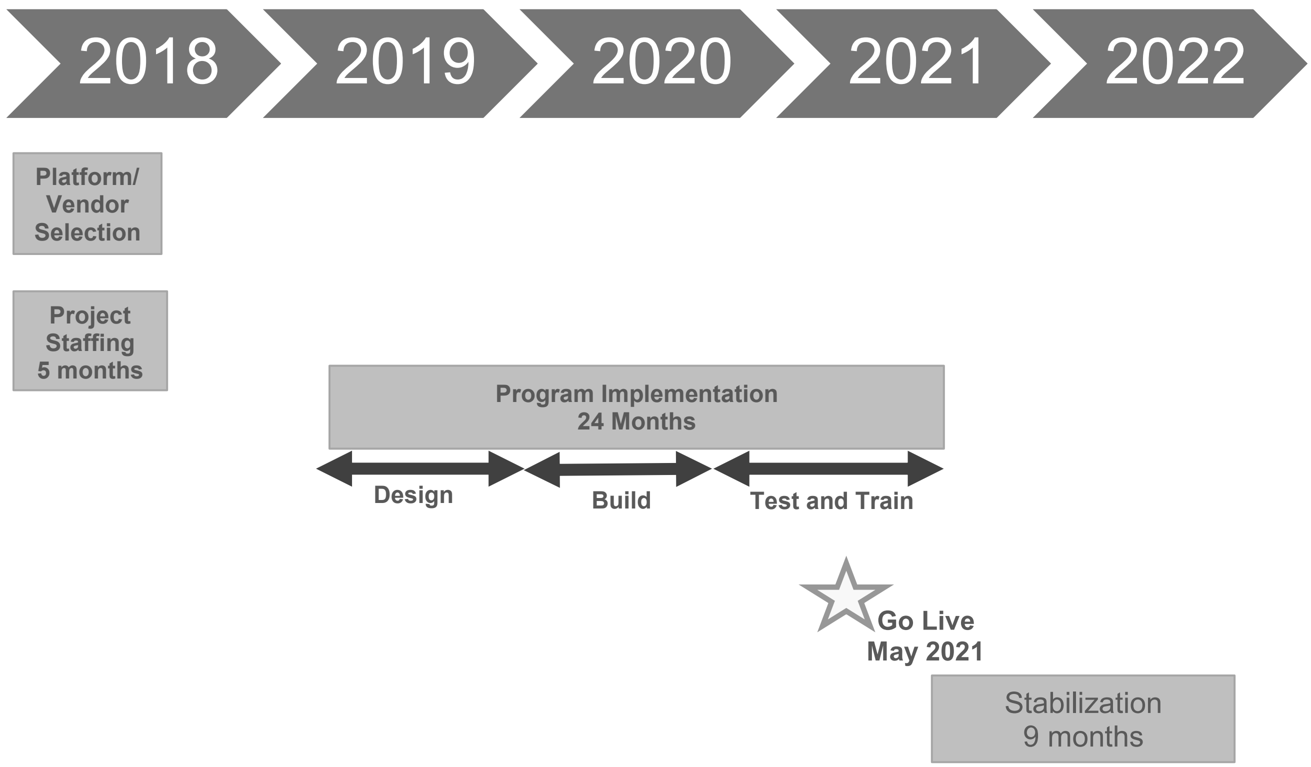
GTS – Gas Transaction System new system implementation plan.
FOMS – Field Order Management System- no major changes.
OCS - Online Customer Service- in CSM scope.

2.7 Project Risks

Risk	Probability	Remediation Steps
Without replacing the legacy CIS application architecture and technology, the system will become more difficult to operate and enhance.	High	Replacing the Legacy CIS with a new solution will provide us scalability and needed sustainability for years to come.
SWG does not have a secure system and is more susceptible to security breaches which can reach sensitive customer data, including PII.	High	Having a modern system with modern security technologies will provide us a plethora of PII data management options and lessen the risk of breaches as we will have limited sensitive customer data present.
The current CSS does not have the ability to provide multiple channels to our customers including self-service.	High	The new CIS will enhance our customer engagement platform with more robust capabilities; customer engagement, self-serve, new product/service offerings, customer contact, etc.
Unable to capture institutional knowledge as business users retire and application knowledge as technical personnel retire.	High	Modernizing our CIS will help SWG attract and retain new talent as a company who is innovative with a sustainable and scalable system.
The current CSS is premise based system and is not the only billing engine.	High	SWG will have one primary billing engine for all customers. This will allow us to have a consolidated and more accurate view of customer accounts for: current and future product offerings, service, programs, rate changes, and accounting.
Unable to expand system to support future territories, products, programs, and services.	High	With a robust solution, SWG will be able to market and expand into more service territories seamlessly, with a configurable solution, in less time, therefore saving capital and O&M spend.
Without a new CIS, we cannot have enhanced query, extract, manipulation and reporting of information.	High	We will have standard out of the box reports, without requiring manual steps thus eliminating human error, and providing real-time reporting capabilities.
SWG is unable to support integration and interfaces between SWG's automated systems to provide for a single system of record for the customer, and eliminate redundancy across systems.	High	Having a central billing engine will allow us to use an enterprise-based approach; establishing interfaces will be analyzed leveraging FTP PUT/GET to convert them into near real time interface using HTTP GET/POST.

The current CSS is a vendor customized system.	Med-High	Configurability of the system will provide SWG the ability to implement and own the solution and with less time to make changes.

2.8 Timeline

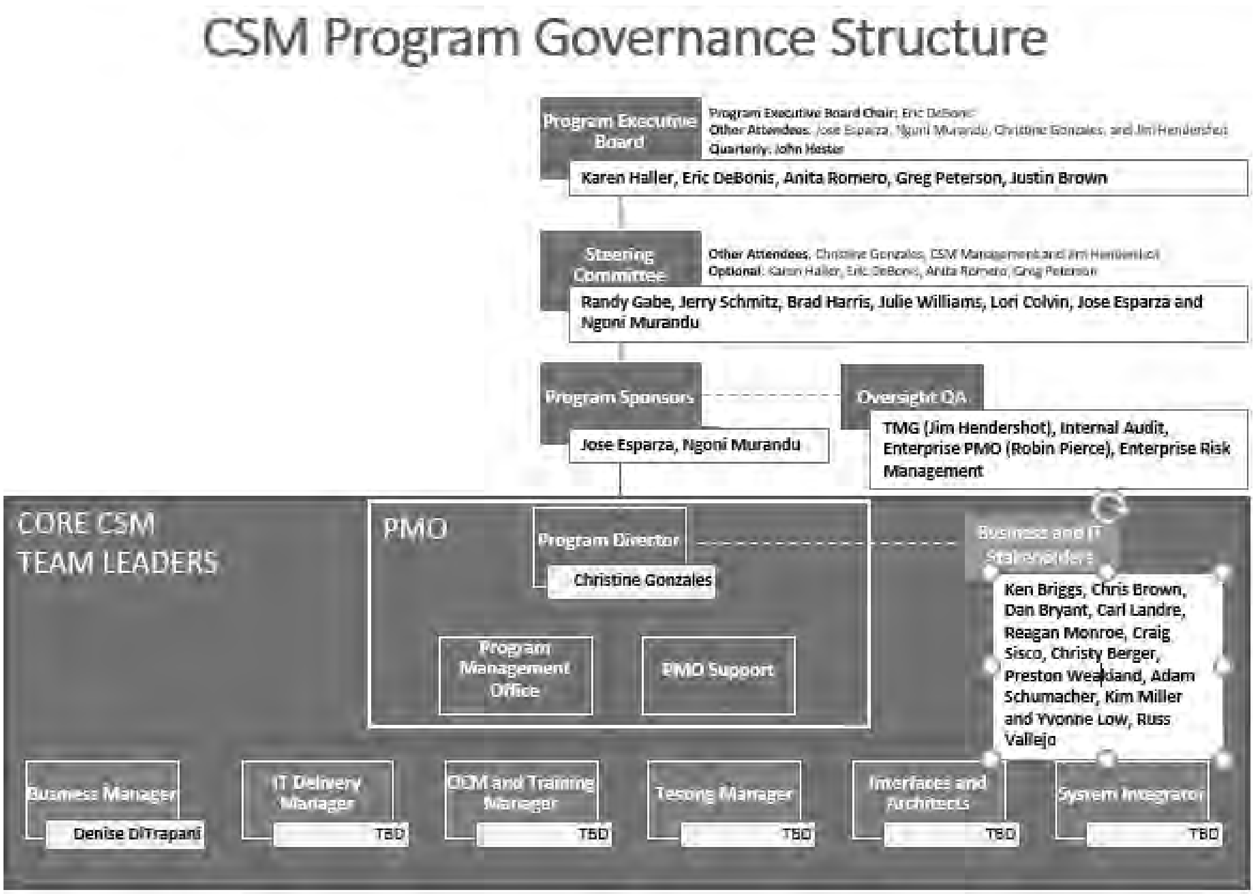


2.9 Project Stakeholders

The following individuals have been identified as Responsible, Accountable, Consulted, and Informed (RACI) in eliciting the high-level business needs and requirements. These individuals are subject to change during the duration of the project.

Name	Title/Department	Role/Expertise	Description (RACI)
Eric Debonis	SVP Operations	Division Operations V/P	R, A, C, I
Anita Romero	SVP/ Staff Operations and Technology	Staff Operations	R, A, C, I
Ngoni Murandu	VP/Information Services / CIO	Information Services	R, A, C, I
Jose Esparza	VP Customer Engagement	Customer Engagement	R, A, C, I
Karen Haller	EVP/ Chief Legal/Admin/Corp Sec	Legal and Admin	R, A, C, I
Greg Peterson	SVP/ Chief Financial Officer	CFO	R, A, C, I
Justin Brown	SVP General Counsel	General Counsel and Regulatory	R,A, C, I
Randy Gabe	VP Gas Resources	Gas Resources	C, I
Jerry Schmitz	VP Engineering Staff	Engineering Staff	C, I
Brad Harris	VP California and Nevada Divisions	Division Operations	C, I
Julie Williams	VP Southern Arizona Division	Division Operations	C, I
Lori Colvin	VP/Controller/CAO	Controller	C, I
Robin Pierce	EPMO Director	EPMO	R, A, C, I
Denise DiTrapani	Manger Call Center	Call Center	R, A, C, I
Ken Briggs	Director Application Services	Application Services	A, C, I
Chris Brown	Manger Gas Purchases and Trans	Gas Supply	A, C, I
Dan Bryant	Director Customer Relations/ SN	Customer Relations	A, C, I
Carl Landre	Director/Technology SIO	Technology SIO	R, A, C, I
Reagan Monroe	Director/ Business Technology	Business Technology Support	C, I

Name	Title/Department	Role/Expertise	Description (RACI)
Craig Sisco	Director/ System Integrity	System Integrity	A, C, I
Christy Berger	Regulatory Professional	Regulatory and Energy Efficiency	C, I
Preston Weakland	Mgr/Ops Planning and Analysis	Division Operations V/P	A, C, I
Adam Schumacher	Mgr/Customer Assistance	Call Center	A, C, I
Kim Miller	Mgr/Customer Assistance	Call Center	A, C, I
Yvonne Low	Dir/Customer Engagement	Customer Engagement	C, I
Russ Vallejo	Mgr/Gas Control & Dispatch	Gas Control & Dispatch	C, I


CSM Program Governance Structure
Program Executive Board
Program Executive Board Chair: Eric DeBonis
Other Attendees: Jose Esparza, Ngoni Murandu, Christine Gonzales, and Jim Hendershot
Quarterly: John Hester
Karen Haller, Eric DeBonis, Anita Romero, Greg Peterson, Justin Brown
Steering Committee
Other Attendees: Christine Gonzales, CSM Management and Jim Hendershot
Optional: Karen Haller, Eric DeBonis, Anita Romero, Greg Peterson
Randy Gabe, Jerry Schmitz, Brad Harris, Julie Williams, Lori Colvin, Jose Esparza and Ngoni Murandu
Program Sponsors
Jose Esparza, Ngoni Murandu
Oversight QA
TMG (Jim Hendershot), Internal Audit, Enterprise PMO (Robin Pierce), Enterprise Risk Management
CORE CSM TEAM LEADERS
PMO
Program Director
Christine Gonzales
Program Management Office
PMO Support
Business and IT Stakeholders
Ken Briggs, Chris Brown, Dan Bryant, Carl Landre, Reagan Monroe, Craig Sisco, Christy Berger, Preston Weakland, Adam Schumacher, Kim Miller and Yvonne Low, Russ Vallejo
Business Manager
Denise DiTrapani
IT Delivery Manager
TBD
OCM and Training Manager
TBD
Testing Manager
TBD
Interfaces and Architects
TBD
System Integrator
TBD

3 Cost Benefit Analysis

The CSM Capital spend was approved by the Board of Directors and updated per SWG 3-year business plan 2019 – 2021. The Capital spend is aligned against current industry standards with a total implementation cost of $144.29M (including O&M). The average cost per customer is $72.14 which aligns with industry comps for gas only, non- municipalities with primarily residential and small business customers run between $60 - $80 cost per customer.

There are no cost benefits as a result of implementing a new CIS. The CIS solution is justified based on our strategic initiative goals and the avoidance of risk associated with maintaining an aging technology infrastructure and application architecture.

3.1 Budget Overview

Description	Period (Execution)	Estimation
CSM Capital Spend (in million)	2019	$34
	2020	$53
	2021	$35.5
	Total	**$122.68**

O&M supports three major program components: Organizational Change Management, Training, and Data Conversion which includes a 25% temporary staff increase for call center and CABO resources for training and stabilization in 2020 – 2022. This update is included in Southwest Gas' 3-year business plan 2019 – 2021.

Description	Period (Execution)	Estimation
CSM O&M Spend	2018	$1.0
	2019	$2.3
	2020	$5.3
	2021	$11.5
	2022	$1.5
	Total	**$21.61**

3.2 Itemized Expenditures

Southwest Gas Customer Systems Modernization Program

Categories	2018 Pre-Planning	2019 Design Phase		2020 Build/Test Phase		2021 Implementation		2022 Stabilization	Total	
	O&M	Capital	O&M	Capital	O&M	Capital	O&M	O&M	Capital	O&M
SWG Labor - Functional	0.00	1.81	0.15	4.38	0.96	3.96	0.90	0.00	**10.15**	**2.01**
SWG Labor - Technical	0.00	2.24	0.50	6.68	1.06	5.54	0.90	0.00	**14.46**	**2.46**
SWG Labor Contingency	0.00	0.20	0.00	1.00	0.00	1.00	0.00	0.00	**2.20**	**0.00**
Solution Integrator	0.00	6.47	0.00	25.30	0.52	13.80	2.95	0.00	**45.57**	**3.47**
Solution Integrator Contingency	0.00	0.20	0.00	3.00	0.00	2.00	0.00	0.00	**5.20**	**0.00**
Software/Hardware	0.00	20.00	0.00	5.00	0.00	2.00	0.00	0.00	**27.00**	**0.00**
Software/Hardware Contingency	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**	**0.00**
3rd Party Vendors Including Edge Systems	0.00	3.00	0.22	5.75	0.33	5.75	0.19	0.00	**14.50**	**0.74**
3rd Party Vendors Including Edge Systems Contingency	0.00	0.10	0.00	2.00	0.00	1.50	0.00	0.00	**3.60**	**0.00**
Call Center and CABO Supplemental Resources	0.00	0.00	0.00	0.00	1.87	0.00	3.74	1.57	**0.00**	**7.18**
Project Travel	0.00	0.00	0.15	0.00	0.15	0.00	0.20	0.00	**0.00**	**0.50**
Program Support	0.00	0.00	0.60	0.00	0.20	0.00	0.30	0.00	**0.00**	**1.10**
Internal and External Communications	0.00	0.00	0.25	0.00	0.25	0.00	0.30	0.00	**0.00**	**0.80**
RFP Process	0.93	0.00	0.46	0.00	0.00	0.00	0.00	0.00	**0.00**	**1.39**
Total	**0.93**	**33.52**	**2.33**	**47.11**	**5.34**	**31.05**	**9.48**	**1.57**	**111.68**	**19.65**
Total Capital Contingency (10%)	N/A	0.50	N/A	6.00	N/A	4.50	N/A	N/A	**11.00**	**0.00**
Total O&M Contingency (10%)	0.00	N/A	0.00	N/A	0.00	N/A	1.96	N/A	**N/A**	**1.96**
								TOTAL BUDGET	**$122.68**	**$21.61**

Itemized spreadsheets:

SWG Business Case Model 12-19-2016 v2

SWG Staffing Workbook 8-20-201

4 Conclusions and Recommendations

4.1 Recommendation

Based on TMG's analysis, SWG made the decision to move forward with a replacement strategy. This includes replacement of the existing systems with a new CIS product solution SWG will enhance the product through user-defined exits and will be responsible for configuring the application. The new CIS solution will accommodate processing for 1.9 million gas customers. All customers will be converted to the new system using a "big bang" approach.

4.2 Justification

The new CIS solution is justified based on the avoidance of risk associated with maintaining an aging technology infrastructure and application architecture. The current CSS is an aged and highly customized system that carries high risk to the company, excessive support costs, and does not allow the company to meet customer demands for an optimal customer experience. A new CIS is required for the company to be more flexible and scalable to promote rapid response to industry and customer demands. The CSM Program will allow the company to manage business more efficiently, respond to customer expectations and position the company for growth, most importantly mitigating the risk of security attacks.

4.3 Organizational Impact

There will be 1,000 users impacted in 12 organizational units going from a mainframe green screen to a web-based system. This will impact over 17 critical business processes.

4.3.1 Business Processes Utilizing Current System

- New customer, Customer moves and changes
- Payment processing
- Rate changes
- Sales and fulfillment
- Collections
- Account final and write off
- Meter reading and route management
- Meter exchanges
- Meter diversion
- Leaks and outages
- Service orders, scheduling, dispatch
- Paper service orders (965s)
- COYL Accounts
- Construction, adding new premise, meter sets, landlord management
- Month end/quarter end balancing, reconciling, reporting

Department	User Type	Functions	Quantity
Customer Care	Secondary	Customer Account Lookup, Communication Events Research	500
Billing	Secondary	Service Account/Statement Account Lookup, Charge Period History, Communication Events Research	100
Credit & Collections	Secondary	Credit Case Events Lookup, Communication Events Research, Payment History, Outstanding Balances	100
Settlement and Assurance	Casual	Service Account Lookup, Usage History, Distributor One-Time Charges	50
Finance	Casual	Statement Account Lookup, Refund Reconciliation Research	100
Regulatory, Compliance & Audit	Casual	Statement View, Bill Messaging Lookup	25
Renewals & Retention	Casual	Customer Account Lookup, Contract Info, Service Account Lookup, Communication Events Research	25
Sales Agents	Primary	Entering and viewing customer contracts	100
		Total	**1000**

4.4 Alternative Solutions

TMG evaluated a total of 10 scenarios for alternatives to replacing the existing legacy CSS and GTS. Any one of the alternatives evaluated could potentially provide temporary fixes to a very limited number of our current issues for up to 7 years and could cost anywhere from $8M to $190M. These alternatives fall short of providing a solid and sustainable structure to our ever-evolving business needs and cannot align with our business strategy; to remain relevant with the times, respond quickly to industry and customer demands especially as we strive to provide optimal customer service. Neither of the alternative solutions will mitigate the impending need for a new CIS.

See alternative solutions considered:

Alternative Solution	Description	Reason for Not Selecting
Status Quo	Retaining the existing CSS/GTS application operating on the mainframe environment without any upgrades.	Current CSS is not sustainable and continues to become obsolete as technology, business demands, and strategy evolve. In order to maintain alignment and reach a top tier of customer service as well as reduce any risk of data breach and loss of revenue, the replacement of CSS is necessary and the most viable solution.
Enhance - Major Upgrades	Addresses some of the functional gaps with enhancements and fixes to CSS which improves the system functionally fit. 1,000 Function Points allowed for (7,500 possible in design).	This solution would not address all the current system issues: technology, application, business, and staffing issues. This would especially inhibit any customer-centric functionality, currently a top priority; as well as the limitations to provide an environment which is easy to change in support of business direction, new products, etc.
Enhance- New Front-End	Purchase of a product which provides for a Business User Interface (BUI). Replace the existing CSS user interface. Approximately 150 views.	This solution would only provide a short-lived solution of 5 to 7 years maximum and will not address all the application, business, or staffing issues surrounding the current system. The new user

Alternative Solution	Description	Reason for Not Selecting
		interface would require retraining and would be limiting to SWG by keeping the existing system that does not provide a flexible environment for future strategic business changes as well as customer and industry demands.
Enhance – New CRM	Purchase of a robust CRM product solution. Roll-out to entire customer base. Approximately 500 function points of 7,500.	Critical requirements would not be addressed with a new CRM. In this scenario, users must access multiple applications (CRM and GTS) to gain a full view of the data; each application must be separately maintained by IT staff. This option would generate large amounts of data and information duplication across both applications. The result still leads to replacing CSS as this solution would only last 5 to 7 years and we would still be missing a system with greater flexibility as well as the need to address all the application, business, and staffing issues surrounding the current system.
Enhance – New Complex Billing	Purchase of a robust complex billing module and roll-out to entire customer base. Approximately 300 function points of 7,500.	This solution is limited to solving issues with functionality and flexibility in complex billing solution. Critical requirements outside of the complex billing engine will not be addressed with this solution and it will still require replacing CSS after 5 to 7 years of implementation; costing $13.2M.
Enhance – Data Warehouse	Purchase of a data warehouse with baseline reports/queries. Secondary/Replicated database. 200 Views.	This solution requires extensive effort to understand and cleanup CSS/GTS in order to load it to the warehouse.

Alternative Solution	Description	Reason for Not Selecting
		The issue remains, supporting an underlying aging and nearly obsolete CIS technology with CSS/GTS. The staffing issues is also a major concern and risk as the workforce supporting this system are all well within retirement age and planning to leave within the next 5 years. Does not address basic CIS product design and technical limitations with CSS.
Replace – Managed Solution	Purchase of a CIS product solution to be run on an internal platform/data center. Regular product releases. Complete replacement of CSS, GTS (billing only) and the Web application.	SWG would need to adjust its business workflow to accommodate and match the product and train the business accordingly. This would be a large enterprise work effort with the need for extensive retraining of user and systems personnel, meticulous project management, and coordination for success (e.g. data conversion, interfaces, enhancements).
Replace – Defer Managed Solution	Wait 2.5 years. Purchase of a CIS product solution to be run on an internal platform/data center. Regular product releases. Complete replacement of CSS, GTS (billing only) and the Web.	Deferment of a managed solution would lead to a higher price tag due to inflation; costs will increase as the current solution needs continued maintenance and will ultimately be replaced. A major concerning factor here is the loss of current resources with the knowledge and skills to operate the current system if we defer, as well as any opportunities of advancing the customer experience.
Replace – Hosted Solution	Purchase of a CIS product solution to be run on an external platform/data center. Regular product releases. Complete replacement of CSS,	This solution entails SWG to tailor its business workflow to match the product and train the business accordingly. Referring to the Managed Solution; this is a large

Alternative Solution	Description	Reason for Not Selecting
	GTS (billing only) and the Web application.	enterprise work effort with the need for extensive project management and coordination for success as well as retraining of user and systems personnel.
Replace – Outsourced Solution	Purchase of a CIS cloud-based solution. Rent not own the software. Pay a per click charge. Limited to no customization of the CIS product.	There are similar disadvantages to the commercial CIS solution. In addition, ongoing operating costs will incur a much higher "per click" charge than other CIS alternatives. In this alternative, SWG is essentially renting the software and does not own it. Termination for cause or convenience must be contemplated and agreed upon, as well as plans established for either scenario. Some vendors may require the utility to conform to the "vanilla" product which typically does not allow the utility to participate in ongoing configuration and operational changes to the in-scope components. Therefore, there may be little buy-in and support across the company for this alternative to do the perceived risk profile. Ultimately, this solution will become more expensive within 3 years of implementation given the operating cost of $1.20 PCPM.

SWG Application Plan Final Report 02

Customer Systems Modernization (CSM

Appendix A: References

The following table summarizes the documents referenced in this document.

Document Name	Description	Location
CIS Assessment Final Report	SWG Application Final Report	Embedded
CSM Org Structure and Roles	CSM Program Governance Structure	Image
SWG - CSM OCM Services	RFP	Embedded
Customer Systems Modernization Business Case v.8	CSM Business Case Summary	Embedded
SWG Staffing Workbook v1.5	Staffing Workbook	Embedded
SWG Business Case Model v.24 Final	Business Case Model	Embedded

Customer Systems Modernization (CSM)

Business Case Summary

October 2018

Case For Change

Technical Risk

The current Customer Service System (CSS) is an aged and highly customized system that carries risk to the company, excessive support cost and hinders the company in meeting customer demands

Flexible Technology

A new Customer Information System (CIS) allows us to be more flexible and scalable to promote rapid response to industry and customer demands

Customer Experience

The Customer Systems Modernization (CSM) program will allow the company to manage business more efficiently, respond to customer expectations and better position the company for the future

SOUTHWEST GAS

Executive Summary

- CIS assessment began in 2016
- 10 primary drivers support the 2017 recommendation to replace existing systems with a new CIS
- Total projected* implementation cost
  - Capital - $122.5M
  - O&M - $21.6M
- 1,000 users impacted in 12 organizational units moving from a mainframe green screen to a web-based system
- Impacts over 20 critical business processes
- Implementation cost projections, timeline and staffing plan align with industry standards

*Cost projections updated in February 2019 when Platform and System Integrator RFP costs are secured

CSM Assessment Roadmap

2016

- TMG, qualified 3rd party vendor, began CIS assessment
- Milestones included strategy, gap analysis, business case, final recommendation

2017

- SWG partnered with TMG to complete an assessment that resulted in the recommendation to replace the current systems with a new CIS
- Developed CSM roadmap, initial “blueprinting” and preliminary estimate
- Preplanning activities began
- Benchmarking with peer utilities occurred and site visits were conducted with tier 1 solution providers

2018

- SWG enlisted specialized program management and quality assurance support to finalize blueprint and implementation plan
- Budget and business case refreshed
- Platform and System Integrator RFP began
- Organizational Change Management (OCM) activities began

10 Primary Drivers to Replace Existing Systems

Technical Risk

- Replace an aging CIS application architecture and technology which is becoming more difficult to operate and enhance
- Ability to have a secure system with less risk to security breaches and limited presence of sensitive customer data
- Ability to capture institutional knowledge as business users retire, and specific application knowledge as technical personnel retire
- Ability to implement an internal configurable solution rather than a vendor customized system

Flexible Technology

- Ability for an expandable system to support future territories, products, programs, and services
- Ability to streamline and align manual and automated business processes to make business operations more efficient
- Enhanced query, extraction, analytical and reporting capabilities
- Ability to support necessary integration and interfaces between SWG's automated systems to provide for a single system of record for the customer and eliminate unnecessary redundancy across systems

Customer Experience

- Ability to provide enhanced levels of customer service via multiple channels including self-service
- Implement one primary billing engine with an emphasis on a customer-centric system rather than location (premise) based

CSS At A Glance

25 Resources Supporting Current CSS

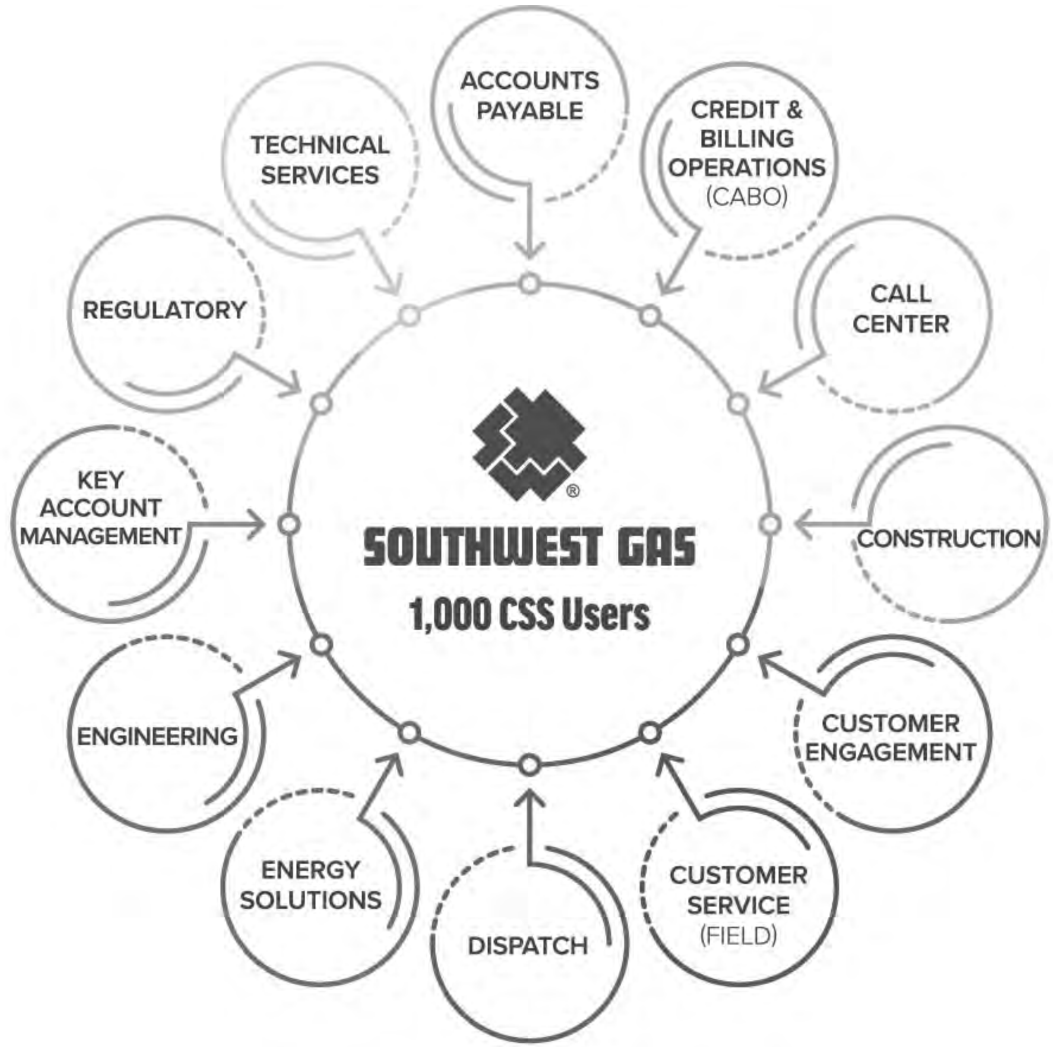
1990 CSS Implementation on 1970's technology

293 Systems and interfaces with CSS

- CSS is used companywide and consists of over 200 screens within 18 subsystems, providing an on-line access to current and historical data
- Provides tenant, premise and utility information and is the meter-to-cash billing system
- Tracks meter/ERT inventory and used to create service orders
- CSS is written in Cobol and runs on an IBM z13s mainframe with z/OS as the operating system

SOUTHWEST GAS

CSS Users



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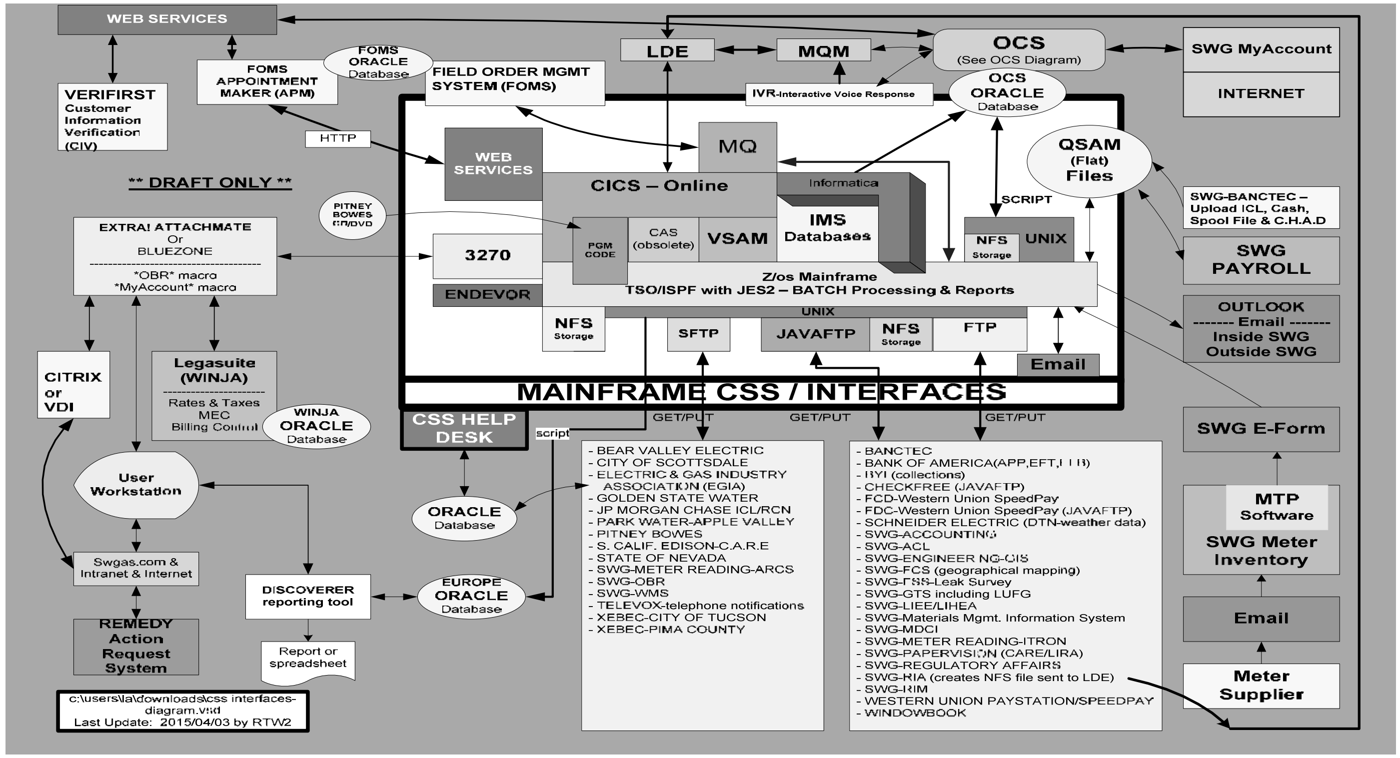
Business Processes Utilizing Current System

- New customer, customer moves and changes
- Payment processing
- Rate changes
- Sales and fulfillment
- Collections
- Account final and write off
- Meter reading and route management
- Meter exchanges
- Meter testing

- Meter diversion
- Leaks and outages
- Service orders, scheduling, dispatch
- Paper service order (965s)
- COYL accounts
- Construction, adding new premise, meter sets, landlord management
- Month end/quarter end balancing, reconciling, reporting
- SOX report management

SOUTHWEST GAS

CSS Integration



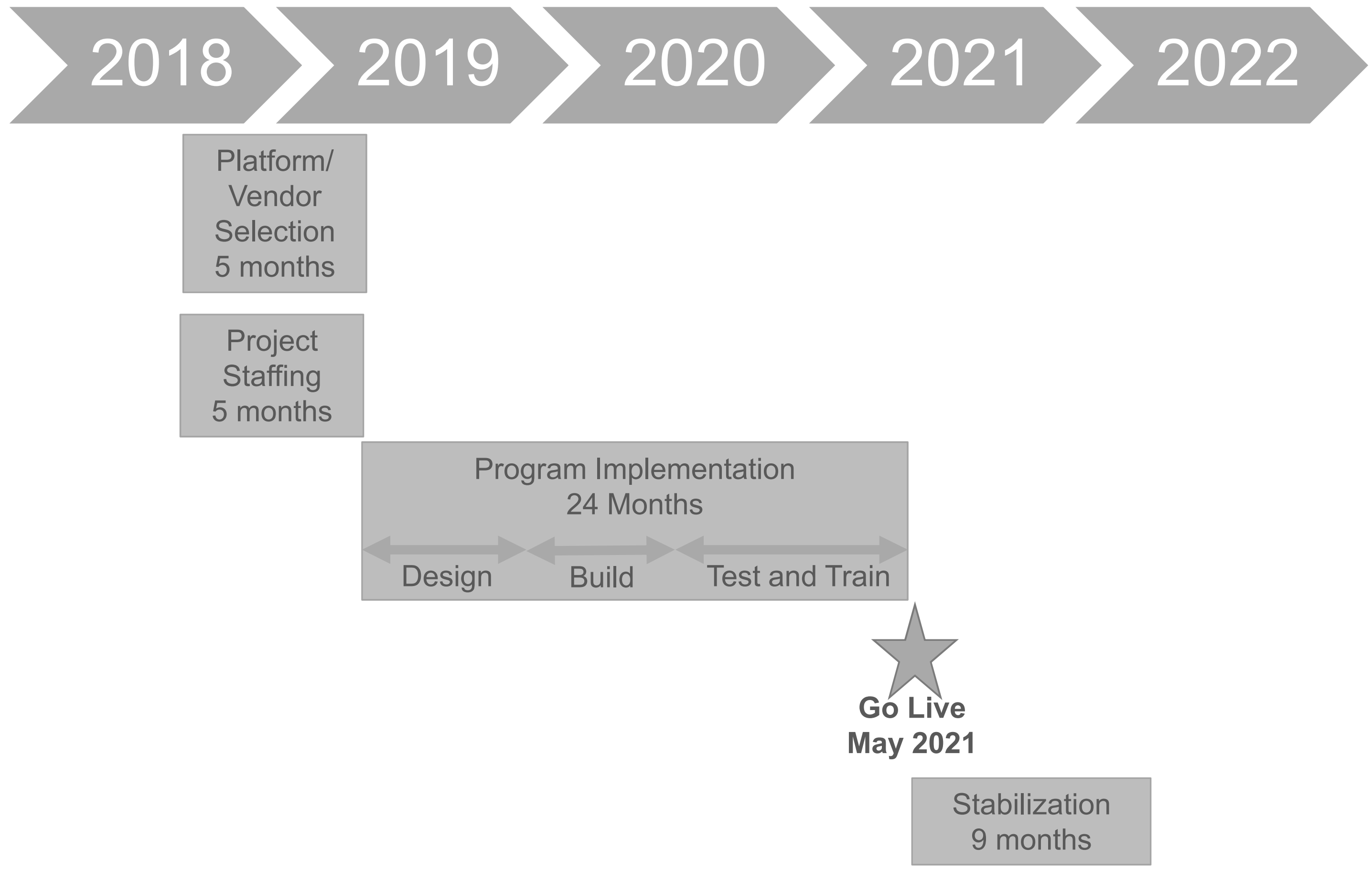
- Lack of preferred methods for interfaces and lack of design patterns in place
- Lack of standard middleware for standardizing business processes across all systems
- Majority of interfaces are flat files with lack of standard format to send and/or receive data from external systems

SOUTHWEST GAS

Targeted Future State CIS

Current CSS	Future CIS
Lack of preferred methods for interfaces and lack of design patterns in place	Use standard service bus for interface and integrations
Lack of standard middleware for standardizing business processes across all systems	Common business process interfaces shares a common design pattern for extensibility and code reusability
Majority of interfaces are flat files missing a standard format to send and / or receive data from external systems	Interfaces will be analyzed leveraging FTP PUT/GET to convert them into near real-time interface using HTTP GET/POST

Business Case Modeled Timeline



SOUTHWEST GAS

CSM Capital Spend

Capital Spend

(in million)

	Budgeted			
CSM	2019	2020	2021	TOTAL
	$34	$53	$35.5	$122.5

- Updated included in SWG 3-year business plan 2019 - 2021
- Compares against industry standards with a total implementation cost of $72.14 per customer or a total of $144.29M (including O&M) per TMG survey
  - Industry comps for gas only, non- municipalities with primarily residential and small business customers run between $60 - $80 cost per customer
- Assumes a 24 month implementation exclusive of post implementation stabilization

SOUTHWEST GAS

CSM O&M Spend

O&M Spend
(in million)

	Budgeted					
CSM	2018	2019	2020	2021	2022	TOTAL
	$1.0	$2.3	$5.3	$11.5	$1.5	$21.6

- O&M supports three major program components: Organizational Change Management, Training and Data Conversion
- Includes 25% temporary staff increase for call center and CABO resources for training and stabilization in 2020 - 2022
- Update is included in SWG 3-year business plan 2019 – 2021

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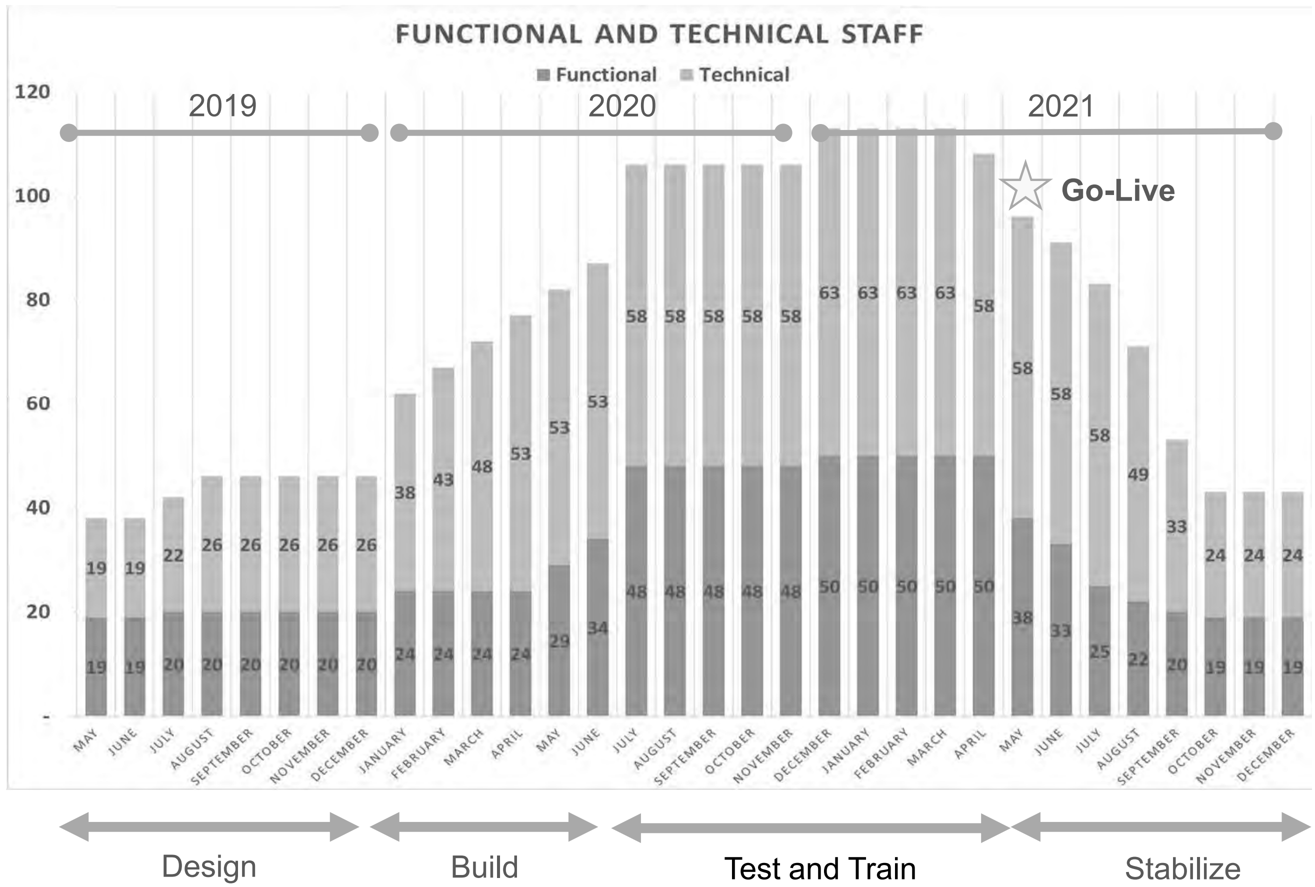
SWG Resource Plan



- **Peak staffing occurs in month 20 with 113 FTE**

SOUTHWEST GAS

Staffing Model Matrix

Functional Peak – FTE Month 20	
Project Administration	1
Communications	1
Functional Leads	1
Functional Support	10
Data Conversion	6
Reporting	4
Testing	15
Change Management	2
Training	8
Post Go Live Support	2
TOTAL FTE	**50**

Technical Peak – FTE Month 20	
Project Administration	1
Audit and Controls/Security	4
Technical Lead	1
Development	5
Interfaces/Integration	6
Reporting/Bill Print/Forms	3
Data Conversion/Clean-Up	5
Infrastructure	3
3rd Party Management	2
Testing	25
Go Live Readiness	1
Post Go Live Support	7
TOTAL FTE	**63**

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Core Team

Core Team Members	Total
Call Center/CABO	4
IS – Data, Integration, Environment	7
Rates	1
Service Order	1
OCM, Training, Communications	4
Marketing/Online Account	2
Financial Management	1
Payments/Refunds/Deposits	1
Program Director/PMO	2
TOTAL FTE	**24**

- During the 24 month implementation phase and the 9 month post-implementation phase the core team staffing will be driven by the staffing plan for specific assignments
- Core team members are defined as being 100% dedicated to the project during the entire 24 month implementation

SOUTHWEST GAS

Industry Benchmarking

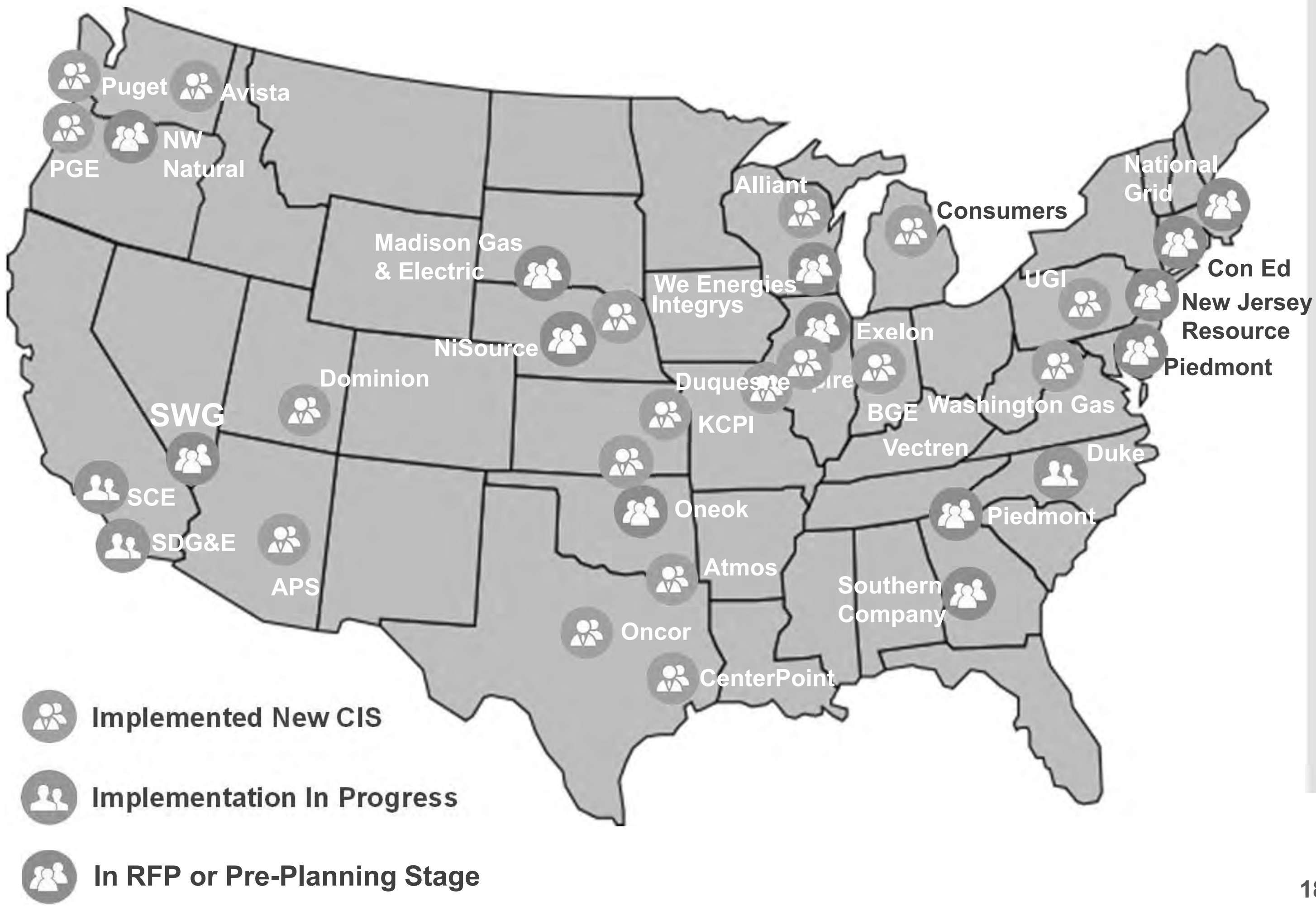
Peer companies with successful implementations

PSE PUGET SOUND ENERGY
Consumers Energy Count on Us®
AVISTA
WGL ENERGY ANSWERS
UGI Energy to do more®
spire
ATMOS energy Your natural gas company
Alliant Energy
QUESTAR Gas
CenterPoint® Energy

Peer companies on legacy systems in pre-planning or considering a new CIS system

ONEOK
New Jersey Natural Gas
Piedmont Natural Gas Energy that shows.
NW Natural®

Peer Utility Maturity Comparisons



Call to Action

- This will be the company's largest business transformational program requiring a fully dedicated team as well as a company-wide engagement at all levels of the organization
- Executive support required to complete the Platform and System Integrator RFP selection to have updated cost estimates in February 2019
- Once approved, executive support required to begin CSM implementation May 2019

Project Horizon

Project Management Plan - Delivery

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Document Status	☐ Draft ☒ In Review ☐ Final ☒ Update After Final
Document Owner(s)	Kwad Mensah
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Document Version Control			
Version	**Date**	**Author**	**Details of Change**
0.1	06/10/2019	Kwad Mensah	Initial Draft
1.1	06/22/2019	Sara Avalos	Comments from SWG
0.3	06/24/2019	Kwad Mensah	Update based on comments and added Risk Management and Issue Management Sections
0.4	06/26/2019	Kwad Mensah	Updated based on feedback from 6/26
0.5	6/26/2019	Kwad Mensah	Updated based on feedback from 6/26
0.6	6/27/2019	Kwad Mensah	Updated with missing links
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1.1	10/16/2019	Kwad Mensah / Karen Mok	Updated sections 3, 5, 6, and 11-16
1.2	10/28/2019	Dana Montgomery	Updates for DBV
1.3	10/31/2019	Christine Gonzales	Updates to sections 5, 6, and 11-16

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Name	**Role**	**Date**

Document Approval		
Name	**Date**	**Comments**
Christine Gonzales	6/28/2019	
Sara Avalos	6/28/2019	

I agree that this document and external documents referenced within this document represents accurate and complete delivery of the Project Management Plan.

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1. Introduction

1.1 Project Management Plan Overview

This Project Management Plan applies to the Project Horizon CIS implementation at Southwest Gas. The Project Management Plan is required reading of all team members with Project Management or Team / Work Stream Lead responsibilities and serves as a guideline for defining, measuring, and monitoring commitment to quality by all team members of the project. It outlines the project's objectives, parties involved in the project planning and execution, the overall timeframe for the project and the delivery strategy for the project.

The Project Management Plan should be reviewed by any new team member with Project Management or Team / Work Stream Lead responsibilities when rolling on to the project.

The current version of the Project Management Plan is located in the SharePoint here: Deliverables

The Project Management Plan is under formal change control and can only be changed via the change request process. The Plan is a living document must be updated when substantive changes are made to the scope of the project.

1.2 Responsibility for the Plan

The Project Management Plan was prepared by the Project Management Team, whom is also responsible for updating it with any significant changes to its contents such as:

- Project scope
- Project tracking processes
- Project methods, standards, and approach

The initial issue of this Project Management Plan – Plan / Initiate, and all major versions, are reviewed and approved by the Project Horizon Program Director and the Project Management Office Lead. This document is accessible to all project team members, project management, and the Quality Assurance (QA) Lead.

2. Project Overview

2.1 Legacy Overview

A key aspect of Project Horizon is replacement of SWG's CSS Customer Information System (CIS). The current CIS has been in production for nearly 29 years; and is based on outmoded COBOL programming language, hosted on an IBM z/Series mainframe, and built on IBM's IMS database and CICS transaction server. SWG has selected a new enterprise customer information and billing system licensed from SAP, the SAP for Utilities platform, with associated software, hardware, data conversion, business processes and business requirements to replace the current CIS. Southwest intends that the new System will be highly integrated with various other existing systems of Client or its Affiliates, including but not limited to: the Gas Transaction System (GTS); Online Customer Self-Service System

(OCS); Field Order Management System (FOMS); and Outage Management System (OMS). Each of these systems are also undergoing changes or replacement as additional aspects of Project Horizon.

2.2 Program Context

Project Horizon and the Company's efforts to modernize these customer information systems and related business processes is intended to create an integrated environment of processes and systems that facilitates achievement of the Company's business vision and objectives through technology, innovation, and continuous operational improvements for safety, service, and reliability.

2.3 High Level Timeline

Project is estimated to have a duration of 23 months from Plan to Deploy with 6 months of post go-live support.

The following provides the estimated duration and timing for each of the Project phases:

Phase	Description	Timeframe
Plan	The foundation of the project cadence and onboarding of the core team	June 17, 2019 to July 19, 2019
Initiate	Creating and finalizing the to-be business process and target solution architecture and detailed implementation plan. Key design decisions (e.g. GTS integration) made to be used as the basis for remaining phases.	July 21, 2019 to November 1, 2019
Design-Build-Validate	Performing the technical designs, build, unit testing, and assembly testing of custom code and configured objects	November 4, 2019 to July 3, 2020
Test	End-to-End, User Acceptance, and performance testing to validate that the system will meet business requirements	July 6, 2020 to December 4, 2020
Deploy	Final operational readiness testing, deployment preparation, and organization preparation to be ready for go-live	December 7, 2020 to April 30, 2021
Stabilization	Post Go-Live support inclusive of Hypercare and Warranty to achieve normal operations in the new solution and to minimize operational impacts	May 1, 2021 to October 31, 2021

3. Organization

3.1 Project Management Continuity

Several key Project Management and Project Leadership resources have been involved in the project from its proposal phase and will continue with the project through implementation. These resources have been selected for their extensive experience. These key resources are:

Role	Name
SWG Enterprise Program Management Office (EPMO)	Robin Pierce
SWG Program Director	Denise DiTrapani
SWG Program Director	Christine Gonzales
Accenture Program Director	Karen Mok
SWG Project Management Office Lead	Sara Avalos
Accenture Project Management Office Lead	Kwad Mensah

Table 1: Key Project Management Office Resources

3.2 Project Organizational Chart and Governance Structure

The Project Organizational Chart provides a hierarchical depiction of the project teams. The Project Organizational Chart is living document that is updated as organizational changes occur and as the project progresses through phases. The project organization chart as of October 2019 is illustrated below.

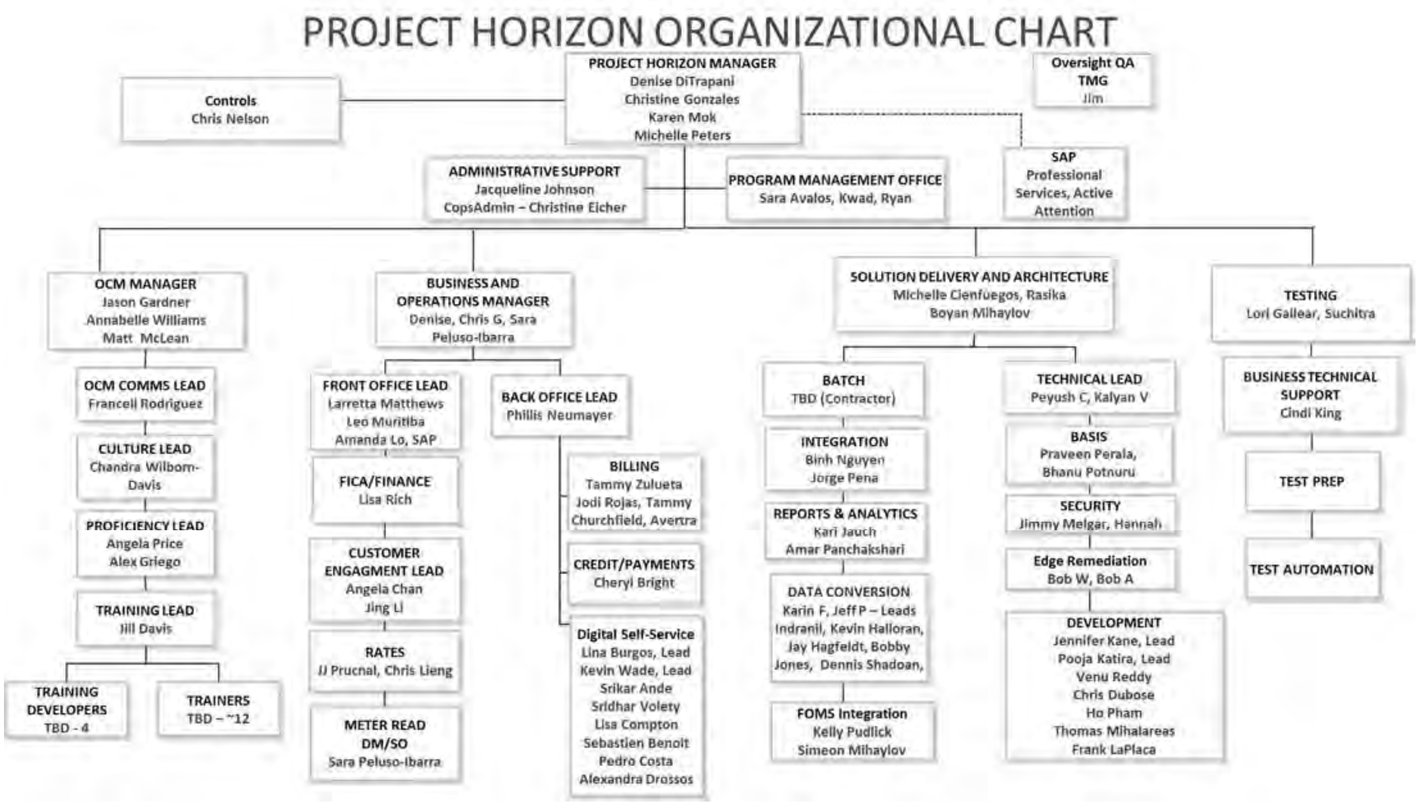


Figure 1: Project Horizon Organizational Chart as of October 2019

The Project Governance structure depicts the governance model for the project and includes all parties that integrate into the project. The Project Governance structure as of October 2019 is illustrated in the figure below.

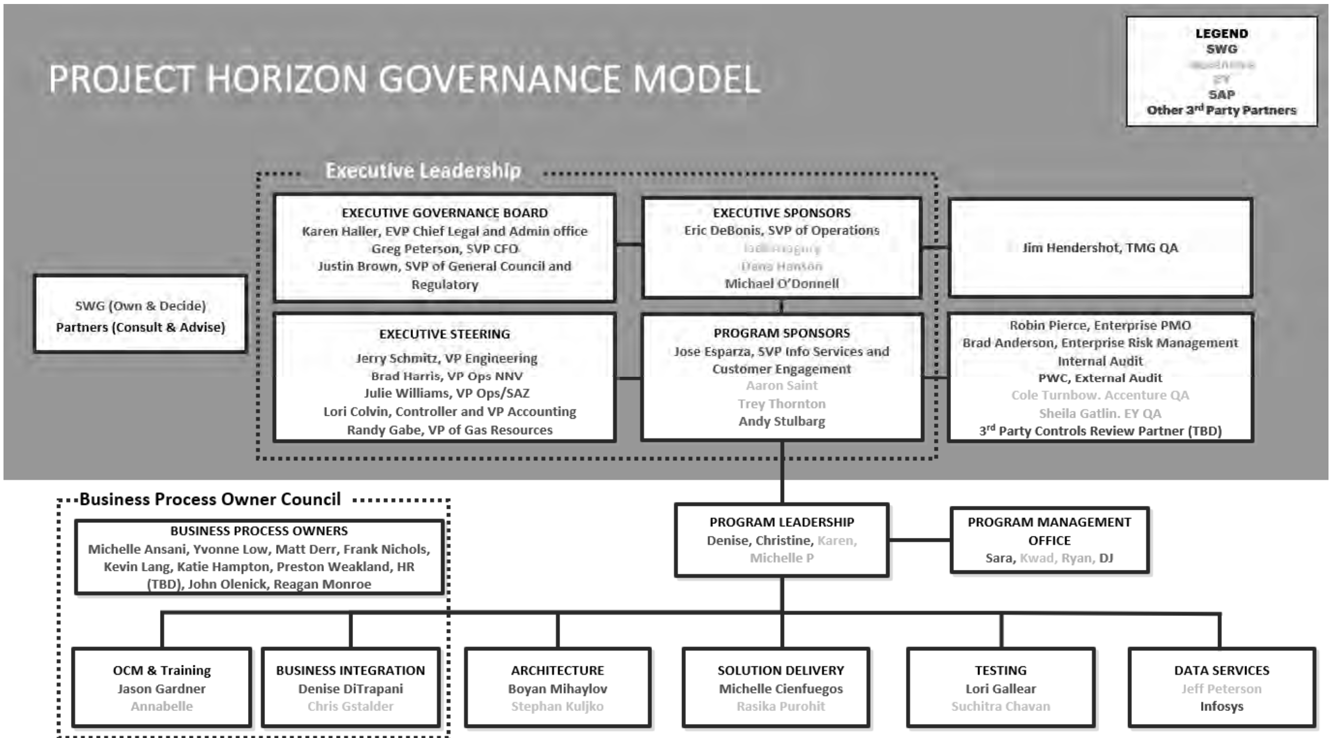


Figure 2: Project Horizon Governance Model as of October 2019

3.2.1 Roles and Responsibilities

Roles and Responsibilities for the Key Project Management Resources are listed below.

Program Director

The Program Director has overall responsibility for the work performed on the project.

- Determine the project approach, staffing, responsibilities, and schedule
- Be accountable for the overall project delivery and set overall direction for the project
- Understand and meet the expectations of the Executive Sponsors, Executive Board and Executive Steering Committee and serve as the point of contact for the executive teams
- Resolve risks and issues escalated by the project team that require attention
- Monitor project-level risk management
- Provide Executive Governance Board and Executive Steering Committee with accurate and timely information regarding project performance
- Monitor progress to help confirm that project objectives are delivered on time and within budget
- Work with the Organizational Change Management (OCM) Lead to develop sponsorship/support for project within affected organizations, and establish a governance organization
- Coordinate the definition of team member roles and expectations, and ensure timely feedback
- Monitor stakeholder expectations and take corrective action to address gaps

- Monitor and maintain project team morale
- Monitor project timelines, milestones, and resource usage and coordinate timely project staffing
- Manage relationships with and coordinate subcontractor arrangements and involvement on the project team
- Monitor subcontractor progress and adherence to contractual agreements
- Ensure that the project team follows all quality assurance processes, including periodic reviews and transitions
- Help confirm that business case is managed and updated throughout the project lifecycle
- Develop and manage the overall project approach and schedule, staffing requirements, and team responsibilities

Project Management Office Lead

The Project Management Office Lead is responsible for the overall delivery and quality of the project.

- Developing, implementing, and maintaining (keeping up to date) the Integrated Project Plan, which includes inputs from detailed work plans and other guiding documentation such as risk and issue logs, change control documents, and status reporting
- Managing deliverables for completeness and quality
- Implementing project management processes such as scope management/change control, risk and issue management, quality management, and configuration management according to the project plan
- Providing guidance/direction on contract, task order, and/or work request issues
- Defining and managing the project quality metrics
- Analysing and interpreting metrics and using them to make needed plan and process changes on the project
- Preparing weekly and monthly project status reports
- Representing Project Horizon in meetings to report progress and communicate issues and risks that will impact schedule
- Resolving issues and/or escalating issues to the appropriate level to be resolved
- Managing changes to commitments/requirements
- Coordinating and participating in quality activities. PMO Lead will coordinate both Process and Quality Assurance Reviews and peer reviews as necessary, as well as participate in Process and Quality Assurance Reviews.
- Ensuring that metrics are collected and kept up to date, using the processes and tools provided as part of the Project, and reporting weekly metrics to Project Leadership and key stakeholders as well as to any other required SWG organizational group

4. Onboarding

4.1 Notification

Approximately 4-6 weeks prior to a resource's start date in the program Resource Plan, PMO sends notification spreadsheet to SWG PMO. Leads should leverage the Onboarding Kit found on the SWG SharePoint here: Onboarding Kit.

4.2 Credentials

Resources will receive credentials from SWG (ID and password). The password must be at least 15 characters long and contain letters, numbers, and a capital letter.

4.3 Security

All project team members are required to obtain a security badge from SWG when they will be at a SWG location for more than one week. Upon joining the project, the team member will contact the PMO to start the process for obtaining a security badge. All team members are required to keep their security badge in their possession at all times and to use it to enter the building. If a security badge is lost or stolen, then contact the SWG's facilities team immediately.

5. Logistics and Infrastructure

5.1 Facilities and Infrastructure

Upon joining the team, team members are directed to the project lead in that facility for assignment of work space, equipment (phone and hardware) and supplies. SWG responsible for providing space to all team members and partners.

5.2 Integrated Work Environment

To encourage an integrated work environment within the project team, the project will use the following communication and work tools:

- Microsoft Office suite of products (Word, Excel, PowerPoint, etc.)
- Microsoft Outlook and Exchange for e-mails, conference room and meeting requests, and calendars
- Microsoft Teams

5.3 Data and Version Management

All electronic versions of information and Deliverables must be maintained in the SharePoint in the required folder structure. Within the SharePoint, there is version control on all approved Deliverables and work products, where the approved change is captured in the document change log and the version number is incremented accordingly. Refer to the change request process for key Project Deliverables and artifacts referenced in section 11.2.

6. Functional Requirements

6.1 Concurrent Projects with Project Horizon Planning Dependencies

Project Horizon has the interproject dependencies with the following other inflight initiatives at SWG:

- Gas Transportation System Replacement Project
- Bill Print Project

6.2 Task-Level Critical Dependencies

The Work Plan contains tasks and task groups which are inter-dependent. When changing the start and end dates for the “parent” task or group, the Work Stream or Team Lead responsible for the task will re-evaluate all “child” tasks or groups for possible revisions.

All inter-dependent tasks have been created as “dependent” tasks in the Integrated Project Plan. Therefore, their relationship will be maintained. A list of the critical dependencies can be generated at any time by using the viewing the project work plan in Microsoft Project.

7. Project Monitoring and Tracking

7.1 Track Project Schedule / Time

Project schedules are tightly managed and reported in status reports. Project teams each have their portion of the Work Plan to manage and control. Work stream and Team Leads are responsible for adding new team members to project efforts, adding tasks for those team members, and ensuring that all team members are familiar with the project tasks. The cadence for activities related to Project Plan Updates and schedule tracking by each of the work plan owners, is depicted in Figure 3 in section 7.2.

There will be no process to capture time in relation to specific Project Horizon tasks.

7.2 Measure, Monitor, and Control Project Performance

Project performance, as it pertains to the Project Schedule managed by the PMO will be measured through the following key metrics and information and variances derived from these metrics:

Actual Percent (%) Complete
Planned Percent (%) Complete
Planned Start Date
Actual Start Date
Actual Date Complete
Planned Date Complete
Schedule Performance Index (SPI)

Along with these metrics, the detailed Project Plans will include additional metadata and tags to allow for analysis of tasks on the critical path, which refers to any task(s) that has an end date beyond the milestone or expected planned completion for a given group of tasks or Phase or major Milestone. The critical path will be included as part of the communication of tasks that are behind and on that critical path.

Other metrics will exist as it pertains to specific work streams and teams and those will be further detailed in strategy and approach Deliverables:
- Data Conversion Strategy
- Master Test Strategy
- Reporting and Analytics Approach

On a weekly basis the team members who own the detailed project plans will update task progress, review dependencies, and review metrics as part of the weekly communication and evaluation of how the Project is tracking against planned tasks. The figure below represents the weekly project plan update, review, and metric creation cadence for Project Horizon

Weekly Project Plan Communication Distribution	Proposed Timing	Recipients	Maintenance Activity	Corresponding Meeting
Plan Maintenance Reminder (Automated)	Wednesday 9am PT	Primary and Secondary plan owners for Functional, Solution Delivery, OCM, and Data Conversion and PMO Leads	Plan owners start plan maintenance activities, collect updates from their teams on task	PMO + Leads meeting (ad hoc, only if needed)
Plan Maintenance Reminder (Automated)	Thursday 9am PT	Primary and Secondary plan owners for Functional, Solution Delivery, OCM, and Data Conversion and PMO Leads	Plan owners continue plan maintenance, collect and refine updates from their teams	Work stream status meetings, will include review of the detailed project plan
Plan Maintenance Reminder (Automated)	Thursday 1pm PT	Primary and Secondary plan owners for Functional, Solution Delivery, OCM, and Data Conversion and PMO Leads		
Plan Maintenance Chaser v1 (Automated based on people who have not made updates)	Thursday 5pm PT	Primary and Secondary plan owners for Functional, Solution Delivery, OCM, and Data Conversion and PMO Leads	PMO checks on who has completed plan maintenance and gets ready for first of Reports and Metrics	Follow-up meetings planned for Thursday / Friday with Plan owners who have not maintained plans
Plan Maintenance Chaser v2 (Automated based on people who have not made updates)	Friday 9AM PT	Primary and Secondary plan owners for Functional, Solution Delivery, OCM, and Data Conversion and PMO Leads		Starts inputs for the Monday status compilation for **Tuesday PM Leads Meeting**
Reports and Metrics v1 (Automated)	Thursday EOD	Primary and Secondary plan owners for Functional, Solution Delivery, OCM, and Data Conversion and PMO Leads	Plan owners continue plan maintenance, collect and refine updates from their teams Work stream status meetings, will include review of the detailed project plan tasks and reports	
Reports and Metrics v2 (Automated)	Friday	Primary and Secondary plan owners for Functional, Solution Delivery, OCM, and Data Conversion and PMO Leads		
Reports and Metrics v3 (Automated)	Monday AM	Primary and Secondary plan owners for Functional, Solution Delivery, OCM, and Data Conversion and PMO Leads	PMO reviews reports and finalizes inputs, follow-ups with individuals on dependency and task progress questions Leads prepare to discuss any upcoming planned date adjustments	Feeds the **Tuesday PM Leads meeting, Wednesday Leadership meeting,** and any **other Leadership Meetings for the week**

Figure 3: PMO Plan Updates and Metrics Reporting Distribution using myPMO Toolset

7.3 Communicate Project Status

Project status is reported in a pyramid fashion, with Individual Status Reports feeding up to Program Leadership Status Report, which feed the overall Project Status Report. There are also other specific functional and technical team reports that are funneled up the overall Project Status Report. This Project Status Report information will be used to communicate status to other Key Stakeholders beyond Program Leadership.

Project Horizon is prepared to use the myPMO toolset with Microsoft Project and SWG SharePoint to generate metrics and reports to feed Project Status reporting.

It is crucial to the success of the project that all team members are kept informed of the project's status, and it is equally crucial the individuals keep their immediate supervisors informed of their own progress.

There are standard Status Report templates that team members must use and fill out with all parties within their work stream including but not limited to offshore resources. Each template contains section headings for the information that must be presented in each of those reports and meetings. The Status Report templates are located on the SharePoint here: PM Leads Meeting.

The reporting schedule for the project status includes both written status reports and status meetings. The overall weekly and monthly cadence can be found in the Horizon Program Management Office Dashboard found on the SWG SharePoint here: Program Management Office Dashboard.

Note that there are other process areas that will have their own status meetings that are not included in the Project Communications Plan. For example, the project has standard daily meetings to provide direction for the day, but that is not in the standard communications plan. Status meetings will have their minutes documented and stored in the following location: Program Leadership Meeting

7.4 Manage Change Control and Change Requests

Any addition, removal, and impactful change to a deliverable task, or activity resulting in a change in effort, schedule, and/or budget will be managed by the PMO via a change control process.

Change Control is the process followed to ensure all changes to the agreed upon scope of Project Horizon are identified, controlled, consistently handled, and traced throughout the Project. The mechanism for submitting any controlled change is through a Change Request.

Change Requests fall into two categories: Administrative and Full Change.

Administrative Changes are those which require small updates to SOWs or documents and do not impact scope, schedule or budget. An example of an Administrative Change is moving a Deliverable from one Work Stream to another.

Full Changes are those that impact scope, schedule or budget. Full Changes will need to be reviewed and approved by the Project Sponsors, Change Control Board (CCB) and appropriate level executive teams. Full changes that require additional funding requests will be communicated up to Executive Governance Board. The Change Control Board will consist of The Project Horizon Program Directors, Business Integration Leads, Solution Delivery and Architecture Leads, the Program Management Office and OCM Leads as required. The CCB will review scope change requests on the Project Horizon as well as review scope change requests from other programs/projects that may impact Project Horizon or impact other in-flight initiatives at SWG.

Changes in scope will be managed and documented through the following Change Control provisions:

- An originating team member, in consultation with his/her Team/Workstream Lead, identifies and initiates the change request process by documenting the request and submitting via the Scope Change Request Form.
- The team member is responsible for adequately documenting the request. Prior to submission, the change request must contain detailed information regarding the change including but not limited to:
  - Description of the change.
  - Business rationale; description of the impact to the overall business objectives
  - Effort (if known)
  - Severity of Impact
  - Alternatives or a work around
  - Date Decision Required (if known)

Once received, Program Leadership and Project Management can request an immediate review of Critical and High Impact Scope Change Requests (SCRs), as deemed by the Workstream/Team Leads. All other SCRs will be reviewed in the change control board meeting. The audience for SCRs will be the members of the CCB as named above.

Program Leadership and Project Management Office Leads review the SCRs to determine their overall impact across the Project Workstreams and recommends to; approve, defer, or reject the SCR. If a SCR exceeds a threshold on size of change or type of impact (dollars, hours, impact to business units, etc.) as decided by Project Management, it would be brought to the Project Sponsors or appropriate level executive teams for review and approval of the recommendation made by Program Leadership.

Once an SCR is approved, the Workstream Leads are responsible for working with the PMO on integrating approved change requests into the Project work plan. The Workstream Leads are additionally responsible for assigning the appropriate resources to complete the work, update requirements and impacted deliverables. The change control template is found here: Change Control Template

8. Project Schedule and Milestones

8.1 Project Timetable

The project work began in June 2019 with mobilization and requirements work completed under the MSA while contract negotiations occurred. The project is divided into the following phases and estimated time frames:

Phase Name	Estimated Timeframe
Plan	June 3, 2019 to July 19, 2019
Initiate	July 21, 2019 to November 1, 2019
Design-Build-Validate	November 4, 2019 to July 3, 2020
Test	July 6, 2020 to December 4, 2020
Deploy	December 7, 2020 to April 30, 2021
Stabilization	May 1, 2021 to October 31, 2021

8.2 Project Work Plan

8.2.1 Project Work Plan Overview

The project integrated work plan will be created during the Plan Phase. The proposed integrated work plan created during the Plan phase will be refined throughout subsequent phases of the project to consider external factors and contingency. Project experience, location, and SWG's organizational structure were all factored into the refined resource plan. The work plan includes specific tasks, deliverables to be produced, resources, planned start date, planned finish date, actual start date, actual finish date. This work plan is the basis for the resource plan. The work plan will be baselined at the beginning of the project and must be re-baselined whenever a significant change is introduced.

The project Work Plan with schedule will be located in the SWG SharePoint and on the Accenture hosted Microsoft Project Server.

Throughout the Project, the project plan will be planned in greater detail as we approach an upcoming phase.

8.2.2 Approach to Detailed Planning

One of the inputs to detailed planning that occurs on a rolling 3-4-month period to further build detailed tasks in a future phase of work is the Project Roadmap.

The Project Horizon Roadmap is a mid-level detail timeline with Gantt Chart bars that helps guide the Project Horizon team as a key input to detailed planning. The Project Horizon Roadmap is found on the SWG SharePoint here: Project Horizon Roadmap and will be refreshed for each phase and as required for approved changed requests.

A focused activity that starts in planning for the Design/Build/Validate ("D/B/V") Phase of Project Horizon is aligning logical groups of functionality, key integrations, and key conversion transform and load objects to planning groups or "D/B/V Planning Waves". These D/B/V Planning Waves are the basis for all detailed task dependencies for the detailed plans managed as part of Project Horizon. The detailed planning wave information is found on the SWG SharePoint here: DBV Planning Waves.

This approach will be consistently followed throughout D/B/V, Assembly Test and Product Test.

Along with the inputs above utilizing the approach of planning 3-4 months ahead in a detailed fashion the Project will continue to build detail in subsequent phases and refresh tasks and dependencies to ensure the detailed Project Plan and information within including dependencies is an accurate communication tool of where the project should be focusing time and effort to get to a successful go-live.

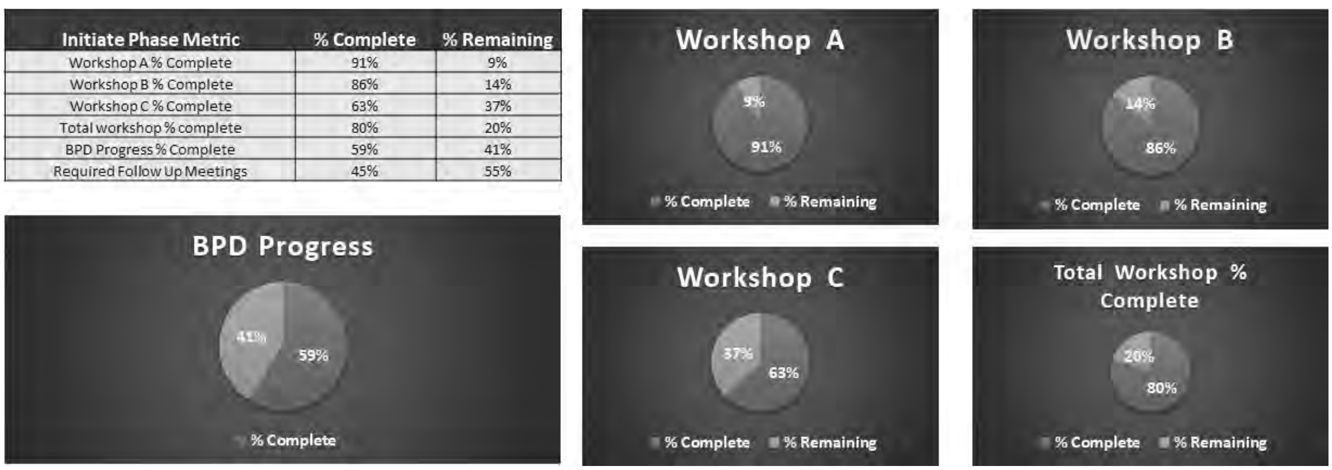
Along with the detailed plan used to communicate percentage complete, dependencies and associated impacts, as well as determine critical path, various tracking spreadsheets with graphs and hill climbers ("Trackers" will be developed and used as a project management tool. Table 2 below provides a list of potential Trackers that will be used across the various phases of Project Horizon.

Initiate	D/B/V	Test (part 1)	Test (part 2)	Deployment
BPD Workshops	FD	AT Scripts (including data prep)	ORT Execution	Go-Live Readiness Criteria

Requirements (Fit/Gap)	TD	AT Execution (pass,fail,no-run)	Batch Verification	Stabilization
BPDs	B/UT	PT Scripts	Go-Live Readiness	Dress Rehearsal
Technical Deep Dives	FUT	PT Execution	Defect Burndown (with ORT and Perf Test)	Training Delivery
	AT Scripts	Automated Scrips	UAT (as applicable)	
	Defects (density, quality, etc.)	Defects (Density, quality, heat maps, etc.)	Operational Procedures/Job Aids/Manual Processes	
	Requirements (Change)	Go-Live Readiness	Performance Test Execution	
	Mock Conversion Results	Training Course Dev	Mock Conversion	
		Mock Conversion	Dress Rehearsals	
			Training Course Data	

Table 2: Potential Trackers

Figure 4 below is an illustration of components of a Tracker that will be used throughout Project Horizon timeline.



Initiate Phase TDD Sessions	% Complete	% Remaining
TDD Session A % Complete	100%	0%
TDD Session B % Complete	85%	15%
TDD Session C % Complete	0%	100%
Total TDD Session % complete	62%	38%

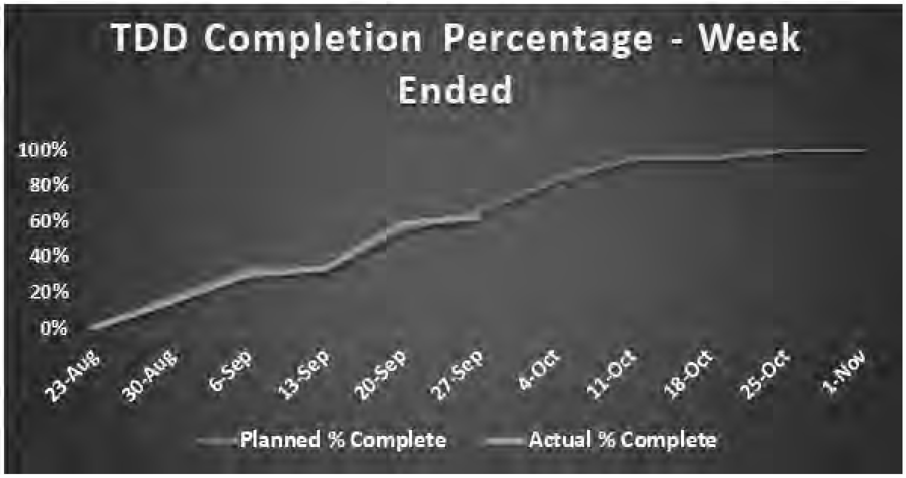


Figure 4: Illustrative Tracker Information

8.3 Project Resource Plan

The project's Resource Plan work product will be created during the Initiate Phase in conjunction with the work plan which identifies team members by name and associates high-level tasks with those team members. This Resource Plan will be baselined and must be re-baselined whenever a significant change in staffing plans or resource allocation is introduced.

NOTE: The resource plan referenced in this Deliverable includes all Core SAP Resources from SWG, Accenture, and SAP. All other resources included as part of Project Horizon are assumed to undergo similar resource plan refresh process during specific phase transitions.

The process for reviewing the resource plan as we transition between all project phases will follow specific steps. The steps will involve comparing the baseline assumptions about estimating factors, resources, and resource mix to the current estimating factors and required resources and resource mix.

The process for reviewing and validating the Project Resource Plan between Phases will be as follows:

- The initial inputs and assumptions for estimating factors and estimates (i.e. RICEFW, number of test Cases, number of integrating systems, expected defect rates) are compared against updated scope rationalized via either RICEFW rationalization and/or Test scope validation
- An updated estimate including total effort and type of work will be created based on the updated, rationalized scope
- A resource plan to deliver the updated scope will be created, based on the resources and resource skill mix required to deliver on the current understanding of the updated scope

- The updated resource plan will be optimized across the core SAP team components, including looking at opportunities to transfer effort between SWG, Accenture, and SAP if a comparable resource is available for the necessary duration
- A comparison of effort by team, work stream, functional area, location, as well resource skill mix will occur between the original resource plan and the updated resource and the delta with reasons for delta will be captured

Following the completion of the Resource Plan review the information will be used as an input to an exercise for scope true-up amongst these and any other known Project delivery or commercial inputs which will impact scope, budget, resources, or timeline for Project Horizon. The Project Leadership team will engage in conversations as part of this scope true-up and decide on follow-up actions, based on the Governance Model outlined in section 3.2.

8.4 Project Planning and Estimating Assumptions

Project planning for the Core SAP scope and estimating was conducted in a bottom-up approach, with the business requirements serving as the basis. Key estimating assumptions that were used include:

- Key SWG personnel will provide the necessary level of involvement, per the agreed upon resource plan
- Project team members will work 40-hour weeks
- Teamwork and collaboration infrastructure are in place at the SWG facilities, no effort/time will be spent on outfitting offices, securing phone lines, printers, copiers, etc.
- Scope is managed from the initial requirements and scope outlined in the Accenture Statement of Work

Note: Estimates for other Project Plan inputs for scope not owned by Accenture will be validated by SWG.

9. Milestones and Deliverables

9.1 Milestone Dates

Major milestones associated with the Project are as follows:

Milestone Description	Date
Milestone 1 - Plan	7/1/2019
Milestone 2 - Plan/Initiate	9/3/2019
Milestone 3 - Initiate	11/1/2019
Milestone 4 - 25% D/B/V	1/3/2020
Milestone 5 - 50% D/B/V	2/3/2020
Milestone 6 - 75% D/B/V	4/3/2020
Milestone 7 - 100% D/B/V	6/1/2020
Milestone 8 - Assembly Test	8/3/2020
Milestone 9 - Product Test	11/2/2020
Milestone 10 - Operational Readiness Test - 50% "System Ready"	1/1/2021
Milestone 11 - Operational Readiness Test 100% + Go Live	5/3/2021

Milestone 12 - Final Acceptance	8/2/2021

Table 3: Milestone Dates

9.2 Deliverables Review and Acceptance Management

Accenture SOW deliverables mapped to each milestone are found in the Deliverables Responsibility Matrix:

Deliverables%20Res
ponsibility%20Matri

The Accenture Project Management Office Lead is responsible for managing the review and approval of these deliverables according to the deliverable acceptance process outlined in the SOW, where deliverables are submitted approval and feedback must be received within 5 business days.

The Deliverable review and acceptance process will be guided by the following expected steps:

1. The Deliverable Owner (Accenture) reviews the template with basic information populated with Deliverable Approver(s) to confirm the format and to introduce the deliverable
2. The Deliverable Owner reviews a work in progress draft of the deliverable with content populated to get some initial feedback from the Deliverable Approver(s) (in person or via email depending on the Deliverable). Expectations will be agreed upon during the template review
3. The Deliverable Owner addresses feedback and provides the updated Deliverable back to the Deliverable Approver(s) until the Deliverable is complete
4. The Deliverable Owner (Accenture) submits the Completed Deliverable for Approval
5. The Deliverable Approver (SWG) accepts (within 5 business days)
6. Deliverable is routed through SWG SharePoint workflow for final acceptance and Approval
7. Deliverables impacted by a Change Request will be updated and flow back through this process for final acceptance and Approval.

If the Deliverable Approver has any feedback on the deliverable following submission for approval, the Deliverable Owner will address the feedback and resubmit.

Deliverables are planned to be submitted for acceptance by the Milestone Dates defined in the workplans.

The full list of Project Horizon Deliverables and proposed approver roles can be found in the SWG SharePoint here: Project Horizon Deliverables List.

10. Communication and Meeting Facilitation

Communication is key to the success of the Project at all phases. There are multiple levels of Project-wide communication that must be managed and forums for communication managed by the PMO.

Communication between teams and within teams is crucial to the progress of the project, as well as the successful development of the solution. Status Reports will be provided weekly to work stream leads, team leads and Project Leadership by the PMO. Individual issues needing attention, progress on assigned work, vacation requests and additional needs for skills should be communicated to Project Leadership using the weekly status report. Key issues should be raised in a status report at the minimum. All issues requiring attention should be raised directly to the team / work stream lead as the need arises.

Issues impacting a milestone date must be escalated in the weekly status reports to bring visibility to Project Leadership.

Status meetings with the project team will communicate project status from management to the various project teams. These meetings will occur at a minimum of once a week but may be daily at peak times of activity in the project, such as dress rehearsals and during the Deployment Phase.

The key meetings to be facilitated by the PMO are summarized in the table below:

Meeting Description	Cadence	Key Attendee Groups
Leadership Meetings	Weekly	Project Leadership, Enterprise PMO Director
Sponsor Meetings	Bi-Weekly	Project Directors, Enterprise PMO Director, Project Sponsors
Change Control Meetings	Ad Hoc	Project Leadership, Functional and Solution Architects and Workstream Leads as needed
Project Status Meetings	Weekly	Project Leadership, Functional and Solution Architects, Workstream Leads
All Hands Meetings	Quarterly, as needed/required	All Project members
Steering Committee Meetings	Monthly, as needed	Project Leadership, Steering Committee, Project Sponsors, Enterprise PMO Director, Third Party Oversight QA
Risk / Issue Meetings	Weekly, as required once we have some risks / issues to review	Project Leadership, Functional and Solution Architects, Workstream Leads, Enterprise Risk Management
Regular Stand Up Meetings	Bi-Weekly, Ad Hoc	All Project members
Key Decision Meetings	Bi-Monthly (might be covered by Risk and Issue or Status Meetings)	Project Leadership, Functional and Solution Architects, Workstream Leads, Project Sponsors, Enterprise PMO Director, Project team members as required
Vendor Management Meeting	Monthly (Start August 2019)	Project Leadership, Vendor Partner Account Leads, Enterprise PMO Director, Workstream Leads as needed
Executive Board Meetings	Monthly, as needed	Executive Board, Project Director, Enterprise PMO Director, Project Sponsor, Third Party Oversight party QA
Business and IT Stakeholder Meetings	Monthly, as needed	Project Leadership, Functional and Solution Architects, Business stakeholders, IT stakeholders
Oversight/Quality Assurance Meetings	Quarterly, as needed	Project Directors, Enterprise PMO Director, Program Sponsors, QA Directors, Third Party Oversight QA, Executive Sponsor as appropriate
Emergency Decision / Escalation Meetings	Ad hoc	Project Leadership, QA, EPMO
Solution Architecture Review Meetings	Bi-Monthly, Ad hoc according to Business Process Design workshop calendar	Sponsors, Project Leadership, Solution Architects, Work Stream Leads
Stage Gate Reviews Meetings	Near End of Phase / Beginning of Phase	Sponsors, Project Leadership, EPMO, Solution Architects, Work Stream Leads

Table 4: PMO Regularly Scheduled Meetings

11. Risk Management

11.1 Risk Definition and Risk Scoring Methodology

A Risk is an event that can affect the project for better or worse; risks can be defined as threats or opportunities. If the risk is a threat, mitigation plans need to be created. If the risk is an opportunity, plans should be made to capitalize on it. Risks identified as opportunities will be entered as Action Items in the RAID tool, which is hosted on the SWG SharePoint. Section11.5 defines how the risks that are threats will be captured in RAID and classified.

The two major variables used in classifying a risk are 1) probability of the risk occurring and 2) the impact or consequence if that risk occurs.

The scoring for Probability falls into three ranges and is assessed initially by the individual identifying the risk. The PMO will confirm the risk probability.

Percent Probability	
High	67-100
Medium	34-66
Low	0 - 33

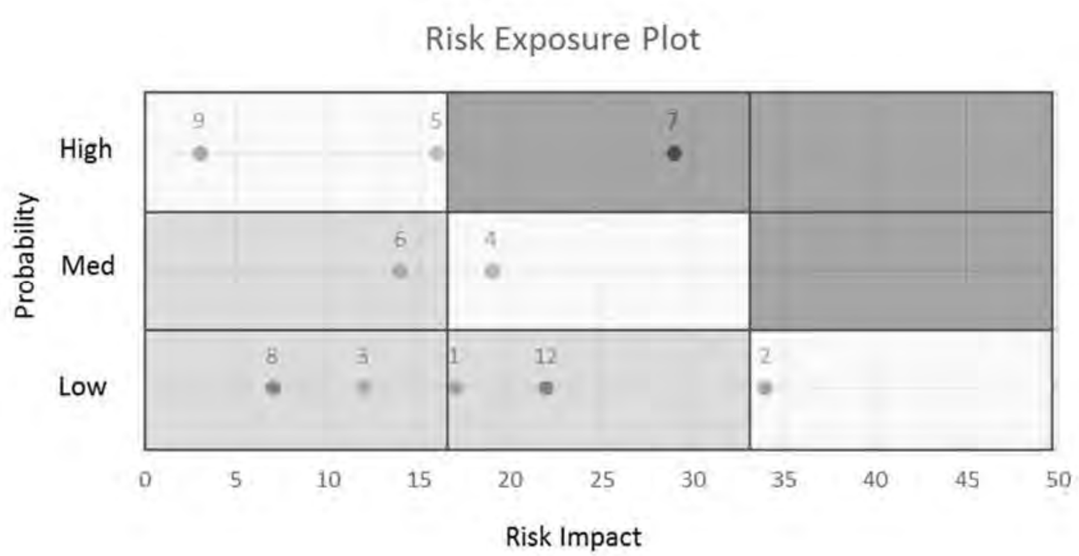
Scoring for Risk Impact will be in ten categories that are again, initially assessed by the individual identifying the risk. There are three levels for each of the impact categories – Low, Medium and High. The definitions for each category are shown below.

Level	Schedule	Cost	Quality	Customer Experience	Regulatory	Scope	Benefits/Outcomes	Data	Privacy	Security
Low	Schedule will be impacted by less than 1 week	Little to no cost impact estimated	Minor impacts to the quality of deliverables or work products (requires little to no rework)	Little to no expected negative impacts to CSAT / expected impacts are positive	Little to no expected impacts to regulated processes or products/programs	Little to no expected increase in estimated RICEFW/effort	Little to no Impact to benefits/business outcomes	Little to no expected impacts to Data	Little to no expected impacts to Privacy	Little to no expected impacts to Security
Medium	Schedule will be impacted by 1-2 weeks	Modest cost impact estimated however it falls within the allocated budget	Modest impacts to the quality of deliverables or work products (requires some rework)	Modest expected negative impacts to CSAT	Modest expected impacts to regulated processes or products/programs	Potential increase in estimated RICEFW/effort	Modest Impact to benefits/business outcomes	Modest expected impact to Data	Modest expected impact to Privacy	Modest expected impacts to Security
High	Schedule will be impacted by more than 2 weeks	Estimated Cost impact is greater than allocated budget and requires escalation	Substantial impacts to the quality of deliverables or work products (requires major rework)	Substantial expected negative impacts to CSAT	Substantial expected impacts to regulated processes or products/programs	Potential Customization required OR significant increase in estimated RICEFW / effort (greater than XXX hours – Value TBD During Plan Phase	Substantial Impact to benefits/business outcomes	Substantial expected impacts to Data	Substantial expected impacts to Privacy.	Substantial expected impacts to Security

Table 5: Risk Scoring Table

The formula that determines the overall Risk Exposure is the combination of Probability and Impact. Project Horizon will plot Risk Exposure in the ranges shown below. Each week, risks and issues will be reviewed in a meeting and the review will focus on the risks in the cadence described below. Risk Owners are expected to attend the meeting and discuss the mitigation plans.

1. **Red –** Risks that fall into red area are categorized as High Exposure and require mitigation and weekly monitoring with PMO and Leadership. These risks are also socialized with Executive Sponsors
2. **Yellow –** Risks that fall into the yellow area are categorized, as Medium Exposure and require a mitigation and are monitored every week by Workstream / Team Leads and PMO
3. **Green** – Risks that fall into the green area are categorized as Low Exposure, require a mitigation plan and are monitored weekly Workstream / Team Leads and PMO



11.2 Guiding Principles and Success Factors for Risk Management

The following guiding principles will guide the Project Horizon Risk Management process:

- Risks originate anywhere in the project and may impede progress unless resolved
- Risks can be identified by any team member but will be entered in the RAID log by leads: Team Lead, Work Stream Lead, PMO Leads, Program Leadership
- Risks requiring executive attention will be monitored and assigned priority based on criticality
- The RAID log on the SWG SharePoint is our Risk Management repository.
- The Project Horizon project will actively monitor and escalate issues to the appropriate level based on escalation criteria established in this document

The following critical success factors are imperative to ensure effective management of risks:

- Clear risk identification, logging, communication, escalation, and resolution procedures
- Common definition and understanding of risks
- Commitment by all leads and project management to execute risk response and escalation
- Commitment by all team members to resolve issues as quickly as possible

11.3 Risk Management Roles and Responsibilities

The stakeholders in the Risk Management process are identified below, as well as the associated key roles and responsibilities:

Roles	Responsibility
Executive Governance Board	• Receive updates on program risks and work with Project Horizon Leadership to mitigate risks
Project Leadership	• Work with PMO, Work Stream Leads, and Team Leads to mitigate risks
Work Stream Leads and Team Leads	• Verify information in risks raised by team members is complete and accurate • Develop risk mitigations • Execute mitigations to resolve risks
Team Member	• Raise risks to Team Leads and Work Stream • Resolve day-to-day problems
Solution Architecture	• Verify information in risks raised by team members is complete and accurate • Develop risk mitigations • Execute mitigations to resolve risks
PMO	• Responsible for the design and oversight of the risk management process • Manage the risk plan • Generate reports for status meeting(s) and ad-hoc requests • Confirm risk probability and impact assessments • Ensure forecast resolution/mitigation dates are adhered to • Monitor risks on a weekly basis

11.4 Risk Management Process

Risk Management goes through the following activities, all of which happen in the Project Horizon RAID log.

- **Identification** - Project Risks are identified and documented in the RAID log
- **Quantify** - Risks are assessed for both probability and impact
- **Prioritize** – The Risks are prioritized for management review and discussion
- **Assign Responsibility** – The appropriate individuals are assigned to manage the risk mitigations
- **Risk Response** - Appropriate mitigations are developed to minimize the realization of each Risk, and are documented
- **Monitor, Communicate, and Report Metrics** - To provide visibility of Risk and progress in mitigating them the reports will be provided on and worked in the weekly Meeting.

The risk management process can be initiated by any work stream or team lead as outlined in section 11~~9~~.2. Initiation of the process starts with inputting a risk with key information in to the agreed upon

risk management tool. The risk must contain key information needed to manage the risk process and track progress.
The risk log, which will be created as a list on the SWG SharePoint, the following information will be captured.

- Risk Number / ID
- Risk Title
- Risk Description
- Workstream
- Target Resolution Date
- Raised By
- Date Raised
- Risk Owner
- Risk Actioner
- Risk Type
- Likelihood
- Impact
- Risk Exposure Score (Calculated)
- Project Impact
- Risk Trigger
- Actions Taken
- Risk Mitigation Strategy
- Risk Contingency Plan
- Risk Status
- Risk Category
- Next Review Date
- Escalation Level

Risks will be reviewed as part of the regular cadence of PMO facilitated meetings and can be updated at any point by the PMO, Project Leadership, risk owner, or risk actioner, must be updated weekly at minimum. Some risks may be classified as a Program level risk which will be shared with Sponsors, Executive Steering Committee, Executive Governance Board, and/or the Business Process Council. Project level risks are managed and mitigated within the Project Team.

11.5 Risk Management Activities Detailed

11.5.1 Identify and Classify Risk

Risk identification is an ongoing process, which is monitored and updated regularly. The Risk Initiator, or team member who reports the risk, will inform the Team or Work stream Lead of any findings. If a risk is reported to the above, the Work Stream or Team Lead will review it and enter the RAID Log. The risk stage is set to "NEW" when risk is entered the Risk Form on the SWG SharePoint.

Risks will be written with a description that clearly articulates the triggers that would need to occur to realize the risk. Using if-then structure for the risk description provides this articulation. Risk dependencies can be captured in several ways. If an issue is associated to the risk, it will be captured on the Risk Form. If there are Actions, Decisions and Assumptions that are associated to the risk. they will also be captured on the Risk Form. If Risks have dependencies on other Risks, they should be noted in the description with the Risk ID.

Only Leads and above can authorize someone to enter risks into the Project Horizon RAID log to ensure that leads are always aware of identified risks.

11.5.2 Quantify Risk

The Risk Creator provides the initial analysis of the risk. Project Horizon Leadership will review and confirm the appropriate information is entered in the risk log, including confirmation of the impact, probability, is entered for all the new risks. If a particular risk lacks information, additional information will be requested from the Risk Creator. Once the Risk has been Quantified, it becomes Open.

11.5.3 Prioritize Risk

The PMO working with Project Horizon Leadership will review the probability and impacts and prioritize the risk.

11.5.4 Determine Risk Owner

The PMO working with Project Horizon Leadership will assign a Risk Owner.

11.5.5 Develop Risk Response

The Risk Owner will develop the appropriate risk response. Red and Yellow (High and Medium Risks) require mitigation strategies. Risk mitigation alternatives are the set of options that may mitigate/subdue risk if implemented. A project risk mitigation strategy is preventative in nature and designed to reduce impact or probability of risk occurrence. A risk mitigation strategy uses acceptance, avoidance, protection, reduction, research, reserves, and transfer to develop alternatives for risk resolution. Each strategy contains objectives, constraints, and alternatives. An issue response is developed if a risk is realized despite the implementation of the risk mitigation strategy.

11.5.6 Execute Risk Mitigation Plan

If the probability and impact values create a Red or Yellow risk exposure score, the Risk Owner should implement the planned risk handling approach. Progress on the mitigation activities will be monitored and reported to Risk Owner on a periodic basis.

11.5.7 Monitor Risk

The PMO will have the overall oversight on risk management activities. The PMO will act as point of escalation if the risk is not manageable by the Risk Owner. The Risk Owner may also decide to assign to a different Risk Owner if the mitigation is not effective or the risk is realized.

11.5.8 Close Risk

When a risk turns into an issue, the risk has expired, diffused or has been removed through the implementation of mitigation plan/contingency plan, the risk is then closed. The PMO will change the state of the risk to either Realized or Closed as appropriate. When a risk is realized, it automatically flows into the Issue Log. The Risk will remain in the Risk Log as Realized and will be locked from further editing.

Risks cannot be “reopened”. Risks that return will need to be added as a new Risk. The initial, closed Risk should be noted in the Description in the Risk Form.

12. Issue Management

12.1 Issue Definition and Issue Scoring Methodology

An issue is an event that has already occurred and—if immediate action is not taken—may have a significant adverse impact on objectives (financial and non-financial) or timeline of the project. Issues may be categorized in in a variety of ways, as identified in the table below. They differ from *risks* in that a risk may become an issue if certain events occur. Risks, however, can often be mitigated before they become issues.

Scoring for Issue Impact will be in ten categories (identical to Risk categories) that are initially assessed by the individual identifying the issue. There are three levels for each of the impact categories – Low, Medium and High. The definitions for each category are shown in the table below. Risks that are realized become issues and will carry forward the impact scores carried as a risk. The impact scores will be validated by the PMO.

Level	Schedule	Cost	Quality	Customer Experience	Regulatory	Scope	Benefits/Outcomes	Data	Privacy	Security
Low	Schedule will be impacted by less than 1 week	Little to no cost impact estimated	Minor impacts to the quality of deliverables or work products (requires little to no rework)	Little to no expected negative impacts to CSAT / expected impacts are positive	Little to no expected impacts to regulated processes or products/programs	Little to no expected increase in estimated RICEFW/effort	Little to no Impact to benefits/business outcomes	Little to no expected impacts to Data	Little to no expected impacts to Privacy	Little to no expected impacts to Security

Medium	Schedule will be impacted by 1-2 weeks	Modest cost impact estimated however it falls within the allocated budget	Modest impacts to the quality of deliverables or work products (requires some rework)	Modest expected negative impacts to CSAT	Modest expected impacts to regulated processes or products/programs	Potential increase in estimated RICEFW/effort	Impact to benefits/business outcomes	Modest expected impact to Data	Modest expected impact to Privacy	Modest expected impacts to Security
High	Schedule will be impacted by more than 2 weeks	Estimated Cost impact is greater than allocated budget and requires escalation	Substantial impacts to the quality of deliverables or work products (requires major rework)	Substantial expected negative impacts to CSAT	Substantial expected impacts to regulated processes or products/programs	Potential Customization required OR significant increase in estimated RICEFW / effort	Substantial Impact to benefits/business outcomes	Substantial expected impacts to Data	Substantial expected impacts to Privacy.	Substantial expected impacts to Security

Table 6: Issue Impact Categories

12.2 Issue Management Approach and Objective

Successful management of a project requires informed, proactive, and timely management of issues. The objectives of the issue management plan are as follows:

- Ensure critical issues are quickly identified in order to communicate, resolve, and escalate in a timely manner
- Facilitate attention to key issues
- Produce meaningful information that allows focused efforts on key issues
- Verify all stakeholders are informed and, if applicable, participate in the resolution process
- Create an audit trail of discussions and resolutions of all issues

12.3 Guiding Principles and Critical Success Factors

The following guiding principles will guide the Project Horizon Issue Management process:

- Issues originate anywhere in the project and may impede progress unless resolved
- Issues can be identified by any team member
- Issues are not a list of tasks or reminders. For Issue definition see (12.1 above)
- The Project Horizon team will actively monitor and escalate Issues to the appropriate level based on escalation criteria established in this document
- Issues requiring executive attention will be monitored and assigned priority based on criticality
- The SWG RAID Tool is our Issue Management repository.

The following critical success factors are imperative to ensure effective management of issues:

- Clear issue identification, logging, communication, escalation, and resolution procedures
- Common definition and understanding of issues
- Commitment by all leads and project management to execute issue resolution and escalation
- Commitment by all team members to resolve issues as quickly as possible

12.4 Issue Management Key Stakeholders

The stakeholders in the Issue Management process are shown below, as well as the associated key roles and responsibilities:

Roles	Responsibility
Executive Governance Board	• Receive updates on program related issues • Support resolution implementation for escalated issues
Project Leadership	• Review and understand critical issues impacting Project Horizon • Approve resolutions for escalated issues • Support resolution implementation for escalated issues • Assist in cross-organization or controversial issue resolution
Work Stream Leads and Team Leads	• Review status, priority, owner, and completeness of issues • Escalate issues as required • Approve resolutions • Support resolution implementation • Assist in cross-organization or controversial issue resolution • Clarify, consolidate and document issues • Maintain data in issue management tool • Establish initial priority, owner, and target due date • Work with other teams to facilitate solutions to issues which are in jeopardy of not meeting target dates
Team Member	• Raise issues to Team Leads and Work Stream Leads • Resolve day-to-day issues
Solution Architecture	• Verify information in issues raised by team members is complete and accurate • Develop risk mitigations • Execute mitigations to resolve issues
PMO	• Responsible for the design and oversight of the issue resolution process • Generate issue reports for status meeting(s) and ad-hoc requests • Monitor the status of issue resolution • Maintain the issue management plan • Establish priority of issues and define target dates • Confirm or establish owner of issue and confirm target dates • Identify issues for escalation to leadership team • Monitor issues on a weekly basis

12.5 Issue Management Process

Issue Management typically goes through the following activities, all of which happen in the RAID log for Project Horizon.

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- **Identification** - Project Issues are identified and documented in the RAID log
- **Assess** - Issues are assessed for both impact
- **Track Issues** – The issue is logged in RAID and assigned an owner so that it can be responded to and monitored
- **Issue Response** - Appropriate resolutions are developed to minimize the impact of the Issue and are documented
- **Execute Issue Response** – The issue resolution is implemented
- **Monitor, Communicate, and Report Metrics** - To provide visibility of Issue and progress in resolving them the reports will be provided on and worked in the weekly Status Meeting

The issue management process begins when an issue is identified and is entered into issue management tool which will be managed in the SWG SharePoint and ends when an issue is resolved and closed.

An issue may be logged in the issue management tool by Project team leads and/or Work Stream Leads. All known information should be captured upon entry. They key information captured for an issue is similar to the information captured on a risk.

- Issue Number / ID
- Issue Title
- Issue Description
- Target Resolution Date
- Severity
- Workstream
- Escalation Level
- Next Review Date
- Raised By
- Issue Owner
- Lead
- Issue Category
- Impact
- Issue Score (Calculated)

- Project Impact
- Related Risk ID
- Next Review Date
- Actions to resolve
- Issue Status
- Action(s) Taken
- Associated Action/Decision

12.6 Issue Management Activities Detailed

12.6.1 Identify and Classify Issue

Issue identification is an ongoing process, which is monitored and updated regularly. The Issue Initiator, or team member who reports the issue, will inform the Team Lead or Work Stream Lead of any findings. If an issue is reported to the above, the lead will review it and enter into the Project Horizon RAID Log. The Issue stage is set to New when issue is entered into the Issue Form of the Project Horizon RAID Log

Issue dependencies can be captured in several ways. If there is an associated Risk, it will be captured on the Issue Form. If there are Actions, Decisions and Assumptions that associated to the issue, they will be captured on the Issue Form. If the Issue is associated with other Issues, they should be noted in the description with the Issue ID.

Only Leads and above will enter issues into the Project Horizon RAID Log to ensure that leads are always aware of identified issues.

12.6.2 Assess Issue

The Issue Creator provides the initial analysis of the issue. The PMO will review and determine the appropriate impact values for all the new issues, even those that are realized risks. If a particular issue lacks information, additional information will be requested from the Issue Creator. Once the Issue has been assessed and all fields are filled out, it becomes Open.

12.6.3 Track Issues

The PMO working with Project Horizon Leadership will monitor and track issues through the Project Horizon RAID tool. An owner will be assigned. Issues will be part of the weekly status reporting and high priority issues will be escalated to the appropriate leadership for resolution.

12.6.4 Develop Issue Response

The Issue Owner will develop the appropriate response. The response needs to engage the right stakeholders, expected resolution timelines and resolution activities.

12.6.5 Execute Issue Response

The issue response will be implemented by the Issue Owner.

12.6.6 Monitor Issue

The PMO will have the overall oversight on issue management activities. The PMO will act as point of escalation if the issue warrants escalation. The Issue Owner may also decide to assign to a different Issue Owner if the response requires other stakeholder involvements.

12.6.7 Close Issue

When the issue has been resolved, the issue is then closed. The PMO will change the state of the issue to Closed. Issues cannot be "reopened". Issues that return will need to be added as a new Issue. The initial, closed Issue should be noted in the Description in the Issue Form.

13. Requirements Management

The critical basis of management of Project Horizon scope and complexity is a thorough and traceable set of requirements and associated documentation managed throughout the project lifecycle. Detailed requirements include functional, quality, interface, data, security, control, content, technical, change enablement, service introduction, deployment, and all other requirements and constraints stated by the business, IS, and other stakeholders. Controls will be tracked in the same consistent understandable manner, like all other types of requirements.

The repository, tools, and process to manage requirements across Project Horizon will experience some evolution as the project progresses through each phase from Initiate Phase to the Design-Build-Validate Phase to the Test and Deployment Phases to Stabilization and Support. The Table 7 below summarizes the Requirements repository, responsible maintenance, accountability, and key reasons for change of requirements throughout the project lifecycle.

Phase	Repository	Responsible for Maintenance	Accountability	Reasons for Change	Control In Place
Initiate	Requirements Traceability Matrix (RTM) – Excel on SharePoint	Work Stream Leads	Solution Architects	Outcomes from To-Be Design Workshop	Status and Approval, Version Control
Design/Build/Validate	Solution Manager Knowledge Warehouse	Solution Architects	Solution Architects	Defects Change Requests	Change Control
Test and Deploy	Solution Manager Knowledge Warehouse Microfocus ALM	Test Lead	Solution Architects Business Integration Leads Solution Delivery Leads	Defects Change Requests	Change Control
Stabilization and Support	Solution Manager Knowledge Warehouse	Business IS	Business Leads Support Leads	Defects New Requirements	Change Control

Table 7: Requirements Repository By Phase

13.1 Initiate Phase Requirements Management

During the Initiate Phase, Requirements are being refined as part of creation of To-Be Design ("Business Process Design" or "BPD") Deliverables. During this phase, requirements will be managed in an Excel repository on the SWG SharePoint in the Deliverable called the Requirements Traceability Matrix (RTM) Document. The RTM is a key project deliverable that evolves through each phase.

During the initiate phase the RTM includes the following information:

- Requirement ID
- Requirement Description
- Work Stream
- Business Process Design
- Type (Business, Technical, Support, Strategic)
- Priority (High, Medium, Low)
- Requirement Status (Draft, In Review, Approved by Work stream Lead, Out of Scope, Deferred)
- Fit / Gap Analysis
- Proposed RICEFW

During the Initiate Phase, the RTM as a requirements repository is used to manage and maintain the bi-directional traceability between the high-level customer requirements, the detailed product requirements, and the fit/gap analysis. The fit/gap analysis helps determine where the standard product can meet requirements versus where a customization may be required to meet the requirement. The RTM is continually refined as part of the creation of BPDs. The primary persons responsible for the maintenance of the RTM are the Work Stream Leads, who are the individuals from Accenture and SWG who are leading a specific functional area (ex: Billing or Payment, Credit, and Collections). The Solution Architects are accountable for the requirements and the approved RTM Deliverable (see Section 9.2 for Deliverable approval process). At the end of the Initiate Phase, the status of requirements will be versioned as "Approved by work stream", "Out of Scope", or "Deferred" in the approved RTM and requirements will be transitioned to use in the Design/Build/Validate Phase.

13.2 Design / Build / Validate Phase Requirements Management

13.2.1 Design/Build Validate Requirement and Deliverable Management

The requirements that are dispositioned in the RTM and signed-off as part of the Initiate Phase Deliverable approval will be used as inputs to key deliverables in the Design/Build//Validate ("D/B/V") phase. The key D/B/V Phase deliverables that will use the dispositioned requirements are summarized in Table 9 below.

Design/Build/Validate Phase Deliverable	Type of Requirements Used as Input
Functional Specifications (All Bundles)	Business, Technical, Support, Strategic
Integration Specifications (All Bundles)	Business Technical

Technical Specifications (All Bundles)	Technical
Conversion Technical Specifications	Business Technical
Baseline Configuration	Business
Configuration Design Documents (All Bundles)	Business
Development Object Code (All Bundles)	Technical Support
Environment Management Strategy Plan	Business Technical Strategic
Identity and Access Management Strategy	Business Technical Strategic
Security Role Definition and Design Document	Business Technical
Reporting and Analytics Approach	Business Technical Strategic
Reporting and Analytics Solution Design (All Bundles)	Business Technical
Reporting and Analytics Solution Objects (All Bundles)	Business Technical
Compliance and Controls Design	Business Technical
Data Retention and Archiving Strategy	Business Technical Strategic Support
Infrastructure Technical Design	Technical
Integration Architecture Design	Technical
Technical Architecture Design	Technical
End User Training Needs Analysis Report (OCM)	Business Support

Table 9: Key D/B/V Phase Deliverables and Requirements Utilization

The requirements which are transitioned from the Initiate Phase to the D/B/V Phase will be loaded in to Solution Manager Knowledge Warehouse. These requirements and any changes to the requirements will be managed via a change control and versioning process outlined by the following steps when a change to requirements is identified.

1) A Work Stream or Team Lead identifies the need for a requirement change
2) The requirement changes including the requirement ID, reason for requested change, alternatives, and impacted deliverables (Business Process Designs, Functional Specification, Integration Specification, Technical Specification, Conversion Technical Specification) or code object is submitted to the Solution Architects via the Change Control Board (CCB)
3) The requirement change is reviewed by the Solution Architects and the first level impact analysis of the change and potential alternative solutions which won't require a requirement change is documented

4) If the CCB deems the requirement change necessary after reviewing the first level of impact analysis, the requirement is routed to the team who requested the change and the other teams impacted by the change for a detailed impact analysis
5) Following completion of the detailed impact analysis, the changed requirement(s) are brought back to the CCB for review
6) IF the requirement change IS approved and the impact is below the threshold allowed for changes to be approved at Program Level (see section 14 Decision Management) , the impacted work streams and teams proceed with making change to requirement in Solution Manager Knowledge Warehouse, design artifacts, and/or code objects
7) IF the requirement change IS approved all identified impacted deliverables must be updated and re-routed through the Deliverable approval process as defined in Section 9.2
8) IF the requirement change is above the allowed threshold tolerance, it will follow the Decision Management process outlined in Section 14
9) IF the requirement change IS NOT approved, the alternative solution is pursued and the reasons for denial of the approval of the requirement change is documented and attached to the requirement

The rigor and adherence to a tightly managed change control process for requirements management starting with the D/B/V phase is of utmost importance in order to maintain the integrity of the solution that was approved coming out of the Initiate Phase and help to mitigate risk on the delivery of Project Horizon on the agreed upon timeline and budget.

All Business Process Design (“BPD”) Deliverables approved by the end of Initiate will be loaded into Solution Manager Knowledge Warehouse. Updates from approved requirements changes will be version controlled and made directly on the documents in Solution Manager.

Functional / Technical Specification Designs will be managed in SWG Microsoft SharePoint while they are being created and reviewed and uploaded to Solution Manager once approved.

13.2.2 Management of Interfacing System Changes Required to Support the Project

A set of pre-defined requirements (Business and Technical) will be assessed as part of the Design / Build / Validate (D/B/V) phase to determine the impact to existing Legacy / Edge systems. These requirements will be incorporated with the to-be SAP delivered solution as part of Project Horizon. The Legacy / Edge system requirements are evaluated as part of a Legacy / Edge Impact Assessment analysis deliverable. Following the approval of this Deliverable, the Legacy / Edge team will work with the impacted Legacy Systems to document requirements and develop design documentation to successfully deliver to those requirements. The process for communication of the requirements starts in the Initiate Phase and continues through the D/B/V Phase. Management of changes to Legacy/Edge systems falls into two categories.

Category 1 – Changes for SWG Owned Legacy / Edge Systems: Changes that need to be made to Legacy/Edge systems owned by SWG will be managed through a D/B/V process similar to that of the core SAP integrations that need to be delivered as part of the Project. Changes to these requirements will be managed using the same change control process and impact analysis steps as outlined in section 11.2.1.

Category 2 – Changes for 3rd Party or Vendor owned systems: Any system changes that need to be made to vendor or 3rd party owned systems, such as banks or state agencies, to support Project Horizon will be managed utilizing the following process:

- Requirements (Integration Points) for each of the impacted Vendor or 3rd Party systems are documented and included in the approved RTM

- The Legacy / Edge Team communicates these requirements to the Vendor contact and requests a confirmation of the requirements along with the approval of the Third-Party Agreement (TPA).
- The TPA is a document summarizing the detailed requirements of the integration points and a description of a successful test execution of the integration between the Project Horizon solution and the Vendor / 3rd Party system. The TPA template for Project Horizon can be found here on the SWG SharePoint
- The approved TPA is baselined along with any design and requirements and artifacts that are associated with the TPA
- The Legacy / Edge requirements from the TPA follow a change control process as outlined in section 11.2.1 in which the CCB monitors and does an impact analysis for requirement changes that pertain to Legacy / Edge Vendor or 3rd Party systems
- The Legacy / Edge team will work with the Vendor / 3rd Party to perform a detailed impact assessment, including making any necessary updates to the TPA
- Note: An approved requirement changes resulting in a change to a Legacy / Edge Vendor or 3rd Party system could impact project timelines or increase risk. This change is evaluated by the CCB during the approval process

The management of changes to Legacy / Edge Vendor or 3rd Party systems are treated differently than SWG owned legacy / Edge systems, due to delivery of requirements outside the direct control or Project Horizon. Interfaces are also one of the highest complexity and critical areas for Project Horizon. These Interfaces / changes to Edge systems require proper oversight from the project team, its stakeholders, and integration partners. Management of the interfaces will require dedicated team members to plan, coordinate, monitor, and control integration related project activities through all phases of the project.

13.3 Test and Deploy Phase Requirements Management

A key component and outcome of the Test and Deploy Phases is the verification of requirements coverage in the solution through test execution. Solution Manager Knowledge Warehouse will remain the system of record and requirements will still be managed via the Solution Architecture review and CCB process as described in Section 11.2.1. In order to enable test planning and execution, Microfocus ALM (‘ALM’) will house a master copy of all in scope requirements from the approved RTM from the prior Project Phases of Initiate and D/B/V. The requirements from ALM will also be fed into a Test Automation tool, such as Worksoft or Tosca to enable test planning and proof of requirement test coverage between manually executed tests and automated tests. Requirements can also be fed to the performance testing tool and record results in Microfocus ALM. Requirements which are being changed due to an approved change request and other artifacts used to support test can reside in the Project SharePoint and will be uploaded to Solution Manager once approved. The diagram below demonstrates an example of synchronization and requirements management in the Test and Deploy phases.

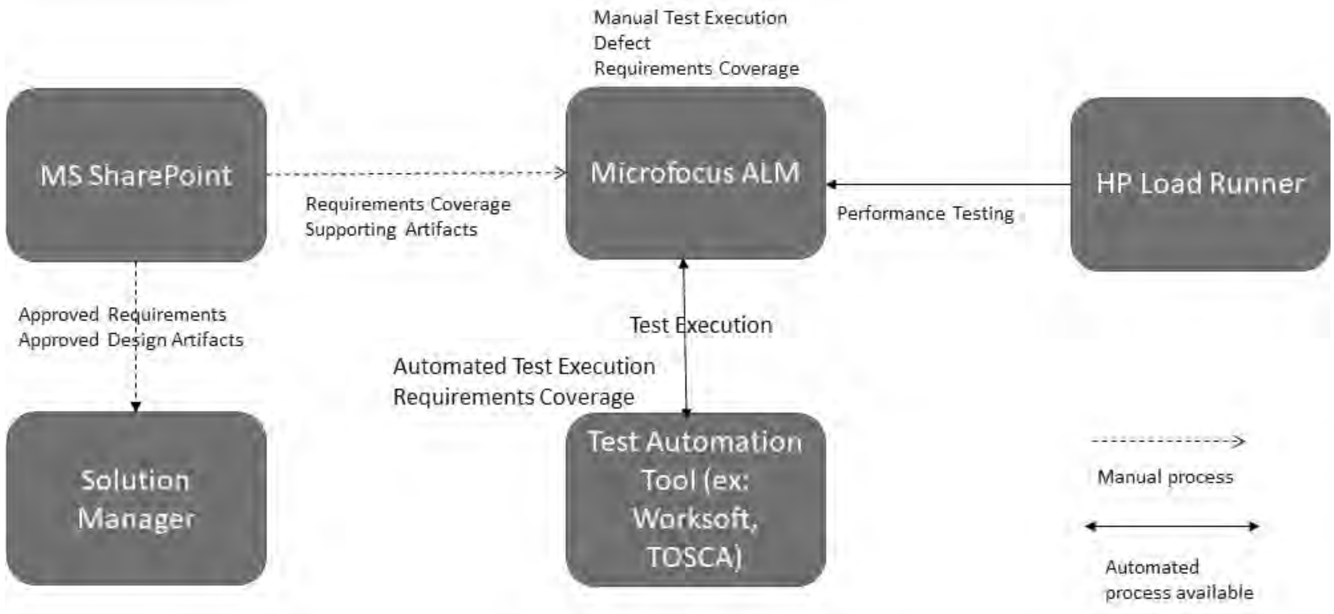


Figure 5: Tools and Synchronization of Requirements during Test and Deploy Phases

Requirements continue to be tightly controlled during the Test and Deploy phases of the Project as any updates to requirements have an exponentially expanding impact to the solution that has already been thorough D/B/V and has begun quality assurance activities as these phases progress. One key addition to the process for Requirements management during the Test and Deploy phases is the way by which requirements change control processes are initiated and who owns the requirements. Requirements change control will most commonly be initiated as part of the defect triage and defect management process when the to-be solution and design and/or requirement do not match in intent or function. The Test Leads take the main responsibility for maintaining requirements during this Phase, with support from the Solution Architects and Business Integration Teams.

Below is a list of key types of situations uncovered during Test or Deploy Phase activities, which can result in a request for a requirement change.

- Solution does not meet requirement and is deemed to not be absorbable by the Project and will not be met as part of the Project. This requirement can be marked as out of scope or deferred
- The implemented solution does not meet an approved requirement and that requirement is deemed as no longer relevant / applicable to a to-be process, so therefore dispositioned as out of scope or deferred
- The implemented solution does not meet an approved requirement and that requirement is deemed as applicable and can be met by a manual process
- In order to fix a defect or implement another requirement, an already approved requirement must be changed

- A design does not meet a requirement (Design Defect) and therefore the application must be changed, design must be changed, and potentially a requirement must be changed

- A Regulatory or Mandated requirement is introduced and must be evaluated for inclusion in scope in order to keep the solution compliant with rules of the Public Utilities Commission

As the Test Phase and Deploy Phase progress there are 2 milestones to signify that changes to requirements are no longer allowed in Project scope. These milestones indicate the start of periods where changes to requirements can only be approved by ProgramSponsors after significant impact analysis and evaluation of the business case for the change ("Freeze Periods").

The first milestone is the start of Test Scope Freeze. Test Scope Freeze is when the body of requirements and testing activities enter a process where changes are not allowed without Executive Approval. This first Freeze Period and commences at the beginning of Operational Readiness Test and Acceptance Test activities. The Test Freeze Period is put in place to help manage the Project to a focused execution of finalized verification activities which start approximately 4 months prior to Project Horizon Go-Live. During the Test Freeze Period, any requested changes to the scope of what is being tested is managed through the change control process outlined in section 11.2.1 along with the additional step of all changes being taken up to the Program Sponsor level approval for changes, per section 14.

The second milestone is the start of Code Freeze. During the Code Freeze Period, any changes to code resulting from defects, requested design changes, and/or requested requirement changes are heavily scrutinized and the majority of those changes are either deferred, rejected, or a process change and/or work around is implemented to address the issue that has been raised. Code Freeze typically will start 4-6 weeks before the Project Horizon Go-Live depending on the stability of the system and the volume of open high severity effects following 3 cycles of ORT and achieving many other system stability go-live readiness criteria.

The Test Scope Freeze and the Code Freeze Periods help to mitigate risk to the successful delivery of the Project and make sure the decision-making process around changes is focused and has high visibility to Executive Sponsorship and other key stakeholders.

13.4 Stabilization and Support Phase Requirements Management

Requirements management during Stabilization and Support Phases occurs in Solution Manager Knowledge Warehouse and is focused on providing support resources with the appropriate traceability of requirements during each phase of the project. Documentation of how the requirement was written, included in design, tested, and validated for final implementation in the Production environment will be provided.
The SWG teams supporting the Project Horizon solution will use requirements to help support issue resolution in the Production system as well as reference for any further enhancement releases which may be scoped for future implementation.

14. Quality Management

Quality Assurance is built into Project Horizon through several channels. TMG Consulting has been engaged to perform overall project oversight services which includes conducting reviews on key Deliverables, processes, and project-wide interviews. TMG reports their observations and findings on a regular basis to Project Leadership, Sponsors, and Executive Sponsors with a documented report being issued monthly. They partner with the delivery teams to improve processes and Deliverables as work is being executed. The implementation and technology partners (namely Accenture, SAP, E&Y, and Infosys) have quality processes built into the development of their Deliverables. Peer and leadership reviews are supplemented by some automated quality reviews of code. Quality control of the software is also addressed through testing, verification and validation. Verification activities ensure that the code meets the specific requirements (built right). Validation demonstrates that a product fulfils its intended use (built the right thing).

The primary implementation partners, Accenture and E&Y, will conduct formal Quality Assurance reviews on their scope of work on a quarterly basis which is coordinated with TMG through the Oversight Committee function and calendar. These QA reviews are conducted by an objective, highly experienced leader in the relevant field and a QA Memo is documented to memorialize and be used as a tracking mechanism providing observations and recommended mitigations if appropriate.

The primary technology partner, SAP, has is being engaged to provide Active Attention Services and Professional Services which include technical and functional solution reviews as-designed by SWG and its implementation partners to assist in achieving Horizon's goal to adopt SAP standard product functions (considering currently available and product roadmap functions) and optimized use of standard product features/capabilities within reason (e.g. aligns to defined project schedule and scope, solution is practically operable within SWG's enterprise landscape, etc.). The objective of these services is to mitigate the risk of future upgrade challenges resulting from design decisions (e.g. unnecessary or overly complex customization).

Deliverable template agreements between SWG and the implementation partners also define the Deliverable quality standards that must be met for a Deliverable to be accepted. Guidelines for structure (consistency, embedded items, style, format), content (completeness, accuracy, grammar, spelling, typography, inclusions and references) and compliance with company branding (as applicable) are considered.

The Quality Management Plan is located on the SWG SharePoint here: Quality Management Plan

15. Stage Gate Reviews

Stage gate reviews will occur through a series of meetings leading up to the planned transition date between Project Phases:

- Plan Phase to Initiate Phase
- Initiate Phase to Design/Build/Validate Phase
- Design/Build/Validate Phase to Test Phase
- Test Phase to Deploy Phase,
- Deploy Phase to Stabilize Phase

The objective of the Stage Gate Review Meetings (also known as "Entry / Exit Criteria Review Meetings") are to review the status of entry criteria to the next project phase and exit criteria from the current phase along with the associated Deliverables, work products, and/or project activities which must be complete in order to deem the exit or entry criteria ready for approval. There will be an assigned verifier from the Project Leadership team for each criterion and that person(s) will review evidence of the criteria being met as part of the Entry Exit Criteria review meetings. Through these meetings final approval and sign-off will be provided for each Entry / Exit criteria and the final planned meeting will be used a Stage Gate Review Meeting where Project Horizon Leadership can agree to transition to the next Project Phase.

Entry / Exit Criteria review meetings will be planned to start 3-6 weeks prior to a planned Phase transition date, depending on the number of criteria to be reviewed and the Project Horizon needs.

A planned task is maintained in the Integrated Project Plan 2-4 weeks before the start of Stage Gate Review Meetings to verify and confirm the Entry/Exit Criteria that were originally included as reference in section 5.7 of the Accenture CIS Project SOW. The agreed upon Entry / Exit Criteria and review meeting results will be stored on the SWG Project SharePoint here: Entry / Exit Criteria Reviews

16. Decision Analysis and Resolution (DAR) Process

16.1 Decision Management

The project will follow a formal decision-making process for those issues, requests or decisions that will have a high impact on the Project. The RAID tool serves as the primary repository for capturing Actions and Decisions which are tracked to provide evidence of the conscientious behaviors and choices made that will impact project execution. Key decisions and actions will be part of the weekly status reporting, as appropriate and will be tracked and monitored by the PMO. The Key Decisions register is maintained in the SWG SharePoint located as follows:
https://sphome.swgas.com/teams/csm/Lists/Issues%20List/AllItems.aspx

An "Action" is defined as a series of tasks that stand outside of the work plan that must be completed to ensure project delivery. The action log will be used to assign and monitor tasks (e.g. Program Level that stem from Risks and Issues, or Team Level, such as actions that come out of Design Workshops).

"Decisions" will be documented in the RAID tool as open for tracking purposes and then memorialized in the tool upon approval of the choice made. A decision may be the result of an action but could be stand alone. If the decision is the result of an action, the decision due by date must align to existing Project Status or Steering Committee meetings (if required) and should have a reasonable duration for the decision making.

Decisions will fall into three main types:

- **Program -** which includes items that are related to major impacts in project scope
- **Technology -** which includes items that impact the solution architecture, can be the technical architecture and system landscape, the technology roadmap, the infrastructure, hosting, data storage, analytics, system performance, or integration
- **Process** - which includes items that do not directly impact the solution set, but impact the To-Be process definition, achievable functional capabilities, RICEFW inventory, configuration, or overall development effort.

Key Decisions are defined as those with a high business or project priority and/or could drive a medium to high level of change to project baseline (scope, solution, effort, budget or schedule), depending on the decision made. Key Decisions are also identifiable by their characteristic of requiring some degree of scenario planning to assess multiple viable solutions and corresponding outcomes possible. Key Decisions will be supported with additional analysis documentation in the form of the Key Design Decision (KDD) form (template below).

Owner:	Solution Delivery Lead
Decision Required: Which tool if any will SWG use to manage exceptions?	
SAP offers a Business Process Exceptions Management (BPEM) framework for process and user-driven exceptions. This framework has been typically enhanced with an SAP-certified exceptions handling tool add-on product to reduce RICEFWs in SAP, improve exception handling features (e.g. provide centralized view of all exceptions associated to customer account), improve handling time, and improve back office usability and reporting. There are multiple Exceptions Management tools considered for procurement. The program direction is required by end of plan phase.	
Recommended Option & Rationale	Avertra's MiBob product was selected based on SWG's scoring evaluation results and project leadership team discussions. This tool was selected over BASIS Technologies' Bdex tool based on the potential machine learning/automation capabilities showcased during the selection process.
Dependencies / Impacted teams	Billing and Exceptions workstream will need this awareness to help properly prepare for their exceptions BPDs and conduct the appropriate fit/gap assessment. Timing of ramp up of the Avertra team will be critical to keep schedule intact.

Decision Due Date	7/22/19
Decision Review Date	7/10/19
Level of Change	Medium
Priority	High
Geographic Scope	All areas
Workstream Impacts (Process / Tech / SA / Operations, Conversion)	Functional, Solution Delivery, Solution Architecture

Time to change	Effort	Budget Impact
Potential impact to completion of BPD on time if clear direction is not given on toolset.	Potential rework to BPD, fit gap, and RICEFW inventory if clear direction is not given on toolset.	Estimated vendor implementation services cost – xxxx Estimated software licensing cost - xxxx

The KDD form captures information concerning impacts to scope, schedule, budget, resources, and other considerations (e.g. business value, architecture sustainability, etc.) backed by supporting analysis. The supporting analysis should generally include some degree of scenario planning that considers the information available to the project team (e.g. verified solution options, stakeholder agreements, partner commitments, relevant benchmark data, known issues based on prior performance both internal and external, etc.), the information not available (i.e. identified unknowns), risks and available mitigations, and assumptions that can be made. These components of the analysis enable the project team and decision-making bodies to assert probabilities of achieving the desired outcomes with each defined option based on the data available (and acknowledging what is not available) to arrive at a conclusion on the "best option" to inform the decision.

These Key Design Decision forms are reviewed with Project Leadership and relevant stakeholders on a regular basis before finalizing and approval. Complete forms are located in the SWG SharePoint here: Key Design Decision

Guidelines for managing project decisions is as follows:

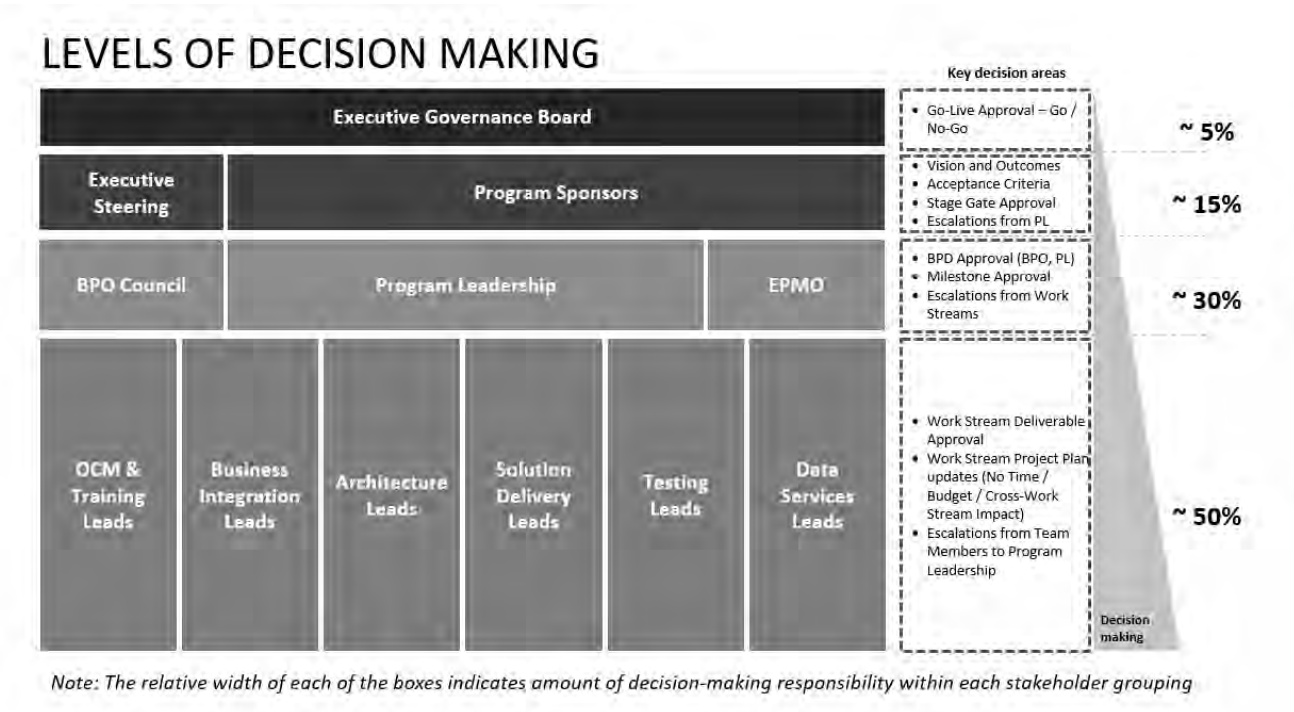
- Actions can be identified by any team member but will be entered in the RAID log by Team Lead and above
- Decision can be identified and entered in the RAID log by Team or Work Stream Leads
- The project will actively monitor Actions and Decisions
- Actions and decisions requiring executive attention will be monitored and assigned priority based on criticality
- The SWG SharePoint RAID tool is our Actions and Decision Management repository.

The following critical success factors are imperative to ensure effective management of project Actions and Decisions:

- Clear identification, logging, communication and resolution procedures
- Common definition and understanding of Actions and Decisions
- Commitment by all leads and project management to execute the processes as outlined
- Commitment by all team members to work actions and make decisions as quickly as possible

16.2 Decision Making Governance

Governance over decisions follows the program governance structure as defined in section 3.2. The approved levels of decision making are designed to empower the project team, in adherence to the project's guiding principles. These are illustrated below:



The approved decision making matrix is stored in the SWG SharePoint as follows:
https://sphome.swgas.com/teams/csm/Shared%20Documents/04%20Horizon%20Workstreams/02.%20PMO/Project%20Governance/Horizon%20Program%20Governance%20RACI_draft_v0.3.xlsx?Web=1

This model has been tested with the involved governance bodies through an initial and extensive table-top decision-making exercise conducted on August 21, 2019. Program leadership will continue to exercise the governance model as the project progresses to ensure the decision-making model continues to be effective and honored as the types of decisions evolve.

The objectives of the exercises conducted were to practice the governance model using real life scenarios and:

- Define/confirm the level of involvement from the organization, business areas, regulatory
- Discuss potential changes to the RACI based on needs (auditable responses)
- Define / confirm methods for communicating on decision-making (tool, inputs, outputs)
- Determine what should be communicated if the decision affects: budget, resources, schedule, customers.

The table below identifies the stakeholders in the Decision Management process, as well as the associated key roles and responsibilities:

Roles	Responsibility
Project Sponsors and Executive Governance Board	• Work with Project Leadership to support expedited decision making • Understand recommendations from Project Leadership to make informed, priorities-based decisions that require allocation of budget and resources.
Project Leadership	• Work with Work Stream Leads and Team Leads to understand actions and decisions that required leadership support or perspective • Work with Work Stream and Team Leads to facilitate expedient decision making • Verify the information captured in the Key Design Decision forms and the RAID tool are accurate • Understand analysis on alternatives conducted by the team and guide/make decisions based on overall project priorities that honor the project mission and charter. Consider project level scope and schedule to recommend priorities for budget and resource allocation. • Raise key decisions to Project Sponsors and Executive Governance Board as needed.
Business Process Owners (BPOs), IS Stakeholders & BPO Council	• Work with Project Leadership and team members to verify complete analysis on key decisions and support decision making • BPO's review, understand, support analysis, and approve process decisions that pertain to the processes they have primary and secondary ownership over. • The BPO Council reviews, understands, and approve process decisions that have cross-functional implications and impacts. In particular this entity weighs in on situations that have 'trade-off' implications across processes. • IS Stakeholders review, understand, support analysis, and support expedited technology decision-making for their respective areas of responsibility.
PMO	• Manage the RAID tool and decision-making planned dates • Ensure forecast due dates for Actions and Decision are adhered to • Conduct analysis on alternative for key decisions from a project management lens. The project management lens considers: implications of the alternative and approved decision on the overall integrated workplan (i.e. plan/schedule viability), resource plan (i.e. resource capacity viability), and other project operations.
Solution Architects	• Identify and document key decisions that impact multiple areas of the solution that cross functional and technical areas • Conduct analysis on alternatives to key decisions from a solution impact lens. The solution impact lens considers: estimated effort and complexity to implement the option, overall solution integrity and sustainability (i.e. risk to the overall solution architecture), products and skills/resources needed to achieve and perform the work, and other solution-oriented considerations.
Work Stream Leads and Team Leads	• Identify and document actions and items needing decision making pertinent to their area of responsibility

	• Contribute to the completion of Key Design Decision forms and verify the completed forms are accurate • Conduct analysis on alternatives to key decisions from a business, process, organizational, data and/or technology lens in line with the workstream/team lead's role.
Team Member	• Raise actions and items needing Decision Making to Project Leadership • Resolve day-to-day problems and conduct analysis on alternatives to team-level decisions

16.3 Decision Making Process

At any point during the project lifecycle, an action or event that requires a decision (e.g. change request, product selection, design decision, etc.) may be observed and brought to the attention of Project Leadership. The project team leads employ their judgment and apply the thresholds defined in the Governance model to determine if the decision is substantial enough to bring it to leadership attention, warrants logging the decision in the decision log, and/or whether it is a Key Decision. If the decision does not require being tracked, an informal decision-making process can be followed and the results documented as part of the relevant deliverable.

The decision analysis and resolution process (DAR) will typically flow as follows:

1. Understand and Document the Context and Intent: This step establishes the context, stakeholders, and forces driving the need for the decision. This step seeks to align, and memorialize, stakeholder expectations, objectives, and interpretations of the drivers for a decision and resolution. This step also provides the project team with a clear mandate or boundary of decision-making scope as it pertains to the issue or situation driving the need for a resolution. This step answers the question – "for what are we solving?"

2. Assess Baseline and Planned Approach: This step identifies and documents the originally expected (baseline and planned) approach, if there was one, to meet the needs as understood in step 1. This serves as a level-setting step. This step answers the question – "what did we assume?"

3. Analyze Impacts for Project Horizon: This step considers the "gap" between step 2 and the needs articulated in step 1. The difference between what was originally planned and what is now understood to be needed can take many forms including, but not limited to: products required, solution architecture approach, business capabilities needed to achieve, total effort required, resource types/skills mix required, timing of resource demands, schedule / time to deliver, total cost to achieve, budget allocation, roles and responsibilities/RACI, etc.

4.Determine Decision Criteria and Decision Makers: Define and document the decision evaluation criteria that will be applied to make the decision and the people who will make the decision per the governance model. The decision criteria should be reviewed and confirmed with the identified decision makers. In this step we also confirm the technique that will be used to make the decision (e.g. Key Decision Document/KDD form, product evaluation scorecard, formal Request for Proposal, or other).

5. Assess Solution Options: This step identifies viable solution options to address gaps in the planned approach and what is needed as determined through step 3. Alternative solutions may be identified through brainstorming sessions with multiple workstreams/teams, partners, interviews, working groups, research, etc.

In this step, the project team and involved stakeholders, work together with partners as needed to assess the viable solution options in terms of estimated cost and resources, complexity, schedule, risk, and impacts. These terms are evaluated from the lens of the project, the company, the business, the customer, and the technology. It is expected that solution options consider both implementation and sustainment (e.g., customer operations and long-term support) factors.

Assess and document the options against the decision criteria. The output of this assessment should yield the top 1 or 2 alternative solutions.

6. Prepare related artifacts, typically the Key Design Decision document (KDD), or Deliverables (e.g. Sensitive PII Decision Assessment). Ascertain and prepare recommendation based on assessment and analysis. Review artifacts/deliverables with identified stakeholders, subject matter advisors, and team members. Action feedback. Update documents and the RAID log accordingly. This step may be repeated multiple times. Update final recommendation based on feedback and discussions.

7. Conduct Leadership and/or Stakeholder Read Out in accordance with the Governance model and request for decision. Resolve decision and document with rationale in the RAID log and corresponding artifacts (e.g. KDD, Assessment deliverable, etc.).

8. Direction provided to Project Horizon on path forward. The PMO updates the RAID log and archives the relevant artifacts in the SWG SharePoint. The PMO works with workstream leads/project leadership to prepare a detailed implementation plan, if relevant, and follows Project Horizon's Change Control Process. This will result in updates to the relevant project management control documents such as the Requirements Traceability Matrix, Process Model, RICEFW Inventory, Resource Plan, Integrated Workplan, etc.

Solutions options are documented using a format such as the following:

Decision Overview / Background:		**<Insert decision overview and background>**						
Included in Scope?	**<Y/N>**	**<Insert any additional comments>**						
Recommendation:		**<Insert decision recommendation>**						
Options and Impacts of Decisions Decision Deadline: DD/MM/YY								
#	**Decision Option:**	**Scope/ Functional Impact:**	**System Impact:**	**Benefits Impact**	**Schedule Impact:**	**Cultural Impact:**	**New / Additional Risk to Project**	**CO (S/M/L)**
<#>	<Insert Decision Option>	<Insert impact on scope and functionality and any considerations>	<Insert impact on system and functionality and any considerations>	<Insert impact on system and functionality and any considerations>	<Insert impact on schedule>	<Insert Impact on culture and any considerations>	<Insert comments regarding risk to project>	<S/M/L>
<#>	<Insert Decision Option>	<Insert impact on scope and functionality and any considerations>	<Insert impact on system and functionality and any considerations>	<Insert impact on system and functionality and any considerations>	<Insert impact on schedule>	<Insert Impact on culture and any considerations>	<Insert comments regarding risk to project>	<S/M/L>
<#>	<Insert Decision Option>	<Insert impact on scope and functionality and any considerations>	<Insert impact on system and functionality and any considerations>	<Insert impact on system and functionality and any considerations>	<Insert impact on schedule>	<Insert Impact on culture and any considerations>	<Insert comments regarding risk to project>	<S/M/L>
Decision Made / Next Steps: **Decision <#>**		**<Insert conclusion or next steps for decision>**						

16.4 Decision Making Forums

There are multiple forums in which Project Horizon decisions will be made.

Many small decisions will be made daily by team members and team leads that stay contained within team-level working sessions and meetings. These are reflected in Project Deliverables and work products. Project Deliverables are formally reviewed and approved according to the Deliverables Responsibility Matrix and approval workflow per section 7.2.

Key Decisions are reviewed and discussed in the weekly "Functional Key Decision and Risk Review" meeting. Attendees of this meeting are: Business Integration/Functional Leads, Solution Delivery Leads, and Solution Architect Leads.

Key Decisions are reviewed, discussed, and approved (or determined as requiring escalation by the Program Directors) per the governance model in the weekly "Project Leadership" meeting. Attendees of this meeting are: Program Directors, Business Integration/Functional Leads, Solution Delivery Leads, Solution Architect Leads, OCM Leads, PMO Leads, and Test/Quality Leads.

Key Decisions that are escalated to the Sponsors, Executive Board, Steering Committee, Enterprise PMO or Vendor Partner meetings are facilitated by the Program Directors. The forums for bringing escalated Key Decisions to these entities are established through the weekly and monthly recurring events defined in the project progress and governance reporting cadence per section 5.2 and 5.3.

Decisions that are escalated to the BPOs, BPO Council and/or IS Stakeholders are facilitated by the Business Integration / Functional Leads and Solution Delivery Leads, with support from the Solution Architect Leads, accordingly. This may be done through documented ad-hoc meetings with authorized stakeholders and/or the weekly Business and IS Stakeholder Meeting/BPO Council.

Project Horizon's ability to stay on schedule and within budget is critically dependent on good, informed decision-making that honors the project's guiding principles and culture priorities. Of equal import is consistent adherence to the approved project governance model and respect for the project's timeline as the pace of decision making (big and small) directly drives the pace of project execution.

17. Recognition Initiatives

Project Horizon has implemented recognition initiatives focused on highlighting team members who are exemplifying the Project culture and have significant contributions. Figure 6 below summarizes the Project Horizon Recognition Program.

Introducing... the Project Horizon Recognition Program!

	Catch Me At My Best	Way of Working Champion	Recognition Leaderboard
WHAT	A ways of acknowledge team members who live our Ways of Working via recognition cards	A way to recognize one team member a week who exemplifies our Ways of Working	Points system to track work streams and team members who are living our Ways of Working
HOW	o Fill out a recognition card to let the person know "they've been caught" (cards and drop box are in lobby) o We will draw one card a week; the winner will get leaderboard points and a prize o Others who have been recognized will also get points, and all recipients will be given their recognition cards	o There will be a nominated Way of Working Champion each week o The current week's Champion will recognize the next week's Champion and hand off the Horizon "mascot" (the new champion must be from another work stream) o Points will be awarded to the Champion's team for the recognition leaderboard	o Work streams and team members will get points for being recognized formally through the Recognition Program and informally through culture moments o OCM will maintain a points tracker and update the leading work streams and team members every week
WHEN	Fill out cards any time (avail. on 9/16)! We will draw our first winning card during the week of 9/23. We will have a drawing each week thereafter.	We will pick our first WoW Champion during the week of 9/16. This person will hand off the "mascot" during the following week, and so on.	We will start tracking points on 9/16. You can also email OCMHorizon@swgas.com or talk to an OCM team member any time to recognize someone informally!

Figure 6: Project Horizon Recognition Program

SOUTHWEST GAS CORPORATION

Human Resources Management System

Business Case

Southwest Gas Corporation
Confidential & Proprietary
Last Updated: 01 Apr 2019
Date Created: 7 Nov 2018
Version v.02

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Document History

This is a list of the versions of this document.

Version	Updated by	Short Description	Date
v.01 Initial	R.Pendowski	Initial version of the business case for the Human Capital Management Project.	13 Nov 2018
v.02 Update	R.Pendowski	Update the document in all areas and initial completion of section 3.	18 Jan 2019

Final Approvals

Final approvals are to be completed after all required participants have reviewed this document and edits have been made.

Approver Name	Title	Signature	Date
Gail Zody-Serbia	Dir. Corp Human Resources	Gail Zody Serbia	9-12-19
Sharon Braddy-McKoy	VP / Human Resources	Sharon Braddy-McKoy	9/20/19

1 Executive Summary

Southwest Gas will digitally transform its Human Resources Management processes and implement industry best practices to provide strategic results and achieve the HR Vision of being customer focus and delivering business driven value through innovation, simplification and operational excellence. To achieve the optimum potential, HR has decided to adopt a complete end to end solution that aligns with industry best practices, provides migration of all existing SWG HR Data, runs on state of the art technology platform, and is compatible with the access methods required by its users.

Continuing to update and upgrade the current ATS solution cannot address the needs of HR and help move the department from a purely transactional operation, burdened by manual and paper processes, to a strategic organization capable of achieving the highest potential in both the short term and into the future.

1.1 Opportunity

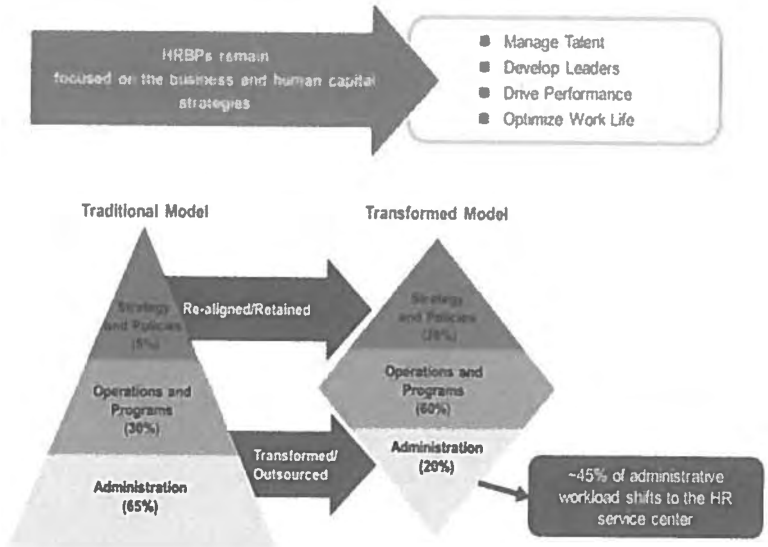
The current HR solution does not provide a comprehensive, seamless, best practices or industry leading processes. In addition, the current solution cannot support the modern technology access (methods or devices) prevalent today that are required by users. For many individuals, the HR solution is the first contact they have with SWG, and the current solution does not portray the company in a competitive, modern or technology savvy organization.

Rather than continue to work on the existing solution, which has been pieced together with add-ons and updates, HR will move forward with a comprehensive solution to meet their current needs, align their processes with best practices, and prepare SWG for the future from a business and technical perspective.

1.1.1 HR Delivery Model: Changes in Roles and Responsibilities

The HR delivery model drives a transformation of HR from 65% administrative and tactical to 20%.

Change in Roles and Responsibilities



1.1.2 HR Shared Services Delivery Model:

Purpose: Centralizing HR administrative/transactional functions handled in multiple locations into a single HR Shared services team which allows front line HR staff to focus and operate at strategic levels.

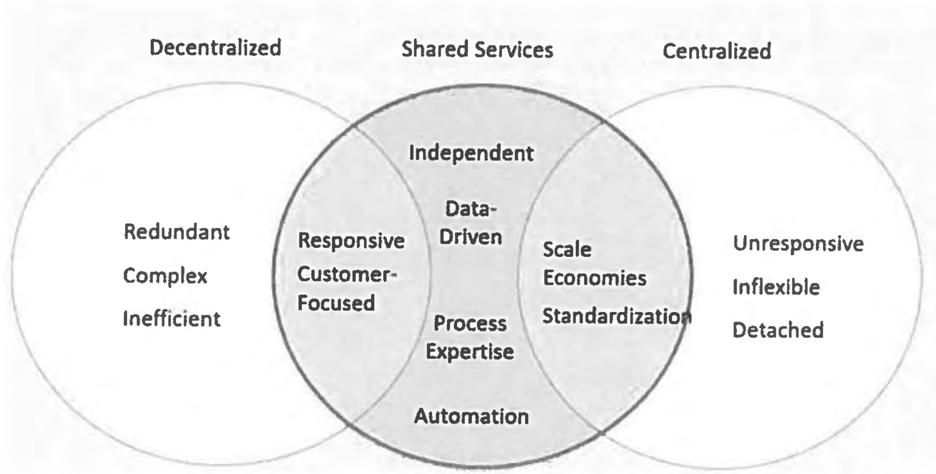
WHY?: HR is defined by both the strategic value it offers and the services it provides to the business. To highlight and reinforce the strategic value, the services offered must not only meet the needs of the organization, they must be efficient. HR Shared Services/HRBP model is a best practice model.

- Companies that adopt an HR Shared Services model reduce process costs by as much as 80%
- 80% of fortune 500 & 94% of fortune 50 companies have adopted HR Shared Services models

Key Objectives:

- Evolve and modernize the current traditional HR operating model
- Leverage technology to support customers via employee/manager self-service
- Combine common HR functions to gain efficiency from work currently decentralized to improve data integrity, compliance, consistency, and standardization
- Process optimization, work is simply transitioned, but the workflow and data is reengineered and focus is on continuous business process improvement, efficiencies, and automation
- Develop performance metric scorecards and service level agreements for ROI
- Shift and support (COE's) centers of excellence (compensation, benefits, recruitment) and HRBP's to focus on the business (operate strategically) leveraging shared services team
- Centralized recruitment

1.1.3 Shared service functions:



HR Administration Transactions Include:

- Recruiting: Interview Coordination, Scheduling, Offer Letters, etc.
- Onboarding: Process Employee Onboarding Transaction Support
- Employee Support: Process First Line Employee Questions on Policy, Guidelines, and Procedures
- Process New Hires: Support new hire data entry, Reporting, and External Reporting Requests
- Support HR Annual Processes (Surge): Re-enrollment
- Support and Process Requests: Reporting and Analytics

1.1.4 Issues identified with the current system include:

- The processes are antiquated, challenging to use, and do not support a strategic HR Delivery Model.
- The processes are transactional in nature and do not support a comprehensive view.
- The system is not intuitive or informative requiring the user to enter and access data in piece-meal fashion
- The system cannot provide a "one-stop" experience for all HR and employee related information and processes (interactive portal).
- There are processes which are paper based that cannot be automated.
- The system is not agile in response to changes required to comply with legislative changes.
- The current onboarding process is burdened by unlinked processes, paper documents, and various email message exchanges.

- The current system does not present new hires with a positive first impression of SWG.
- The current system does not offer mobile technologies which are prevalent with employees, potential hires, or retirees.
- The current system does not provide any linkage to job aggregators for recruiting of new hires which impacts the talent pipeline.
- The cost of ownership and maintenance of the system, based on the number of customized processes, is beyond the value the system offers moving forward.

1.2 Anticipated Outcomes

Project Outcomes include:

1. A comprehensive Human Capital Management solution supported by state of the art technology that interfaces easily to and from other solutions
2. Selection of a vendor to partner with that can provide the implementation of the selected solution that meets the requirements of SWG
3. Incorporation and integration of the solutions best practices and legislative compliance that will drive change in the HR procedures at SWG
4. The full adoption of the solutions business process as best practices by the HR Staff with little or no customization
5. Development and deployment of intuitive training, help and case based smart support functions.
6. The extraction, transformation and migration of all existing SWG HR data from the current eBusiness Suite to the selected solution.
7. Development and implementation of interfaces required between existing systems, i.e., payroll, time reporting, etc.
8. Deployment of the infrastructure required to support devices aligned with the needs of current and future employees.

2 Project Overview

2.1 Project Scope

2.1.1 In Scope

The selection of a comprehensive Human Resources Management System that provides all the required functional needs of the company, provides industry best practices in its processes, has a current state of the art technical platform, and that is compatible with the access needs of all users.

Identification and engagement of a vendor to implement the selected solution (Implementor), migration of all SW Gas data, and the configuration of the selected solution to provide best practice processing and support strategic operations-driven process flows.

The implementor engaged will determine and present the implementation strategy to use in deploying the selected solution.

Re-engineer the legacy processes and modeling them within the selected solution's comprehensive HR best practices to provide operational direction which are based on HR's strategic goals.

Charter and engage a governance board to provide guidance on changes to the business processes and assist in the overcoming any cultural resistance.

Deployment of the selected solution, the migration of all data from the current ORACLE eBusiness Suite, creation of interfaces necessary for read only access and all known business processes not part of the selected solution (i.e., payroll), and the conversion of all customized logic/programming to the selected solution's standard processing.

Provide rollout and support: develop documentation including training manuals and help text data; provide user training and train the trainer instruction; provide support for the users during the rollout.

2.1.1.1 Comprehensive HR Business Functional Requirements

Self-Service Core Access / Processes

Talent Management

Recruiting

Compensation

Benefits

Performance Management

Employee Training and Development (LMS)

Workforce Management

2.1.1.2 Non-Functional Requirements

State of the art technology platform

Modern device support and access

Intuitive and Artificial Intelligence Based processes and associated training

Robotic Chat Bots

Automated Workflows (eliminate all manual and paper-based processes)

Business Intelligence Reporting (Dashboards and KPIs)

2.1.2 Out of Scope

The selected solution will be comprehensive and include processes which will not be replaced and are not in scope. These standalone systems have been identified in the following sections.

2.1.2.1 Payroll (Out of scope)

The payroll system will not be replaced; however, interfacing with this solution is in scope.

2.1.2.2 Time and Attendance (Out of Scope)

Time and Attendance is currently done through Hourglass and will not be part of this project which includes Absence Management and Leave Management. Interfacing will be included as required.

2.2 High-Level Business Requirements

[Describe the scope for the proposed project.]

The following are initial high-level business requirements:

BR#	Requirement Name	Description
BR-001	Self-Serve Employee Processes and Access	Single access point for all employee, retiree, and potential hire processes, data entry, and reporting.
BR-002	Self-Serve Management Level Processes and Access	Single access point for all managers for all HR and employee management processes.
BR-003	Open Enrolment Processing	Providing and processing the annual selections made by employees and retirees for their participation in benefits programs offered by the company.
BA-004	Life Event Management	Online processing of life-events by the employee which may include marriage, divorce, new dependents, death, loss of benefits from secondary source, etc.

BR#	Requirement Name	Description
BR-005	System of Record	Online process for attaching documents supporting compliance and employment data and its required validation.
BR-006	Workforce Management - Workforce Predictions and Modelling	Strategic reporting and planning of staffing requirements and succession planning.
BR-007	Compensation Management	Management of compensation details, strategies and guidelines.
BR-008	Incentive Compensation	Additional compensation management based on employee performance which is above the normal compensation.
BR-009	Benefits	Integrated management of health, pension, and other employee welfare programs.
BR-010	Sourcing, Recruiting and Onboarding	Finding and hiring of talent that fits the business needs and the successful onboarding new hires to get them up to speed and provide value faster.
BR-011	Goals and Performance	Assignment and management of objectives and the review of performance used to develop the employees' talent, skills and experience while providing for the organization needs and to meet its overall goals.
BR-012	Succession Planning	Identifying and developing individuals to fill positions including leadership roles for staff that leave, retire, get promoted, etc.
BR-013	Modern User Interfaces and Mobile Access	The incorporation of modern devices and a user-friendly experience that allows the user to interact in a simple and intuitive way.
BR-014	Paperless Workflow Processing	All complex processes will be defined as a workflow that is intuitive, has no breaks in the process, and has no paper-based processes.

BR#	Requirement Name	Description
BR-015	Artificial Intelligence based process with self-help support and Robotic Chat Bots	AI will be able to understand the processes performed and their repetition, trigger the next or additional processes based on the user's entries, and make recommendations to the users. This will make the system more useful, required less support, and facility completion without using traditional text-based help.
BR-016	Business Intelligence Reporting and KPIs	A business intelligence dashboard with visual sections that displaying metrics and key performance indicators. The Dashboards will consolidate and arrange results, metrics and performance data on single screen.

2.3 Current State

The current HRMS system is Oracle eBusiness Suite provides standard processing available in HR solutions; however, the technology platform it is built on does not currently support all the requirements of the SWG HR.

This solution was implemented in 2002 and its technology reflects the era. At the time of implementation, the direction given was to replicate the processes which existed on the retire mainframe-based system. In order to recreate these processes, the system was highly customized. The overall cost of ownership of these extended customizations was not only high at the time of it was deployed but continues to have a high cost of continued use as the system is upgraded by the vendor. The business process which are supported by the current system, are not easy to modify and do not permit the timely updates required for legislative and compliance changes.

Access by the users of the system are required access the Oracle system through SWG which does not permit potential employees or retirees access to the system. Interaction with new recruits is hindered by the system which forces the onboarding process to be semi manual and paper based which adds to the timeline.

2.4 Future State

Migration to a new HR solution that upgrades the processes and aligns them with industry best practices.

Reduce the administrative processes by 60%. (need verification)

Accessibility through modern and updated devices which are supportable in the future.

Ability to apply legislative changes quickly and effectively.

Elimination of paper based manual processes.

Reduction of the overall cost of ownership associated with maintenance of the older solution.

Providing a modern approach to recruitment which offers a positive first impression to potential candidates.

2.5 Project Assumptions

- The implementor will be working directly with HR users to develop requirements which will be pinned to best practices in the HCM Cloud solution.
- The implementor will bridge the gap between existing processes and new solutions features.
- The HR users will NOT have a broad ability to modify the processes in a cloud-based solution and may see considerable change between the legacy and new processes.
- Customizations a cloud-based solution will be difficult and expensive to develop and support.
- The business users at SWG will have an open mind to the business process changes and their adoption in the solution.
- The selected solution has <u>ALL</u> the necessary processes required by SWG HR.

2.6 Project Constraints

- SW Gas employee's time is limited and may be constrained.

2.7 Dependencies

The following dependencies have been identified for this project.

2.7.1 Project Dependencies

Customer Service Replacement Project

2.7.2 System Dependencies

Payroll System must be integrated with the HR solution.

Time and attendance system will be integrated with the new solution.

2.8 Project Risks

[List the preliminary risks for the proposed project.]

Risk	Probability	Remediation Steps
Resources not available to make deadline prior to the ATS/Platform expiration.	High	• Pay month to month short term
Extended Timeline due to Business Process Review, Configuration, Testing, Training and Implementation/Deployment	High	• Assure the implementor is well versed in training and training material • Part of the requirement for implementor • Get a functional HR Analyst to help with the business processes set up from and throughout implementation
Key decisions and policy changes	High	• HR Governance board with regular meeting to resolve issues. • Assure HR Analyst has been hired as part of implementation to manage the changes.
Changes to employee handbook	High	• Assure HR Analyst has been hired as part of implementation to manage the changes.
The business will have a learning curve during the initial installation; however, subsequent updates and releases will experience a faster than average time required to get up to speed.	High	• Assure analyst has been hired as part of implementation to manage the changes.

2.9 Timeline

Deliverables	Timeframe	Health
Project Kickoff	January 2019	Anticipated
Business Case Development	January 2019	In Progress
RFI/RFP Process for Implementor	March 2019	Anticipated
Technical Review	March 2019	In Progress
Justification Memo / Template	March 2019	In Progress
Phase I (2019)	March – Dec 2019	Anticipated
Phase II (2020)	Jan – June 2020	Anticipated

Deliverables	Timeframe	Health
Phase III (2021)	Jan – June 2021	Anticipated
Project Completion (initial)	June 2019	Anticipated

This project is broken down into three phases:

Phase I (2019) – will include deployment of the HCM Core, Recruitment, Benefits, System of Record, Employee/Retiree/Applicant portals, Compliance Management

Phase II (2020) – will include deployment of help desk functionality

Phase III (2021) – will include deployment of Compensation Management, Performance Management, Workforce Planning, and possibly Learning Management System

2.10 Project Stakeholders

The following individuals have been identified as Responsible, Accountable, Consulted, and Informed (RACI) in eliciting the high-level business needs and requirements. These individuals are subject to change during the duration of the project.

Name	Title/Department	Role/Expertise	Description (RACI)
Gail Zody-Serbia	Dir. Corp Human Resources	Stakeholder	Accountable
Hugh Winesett	Manager/Business Technical Support ORACLE Business Support	Stakeholder	Accountable
Chris Thomas	Dir/Compensation and Benefits	Stakeholder	Accountable
Sharon Braddy-McKoy	VP / Human Resources	Steering Committee	Informed

3 Cost Benefit Analysis

[Include information to quantify the financial benefits of the proposed project to illustrate the costs of the project and compare them with the benefits and savings to determine if the project is worth completing.]

3.1 Alternative Approaches

Alternative Solution	Description	Reason for Not Selecting
New Solution Deployment	Select new solution to support the business based on their requirements and the current solutions offerings	Selected
Maintain Current Situation	Leave the current solution in place and provide addition functionality already budgeted	The business process advancement received from the updated solution was too significant, the necessary access requirements could not be met.

3.2 Budget Overview

Description	Period (Execution)	Budget Type	Estimation
Software Subscription	2020 Calendar Year	O&M	$150,000
Solution Implementation	2019-Calendar Year		**$500,000**
OCM HR Training etc.	2019 Calendar Year	O&M	$250,000
Software Subscription	2020 Calendar Year	O&M	$375,000
Solution Implementation	2020 Calendar Year		**$2,200,000**
Solution Implementation	2021 Calendar Year		**$500,000**
Software Subscription	2011 Calendar Year	O&M	$375,000
		Total	$4,350,000

3.3 Itemized Financial Expectation

[Include high-level expenditure information.]

Item	Action Type (Cost/Savings)	Description (Rationale)
1). Migration to a new HR solution that upgrades the processes and aligns them with industry best practices and reduces some administration tasks by 60%. 2). Remove Manual Processes 3). Elimination of paper-based processes	Savings	Less issues to resolve, missed processes, or delays.
Accessibility through modern and updated devices which are supportable in the future.	Savings	Ability to access the solution reduces manual paper work, phone support, and other user contact.
Ability to apply legislative changes quickly and effectively.	Efficiency	
Reduction of the overall cost of ownership associated with maintenance of the older solution.	Savings	Reduction of support due to potential move to SAAS, or like solution

3.4 Intangible Benefits

The new Solution will provide an improved process to potential employment candidates and a positive perception of SW Gas during the recruitment processes. This will help the continuous flow of superior candidates.

Item	Action Type (Cost/Savings)	Description (Rationale)
Providing a modern approach to recruitment which offers a positive first impression to potential candidates	Nontangible	The first impress of candidates can influence their decision to accept a position with SW Gas

Human Capital Management

Project Charter

Document Control

Document Information

	Information
Prepared by	Wayne Biernacki, Riki Delotch
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Role	Name	Signature	Date
Project Sponsor	Sharon Braddy-Mckoy	e-approval on file	03/2/20
Project Oversight Committee [applicable members]	Reagan Monroe	e-approval on file	11/6/19
	Gail Zody-Serbia	e-approval on file	11/9/19

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1 Executive Summary

The purpose of the Human Capital management (HCM) project is to replace the current Human Resources System(HRMS). This new HCM solution will digitally transform the current HRMS processes by migrating to a modern HR Application suite. Migrating HR's applications to Oracle's HCM Cloud solution will digitally transform HR's business processes by improving the user experience through AI Guided Learning, full mobile access, robotic chat bots, improved HR processes through fully paperless workflow, and business intelligence insight (Dashboards and KPIs). It will establish a strong application foundation with leading practices and technologies for years to come.

2 Project Definition

2.1 Background

The last major upgrade of the HRMS systems occurred in the summer of 2002. The HR department upgraded their software from a centralized mainframe-based application to Oracle eBusiness Suite (EBS) 11.5. The software transformed processes and afforded the HR to take advantage of the latest technologies of the time. Since implementation in 2002, Oracle has released one major version and several minor versions. Oracle EBS has not been able to effectively keep up with the changing technologies that employees, future employees, and management now expect such as a modern user interface, Artificial Intelligence (AI), Mobile Access, and Business Intelligence (BI) insight and reporting.

2.2 Business Objectives

The following business goals and objectives will be achieved within the scope of the project:

- Support compliance management & reporting (Background, drug testing, I-9, verify, AAP) to better meet compliance standards
- Enhance/Improve applicant user experience to include mobile application functionality, and electronic new hire paperwork

- Deploy workflow configuration management for position authorization as well as wet signature approvals that the system can automate (no more paper)
- Focus on business process redesign and benchmark leading practices to support agility
- Provide benefit interactive portal capabilities for current employees as well as retirees (currently manual process for retired employees)
- Reduce customization and move towards configuration for ease of upgrades and business process changes
- Have the system work for us instead of customizing the system to meet our current business processes
- Phased approach to achieve optimal system offerings & to support change management and user adoption

2.3 Scope

The primary scope of the project is described as follows:

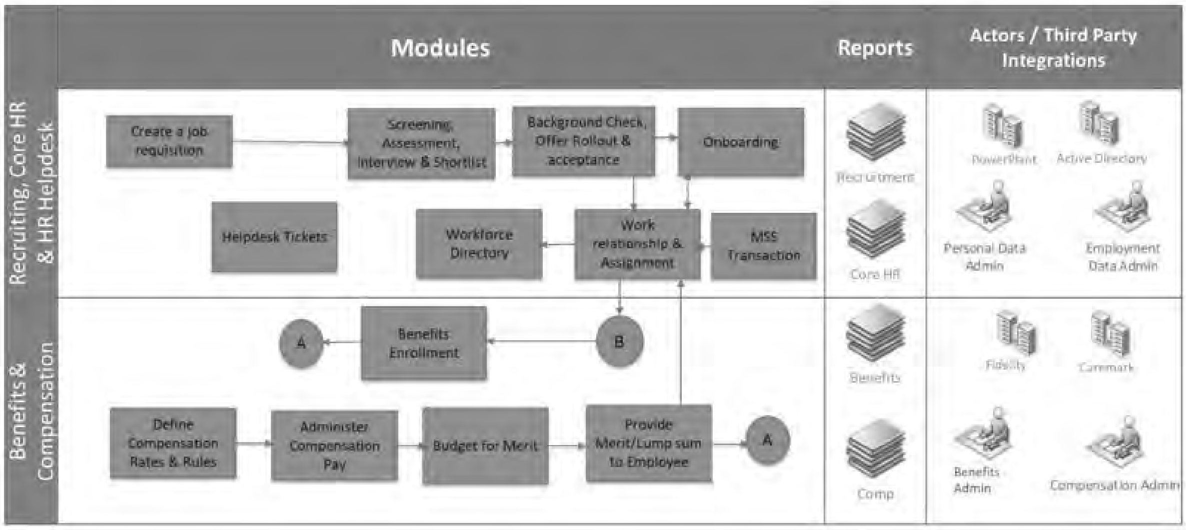
The configuration of a comprehensive Human Capital Management System that provides all the required functional needs of the company, industry best practices in its processes, a current state of the art technical platform, and that is compatible with the access needs of all users.

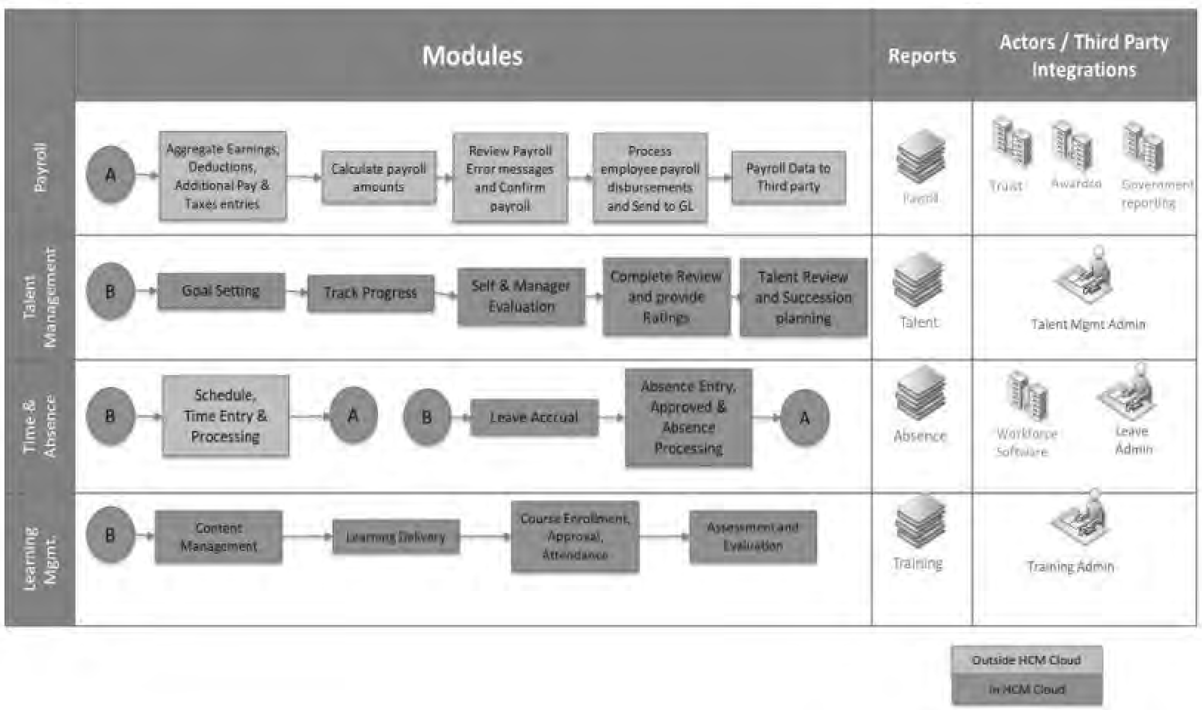
Re-engineer the legacy processes and modeling them within the selected solution’s comprehensive best practices.

Deployment of the selected solution, migrating all data from the current Oracle 12.2.4 e-Business Suite, creation of interfaces necessary for read only access and all known business processes not part of the selected solution (i.e., Payroll), and the conversion of all customized logic/programming to the selected solution’s standard processing.

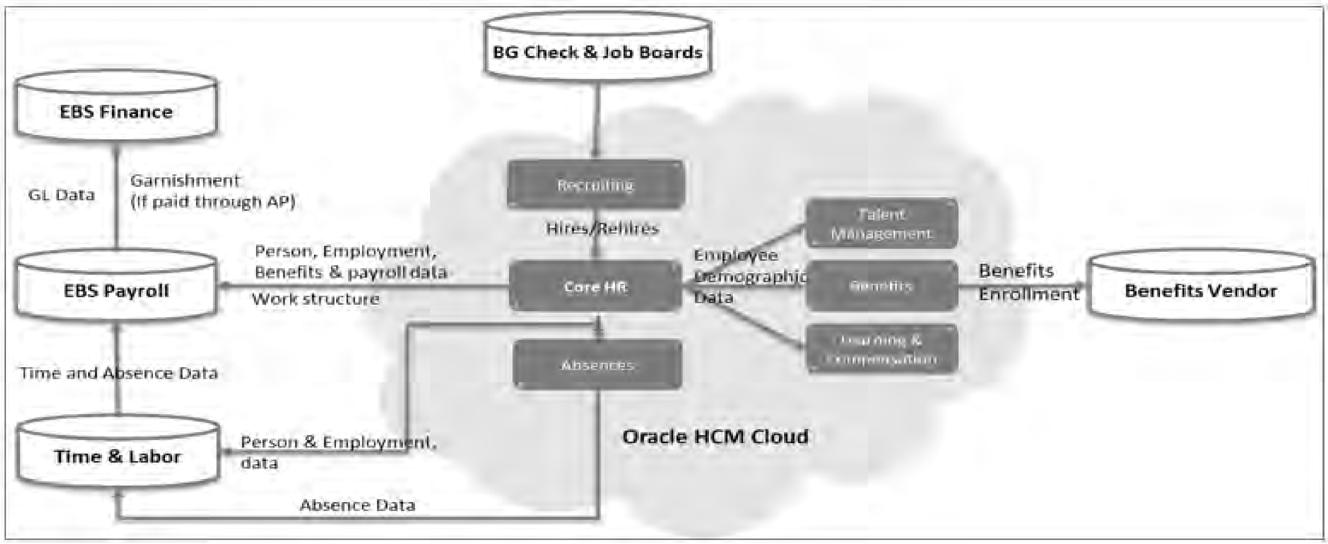
2.4 High Level Application or Business Process Diagrams

The to- be Business Process Diagrams:

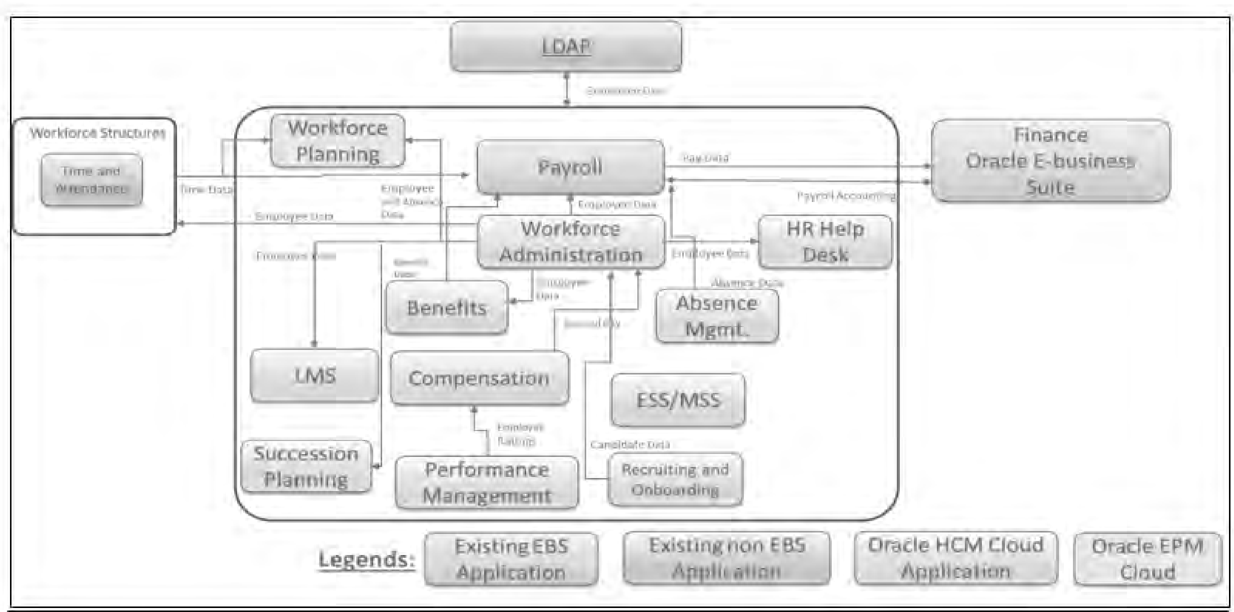




The to-be integration for SWG:



End of Phase 2 SWG Application Design:



2.5 Key Deliverables and Approvers

Deliverable	Components	Approval
Specifications	Functional/Technical	Project Team
Upgraded Applications	DB/Application Servers	Project Team
Go-live	Cutover Plan	Oversight/Sponsor

2.6 Financial Plan

On August 8, 2019, the Steering Committee approved the recommended Capital budget of $3.2M, supported by the Oversight Committee.

Expenditure Category	Capital	2020 O&M
Platform Vendor (Subscription)		$375,000 (Annual Expense)
SI Implementor	$2,200,000	
Organizational Change Management		$175,000
Project Management	$450,000	
Staff Augmentation	$250,000	
Contingency	$300,000	
Total	$3,200,000	$550,000

3 Project Organization

3.1 Roles

Role	Name	Title	Department
Sponsor	Sharon Braddy-McKoy	VP/Human Resource	Human Resources
Steering	Sharon Braddy-McKoy	VP	Human Resources
	Eric DeBonis	SVP	Operations
	Raied Stanley	VP	Info Services/CIO
Oversight	Katie Hampton	Dir/Internal Audit	Internal Audit
	Catherine Mazzeo	Managing Counsel	Regulation & Litigation
	Craig Sisco	Dir/Business Technology Support	Business Technology Support
	Preston Weaklend	Sr Mgr/Ops Planning & Analysis	Ops Planning & Analysis
	Gail Zody-Serbia	Dir/Corp Human Resources	Human Resources
	Fred Harvey	Dir/Compensation & Benefits	Human Resources
Project Manager(s)	Wayne Biernacki	Senior Project Manger	Enterprise Project Management Office
	Riki Delotch	Project Manager	Enterprise Project Management Office
Project Team	Gail Zody-Serbia	Dir/ Human Resources	Human Resources

Role	Name	Title	Department
	Elaine Babcock	Mgr/Division Human Resources	Human Resources
	Erin Henlin	Mgr/Division Human Resources	Human Resources
	Telma Lopez	Mgr/Diversity Programs	Human Resources
	Tammy Short	Mgr/Human Resources	Human Resources
	Fred Harvey	Dir/Compensation & Benefits	Human Resources
	Bonnie Garlin	Mgr/Compensation	Human Resources
	Jude Kikuta	Mgr/Benefits	Human Resources
	Hugh Winesett	Mgr/ Business Technology Support	Business Technology Support
	Jayanthi Bandi	Contractor/Enterprise Outcomes, Inc.	Business Technology Support
	Craig Cohen	Analyst/Systems	Business Technology Support
	Paige Ribera	Analyst II/Programmer	Business Technology Support
	Toni Sikorski	Analyst/Systems	Business Technology Support
	Aparna Tirumala	Sr Analyst/Business Tech Supp	Business Technology Support

3.2 Responsibilities

Project Sponsor

The Project Sponsor will be primarily responsible for:

- Acting as the Steering Committee and Chair the Oversight Committee
- Guiding the project's strategic direction to ensure corporate strategic alignment and executive support
- Making key financial and staffing decisions
- Communicating status, critical issues and changes to senior management and escalating issues to the Steering Committee and up to and including the CEO as required
- Issuing a Project Charter Memo to inform affected and interested departments and personnel about the start of the project
- Working with the Project Manager to establish the project organization, including Oversight and team members
- Approving the Project Charter

- Authorizing acceptance of the final deliverables of the project
- Approving changes to the project scope with commercial impact
- Approving project go/no go decisions
- Approve long term application support structure

Project Steering Committee

The Project Steering Committee will be primarily responsible for:

- Participates on the Project Steering Committee
- Providing overall project direction and vision
- Review the project scope as issues may present changes to be considered
- Providing financial oversight
- Providing direction for escalated issues
- Being an advocate for the project's outcomes, and report on the project to senior management

Project Oversight Committee / Business Process Council

The Project Oversight Committee will be primarily responsible for:

- Staffing the project team with appropriately skilled employees
- Recommending to the Project Manager issues or changes that should be escalated to the Sponsor
- Empowering and supporting decisions made by the team
- Monitoring progress and priorities
- Supporting organizational change management
- Assisting with the resolution of risks, issues, and change requests
- Providing high-level planning and coordination for the project
- Ensuring the team has everything needed to deliver successfully
- Determine long term application support structure

Senior Project Manager

The Senior Project Manager will be primarily responsible for:

- Making decisions to manage and mitigate project level risks and issues.
- Making scope change decisions recommended by the Project Manager, project teams, or vendors that are within the boundaries of established budgets.
- Making schedule change decisions that may affect major milestones but do not affect the go-live date.
- Escalating issues or changes to the Sponsor.
- Facilitating the Steering Committee meetings and Sponsor updates.
- Facilitating the Oversight Committee meetings.
- Ensuring the project is integrated with strategic direction, and corporate and external initiatives and projects.
- Managing the project relationships and stakeholders.
- Overseeing the OCM plan and progress.
- Recommending project go/no go decisions for major milestones.
- Evaluating and selecting deployment options.
- Coordinating communications
- Managing project staff and reallocating existing resources as needed to maintain the schedule.
- Managing vendor contracts and compliance.
- Reviewing project status from schedule, accomplishments, quality, and cost perspectives.
- Prioritizing critical Project tasks.
- Overseeing project activities, budgets, schedules and milestones as authorized by the Sponsor.
- Identifying Contract Administration requirements and adhering to established vendor management policies and agreements.
- Overseeing project controls.
- Communicating project progress through periodic project status meetings or reports.
- Validating post project completion and application owner responsibilities.
- Developing and assigning project roles and responsibilities.

Project Manager

The Project Manager will be primarily responsible for:

- Making decisions to manage and mitigate risks and issues.
- Managing the scope change process.
- Making schedule change decisions that do not affect other projects, major milestones or the go-live date.
- Managing project staff to maintain the schedule.
- Escalating issues to the Senior Project Manager.
- Leading daily project activities to meet project goals.
- Reviewing project status from schedule, accomplishments, quality, and cost perspectives.
- Prioritizing critical project tasks.
- Managing project activities, budgets, schedules and milestones as authorized by the Senior Project Manager.
- Identifying IS requirements and dependencies.
- Complying with Project Management Office standards and communication updates, including Brightwork Updates.
- Coordinating with Project Managers responsible for other initiatives.
- Escalating issues for resolution to the Senior Project Manager.
- Organizing and managing training and communications with the teams to accomplish tasks and produce deliverables.
- Creating and Managing the OCM Plan and progress.
- Undertaking the activities required to initiate, plan, execute, and close the project successfully.
- Developing deployment options.
- Establishing and managing project controls.
- Communicating project progress through periodic project status meetings or reports.

Project Team Members

The Project Team members will be primarily responsible for:

- Serving as principal expert in their area.

- Leading the implementation of process improvements and other related business and data changes.
- Making decisions and improvement recommendations that may impact people, process or systems as empowered by their management.
- Consulting and involving other key resources or SMEs as needed.
- Managing the scope, activities and deliverables (first line of defense against "scope creep").
- Testing of system or process changes to ensure they meet the business needs.
- Designing and delivering training (if required) to the end users.
- Communicating project status to home department and/or management.
- Recommending project go/no go decisions.

Project Subject Matter Experts

The Subject Matter Expert members will be primarily responsible for:

- Serving as expert in their functional process area.
- Participating in business process analysis including attending meetings and workshops, identifying requirements, and reviewing the design of the to-be processes, UAT test plans, and training materials.
- Assisting with implementing improvements and other related process changes in their departments.
- Consulting with and involving other key resources or SMEs as needed.
- Raising potential issues and risks to team members and project manager.
- Communicating project status to their department and/or management as appropriate.

3.3 Stakeholders

Stakeholder / Group	Stakeholder Interest
Human Resources	High
Oracle Business Support	High
Application Services	High
Payroll	High

All Employees	High

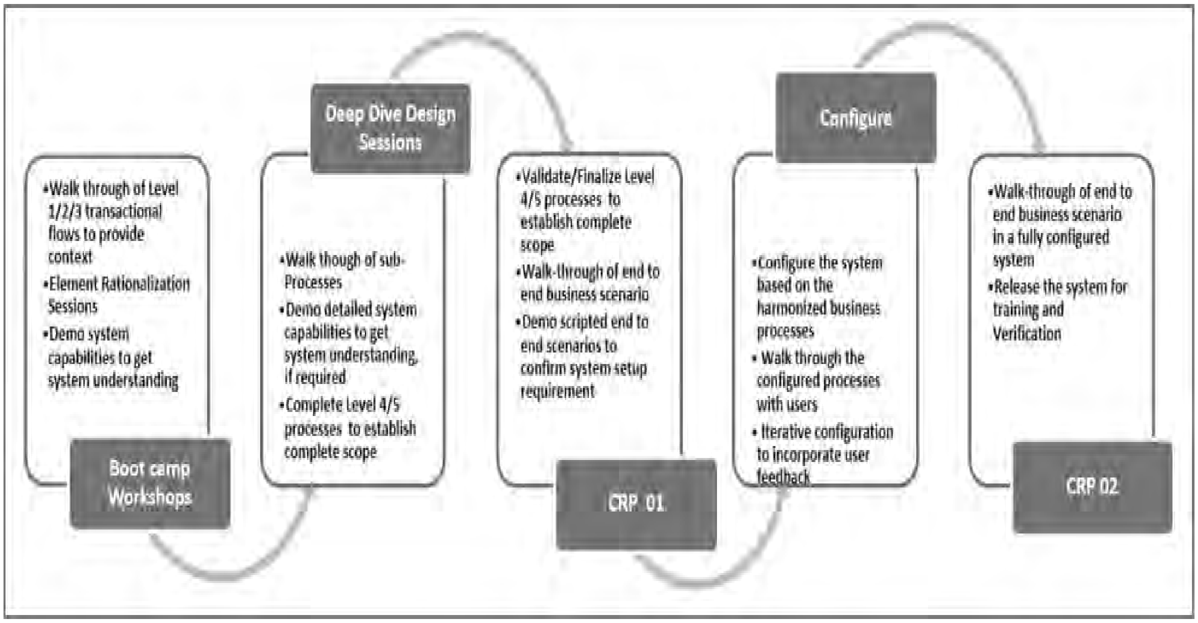
3.4 Resource Plan

SWG HCM Transform																				
Phase 1 timelines		Discover		Modelling				Realization		Deploy		Hypercare								
Phase 2 timelines													Discover	Modelling		Realization		Deploy	Hypercare	
		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	
Role	**Key Responsibilities**	**M1**	**M2**	**M3**	**M4**	**M5**	**M6**	**M7**	**M8**	**M9**	**M10**	**M11**	**M12**	**M13**	**M14**	**M15**	**M16**	**M17**	**M18**	**Total PM**
Program Manager	Plan and execute the overall Program along with Infosys Program Manager	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	**18**
Business Process Owner / Leads (BPOs) **(Phase 1)**	Overall owner of HR business processes at SWG	0.5	1.5	1	1	1	0.5	0.5	1	1	1									**9**
SMEs **(Phase 1)**	Single point of contact for implementation team and facilitate the discussions with business teams for their respective areas	0.75	1.5	1.5	1.5	1.5	0.75	0.75	1.5	1.5	1.5									**12.75**
Business Process Owner / Leads (BPOs) **(Phase 2)**	Overall owner of HR business processes at SWG	0.5	0.75										0.5	0.5	0.5	0.5	0.5	0.5	0.1	**4.35**
SMEs **(Phase 2)**	SPOC for implementation team and facilitate the discussions with business teams	0.5	0.75										0.75	0.75	0.75	0.75	0.75	0.75	0.3	**6.05**
OCM and Training	Execution of all OCM activities and End User Training	0.25	0.25	0.25	0.25	0.5	0.5	0.5	0.75	0.75	0.75		0.75	0.75	0.75	1	1	1		**10**
IT SPOC	Technical SPOC for clarifications and coordination, Participation in critical Technical Discussion	0.5	0.5	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75		0.25	0.25	0.5	0.5	0.5	0.5		**9.5**
Data Specialist	SPOC for data migration activities; Co-ordinate data collection and resolution of issues	0.25	0.25	0.25	0.25	0.25	0.25	0.5	0.5	0.5	0.5		0	0.25	0.25	0.25	0.25	0.25	0	**4.75**

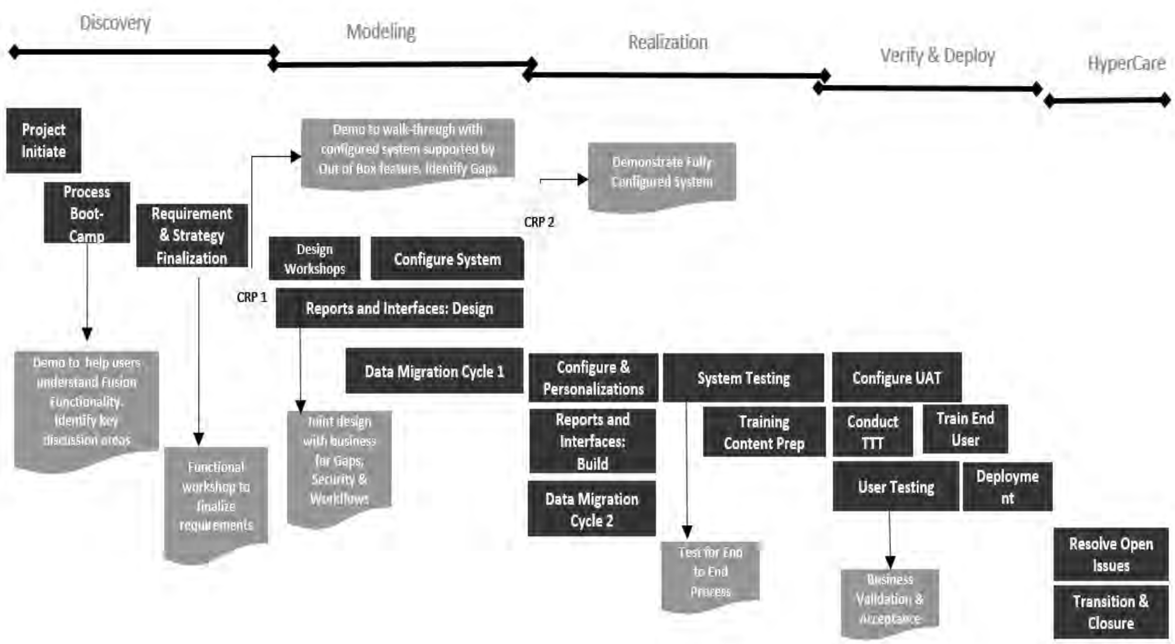
4 Implementation Plan/Project Approach

4.1 Methodology and approach (if not SWG)

Accelerated Cloud Transformation (ACT) Methodology will be used for this implementation. ACT is a unique methodology with a focus on end to end process. This methodology ensures cloud transformation happens on time and on value with highest levels of predictability and agility. This methodology provides an implementation approach that is rapid, broadly adaptive, and business-focused. This methodology is built on the top of Infosys experience of implementing cloud transformation programs using home grown process frameworks.



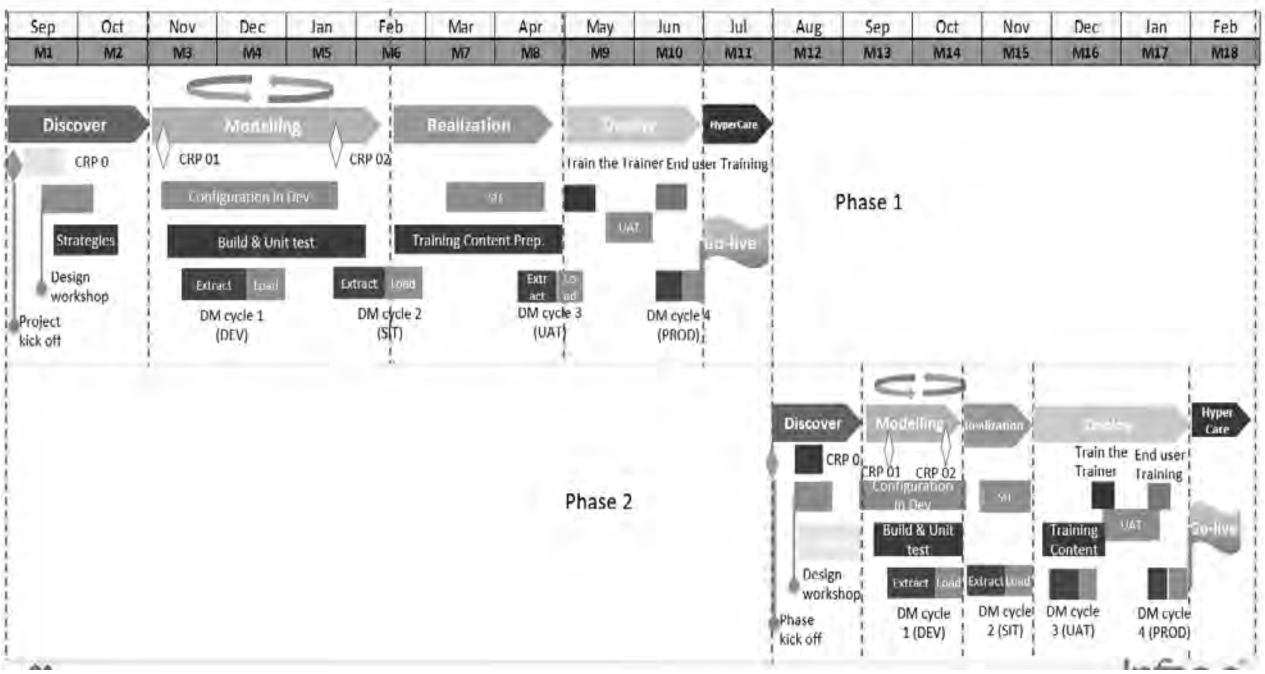
4.2 Overall Approach



4.3 Project Time Line

The implementation will be a two-phased approach to be executed in 18 months, with preliminary timeline below:

Modules Phase →	Phase 1	Phase 2
Oracle HCM Cloud Modules	• Core HR • Health and Safety • Profile Management • ESS, MSS (including Payroll Self-Service to update bank details) • Benefits • Absence Management • Recruiting and Onboarding	• Compensation • Learning Management • Succession Planning • Performance Management • Goals Management • Career Development • HR Help Desk
Phase Start Date	15 – Sep –2019	03 – Aug – 2020
Preliminary Go-Live Date	06 – Jul – 2020	01 – Feb – 2021



4.4 Milestones

Milestone	Target
Release 1 – Kick-off	November 2019
Release 1 – UAT	March 2020
Release 1 – Go Live	July 2020

Release 2 – Kick-off	September 2020
Release 2 – UAT	November 2020
Release 2 – Go Live	February 2021

4.5 Quality Plan

4.5.1 Change Management

Process	Description
Scope changes	The Sponsor is responsible for approval of changes affecting budget or overall timeline during the project.
Process/organizational change management	The Project team and Oversight Committee are responsible for process and organizational change management for the project.

4.5.2 Quality Management

Process	Description
Testing strategy	We are adopting the vendor implementation testing strategy, involving Unit testing, Integration Testing, UAT and Mock Cutover Testing.

4.5.3 Risk Management

- Conflicting priorities and resource contention with other large projects
- Resource constraints of HR team will impact participation on the project
- Resistance to change by workforce impacts adoption / solution rollout

4.5.4 Issue/Action Item/Defect Management

A list of Issues for the project will be maintained. Vendor will provide defect management process for the team to follow as part of their methodology.

4.5.5 Communication Management

Process	Description
Team Meetings	Project team will meet as needed to discuss progress, task assignments, risks, issues and any changes.

Project Oversight Committee meetings	Periodic meetings to report on key project deliverables, milestones, key discoveries and issues.
Status Reports	Distributed to project team, key stakeholders, project sponsor, oversight committees monthly.
Project Portfolio Status Report	Updated as needed for the Project Review Board

4.6 Completion Criteria

Criteria	Description
Scope	Project must have delivered the business objectives and functional scope described in this document
Deliverables	Project must have produced the deliverables specified in this document.
Acceptance	Successful completion Mock Cutovers and UAT
General	The project must have produced the deliverables within specifications.

5 Project Considerations

5.1 Assumptions

Within this project, it is assumed that:

- Scheduling conflicts with other projects in progress will not influence this project or schedule.
- Resources identified in this document will be available.
- Cooperation and support from the various departments will be provided.
- Team members are empowered by their management to make reasonable process decisions in their functional area.
- SWG management recognizes this project as a priority and will provide additional resources if necessary.

- Changes required by this project will be prioritized to meet necessary deadlines.
- Introduction of new technology will not impact application or timeline.

5.2 Constraints

Schedule has been developed based on typical human resource constraints during the peak HR resource availability.

Schedule also must consider Southwest Gas yearly holiday schedule.

5.3 Dependencies

Project /Initiative	Type	Description
OQ Badges	ITS	Employee & contractor badge management
MSS Team's Initiative	Azure	Initiative to create a solution using Azure for employees and contractors.

6 Appendix

6.1 Supporting Documentation (N/A)

Distribution and Transmission Risk Modeling Project

Business Case

Southwest Gas Corporation
Confidential & Proprietary
Date Created: April 2, 2018
Last Updated: See document control
Version: See document control

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Final Approvals

Approver Name	Title	Signature	Date
Jerry Schmitz (Sponsor)	VP/Engineering Staff	Jerry Schmitz (Jun 24, 2019)	Jun 24, 2019
Craig Sisco	Director/Engineering Staff/System Integrity	Craig S Sisco (Jun 21, 2019)	Jun 21, 2019
Ngoni Murandu	VP, Information Services/CIO	Ngoni Murandu (Jun 24, 2019)	Jun 24, 2019

1 Executive Summary

The purpose of this business case is to document the business drivers for the implementation of a Pipeline Integrity Management (PIM) solution. The PIM solution will provide Southwest Gas (SWG) with advanced capabilities to perform industry standard distribution and transmission risk modeling for its Distribution Integrity Management Program (DIMP), and its Transmission Integrity Management Program (TRIMP). The PIM solution will support risk modeling of the pipeline infrastructure using a programmatic algorithm-based methodology.

The PIM solution will be able to integrate with various engineering and environmental datasets to provide a comprehensive data analysis and risk ranking approach. The solution will support SWG's efforts to maintain compliance with industry best practices, standards, and regulations. The system will allow SWG to develop a data driven strategy for the prioritization of risks and support its pipeline monitoring schedules and replacements projects.

1.1 Opportunity

Achieve compliance through implementation of a risk modeling solution that leverages current and historical data by which to identify trends and patterns for DIMP and create an on-premise single risk modeling solution for both DIMP and TRIMP.

1.2 Anticipated Outcomes

- To implement a PIM solution that provides Southwest Gas with the ability to apply risk modeling methods that are consistent with industry best practices, standards, and regulations.
- To strengthen the risk modeling capabilities of both the SWG DIMP and TRIMP programs.
- To create a database of leak repair data drawn from legacy data sources that can be reviewed, updated, and verified to be correct by DIMP system analysts.
- To interface (linking) verified leak data with SWG ArcGIS and assign GIS mapping coordinates and work request numbers (WR#) to pipeline segments.
- To provide a new data source for PHMSA and CA GO 112F.

2 Project Overview

2.1 Project Scope

2.1.1 In Scope

- Engagement of vendor and consulting services.
- Acquisition and licensing of a Pipeline Integrity Management Solution.
- User training for the Pipeline Integrity Management Solution.
- Acquisition and licensing of ArcGIS Pipeline Referencing (APR) Software (used for Linear Referencing of Transmission pipeline).
- User training for APR software.
- Implementation of the Pipeline Integrity Management Solution for Distribution Integrity Management Program (DIMP) before the end of November 2019.
- Implementation of the Pipeline Integrity Management Solution for Transmission Integrity Management Program (TRIMP).

- Infrastructure implementation and deployment, configuration of servers and software.
- Configuration and integration of the Pipeline Integrity Management Solution into the SWG infrastructure.
- Development and implementation of a risk modeling approach that explicitly defines risk as the product of likelihood times consequence, and is consistent with industry best practices, standards, and regulations.
    - Distribution Risk Assessment Model (DRAM)
    - Keifner Risk Model
- Development of a process to generate leak rate analysis results.
- Validation testing, documentation and approval of the risk modeling approach and results.
- Architecting, design, and development of a hosted target platform for extracted SWG source data from Field Order Management System (FOMS), Work Manager and Customer CSS (DataMart).
- Integration of Above Ground Leak Data.
- Integration of Below Ground Leak Data.
- Standardization and cleansing of leak data and leak cause type descriptions.
- Linking of leak repair data and GIS data (Hybrid Model).
- Integration of leak rate history data.
- Integration of inspection data.
- Integration of material investigation data.
- Integration of damage cause data.
- Integration of maintenance data.
- Integration of cathodic protection data.
- Integration of environmental data.
- Integration of linear reference data.
- Extraction, Transformation and Loading (ETL) of SWG source data into target hosting platform.
- Interface some of the updated and verified leak data with SWG ArcGIS to map X, Y coordinates and Work Request numbers (WR#) to pipeline segments.
- Configuration of PHMSA Report Model.
- Provide new data source inputs for PHMSA and CA GO 112F reporting.
- Creation of User Guide and Tutorial.

2.1.2 Out of Scope

The following content, activities and deliverables are out of scope for this project.

- Creation of DOT PHMSA Report
- Creation of California GO 112F Report
- Interfacing or Integration with MAOP Uptime.
- All other reports not specifically defined within scope.
- Integration with any other engineering system not specifically defined within scope.

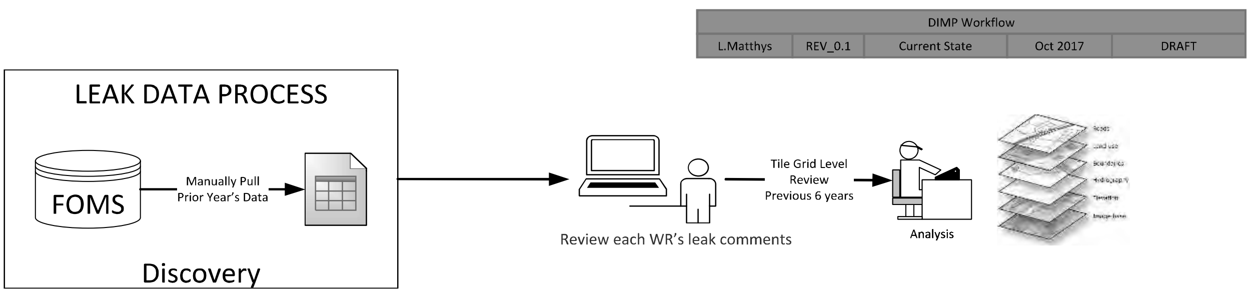
2.2 High-Level Business Requirements

The following are initial high-level business requirements:

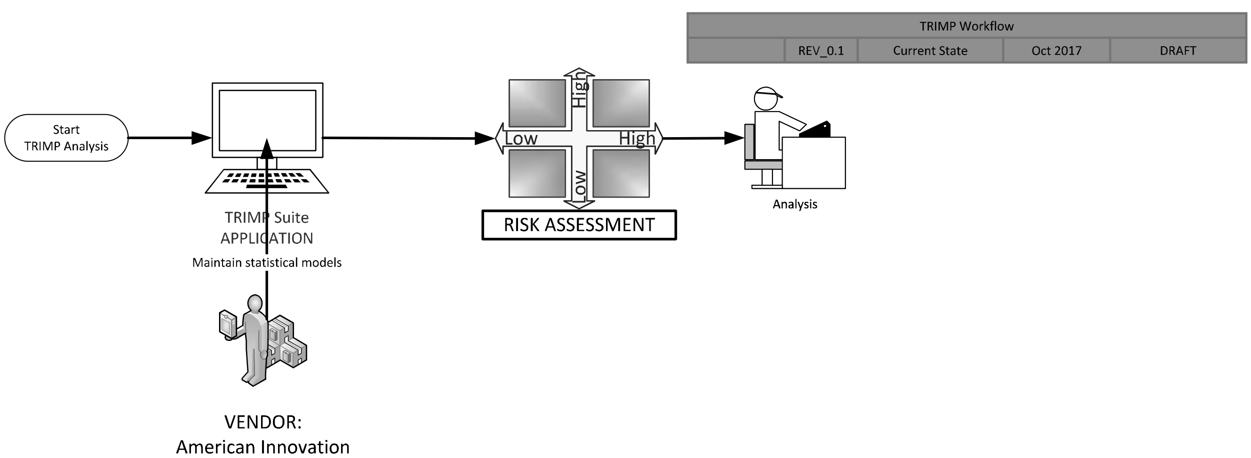
BR#	Requirement Name	Description
2.2.1	Employ risk modeling / risk assessment.	Implement a Pipeline Integrity Management solution for DIMP and TRIMP that will provide Southwest Gas with an ability to apply risk modeling methods that are consistent with industry best practices, standards, and regulations.
2.2.2	Standardize legacy leak repair data.	Create a consolidated repository for users to review, assign and update leak repair data from many legacy data sources.
2.2.3	Assign leak repair records to ArcGIS features (mains, services).	Standardize leak repair records with x, y coordinates to assign repairs to ArcGIS mains and services for determining risk probabilities.

2.3 Current State

2.3.1 DIMP Current State



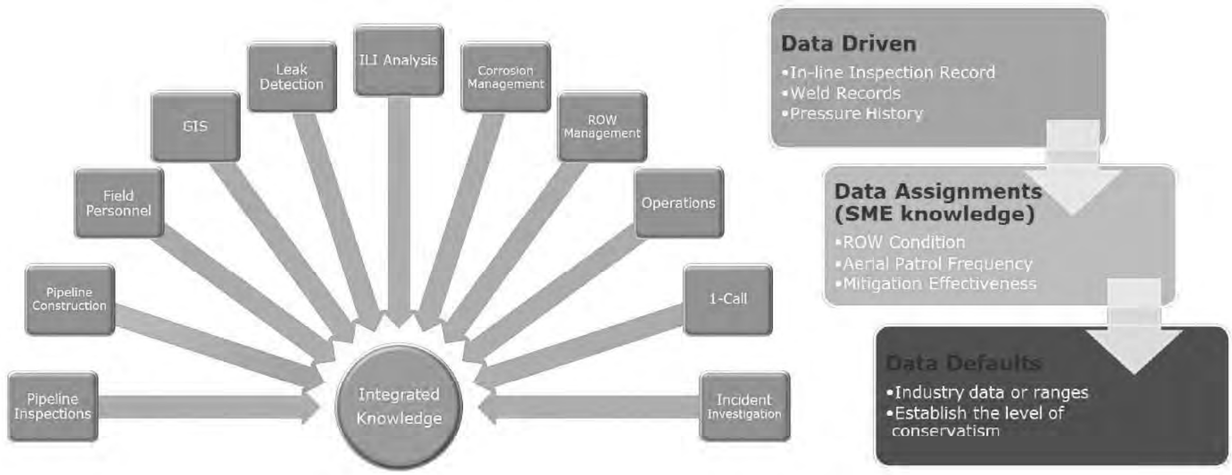
2.3.2 TRIMP Current State



DIMP does not have an algorithm-based risk model. The risk assessment process involves analyzing the most recent past calendar year of reported leak data. The process requires extensive data preparation before leak repair records can be reviewed, in order to standardize leak repair records from several legacy data sources that do not share a common data model.

TRIMP does have an algorithm-based relative risk model, however, the algorithm is maintained by American Innovation and uses SWG and third-party data sets.

2.4 Future State



The future state will integrate DIMP and TRIMP risk modeling and will give the TRIMP group the ability to maintain their current risk assessment process without the dependency of the third party.

2.5 Project Assumptions

- Subject Matter Experts will be available to define and agree functional requirements.

2.6 Project Constraints

- The DIMP solution must be implemented before the end of 2019 to meet commitments to CA and NV commissions.
- A risk modelling solution will be selected from a third-party vendor; it will not be developed in-house.

2.7 Dependencies

The following dependencies have been identified for this project:

2.7.1 System Dependencies

Data Description	Category	System Name
Below ground leak repair records.	DIMP Below Ground	SWG FOMS WM
Below ground pipe material submitted to lab.	DIMP Below Ground	SWG MID

Data Description	Category	System Name
Damage caused to above and below ground pipe that may or may not have included a release of gas.	DIMP Above and Below Ground	SWG DCD
Field dispatches to investigate reported leaks.	DIMP Above Ground	SWG CSS Dispatch Log
Call center-received reported leaks.	DIMP Above Ground	CSS
Ingests cleansed leak repair records from the database to assign leak records by x, y coordinates to ArcGIS features (mains, services) for risk modeling and risk model viewing.	DIMP Above and Below Ground	ESRI ArcMAP
Geographic Information System to visualize SWG pipeline infrastructure data. Stores ArcMAP leak records assigned to ArcGIS features in the Gas Leak Feature Class (Table). TRIMP linear referencing tool for TRIMP to measure distances to locate events along the transmission pipeline.	DIMP Above and Below Ground	ESRI ArcGIS
TRIMP 3rd party supported solution – will be replaced by COTS solution.	TRIMP	American Innovations TRIMP Suite with linear referencing Pickup Sticks

2.8 Project Risks

Risk	Probability	Mitigation
If implementation of a solution for DIMP is late, there may be regulatory consequences	Medium	Ensure the project is assign appropriate priority.
Data cleansing of historical leak data may be difficult	High	Focus on data cleansing early in the project, identify challenges, define options and solutions and implement in a timely manner.

Risk	Probability	Mitigation
The appropriate resources may not be able to provide the required level of effort to meet the target implementation dates.	High	Focus on key critical activities first. Modify dates as needed.

2.9 Timeline

The project will start in November 2017. The DIMP solution will be implemented before the end of 2019. The TRIMP solution will be implemented earlier.

2.10 Project Stakeholders

The following individuals have been identified as Responsible, Accountable, Consulted, and Informed (RACI) in eliciting the high-level business needs and requirements. These individuals are subject to change during the duration of the project.

Role	Name	Title	Department	RACI
Sponsor	Jerry Schmitz	VP/Engineering Staff	Engineering Staff	A, I
Steering	Brad Harris	VP CA and Northern NV Division	Division Operations	I
	Ngoni Murandu	VP Information Services/CIO	Information Services	I
	Chris Sohus	VP Southern NV Division	Division Operations	I
	Frank Stanbrough	VP Risk Management and Compliance	Risk Management	I
Oversight	Brad Anderson	Corporate Risk Manager	Risk Management	C
	Chris Anderson	Dir. Gas Operations Paiute	Engineering	C
	Ken Briggs	Dir. Application Services	Application Services	C
	Tom Cardin	Dir. Gas Operations SNV	Division Operations	C
	Michael Chase	General Manager Operations CAZ	Division Operations	C
	Craig Sisco	Dir. Engineering Staff/System Integrity	System Integrity	A, C

Role	Name	Title	Department	RACI
SMEs	Mary Bartholomew	Manager Engineering Staff	System Integrity	C
	Joel Martell	Manager Engineering Staff	System Integrity	C
Project Team	TBD			

3 Cost Benefit Analysis

3.1 Budget Overview

Description	Period (Execution)	Budget Type	Estimation
Implementation Services	2018 – 2019	Capital	$857,500
Software Licenses	2018	Capital	$127,500
Software Maintenance (Yr1)	2019 – 2020	O&M	$24,375
Training	2019	O&M	$50,000
Extended Support	2019 – 2020	O&M	$66,300
Contingency	2017 – 2019	Capital	$100,000
		Total	**$1,225,675.00**

3.2 Intangible Benefits

- The project will implement a standard approach for risk modelling for DIMP and TRIMP.
- The project will select an industry standard tool (Commercial Off the Shelf Solution – COTS) that supports industry standard practices for risk modelling.
- The use of a COTS will ensure that tools and practices remain current as industry standards and technology advance.
- Use of a COTS will leverage knowledge across the utility industry, as captured in the tool by the selected vendor.
- The project will develop and implement new internal tools and practices to consolidate, clean, and maintain leak related data.
- The selected COTS will interface with the existing GIS solution to provide graphical representation of risk modelling results, providing rapid insight into risks.

4 Conclusions and Recommendations

4.1 Recommendation

A third-party vendor will be selected to implement a COTS solution to address the business problem.

4.2 Alternative Solutions

The following alternatives were considered:

Alternative Solution	Description	Reason for Not Selecting
Continue to use the existing solutions.	Solutions are in place currently	Some state pipeline safety staff have expressed concerns about the SWG existing system. The existing TRIMP solution is dated, requires external skills to support, and those skills are in limited supply. At some point in the future, they will no longer be available.
Internal Project	Develop solutions internally to replace the current ones.	Complex functionality would need to be developed. Ongoing support and maintenance costs will be significant and difficult to forecast. Integrating an internal solution that could provide rich graphical analysis with GIS would be extremely costly and difficult. Maintaining currency with industry developments, best practices and federal and state requirements would be costly and complex.

4.3 Justification

- The project will address the concerns raised by the California, Arizona and Nevada Integrity Management Program Audit in October 2016.
- Benefits in compliance, effectiveness, and efficiency will be realized from the use of an off the shelf solution for the implementation and on-going management of risk modelling for both TRIMP and DIMP.

Appendix A: References

The following table summarizes the documents referenced in this document.

Document Name	Description	Location
Project Brief - Distribution and Transmission Integrity	Project brief submitted to Project Review Board; represents initial project request.	Project Brief

Business Case - DIMP - TRIMP Risk Modeling Project

Final Audit Report 2019-06-24

Created:	2019-06-20
By:	Andrew Hartnett (Andrew.Hartnett@swgas.com)
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"Business Case - DIMP - TRIMP Risk Modeling Project" History

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2019-06-24 - 8:04:37 PM GMT

MEMORANDUM

To: Jerry Schmitz, VP Engineering Staff

Joel Martell, Mgr/Engineering Staff

Mary Bartholomew, Mgr/Engineering Staff

From: **Karen O'Dell,** Project Manager

Date: January 21, 2021

Subject: DIMP & TRIMP Risk Modeling Project Closure Memo

The DIMP & TRIMP Risk Modeling Project was initiated the first quarter of 2018 and implemented into Production on December 31, 2020.

The objectives of the project were to design, purchase and deploy the Synergi Pipeline application in order to provide the following benefits for the Company:

- Implement a Pipeline Integrity Management solution to provide Southwest Gas (SWG) with an ability to apply risk modeling methods that are consistent with industry best practices, standards and regulations
- Strengthen the risk modeling capabilities of both SWG DIMP and TRIMP programs
- Create a repository of leak data drawn from legacy data sources that becomes a new source of truth for SWG leak repairs after it has been reviewed, updated and verified by DIMP analysts.
- Link verified leak data with SWG ArcGIS
- Replace the current TRIMP Suite solution

The project met these objectives by:

- Configuring, testing and implementing the Synergi Pipeline application for both DIMP and TRIMP
- Developing, testing and implementing a Leak Analysis Data System (LADS)
- Developing, testing and implementing a LADS GIS Interface
- Configuring, installing and testing the Synergi Pipeline HCA application

- Creating and configuring a combination of ArcPro, ArcMap and HCA for TRIMP

It was agreed to defer the following items to post Go-Live and responsibility will be transferred to the project's Business Owner or delegate(s) for completion:

1. DIMP calibration of the Production environment
2. Fieldsmart and posting standards updates
3. GIS Reporting Dashboard for unrelated leaks
4. Create calculation for DIMP corrosion on plastic (riser connections)
5. HCA web view fix and ini configuration updates
6. Demo of production solution to compliance and governance

This memo signifies the completion of the DIMP & TRIMP Risk Modeling Project for Southwest Gas Corporation. Signatures below indicate acceptance of the project deliverables and post Go-Live action items.

Project Sponsor

Jerry Schmitz (Jan 22, 2021 11:48 PST)

Jerry Schmitz
VP/Engineering Staff

Business Owners

Joel Martell

Joel Martell
Mgr/Engineering Staff

Mary Bartholomew (Jan 22, 2021 11:40 PST)

Mary Bartholomew
Mgr/Engineering Staff

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Ken Briggs
Chris Anderson
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Reagan Monroe
Robin Pierce
Craig Sisco

Team cc:

Jason Anderson

Page 3

Lauren Basham
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Craig Ferris
Shadreh Gilliam
Dina Lewis
Patrick Lunn
Joel Martell
Lumi Matthys
Paul McNeff
Howard Norton
Roger Ragoonanan
Luke Thornton
Paul Torregrossa
Alexandra Washburn
Steven Sung
Karen O'Dell

DIMP and TRIMP Risk Modeling Project Closure Memo

Final Audit Report 2021-01-25

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Document e-signed by Joel Martell (joel.martell@swgas.com)
Signature Date: 2021-01-25 - 3:57:05 PM GMT - Time Source: server- IP address: 167.207.140.101

Agreement completed.

2021-01-25 - 3:57:05 PM GMT

AFFIRMATION

STATE OF NEVADA)

: ss.

COUNTY OF CLARK)

Raied Stanley being first duly sworn, deposes and says:

That I am the person identified in the Prepared Direct Testimony, and the exhibits applicable to my testimony; that such testimony and exhibits were prepared by me or under my direction; that the answers and information set forth therein are true to the best of my own knowledge and belief.

Raied Stanley

Signed and sworn to before me on this 24th day of August, 2021.

Notary Public

NOTARY PUBLIC
STATE OF NEVADA
County of Clark
STELLA MENESES
Appt. No. 99-51091-1
My Appt. Expires Dec. 8, 2022