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DOUG LITTLE –CHAIRMAN
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BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS.

DOCKET NO. G-01551A-16-0107

STAFF'S NOTICE OF FILING DIRECT TESTIMONIES

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimonies of Brian K. Bozzo, Blessing N. Chukwu, Yue "Nick" Liu, Kirk S. Balcom, Howard E. Lubow, Julie McNeely-Kirwan, Alan Borne, and Ranelle Paladino, *(except that related to rate-design)* in the above-referenced matter.

RESPECTFULLY SUBMITTED this 30th day of November, 2016.

Charles H. Hains
Robert Geake
Attorneys, Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

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On this 30th day of November, 2016, the foregoing document was filed with Docket Control as an Utilities Division Pre-Filed Testimony, and copies of the foregoing were mailed on behalf of the Utilities Division to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

Catherine M Mazzeo
SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193
catherine.mazzeo@swgas.com
matt.derr@swgas.com
Consented to Service by Email

Michael Patten
SNELL & WILMER, LLP
One Arizona Center
400 East Van Buren Street
Phoenix, Arizona 85004

Gary Yaquinto
ARIZONA INVESTMENT COUNCIL
2100 North Central Avenue, Suite 210
Phoenix, Arizona 85004
gyaquinto@arizonaic.org
Consented to Service by Email

Daniel Pozefsky
RUCO
1110 West Washington, Suite 220
Phoenix, Arizona 85007

Meghan H. Grabel
OSBORN MALADON, PA
2929 North Central Avenue Suite 2100
Phoenix, Arizona 85012
mgrabel@omlaw.com
Consented to Service by Email

Craig A. Marks
CRAIG A. MARKS, PLC
10645 North Tatum Blvd.
Suite 200-676
Phoenix, Arizona 85028
craig.marks@azbar.org
TDickey@vmiholdings.com
Consented to Service by Email

Richard Gayer
526 West Wilshire Drive
Phoenix, Arizona 85003
rgayer@cox.net
Consented to Service by Email

Cynthia Zwick
ARIZONA COMMUNITY ACTION ASSOCIATION
2700 North Third Street - 3040
Phoenix, Arizona 85004

Janet Wagner, Interim Chief Counsel
Legal Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Jeffrey Hatch-Miller, Interim Director
Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Jeffrey Crockett
CROCKETT LAW GROUP, PLLC
2198 East Camelback Road, Suite 305
Phoenix, Arizona 85016
jeff@jeffcrockettlaw.com
Consented to Service by Email

Bob Miller
PROPERTY OWNERS AND RESIDENTS ASSOCIATION
13815 Camino del Sol
Sun City West, Arizona 85375
Bob.miller@porascw.org
Rob.robbins@porascw.org
Consented to Service by Email

By: Roseann Osorio
Roseann Osorio
Executive Legal Assistant

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
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IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS	DOCKET NO. G-01551A-16-0107

DIRECT

TESTIMONY

OF

BRIAN K. BOZZO

ADMINISTRATIVE SERVICES OFFICER II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 30, 2016

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

Southwest Gas Corporation ("Southwest" or "Company") is engaged in providing natural gas service within portions of Arizona pursuant to authority granted by the Arizona Corporation Commission ("Commission" or "ACC"). Southwest serves approximately one million customers in the counties of Gila, La Paz, Cochise, Graham, Maricopa, Pima, Greenlee, Mohave, Pinal and Yuma, Arizona. Of these customers, approximately 990,000 are Residential while 40,000 are Commercial. Southwest also serves a smaller number of Industrial, Irrigation and Transportation customers.

On May 2, 2016, Southwest docketed a rate case application with the Commission for the establishment of just and reasonable rates and charges. The application utilizes a test year consisting of the 12 months ended November 30, 2015. The Company seeks a total rate increase of \$31,926,894 over its adjusted test year revenues of \$481,681,406 for a total revenue requirement of \$513,608,300. The Company's requested rate increase results in an operating income of \$108,844,799 or a 6.01 percent rate of return on its adjusted Fair Value Rate Base ("FVRB") of \$1,812,414,667.

Staff recommends a total rate increase of \$11,318,939 over its adjusted test year revenues of \$481,681,406 for a total revenue requirement of \$493,000,345. Staff's requested rate increase results in an operating income of \$100,967,708 or a 5.61 percent rate of return on its adjusted Fair Value Rate Base ("FVRB") of \$1,801,065,079.

Mr. Bozzo's direct testimony addresses Staff recommendations covering revenues, expenses, revenue requirement and compliance requirement.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Brian K. Bozzo. I am an Administrative Services Officer in the Utilities Division of the Arizona Corporation Commission ("Commission" or "ACC") located at 1200 West Washington, Phoenix Arizona.

Q. Please identify your current position in the Utilities Division.

A. I am currently assigned in the Utilities Division Revenue Requirements and Audits ("RRA") section as an Administrative Services Officer II. The RRA Section investigates regulatory and utility issues and is responsible for conducting audits of rate change request filings, preparing economic analysis in the preparation of financial and statistical reports, formulating recommendations, and developing testimony and evidence in the disposition of Commission proceedings dealing with utility applications and services.

Q. Have you ever testified before the Commission?

A. Yes.

Q. Please describe the typical duties associated with your position.

A. I perform financial analysis, conduct audits of utility books and records, determine revenue requirements, and develop rate design recommendations for complex regulatory matters. This includes making pro forma adjustments to rate base and operating expenses, developing rate schedules and calculating net incomes and resulting rates of return. I have also composed numerous staff reports, prepared direct and surrebuttal testimony encompassing recommendations to the Commission and served as a Staff witness in various types of utility rate hearings.

Q. Please provide a brief summary of your educational background.

A. I attended the University of Arizona in Tucson, Arizona. In 1993, I received my Bachelor of Science degree in Business Administration with a major in General Business. The General Business program centered on the primary areas of business administration.

Q. What is the purpose of this testimony?

A. The purpose of my testimony is to present Staff's recommendations regarding the revenue, expense, pro forma adjustments and revenue requirement amounts proposed by Southwest.

II. BACKGROUND

Q. Has Southwest filed an application for an increase in its current rates and charges?

A. Yes. On May 2, 2016, Southwest docketed a rate case application which was based on a revenue deficiency of $31.9 million. The Company's current rates and charges were approved by the Commission in Decision No. 72723, based on a test year ended June 30, 2010.

Q. Please provide relevant background information included in the current rate application.

A. Southwest operates as a public utility subject to the jurisdiction of the Commission and pursuant to Article XV of the Arizona Constitution and Title 40 of the Arizona Revised Statutes ("A.R.S."). The Company is engaged in the retail distribution, transportation and sale of natural gas for domestic, commercial, agricultural and industrial uses. Southwest currently serves approximately 1.9 million customers in Arizona, California and Nevada. Approximately 54 percent of the Company's customers are located in the State of Arizona, including portions of Cochise, Gila, Graham, Greenlee, La Paz, Maricopa, Mohave, Pima, Pinal and Yuma counties. For operational purposes, Southwest's central Arizona division headquarters are in Phoenix and its southern Arizona division headquarters are in Tucson.

III. REVENUE REQUIREMENT

Q. Does your testimony address the overall revenue requirement proposed by Southwest under original cost rate base ("OCRB")?

A. Yes. However, Southwest also utilized a fair value rate base ("FVRB") which is derived as the simple average of OCRB and its reconstruction cost new depreciation ("RCND") Rate Base.

Q. What revenue increase is the Company seeking under OCRB?

A. Southwest proposes an overall increase in base revenue of $31,926,895, or an approximate 6.63 percent increase, based on current adjusted base revenues of $481,681,406. The Company's total operating revenue including the proposed increase is $513,608,300. These amounts are shown on Company Schedule A-1, Sheet 2 of 3, Line 3 of the Company's application.

Q. What revenue increase is Staff recommending under fair value rate of return ("FVROR")?

A. Staff recommends an overall increase in base revenue of $11,318,939 on adjusted fair value rate base using Staff Witness Liu's fair value rate of return ("FVROR") recommendation. As shown on Schedule BKB-1, Staff's jurisdictional revenue deficiency is $11,318,939. On adjusted fair value rate base ("FVRB") and utilizing Staff's recommended fair value rate of return of 5.61 percent. Please see the written testimony of Mr. Liu for details on the determination of FVROR.

A. Company Selected Test Year

Q. What is the test year as it applies to a utility rate case approval request filing?

A. The test year is an assemblage of costs relating to investment and operations from a specific, recent 12 month period of Company operations. The ACC uses a historical test year concept and therefore bases rate case analysis on historical operating information. However, the historical costs serve only as the base foundation for the rate case information and are often modified by the use of pro forma adjustments which either increase or decrease the level of the historic costs. In this way, actual operating results are updated to represent going forward cost levels and thereby determine rates that are applied to future periods.

Q. What test year is Southwest utilizing in this proceeding?

A. The Company's rate application utilizes a historic test year ending November 30, 2015.

Q. Has the Company provided any information on the selection of the test year?

A. Yes. Company witness Cunningham's testimony at page 3, line 1 indicates that per the Settlement Agreement in Decision No. 72723, the Company agreed to file a rate case application "no earlier" than November 30, 2015. She further stated that "since the Company determined that a revenue deficiency existed at this date, the test year in the GRC is the twelve months ended November 30, 2015". Staff has accepted the Company selection of the November 30, 2015 ending test year.

B. Summary of Company Proposed and Staff Adjusted Revenue Requirement

Q. Please provide a brief summary of your conclusions on revenue requirement.

A. The Company's request for revenue requirement is higher than the recommendation of Staff. Staff has calculated a jurisdictional base rate revenue requirement deficiency on FVRB of $11,318,939 million as opposed to the $31,926,894 million requested by the Company.

Q. How was Staff's revenue requirement deficiency calculated?

A. Staff's revenue requirement deficiency and the overall revenue requirement recommendation are based on the combination of my adjustments to operating income, Staff Witness Chukwu's adjustments to rate base, the 5.61 percent FVROR recommendation of Mr. Liu, and recommendations made by Staff Witness Balcom of Overland Consulting. The impact of these recommendations can be seen on Staff schedule BKB-1.

C. Staff Accounting Schedules

Q. How are Staff's accounting schedules organized for your testimony?

A. The accounting schedules formulated by Staff are attached to this written testimony and are organized into both summary schedules and individual adjustment schedules. The areas covered in my testimony are the revenue requirement and operating income sections. The summary schedules sponsored in my testimony include Schedule BKB-1 – Revenue Requirement, Schedule BKB-2 – Gross Revenue Conversion Factor, Schedule BKB-10 – Operating Income Statement and BKB-11 – Income Statement Adjustments. I also sponsor income statement adjustments on Schedule BKB-12 through BKB-19. These adjustments are for costs related to the Management Incentive Program ("MIP"), Restricted Stock/Unit Plan ("RSUP"), Supplemental Executive Retirement Plan ("SERP"), Director's and Officer's Liability Insurance ("D&O Insurance"), Employee Vehicles, Self-Insurance Expense, Rate Case Expense, Investor Relations Expense, Income Tax Expense, Depreciation Expense and Property Tax Expense.

Q. Does your testimony sponsor schedules/recommendations regarding Rate Base or Cost of Capital?

A. No. Staff's schedules do include the rate base adjustment schedules of Ms. Chukwu and the cost of capital schedules of Mr. Liu. But these sections are not explained as part of my assignment in this case. Please see their testimonies for details of the accounting schedules and overall recommendations in the Rate Base and Cost of Capital areas.

Q. What is shown on Schedule BKB-1?

A. Schedule BKB-1 presents a summary encompassing Staff's recommended adjustments for this rate case. This schedule identifies the revenue requirement increase needed for the Company to achieve the recommended rate of return on Staff's proposed FVRB. The operating income amounts are taken from Schedule BKB-10. The Rate Base and Cost of Capital amounts are taken from the testimonies and schedules of Ms. Chukwu and Mr. Liu.

Q. How is Staff's revenue requirement calculated on Schedule BKB-1?

A. The schedule begins with the adjusted rate base, adjusted operating income and rate of return amounts shown on lines 1, 2 and 3 of the individual columns. Multiplying the amount on lines 1 and 4 provides the required operating income amounts shown on line 5. The operating income deficiency on line 6 is the result of subtracting the adjusted operating income amount on line 2 from the required operating income amount on line 5. The operating income deficiency amount on line 6 is then multiplied by the gross revenue conversion factor ("GRCF") on line 7 to determine the required revenue increase as shown on line 8.

Q. Does Staff agree with the GRCF proposed by the Company?

A. No. The Company proposed a GRCF of 1.6329. As shown on Schedule BKB-1, Staff recommends a GRCF of 1.6226.

D. Return on Fair Value Rate Base

Q. How was Southwest's FVRB determined?

A. The FVRB is determined by averaging the OCRB and the RCND.

Q. How did Southwest determine the rate of return to apply to FVRB in its filing?

A. The Company applied its proposed FVROR to its adjusted FVRB. This can be seen on Staff Schedule BKB-1, Line 8, Column A. As shown in column A, Southwest calculated an operating income deficiency of $19,551,763 and an overall increase in gross revenue requirements of $31,926,894.

Q. How was Staff's fair value rate base determined?

A. Staff's FVRB is also determined by averaging the OCRB and the RCND.

Q. How did Staff determine the rate of return to apply to FVRB in its filing?

A. Staff applied its proposed FVROR to its adjusted FVRB. This can be seen on Staff Schedule BKB-1, Line 8, Column B. As shown in column B, Staff calculated an operating income deficiency of $6,975,804 and an overall increase in gross revenue requirements of $11,318,939.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please explain how Staff presents its proposed adjustments to operating income.

A. Staff's schedules include Staff Schedule BKB-10 which is titled the "Operating Income Statement – Test Year and Staff Recommended" schedule. This schedule summarizes the revenue, expenses and net operating income recommended by Staff. Staff Schedule BKB-11 presents the detail to those individual adjustments that compose the summarized information on BKB-10. Southwest proposes an adjusted test year net operating income of $89,293,036. Staff recommends an adjusted test year net operating income of $93,991,904, Staff's adjusted current net operating income is $4,698,869 greater than that proposed by the Company. The following section of my testimony provides Staff's discussion of its recommended adjustments to operating income. These adjustments are discussed in the order in which they appear on Staff Schedule BKB-11.

C-1 Management Incentive Plan Expense

Q. Please explain Staff Adjustment C-1 to Management Incentive Plan ("MIP") expense.

A. Staff's adjustment to MIP expense continues the sharing of expense between ratepayers and shareholders. It recognizes the benefits and effects of incentive goal management and considers that both ratepayers and shareholders stand to gain from increases in efficiency and improved performance. As shown on Staff Schedule C-1, Staff recommends that the MIP expense be reduced by $974,781 to recognize the allocation of 20 percent of this expense to shareholders.

Q. Provide a brief explanation of the term MIP.

A. On Page 5, Line 7 of Company witness Holmen's testimony, he describes the Company's MIP as follows:

> "The MIP is an annual incentive program that provides Executives and other participating employees with an opportunity to receive variable, at-risk pay based upon the achievement of specific benchmarks that are critical to the short-term and long-term success of the Company and that reward superior performance for the Company's customers."

Q. Did Southwest have incentive compensation plans in place during the Test Year?

A. Yes. The Company had both a MIP and a Restricted Stock/Unit Plan ("RSUP") in effect during the test year.

Q. Did Staff issue discovery seeking details of the MIP?

A. Yes. The Company's response to data request Staff 2-031 provides the following detail information on the MIP:

> "The Management Incentive Plan ("MIP") provides variable at-risk compensation to executives and upper level management based upon the achievement of specific benchmarks vital to the Company's short and long-term success. The MIP provides a direct link between executive and employee compensation and customer service, and incentivizes management

> to operate the Company in an efficient manner that minimizes customer rates which maximizing customer satisfaction and safety.
>
> The MIP is at-risk each year based on performance relative to four measures: customer satisfaction, customer-to-employee ratio, return on equity ("ROE") and operating costs each contributing 25 percent toward the total award for the year. For plan year 2015, two additional measures were added for safety, which underscore the Company's emphasis in this area: damages per 1,000 tickets and incident response time. The four existing measures were weighted at 20 percent with the two new safety measures weighted at 10 percent each.
>
> Historically, forty percent of the total earned under the MIP was paid in cash immediately following the financial close of the most recent calendar year. The remaining 60 percent was issued as performance shares and vested three years in the future. For plan year 2015, the cash portion of the MIP increased from 40 to 60 percent of the total earned, with the remaining 40 percent issued as performance shares, vesting three years in the future. The longer-term performance shares act as a retention tool while aligning the interests of customers, Southwest Gas management, and shareholders for continued financial and customer oriented performance."

Q. Has the Company provided data response information from a prior case detailing and defining each performance measure that serves as a goal of the MIP?

A. Yes. The Company described the nature of each measure in response to data request STF-6-1:

> "The MIP is variable compensation at-risk each year based on the performance relative to four measures that define the goals and benchmarks of the MIP, all designed to align the interests of customers, SWG management and shareholders. The measures are: (1) customer satisfaction; (2) customer-to employee ratio; (3) return on equity; and (4) operating costs.
>
> **Customer Satisfaction**
>
> The customer satisfaction performance measure is a standard measure of performance in the utility industry and SWG is an industry leader in this area. SWG routinely performs in the low-to-mid 90's under this metric. Performance is currently measured monthly by an independent third-party, and the process is periodically audited by the SWG Internal Audit department. The target for this measure is set at 85 percent and is measured individually for each SWG operating division. This measure is a direct representation of the quality and efficiency of the service provided to SWG customers.
>
> The customer satisfaction metric measures the quality, efficiency and reliability of service provided to SWG customers by capturing satisfaction levels of customers following recent contact with SWG. The goal of this metric is to maintain and enhance the customer experience by developing a solid service relationship upon which customers can depend. The

information collected through the tracking program provides management with a tool to improve customer satisfaction and provides awareness of areas which may need attention while further solidifying an efficient and dependable customer service relationship.

Customer-to-Employee Ratio

The customer-to-employee ratio performance measure compares the actual prior year customer-to-employee ratio to an established benchmark. This is a standard productivity measure in the utility industry. Labor costs plus loadings represent nearly two-thirds of SWGs' total operations and maintenance expense. The SWG customer-to-employee ratio has shown consistent improvement during the past 10 years.

The customer-to-employee ratio illustrates a company's ability to operate efficiently. Therefore, a favorable customer-to-employee ratio indicates that a company is achieving increased efficiencies while at the same time controlling labor costs. The executive management team at SWG takes a hands-on approach to managing employee headcount, which includes reduction through attrition, detailed reviews of position requests and challenging employees to develop and embrace change (including technological advances) that yields higher productivity.

Return of Equity (ROE)

The ROE performance measure considers the authorized weighted average ROE of the returns utilized to establish rates in each of the regulatory jurisdictions in which SWG operates and is theoretically the ROE that SWG should be able to achieve on a company-wide basis. Over the last 10 years, SWG has experienced an actual average ROE of 6.9 percent, compared to an average authorized weighted average ROE of 10.8 percent for the same period. The target for this measure represents 80 percent of the Company-wide authorized weighted-average ROE.

ROE is the total measure of SWG's performance and annually measures SWG's ability to manage costs. Indeed, SWG must judiciously manage costs in order to maximize earnings (ROE), which, in turn, benefits customers by minimizing rate increases.

Operating Costs

The operating costs performance measure quantifies management effectiveness in controlling operation and maintenance costs. The use of the rolling 10-year average used in prior years was replaced with a target that reflects estimated inflation and a growth factor. The inflation factor is determined by the Blue Chip Economic Indicators publication and the growth factor is based on customer growth.

As previously noted, the operating costs performance measure quantifies management effectiveness in controlling operating costs. The target for this

> measure is based on productivity efficiencies and is dependent upon management to act prudently to support cost containment, which, in turn, benefits customers by providing a reasonable cost of service."

Q. What changes were made in the MIP since the prior case?

A. The testimony of Company witness Holmen indicates that Southwest has modified the MIP from the prior rate case. The Company has included new Safety and Construction Development performance measures to the plan. The new Safety measure is meant to measure success in "minimizing damages per 1,000 tickets and incident response time" and applies to all plan participants. And a sixth metric has been added which specifically applies to three executives only (the Company's President/CEO, the CFO and its SVP, Corporate Development). This measure is connected to Southwest's non-regulated construction services sector. In 2015, Southwest also began paying 60 percent of the MIP award in cash while the remaining 40 percent is paid in performance shares as restricted stock units.

Q. Are the current MIP performance measures composed of the four existing measures in place prior to the test year and the new Safety measure that was recently added to the MIP plan?

A. Yes. Southwest's broad based MIP has five performance measures in place at this time, the Customer Satisfaction metric, the Customer-to-Employee Ratio, Safety, Operating Cost Containment and Return on Equity ("ROE"). Prior to the test year, the former MIP consisted of those measures with the exclusion of the Safety metric. The five current measures, including the Safety metric, are the Southwest MIP performance measures that will be in effect on a going forward basis. On page 20-22 of Company witness Holmen's direct testimony, the Company outlines that four of the five performance measures provide a "direct benefit" to customer/ratepayers and further identifies that the Customer Satisfaction measure is "explicitly tied to customer satisfaction" and so benefits ratepayers.

Q. What is the historic rationale for allocating a portion of Southwest's MIP expenses to shareholders?

A. Incentive compensation programs are structured to provide benefits to both shareholders of the organization and the ratepayers that receive utility service. The historic removal of 50 percent of the MIP expense constituted an equal sharing of the cost associated with generating these benefits and was meant to provide a balance between the benefits attained by both shareholder and ratepayer interests. Both shareholders and ratepayers stand to benefit from the achievement of performance goals.

Q. What Southwest employees are eligible for MIP award?

A. According to Southwest's response to Staff DR 2-031, the positons eligible to receive a MIP award are as follows:

<u>**Position**</u>
CEO
President
Executive VP
Senior VP
Vice President
Non-Officers
Director/Senior Manager
Key Management Employees

Q. Has the Company provided data response information showing that MIP performance measures were designed to address interests of both customers and shareholders?

A. Yes. This information was addressed in Southwest's prior case (Docket No. G-01551A-10-0458) and that information is outlined in above question about "detailing and defining" the performance measures. The introductory section of that response provides the following:

> "The MIP is variable compensation at-risk each year based on the performance relative to four measures that define the goals and benchmarks

> of the MIP, all designed to align the interests of customers, SWG management and shareholders. The measures are: (1) customer satisfaction; (2) customer-to employee ratio; (3) return on equity; and (4) operating costs."

Additionally, in the prior case (Docket No. G-01551A-10-0458), Southwest's response to Staff DR 11-10(a) stated the following on the purpose of the historic performance measures:

> "… the mix of performance measures and their respective targets are designed to address the interests of both customers and shareholders through the Company's financial performance, increased productivity and customer satisfaction."

Q. Did Decision No. 71914 include a Commission a decision on allocating a percent of incentive compensation cost to shareholders?

A. Yes. The Commission provided the following at Page 28, line 19.

> "We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area. Therefore, consistent with the recent cases cited above, we will adopt the recommendation of Staff and RUCO on this issue …"

Q. Has the Commission issued a recent rate decision that resulted in a different outcome on the MIP than that in Decision No. 71914?

A. Yes. In Docket No. WS-01303A-14-0010 and Decision No. 75268 (dated September 8, 2015) for EPCOR Water Arizona, Inc. ("EPCOR"), the Commission made the following conclusions as shown on Page 31, Line 16:

> "Staff recommends reducing EPCOR's request for incentive compensation by 50 percent, stating the compensation programs should be borne by both shareholders and ratepayers as each group benefits. (Ex. S-13, at 7-8.)"

> "The real issue in evaluating incentive compensation is whether total compensation, including the incentive pay, is reasonable. If overall compensation for employees is reasonable, it should be allowed assuming the allocation methods are reasonable …"

> "The evidence in the record does not indicate that the overall compensation requested by EPCOR is excessive or unreasonable. Rather, Staff and RUCO argue that placing a label of "incentive" on a portion of total wages is sufficient to require the disallowance of some or all of that compensation. We believe that the Company's compensation request is reasonable with the removal of the 10 percent of pay tied to the Company's financial performance. We therefore adopt EPCOR's proposal on this issue."

Q. Has evidence been provided in the docket to show that Southwest's compensation levels are unreasonable?

A. No. Certainly, Southwest has provided testimony on compensation in its rate application. The Company hired a consultant from Korn Ferry Hay Group ("Hay Group") to provide testimony on "the competitive positioning of the Company's executive compensation pay levels and design relative to the market …". This testimony is provided by Company witness Holmen and presents the consultant's conclusion that Southwest's aggregate compensation has been "within or below" the compensation levels of comparative markets.

Q. Please summarize Staff's recommendation concerning Southwest's MIP expense.

A. Staff recommends continuing the historic position of sharing the MIP expense between ratepayers and shareholders. Staff recommends the disallowance of 20 percent of the MIP expense related to the ROE performance measure. As seen on Staff Schedule BKB-12, adjustment C-1 this results in a reduction to test year expense of $974,780.

C-2 Stock-Based Compensation (Restricted Stock/Unit Plan)

Q. Does the Company have a stock-based compensation plan called the Restricted Stock/Unit Plan?

A. Yes.

Q. Briefly describe RSUP.

A. The RSUP is a long term incentive plan introduced by the Company in 2006. It replaced the Company's then existing Stock Options program, and remained in operation for the Company during the Test Year.

Q. What is the purpose of the program and who may participate?

A. The Company's response to data request Staff 2-031 describes the RSUP plan details as follows:

> **<u>Restricted Stock/Unit Plan</u>**
> "The second component of variable at-risk pay is the Restricted Stock/Unit Plan ("RSUP"). The RSUP is a long–term incentive plan designed to enhance the competitive position of the total direct compensation and to further align customer, management and shareholder interests, while rewarding sustained performance with respect to the metrics the MIP measures on an annual basis.
>
> The RSUP is available to officers and other key management employees. The RSUP is measured as a percentage of year-end base salary and varies by title, as follows:

Position	% of Base Salary	% Value Range Distribution
CEO	45	22.5 to 67.5
President	30	15.0 to 45.0
Executive VP	25	12.5 to 37.5
Senior VP	20	10.0 to 30.0
Vice President	15	7.5 to 22.5
Other Participants	10	5.0 to 15.0

> As a measurement of long-term sustained performance, the average MIP award over the three year period ending before the award date is the criteria used to calculate awards for officers and key employees. Amounts granted pursuant to the RSUP range from 50 to 150 percent of the target for each participant. The minimum three-year average MIP percent of target achieved required to receive a distribution under the RSUP is 90 percent. The dollar amount distributed under the RSUP is converted to restricted share units using the market price on the date such awards are approved by the Company's Board of Directors. The units vest over a three year period with 40 percent for the first year and 30 percent for the second and third years."

Q. Did SWG have stock option expense in its prior rate case?

A. Yes, Southwest included expenses related to the RSUP in the cost of service in the prior case.

Q. Please discuss the RSUP recommendation made by Staff in the prior case.

A. In the Direct Testimony of Staff Witness Ralph Smith filed on June 10, 2011 in Docket No. G-01551A-10-0458, Page 34, Line 7, Mr. Smith recommended the full disallowance of the Company RSUP costs included in the rate case:

> "As shown on Schedule C-4, this adjustment decreases test year expense by $1,033,723 to reflect the removal of Southwest's RSUP compensation expense that is allocated to Arizona operations. The expense of providing other stock-based compensation to officers and employees beyond their other compensation should be borne by shareholders and not by ratepayers. As noted above, the stock-based compensation addressed in Staff Adjustment C-4 is for stock-based compensation other than MIP."

Q. Please explain Staff's adjustment to RSUP expense in the current case.

A. As shown on Staff Schedule BKB-13, Staff adjustment C-2 decreases test year RSUP expense by $2,550,494 to reflect the disallowance of the RSUP expense allocated to Arizona. Staff continues to recommend that incentive compensation and stock-based compensation expenditures specifically for high level employees are costs that are properly borne by shareholders rather than ratepayers.

C-3 Supplemental Executive Retirement Plan Expense

Q. Provide a brief explanation of the term SERP.

A. A SERP is a retirement plan for top "executive" employees of a business enterprise. It is created and managed specifically to supplement standard retirement benefits and compensation offered by a Company. Such a plan is considered to improve the benefits of the Company so the firm can attract and retain highly competent, top executives. A SERP would also enable individual executives to maintain a higher standard of living as they move into their retirement years in appreciation for valued service to the Company. An important element of the SERP is that it provides benefits to executives above and beyond basic plans that have Internal Revenue Service ("IRS") limits.

Q. Does Southwest have other plans or programs in addition to the aforementioned incentive programs?

A. Yes. The Company has a number of such plans including the Employee Investment Plan/401(k) ("EIP"), The Executive Deferral Plan ("EDP"), and the Defined Benefit Retirement Plan ("DBRP") in addition to the SERP.

Q. Did the Company provide a summary of the individual retirement/savings programs?

A. The Company's response to data request Staff 2-031 provides the following summary information on the above plans:

> **<u>Employee Investment Plan/401(k)</u>**
> The Southwest Gas Corporation Employee Investment Plan ("EIP") is a qualified defined contribution plan that provides a retirement savings mechanism by allowing tax-deferred contributions and the tax-deferred growth of earnings. As a part of the plan, the Company provides matching contributions equal to one-half the deferred amount up to 7 percent of their annual salary. Employees control how savings are invested by investing in any of the investment options the EIP offers. The Internal Revenue Service ("IRS") limits the amount participants can contribute to the EIP to $28,000 plus an additional $6,000 in catch-up contributions for participants age 50 or older. Officers of Southwest Gas may invest in the EIP, but they are not eligible to receive a Company match under this plan.
>
> **<u>Executive Deferral Plan</u>**
> The Executive deferral Plan ("EDP"), allows executives at the vice president level and above to supplement their salary deferral opportunities by deferring up to 100 percent of their annual compensation and 100 percent of the cash portion of their variable at-risk compensation. As a part of the EDP, the Company provides matching contributions that parallel the contributions made under the Company's EIP. Payouts under the EDP begin six months after the retirement date based on pre-selected time periods or at some other employment terminating event. Interest on EDP deferrals and the matching contributions is accrued annually at 150 percent of the Moody's Seasoned Corporate Bond Rate.

The EDP is an unqualified plan and, as such, participant balances are not guaranteed (i.e. participants are general unsecured creditors of the Company and their contribution to this account are at risk).

Southwest Gas maintains the EDP to attract and retain qualified executives in a competitive marketplace in which the majority of the Company's peer companies offer comparable executive retirement programs. The EDP provides participating executives the opportunity to receive retirement benefits available to other Company employees under the EIP, thereby putting them on a par with other employees with respect to the level of benefits received at retirement.

Pension

The Company's non-contributory, Defined Benefit Retirement Plan ("DBRP"), is available to all employees of the Company, including executives. Benefits are based on an employee's years of service, up to a maximum of 30 years, and the 12-month average of the employee's highest five consecutive years' salaries, excluding bonuses, within the final ten years of service. The IRS limits the amount of annual compensation that can be considered in determining benefits under the DBRP. For 2015, the maximum annual compensation amount was $265,000. In future years, the maximum annual compensation will be adjusted to reflect changes in the cost of living as established by the IRS.

Supplemental Executive Retirement Plan

Executives also participate in the Company's SERP. The SERP supplements the basic retirement plan for qualifying executives by providing a normal retirement benefit at a level of 50% to 60% of base salary, without regard to the IRS limits applicable to the DBRP. SERP benefits are based on the 12-month average of the highest consecutive 36 months of salary. Generally officers must be at least 55 years of age with 20 or more years of service to receive retirement benefits. Some reductions may apply, depending on an officer's age and years of service at the date of retirement.

The SERP is an unqualified plan and, as such, payments are not guaranteed (i.e. participants are general unsecured creditors of the Company). Benefits payable under the SERP are offset by benefits payable under the DBRP to avoid the double-payment of benefits.

As with the EDP, Southwest Gas maintains the SERP to attract and retain qualified executives in a competitive marketplace in which the majority of the Company's peer companies offer comparable executive retirement programs. The SERP provides participating executives the opportunity to receive retirement benefits available to other Company employees under the DBRP, thereby putting them on par with other employees with respect to the level of benefits received at retirement.

Q. Is the SERP designated for highly compensated executives such as members of the Board of Directors ("BOD")?

A. Yes. The Company's response to data request Staff 10-017 provides that: "An executive shall become a participant in the Plan as of the effective date of his/her election by the Board of Directors ("BOD") as an officer of the Company". Although it is for officers/executives, SERP is an "unqualified plan" which indicates that plan payments are not guaranteed. In addition, the summary information in data request Staff 2-031 (above) states that SERP retirement benefits generally apply to officers of age 55 or older (with a minimum of 20 years of service) and are "based on the 12-month average of the highest consecutive 36 months of salary".

Q. What adjustment does Staff recommend to Southwest's SERP expense?

A. Staff recommends sharing the SERP expense between ratepayers and shareholders by allocating 50 percent of SERP costs to shareholders of the Company. Therefore, as outlined on Staff Schedule BKB-14, Staff adjustment C-3 recommends that SERP expense totaling $813,602 be removed from Southwest's rate case.

C-4 Directors and Officers Liability Insurance Expense

Q. What is Directors and Officers Liability Insurance ("D&O Insurance")?

A. D&O Insurance is liability insurance which covers directors and officers of a company from legal claims from others while serving on a board of directors or as an officer. This protection aims to cover corporate employees against lawsuits resulting from management decisions that ultimately or allegedly had adverse and or unintended consequences.

Q. Has the Company included D&O Insurance costs in this rate case?

A. Yes. The Company included these costs in expenses and in the rate base.

Q. Has the Company provided clarifying information on the need for D&O Insurance?

A. The Company's response to data request Staff 10-026 provides the following on D&O Insurance:

> "It is necessary for the Company to maintain a strong program of D&O coverage in order to continue to attract and retain competent and experienced directors and officers. Because of the potential of shareholder or other stakeholder lawsuits against corporate directors and officers, the risk of sitting on a board of directors without corporate insurance coverage could outweigh any advantages of serving on a board of directors. Consequently, this would decrease the Company's ability to attract highly qualified outside directors with their unique areas of expertise. Therefore, the Company maintains corporate indemnification for its directors and officers, as well as provides liability insurance coverage to protect both the individual directors and officers and the overall Company from D&O exposure. Also included is entity coverage against corporate entity securities claims. D&O insurance is purchased to protect the Company and its customers against some of the risks of doing business, just like any other insurance policy purchased by the Company.
>
> D&O insurance claims could be brought by a wide variety of stakeholders, including competitors, vendors, creditors, employees, customers, governmental agencies, or shareholders, just to name a few, for actual or alleged errors, misstatements, omissions, breech of duty, etc. that occurred during the execution of director's or officer's fiduciary duties to the Company."

Q. Was a D&O Insurance adjustment made in the last Southwest Arizona rate case?

A. Yes. In the June 10, 2011 Direct Testimony of Mr. Smith filed in Docket No. G-01551A-10-0458, Page 55, Line 9, Mr. Smith recommended the disallowance of 50 percent of the Company D&O Insurance expense included in the rate case. Staff's testimony stated "… SWG's proposed test year expense for D&O Insurance should be reduced by $386,403 to reflect an allocation of 50 percent of this expense to shareholders."

In explanation, Mr. Smith stated at, Page 53, Line 22:

> "This type of insurance coverage usually comes into play when a shareholder sues the officers and directors of a public company, such as Southwest. Thus, it helps [to] protect the officers and directors from the costs of a shareholder lawsuit. Shareholders benefit from payouts under the policy that would reduce the cost not recoverable from ratepayers. On the other hand,

> ratepayers benefit from this because having such insurance improves the ability of the corporation to attract and retain qualified directors and officers and enables the directors and officers to make decisions without fear of personal liability. Consequently, it is reasonable for shareholders to bear some of the cost for the D&O Insurance."

Further, at Page 54, Line 16 through Page 55, Line 5, Mr. Smith discusses other jurisdictions (Arkansas, California, Connecticut and Florida) that shared D&O Insurance expense between shareholders and ratepayers on a 50/50 or greater basis. Additionally, in his written testimony, he attached excerpts from decisions in other state Commission orders on the subject.

Q. Please provide a summary of Staff's adjustment to D&O Insurance expense.

A. As shown on Staff Schedule BKB-15, Staff adjustment C-4, reduced Southwest's D&O test year insurance expense by $333,962 to reflect a 50 percent allocation of this expense to shareholders.

Q. Has Staff proposed a corresponding adjustment to rate base?

A. Yes. As mentioned above, the Company included D&O Insurance costs in both expenses and rate base as a prepayment in the Company's proposed working capital allowance. My adjustment C-4 addresses the disallowance of 50 percent of the D&O Insurance expense that Staff recommends be allocated to shareholders. A corresponding adjustment to remove 50 percent of the prepaid D&O insurance costs was recognized as a reduction to rate base section on Staff schedule BNC-3. Please see the testimony of Ms. Chukwu for details on the rate base portion of Staff's overall D&O Insurance adjustment.

C-5 Employee Vehicle Compensation Expense

Q. Does the Company discuss employee vehicle expense in its rate application?

A. Yes. Southwest's rate case schedules include pro forma adjustment No. 6 related to employee use of Company vehicles.

Q. Please provide a summary of the employee vehicle expense issue.

A. On Page 23, Line 1 of Company witness Cunningham's testimony, the Company provides the following detail on employee vehicle compensation:

> "The Adjustment No. 6 removes from test year expenses the cost of Company vehicles related to personal use by employees. This adjustment is consistent with those approved in Southwest's last several rate cases. This adjustment reduces operating expenses by $62,108."

The Company's purpose in sponsoring this adjustment was to proactively remove these expenses from the test year amounts allowed in this case. To accomplish this, the Company identified Arizona costs for removal and then calculated the Arizona portion of the System Allocable costs for further exclusion. As such, the Company schedule begins with Arizona direct charges of ($55,112) prior to calculating the System Allocable portion. The Company's System Allocable amount of ($302,089) is multiplied by a 4.13 percent MMF allocation (Lines 3 and 4). It is further reduced by an Arizona 4-Factor allocation of 56.07 percent (Line 5 and 6). The surviving amount of ($6,996) is the Company proposed portion of System Allocable vehicle expenses allocated to Arizona. This is combined with the Arizona direct charges of ($55,112) for a Company proposed reduction to employee vehicle compensation expense of ($62,108).

Q. Did Staff agree with the Company's calculations on employee vehicle compensation?

A. No. Staff's review of the pro forma Adjustment No. 6 amounts showed that the Company calculation needed restating due to a computer entry error. Specifically, Staff noted that the surviving amount after application of the 4.13 MMF allocation (Line 4) was incorrect. The Company calculation multiplied the ($302,089) System Allocable amount by 4.13 percent rather than removing an amount equivalent to 4.13 percent from the ($302,089) amount. Subsequently, the application of the Arizona 4-Factor allocation of 56.07 percentage began with an incorrect number and the Company proposed vehicle compensation expense of ($62,108) was understated.

Q. Did Staff recalculate pro forma adjustment No. 6?

A. Yes. Staff recalculated the pro forma adjustment by reducing the ($302,089) of System Allocable expense by an amount equivalent to the 4.13 percent allocation percentage and continued the calculation to its conclusion. The calculation results in a restated pro forma adjustment No. 6 amount of ($217,494).

Q. Has the Company addressed the need to restate pro forma adjustment No. 6?

A. Yes. In response to Staff DR 10.28, the Company recalculated their pro forma adjustment and stated the following: "The total Employee Vehicle Compensation adjustment should have reduced expenses on Line 7 by $217,494, rather than $62,108."

Q. Please summarize Staff's adjustment to employee vehicle compensation expense.

A. The Company's original pro forma reduced expenses in this account by ($62.108) and Staff's recalculated amount produces an adjustment totaling ($217,494). Since the ($62,108) has already been removed from the case via pro forma adjustment No. 6, Staff's adjustment is the net of ($217,494) and (62,108). As shown on Staff Schedule BKB-16 and Staff adjustment C-5, Staff's recalculation of pro forma adjustment No. 6 results in a reduction to the Company's proposed employee vehicle compensation totaling ($155,386).

C-6 Self-Insurance Expense

Q. Did the Company include a pro forma Adjustment related to Self-Insurance Expense in this rate case?

A. Yes. Southwest's pro forma adjustment No. 9 seeks to normalize the test year expense level of this expense.

Q. Please provide a summary of the self-insurance issue.

A. On Page 23, Line 9 of Company witness Cunningham's testimony, the Company provides the following detail on the level of self-insurance claims in the test year:

> "The Company is self-insured for up to $1 million of claims expense for each occurrence (per occurrence component). To the extent that a specific claim exceeds $1 million, the Company is self-insured for the excess over $1 million up to an aggregate (aggregate component) of $4 million. Once the $4 million aggregate is reached, any amount paid above the $4 million is the responsibility of the insurance carrier."

The Company therefore tracks claims paid in three component levels of self-insurance, < $1,000,000, at $1,000,000 and the $4,000,000 Aggregate level.

Q. Please discuss the Company's pro forma Adjustment No. 9 shown on Company Schedule C-2, Adjustment No. 9, Sheet 2 of 2.

A. Pro forma Adjustment No. 9 provides the amount of claims paid for each of the three component levels under both Arizona Direct and System Allocable expenses. Total claims paid for these costs (Line 4) were $6,260,345 and $9,508,854, respectively. These amounts are divided by 10 to apply a ten year claims average. The 10 year claims average amounts of $626,035 and $950,885 were then compared to the test year recorded expense (Line 6) to produce Company adjustment amounts of $519,680 and $328,385, respectively. After allocation, the Arizona portion of the $328,385 System Allocable amount is $176,517. The $519,680 Arizona direct cost and the $176,517 Arizona portion of the System Allocable cost combine to a total Company pro forma adjustment which increases Self-insurance expense by $696,197.

Q. Does Staff agree with the Company proposed adjustment on Self-insurance?

A. No. Staff's review of the work paper showed that the Company inputs on Line 3 of pro forma Adjustment No. 9 needed restating. Specifically, Staff noted that the Company omitted entering a $4,000,000 claim under Arizona Direct expense and improperly included an $8,000,000 claim under System Allocable expense. Staff therefore concluded that the Line 3 amounts of -0- and $8,000,000 proposed by Southwest is not correct.

Q. Did Staff recalculate the Company's pro forma adjustment No. 9?

A. Yes. Staff recalculated the pro forma adjustment by replacing the Line 3 inputs. Staff inserted the missing $4,000,000 claim in the Arizona Direct column and removed the $8,000,000 claim entered under the System Allocable column. After adjustment, Staff's Line 3 Arizona Direct and System Allocable claim inputs were $4,000,000 and -0-. Staff then recalculated the pro forma adjustment. The recalculation by Staff resulted in a decrease of $30,030 to recoverable Self-insurance expense. This is captured on Staff Schedule BKB-17 in Staff operating adjustment No. 6.

C-7 Rate Case Expense

Q. Does the Company discuss Rate Case Expense in its rate application?

A. Yes. Southwest's rate case schedules include pro forma Adjustment No. 12 related to rate case expense.

Q. Please provide a summary of the rate case expense issue.

A. On Page 26, Line 1 of Company witness Cunningham's testimony, the Company provides the following detail on rate case expense:

> "The Company estimated the incremental costs that would be incurred to prepare and process this general rate case, including printing, postage, court reporting, noticing, publication, travel, and outside consultants. The total incremental costs are divided by four, which is roughly equal to the number of years in one rate case cycle, to calculate an annual amortization to Account 928. The adjustment, which increases operating expenses by $35,112, is the difference between this new amortization amount and the amount of rate case expense amortized on the Company's books during the test year."

Q. Please discuss Company pro forma adjustment No. 12 on Schedule C-2, Adjustment No. 12, Sheet 1 of 1.

A. Company pro forma adjustment No. 12 outlines estimated cost figures employed by the Company to annualize rate case expense. The Company estimates $150,000 for printing, copying, postage and freight costs (Line 1), $265,000 for professional services (Line 2), $35,000 for Notice/Publication costs, $1,000 for court reporting and $125,000 for travel/transportation/misc. costs. The total of Company estimated rate case costs is $576,000.

Q. Did Staff remove any portion of Southwest's $576,000 in estimated rate case expense?

A. Yes. During its review, Staff identified a $50,000 Study that Southwest commissioned from IHS Economics and Country Risk. The Company's response to data request RUCO 2-006 and the related RUCO 2.06_Attachment 1 included the following information on Southwest's purpose for the contract and the overall need for the study:

> "Conduct a study to estimate the economic impacts of pipeline replacement on the state and local economies in the Arizona service area. Using investment and operational data provided by Southwest Gas, IHS will provide estimates of the direct, indirect and induced impacts of pipeline replacement on gross state product, labor income, value of output, generated tax revenues and jobs. IHS will deliver to Southwest Gas a final report of approximately 15 pages in length and an accompanying PowerPoint presentation that summarizes the key findings of the study."

> "The purpose of and the need for the IHS study was to quantify and demonstrate the broad statewide economic benefits associated with the Company's proposed capital investments in Arizona gas infrastructure."

Q. Did Staff agree with the Company's inclusion of the IHS Study costs?

A. No. Staff concluded that the burden for the $50,000 cost of the IHS study was best borne by shareholders rather than ratepayers and should not be a recoverable item in rates. Further, Staff would note that this study failed to consider the impact associated with the loss in disposable ratepayer income resulting from the need to pay higher gas utility rates. Staff therefore removed the $50,000 cost from the Company's $576,000 rate case expense estimate, reducing the amount to $526,000. Staff then amortized the estimated rate case amount over 5 years.

Q. Why did Staff amortize the rate case amount over a 5 year period?

A. Staff utilized a 5 year period because it has been over 5 years since the last case. The appropriateness of the period is reinforced by the May 2, 2016 application of the Company in the introduction to Part 1, Page 1. This introduction states:

> "As set forth more fully in the supporting testimony, it has been more than five years since the Company last filed a general rate case, and currently effective rates are based upon the level of operating expenses and capital investments made by the Company prior to June 30, 2010."

Staff's $105,200 annual rate case expense is the result of applying Staff's 5 year amortization period to Staff's $526,000 estimated rate case amount. The result is a reduction of $38,800 in annual rate case expense recovery.

C-8 Investor Relations Costs

Q. Did Southwest discuss investor relations costs on discovery?

A. Yes. The Company's response to data request RUCO 3-006 stated that investor relations costs were included in the application. The Company's response in RUCO 3.06_Attachment 1 also included a full page listing of investor relation costs for the test year totaling $388,576. Southwest was also asked for a brief description of the costs but a high level summary of the costs was not provided. The Company's data response did clarify that the costs "are incurred at the corporate level, and are prior to allocation to Arizona".

Q. The $388,576 in investor relations expenses are not the costs specifically allocated to Arizona?

A. That is correct. Staff therefore applied a MMF allocation percentage of 4.13 percent to the $388,576 in costs and removed that quantity prior to applying the Arizona 4-Factor allocation percentage of 56.07 percent to reach an Arizona total for investor relations expense of $208,876. Staff recommends that investor relations expense be reduced by a total of $104,438 to reflect Staff's 50 percent allocation of these costs to shareholders. This is captured on Staff Schedule BKB-19 in Staff Operating Adjustment No. 8.

C-9 Income Taxes and Interest Synchronization

Q. Please explain Staff's adjustment related to interest synchronization.

A. Staff adjusted interest expense in its income tax calculation because the rate base recommended by Ms. Chukwu is different than that proposed by the Company. The calculation of the interest synchronization adjustment is shown on Schedule BKB-2. Staff's recommended income tax expense is $37,501,454, an increase of $3,249,319 over the Company's adjusted test year figure of $34,252,135.

C-10 Depreciation Expense

Q. Was Southwest required to provide a depreciation study in the current rate case?

A. Yes. On Page 44, line 21 of Decision No. 72723, the Commission issued the following ordering paragraph:

> "The Settlement requires SWG to file a comprehensive depreciation study in its next general rate case that addresses depreciation and amortization rates for all of the Company's jurisdictional Direct and System Allocable depreciable and amortizable plant accounts."

Q. Did Southwest's pending rate case include a pro forma adjustment to address the implementation of the new depreciation rates?

A. Yes. Company pro forma adjustment No. 14 addressed the implementation of the new rates and the proposed impact to Depreciation expense. The implementation of the new depreciation rates proposed by the Company had a very significant impact on depreciation expense outlined in pro forma adjustment No. 14, decreasing Company proposed depreciation expense of $41,806,078.

Q. Did Staff contract with a consultant to review the rates presented in the depreciation study?

A. Yes. Overland Consulting ("Overland") was assigned to review the Company proposed depreciation rates and offer written testimony on the depreciation study. A number of the depreciation rates were adjusted by Overland. As shown in schedule BKB-21, the effect of the Overland recommendations is a $3,053,267 decrease to the Company proposed depreciation expense. Please refer to the testimony of Mr. Balcom for further details of Staff's depreciation study analysis. Staff notes that the depreciation expense calculation reflects other adjustments to rate base that Staff has proposed.

C-11 Property Tax

Q. Does Staff's recommendation include an adjustment to Property Taxes?

A. Yes. Staff's property tax adjustment of $106,556 is shown on Staff schedule BKB-22.

V. COMPLIANCE REQUIREMENT

Q. Did Staff issue a data request asking that Southwest identify any compliance items that were outdated?

A. Yes. Staff Data Request 2-064 sought the following from the Company:

> **Q. Please refer to all Southwest Gas compliance requirements that have been imposed on the Company by previous decisions of the Commission. Prepare and provide a detailed listing of all compliance items that the Company considers to be outdated, inefficient and/or unnecessary. The listing should include the decision number, page number, line number and complete ordering paragraph of each individual compliance requirement that the Company would like reviewed during the rate case for removal/termination by the Commission. Also, include a full explanation of why the Company supports removal of the each compliance item on the list.**
>
> A. The Company appreciates Staff's desire to consider removing outdated and unnecessary compliance items. The Company has identified the following compliance items to be reviewed for removal/termination in this proceeding.

Q. Please present the Company outline for each of the outdated compliance items and provide Staff's position indicating whether Staff is in agreement with the Company.

A. The Company and Staff information is provided below. Staff has listed the Company identified compliance items, the Company responses on those items and Staff's recommendations on the elimination of these compliance items:

1. <u>Docket No. 98-0184, Page No. 4, Line No. 10</u>. <u>Issue</u>: Notify the ACC about use of IPCS in last year. <u>Company reason to eliminate</u>: Southwest Gas has rarely utilized this program, and in fact has not utilized it in the past decade.

   <u>Staff response</u>: Staff agrees that the program is no longer utilized by the Company and that there is nothing to report. Therefore, Staff agrees that it is reasonable to discontinue the Compliance reporting on this matter. Summary: Eliminate.

2. <u>Docket No. 04-0876, Page No. 67, Line No. 4</u>. <u>Issue</u>: Notify the ACC about intervention in FERC Dockets. <u>Company reason to eliminate</u>: Company has been proving this information with no action from Staff. Staff frequently intervenes along with the Company in these proceedings. Company works with Staff on issues of shared interest at other times. Requirement to file a letter is outdated and unnecessary, particularly given the development of electronic notifications and access that has occurred since this compliance item was ordered.

Staff response: Staff agrees that the FERC requirement is no longer necessary. Southwest will continue to work with Staff on pipeline issues relating to Arizona even in the absence of this requirement. Staff agrees that it is reasonable to discontinue the Compliance reporting on this matter. Summary: Eliminate.

3. Docket No. 10-0458, Page No. 43, Line No. 7. Issue: Quarterly Decoupling Reports. Company reason to eliminate: Southwest Gas' decoupling mechanism is subject to annual review by Staff and vote by the Commission, no action is taken on quarterly decoupling reports. To simplify compliance requirements and review from Staff, the Company would be comfortable including a section on an analysis of decoupling bill impacts in its annual decoupling filing.

   Staff response: Staff supports further consideration of reporting requirements depending on what form of decoupling is ultimately ordered in the current case. Therefore, Staff recommends that the elimination or modification of this compliance item be determined in conjunction with the adjudication of the rate case. Summary: Defer to end of the current case.

4. Docket No. 10-0458, Page No. 43, Line No. 22. Issue: Semiannual Communications report. Company reason to eliminate: The settlement agreement approved in Decision No. 72723 requires the Company to file semiannual reports detailing developments in its efforts to improve communications with customers, including a section on whether the Company can use texting to communicate with customers. The Company has since implemented the following communication enhancements, and believes this compliance item is no longer necessary:

   1. In June 2013, the Company fully implemented text messaging, allowing customers to receive information during a natural gas service interruption.

   2. The Company implemented outage notification calls to notify affected customers during a natural gas service interruption.

   3. The Company increased its use of social media, including Facebook and Twitter to communicate with customers and the general public during natural gas service interruptions, and natural gas safety messaging.

   4. The Company recently redesigned its website to improve the customer experience, including pages in Spanish.

5. The Company created video content on You Tube, and these videos are distributed on the Company's social media pages.

<u>Staff response</u>: This compliance item was created as a temporary item per Commission requirement after the 2011 outages. Staff believes it is reasonable for this item to have run its course because the Company has made many improvements in this area. Staff agrees that it is reasonable to discontinue the Compliance reporting on this matter. Summary: Eliminate.

Q. Please summarize Staff's recommendations on the four "outdated" compliance items presented by the Company.

A. Staff concurs with the Company that item numbers 1, 2 & 4 are no longer necessary and should be eliminated. Staff recommends that item number 3 be deferred and reconsidered within the context of the Commission's decision on the decoupling issue in this rate case.

Q. Does Staff have any other issue with Southwest over Compliance matters?

A. No. The Company works well with Staff and positively manages its compliance responsibilities.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Southwest Gas Corporation **Schedule BKB-1**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY FAIR VALUE	[B] STAFF FAIR VALUE
1	Adjusted Rate Base	$1,812,414,667	$1,801,065,079
2	Adjusted Operating Income (Loss)	$89,293,036	$93,991,904
3	Current Rate of Return (L2 / L1)	4.93%	5.22%
4	Required Rate of Return	6.01%	5.61%
5	Required Operating Income (L4 * L1)	$108,844,799	$100,967,708
6	Operating Income Deficiency (L5 - L2)	$19,551,763	$6,975,804
7	Gross Revenue Conversion Factor	1.6329	1.6226
8	Required Revenue Increase (L7 * L6)	$31,926,894	$11,318,939
9	Adjusted Test Year Revenue	$481,681,406	$481,681,406
10	Proposed Annual Revenue (L8 + L9)	$513,608,300	$493,000,345
11	Required Increase in Revenue (%)	6.63%	2.35%

Southwest Gas Corporation **Schedule BKB-2**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

GROSS REVENUE CONVERSION FACTOR

Line No.	Description	[A] Rate	[B] Company Proposed	[C] Staff Recommended
1	Gross Revenue		1.0000	1.0000
2	Less: Uncollectible Revenue	0.30%	0.0030	0.0030
3	State Taxable Income		0.9970	0.9970
4	Less: State Income Taxes	4.90%	0.0489	0.0489
5	Federal Taxable Income		0.9481	0.9481
6	Federal Income Tax	35.00%	0.3318	0.3318
7	Change in Net Operating Income		0.6163	0.6163
8	Gross Revenue Conversion Factor		1.6226	1.6226
9				
10				
11	Components of Revenue Requirement Increase		Amount	Percent
12	Net Income		$6,975,636	61.6280%
13	Federal and State Income Taxes		4,309,063	38.0695%
14	Uncollectibles		34,240	0.3025%
15	Total Revenue Increase		$11,318,939	100.0000%
16	Computation of State and Federal Income Tax Rate		L.13 / L.3	38.1850%
17	Per SWG Schedule C-3, page 2 of2			38.5750%
18				
19				
20				
21	Adjusted rate base		$1,801,065,079	
22	Weighted cost of debt		1.85%	
23	Synchronized interest per Staff		$33,283,449	
24	Synchronized interest per Company		$33,627,705	
25	Difference (decreased) increased interest deduction		($344,256)	

Southwest Gas Corporation **Schedule BKB-10**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

OPERATING INCOME STATEMENT - TEST YEAR AND STAFF RECOMMENDED

Line No.	Description	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF RECOMMENDED CHANGES	[E] STAFF RECOMMENDED
1	**Operating Revenues**					
2	Revenues	$481,681,406	$0	$481,681,406	$11,318,939	$493,000,345
3	Gas Cost	0	0	0	0	0
4	Total Margin	$481,681,406	$0	$481,681,406	$11,318,939	$493,000,345
5						
6	**Operating Expenses**					
7	Other Gas Supply	$1,345,425	$0	$1,345,425	$0	$1,345,425
8	Distribution	111,226,774	0	111,226,774	0	111,226,774
9	Customer Accounts	27,827,100	0	27,827,100	0	27,827,100
10	Customer Information	872,491	0	872,491	0	872,491
11	Sales	0	0	0	0	0
12	Administrative and General					
13	Direct	6,052,009	(213,806)	5,838,203	0	5,838,203
14	System Allocable	70,960,598	(4,787,671)	66,172,927	0	66,172,927
15	Depreciation and Amortization					
16	Direct	83,124,568	(2,923,718)	80,200,850	0	80,200,850
17	System Allocable	12,796,366	(129,549)	12,666,817	0	12,666,817
18	Regulatory Amortizations	(52,943)	0	(52,943)	0	(52,943)
19	Other Taxes	41,628,621	106,556	41,735,177	0	41,735,177
20	Interest on Customer Deposits	2,355,227	0	2,355,227	0	2,355,227
21	Income Taxes	34,252,135	3,249,319	37,501,454	4,322,137	41,823,591
22	Total Operating Expenses	$392,388,370	($4,698,869)	$387,689,501	$4,322,137	$392,011,638
23						
24	Net Operating Income	$89,293,036	$4,698,869	$93,991,904	$6,996,802	$100,988,706

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BKB-11

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] Management Incentive Program Ref: Sch BKB-12	[C] Restricted Stock/Unit Plan Ref: Sch BKB-13	[D] Supplemental Executive Retirement Plan Ref: Sch BKB-14	[E] Directors and Officers Liability Insurance Ref: Sch BKB-15	[F] Employee Vehicle Compensation Ref: Sch BKB-16	[G] Self Insurance Expense Ref: Sch BKB-17	[H] Rate Case Expense Ref: Sch BKB-18	[I] Investor Relations Ref: Sch BKB-19	[J] Income Taxes Ref: Sch BKB-20	[K] Depreciation Ref: Sch BKB-21	[L] Property Taxes Ref: Sch BKB-21	[M] Staff Adjusted
1	**Operating Revenues**														
2	Operating Revenue		$481,681,406	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$481,681,406
3	Purchased Gas Cost														
4	Natural Gas Transmission Line Purchases	803	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Purchased Gas Cost Adjustments	805.1	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Gas Withdrawn From Storage	808.1	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Gas Delivered To Storage	808.2	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Gas Used for Compressor Station Fuel	810	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total Purchased Gas Cost		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Total Margin		$481,681,406	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$481,681,406
11															
12	**Operating Expenses**														
13	Other Gas Costs														
14	Other Gas Supply	813	$1,345,425	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,345,425
15															
16	Storage														
17	Placeholder		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18															
19	Transmission														
20	Transmission and Compression of Gas by Others	858	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21															
22	Distribution														
23	Operation Supervision and Engineering	870	$11,760,676	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,760,676
24	Operation Distribution Load Dispatching	871	549,454	0	0	0	0	0	0	0	0	0	0	0	549,454
25	Operation Mains and Services	874	10,858,237	0	0	0	0	0	0	0	0	0	0	0	10,858,237
26	Operation Measuring and Regulation Station	875	2,973,651	0	0	0	0	0	0	0	0	0	0	0	2,973,651
27	Operation Meter and House Regulator	878	10,176,268	0	0	0	0	0	0	0	0	0	0	0	10,176,268
28	Customer Installation	879	12,339,190	0	0	0	0	0	0	0	0	0	0	0	12,339,190
29	Other	880	14,651,601	0	0	0	0	0	0	0	0	0	0	0	14,651,601
30	Rents	881	377,364	0	0	0	0	0	0	0	0	0	0	0	377,364
31	Maintenance Supervision and Engineering	885	3,082,151	0	0	0	0	0	0	0	0	0	0	0	3,082,151
32	Maintenance of Structures and Improvements	886	96,140	0	0	0	0	0	0	0	0	0	0	0	96,140
33	Maintenance of Mains	887	23,091,820	0	0	0	0	0	0	0	0	0	0	0	23,091,820
34	Maintenance of Measuring and Reg. Station Eq.	889	2,414,876	0	0	0	0	0	0	0	0	0	0	0	2,414,876
35	Maintenance of Services	892	14,293,646	0	0	0	0	0	0	0	0	0	0	0	14,293,646
36	Maintenance of Meters and House Regulators	893	4,068,468	0	0	0	0	0	0	0	0	0	0	0	4,068,468
37	Maintenance of Other Equipment	894	493,233	0	0	0	0	0	0	0	0	0	0	0	493,233
38	Total Distribution		$111,226,774	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$111,226,774
39															
40	Customer Accounts														
41	Supervision	901	$1,804,819	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,804,819
42	Meter Reading	902	1,703,419	0	0	0	0	0	0	0	0	0	0	0	1,703,419
43	Customer Records and Collection	903	21,847,446	0	0	0	0	0	0	0	0	0	0	0	21,847,446
44	Uncollectible Accounts	904	2,272,445	0	0	0	0	0	0	0	0	0	0	0	2,272,445
45	Miscellaneous	905	198,971	0	0	0	0	0	0	0	0	0	0	0	198,971
46	Total Customer Accounts		$27,827,100	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27,827,100
47															
48	Customer Service and Information														
49	Customer Assistance	908	$525,353	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$525,353
50	Informational and Instructional Advertising	909	0	0	0	0	0	0	0	0	0	0	0	0	0
51	Miscellaneous	910	347,138	0	0	0	0	0	0	0	0	0	0	0	347,138
52	Total Customer Service and Information		$872,491	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$872,491
53															
54	Sales														
55	Supervision	911	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
56	Demonstration and Selling	912	0	0	0	0	0	0	0	0	0	0	0	0	0
57	Advertising	913	0	0	0	0	0	0	0	0	0	0	0	0	0
58	Total Sales		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
59															
60	Total O&M		$141,271,789	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$141,271,789
61															
62	Administrative and General (A&G)														
63	Direct														
64	A&G Salaries	920	$25,915	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,915
65	Office Supplies and Expenses	921	0	0	0	0	0	0	0	0	0	0	0	0	0
66	A&G Expenses Transferred (Credit)	922	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Outside Services	923	233,835	0	0	0	0	0	0	0	0	0	0	0	233,835
68	Property Insurance	924	519,680	0	0	0	0	0	0	0	0	0	0	0	519,680
69	Injuries and Damages	925	162,325	0	0	0	0	0	400,001	0	0	0	0	0	562,325
70	Employee Pension and Benefits	926	3,607	0	0	(575,006)	0	0	0	0	0	0	0	0	(571,399)
71	Regulatory Commission Expenses	928	144,000	0	0	0	0	0	0	(38,800)	0	0	0	0	105,200
72	Safety Advertising	930.1	1,679,732	0	0	0	0	0	0	0	0	0	0	0	1,679,732
73	Miscellaneous General	930.2	0	0	0	0	0	0	0	0	0	0	0	0	0
74	Rents	931	0	0	0	0	0	0	0	0	0	0	0	0	0

75	Maintenance of General Plant	935	3,282,914	0	0	0	0	0	0	0	0	0	0	0	3,282,914
76	Total Direct A&G		$6,052,009	$0	$0	($575,006)	$0	$0	$400,001	($38,800)	$0	$0	$0	$0	$5,838,203
77															
78	System Allocable														
79	A&G Salaries	920	$44,267,104	($974,780)	($1,578,508)	$0	$0	($155,385)	$0	$0	$0	$0	$0	$0	$41,558,430
80	Office Supplies and Expenses	921	8,423,284	0	0	0	0	0	0	0	(3,963)	0	0	0	8,419,321
81	A&G Expenses Transferred (Credit)	922	(8,204,993)	0	0	0	0	0	0	0	0	0	0	0	(8,204,993)
82	Outside Services	923	12,807,779	0	0	0	0	0	0	0	0	0	0	0	12,807,779
83	Property Insurance	924	436,721	0	0	0	0	0	0	0	0	0	0	0	436,721
84	Injuries and Damages	925	6,530,513	0	0	0	(333,962)	0	(430,023)	0	0	0	0	0	5,766,529
85	Employee Pension and Benefits	926	(5,337)	0	0	(238,595)	0	0	0	0	0	0	0	0	(243,931)
86	Regulatory Commission Expenses	928	0	0	0	0	0	0	0	0	0	0	0	0	0
87	Safety Advertising	930.1	0	0	0	0	0	0	0	0	0	0	0	0	0
88	Miscellaneous General	930.2	3,922,005	0	(971,983)	0	0	0	0	0	(100,473)	0	0	0	2,849,550
89	Rents	931	1,576,774	0	0	0	0	0	0	0	0	0	0	0	1,576,774
90	Maintenance of General Plant	935	1,206,748	0	0	0	0	0	0	0	0	0	0	0	1,206,748
91	Total System Allocable A&G		$70,960,598	($974,780)	($2,550,491)	($238,595)	($333,962)	($155,385)	($430,023)	$0	($104,435)	$0	$0	$0	$66,172,927
92	Total A&G		$77,012,607	($974,780)	($2,550,491)	($238,595)	($333,962)	($155,385)	($430,023)	$0	($104,435)	$0	$0	$0	$72,011,130
93															
94	Depreciation and Amortization														
95	Direct		$83,124,568	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,923,718)	$0	$80,200,850
96	System Allocable		12,796,366	0	0	0	0	0	0	0	0	0	(129,549)	0	12,666,817
97	Regulatory Amortizations		(52,943)	0	0	0	0	0	0	0	0	0	0	0	(52,943)
98	Other Taxes		41,628,621	0	0	0	0	0	0	0	0	0	0	106,556	41,735,177
99	Interest on Customer Deposits		2,355,227	0	0	0	0	0	0	0	0	0	0	0	2,355,227
100	Income Taxes		34,252,135	0	0	0	0	0	0	0	0	3,249,319	0	0	37,501,454
101	Total Operating Expenses		$392,388,370	($974,780)	($2,550,491)	($813,601)	($333,962)	($155,385)	($30,022)	($38,800)	($104,435)	$3,249,319	($3,053,267)	$106,556	$387,689,501
102															
103	Net Operating Income		$89,293,036	$974,780	$2,550,491	$813,601	$333,962	$155,385	$30,022	$38,800	$104,435	($3,249,319)	$3,053,267	($106,556)	$93,991,904

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BKB-12

OPERATING ADJUSTMENT NO. 1 - MANAGEMENT INCENTIVE PROGRAM

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	A&G Salaries				
2	Direct	920	$25,915	$0	$25,915
3	System Allocable	920	44,267,104	(974,780)	43,292,324
4	**Total A&G Salaries**	920	**$44,293,019**	**($974,780)**	**$43,318,239**
5					
6					
7					
8	Test Year Management Incentive Program Expense (Corporate)				$9,067,243
9	Paiute Allocation Rate				4.13%
10	Less: Paiute SG TC MMF Allocation (Line 8 * Line 9)				$374,713
11	After Allocations to FERC Jurisdictions (L8 - L10)				$8,692,530
12	Arizona Four Factor Allocation				56.07%
13	Test Year amount of Management Incentive Program Expense (Arizona) (L11 * L12)				$4,873,902
14	Shareholder allocation percentage				20.00%
15	20% Allocation of MIP Expense to Shareholders (L13 * L14)				$974,780

REFERENCES:
Column [A]: Company Schedule C-1 O&M Summary, Column e
Column [B]: Company response to Staff DR 10-009 and Staff DR 10-010
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BKB-13

OPERATING ADJUSTMENT NO. 2 - RESTRICTED STOCK/UNIT PLAN ("RSUP")

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	A&G Salaries				
2	Direct	920	$25,915	$0	$25,915
3	System Allocable	920	44,267,104	(1,578,508)	42,688,596
4	**Total A&G Salaries**	920	$44,293,019	($1,578,508)	$42,714,511
5					
6	Miscellaneous General				
7	Direct	930.2	$0	$0	$0
8	System Allocable	930.2	3,922,005	(971,983)	2,950,023
9	**Total Miscellaneous General**	930.2	$3,922,005	($971,983)	$2,950,023
10					
11					
12					

LINE NO.	DESCRIPTION	920	930.2
13		920	930.2
14	Test Year Incentive Compensation Plans Other than MIP (Corporate)	$2,936,604	$1,808,244
15	Paiute Allocation Rate	4.13%	4.13%
16	Less: Paiute SG TC MMF Allocation (Line 14 * Line 15)	$121,358	$74,727
17	After Allocations to FERC Jurisdictions (L14 - L16)	$2,815,246	$1,733,517
18	Arizona Four Factor Allocation	56.07%	56.07%
19	Test Year amount of Management Incentive Program Expense (Arizona) (L17 * L18)	$1,578,508	$971,983

REFERENCES:
Column [A]: Company Schedule C-1 O&M Summary, Column e
Column [B]: Company response to Staff DR 10-009, Staff DR 10-011 and Staff DR 10-013
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BKB-14

OPERATING ADJUSTMENT NO. 3 - SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP")

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED	
1	A&G Salaries					
2	Direct	926	$25,915	($575,006)	($549,091)	
3	System Allocable	926	44,267,104	(238,595)	44,028,510	
4	**Total A&G Salaries**	926	$44,293,019	($813,601)	$43,479,418	
5						
6						
7						
8					Arizona	50%
9					Amount	Sharing
10	Test Year Supplemental Executive Retirement Expense (Arizona)		$1,285,966	72.99%	$938,618	$469,309
11	Test Year Supplemental Executive Retirement Expense (Corporate Direct Arizona)		211,395	100.00%	211,395	105,698
12	System Allocable Amount of SERP		499,837	95.47%	477,189	238,595
13	Total		$1,997,198		$1,627,202	$813,601
14						

REFERENCES:
Column [A]: Company Schedule C-1 O&M Summary, Column e
Column [B]: Company response to Staff DR 10-019
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation **Schedule BKB-15**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

OPERATING ADJUSTMENT NO. 4 - DIRECTORS AND OFFICERS LIABILITY INSURANCE

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Injuries and Damages				
2	Direct	925	$162,325	$0	$162,325
3	System Allocable	925	6,530,513	($333,962)	6,196,552
4	**Total Injuries and Damages**	925	$6,692,838	($333,962)	$6,358,876
5					
6					
7					
8	Test Year Directors and Officers Liability Insurance Expense (Corporate)				$1,242,581
9	Paiute Allocation Rate				4.13%
10	Less: Paiute SG TC MMF Allocation (Line 8 * Line 9)				$51,351
11	After Allocations to FERC Jurisdictions (L8 - L10)				$1,191,230
12	Arizona Four Factor Allocation				56.07%
13	Test Year Directors and Officers Liability Insurance Expense Amount (Arizona) (L11 * L12)				$667,923
14	Shareholder allocation percentage				50.00%
15	50% Allocation of MIP Expense to Shareholders (L13 * L14)				$333,962

REFERENCES:
Column [A]: Company Schedule C-1 O&M Summary, Column e
Column [B]: Company response to STF DR 9-002 and RUCO 5-012
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BKB-16

OPERATING ADJUSTMENT NO. 5 - EMPLOYEE VEHICLE COMPENSATION

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	A&G Salaries				
2	Direct	920	$25,915	$0	$25,915
3	System Allocable	920	44,267,104	(155,385)	44,111,719
4	**Total A&G Salaries**	920	$44,293,019	($155,385)	$44,137,634
5					
6					
7					
8	Test Year Employee Vehicle Compensation Expense (Corporate)				($302,089)
9	Paiute Allocation Rate				4.13%
10	Less: Paiute SG TC MMF Allocation (Line 8 * Line 9)				($12,484)
11	After Allocations to FERC Jurisdictions (L8 - L10)				($289,605)
12	Arizona Four Factor Allocation				56.07%
13	Test Year Employee Vehicle Compensation Expense Amount (Arizona) (L11 * L12)				($162,381)
14					
15	Original Adjustment by the Company				($6,996)
16	Staff Adjustment				($155,385)

REFERENCES:
Column [A]: Company Schedule C-1 O & M Summary, Colunn e
Column [B]: Company response to Staff DR 10-028
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BKB-17

OPERATING ADJUSTMENT NO. 6 - SELF INSURANCE

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Injuries and Damages				
2	Direct	925	$162,325	$400,001	$562,325
3	System Allocable	925	6,530,513	(430,023)	6,100,490
4	**Total Injuries and Damages**	925	$6,692,838	($30,022)	$6,662,815
5					
6					
7					

		Arizona Direct	System Allocable
8	**Claims Paid**		
9	< $1,000,000	$5,260,345	$1,508,854
10	at $1,000,000	1,000,000	0
11	$4,000,000 Aggregate	4,000,000	0
12	**Total Claims Paid**	$10,260,345	$1,508,854
13	10-Year Average (Line 12/10)	1,026,035	150,885
14	Recorded During Test Year	106,354	622,500
15	Staff Calculated Amount of Self Insurance Expense (L13 - L14)	$919,681	($471,615)
16	Company Pro Forma Adjustment (Arizona)	$519,680	
17	Staff Calculated Adjustment (L15 - L16)	$400,001	
18			
19	Test Year Self Insurance Expense (Corporate) (L15)		($471,615)
20	Paiute Allocation Rate		4.13%
21	Less: Paiute SG TC MMF Allocation (L19 * L20)		($19,490)
22	After Allocations to FERC Jurisdictions (L19 - L21)		($452,125)
23	Arizona Four Factor Allocation		56.07%
24	Test Year Self Insurance Expense Amount (Arizona) (L22 * L23)		($253,506)
25	Company Pro Forma Adjustment (Corporate)		$176,517
26	Staff Calculated Adjustment		($430,023)

REFERENCES:
Column [A]: Company Schedule C-1 O&M Summary, Column e
Column [B]: Staff detail as shown above
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation **Schedule BKB-18**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

OPERATING ADJUSTMENT NO. 7 - RATE CASE EXPENSE

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Regulatory Commission Expenses	928	$144,000	($38,800)	$105,200
2					
3					
4					
5					
4	Printing/Copying/Postage/Freight		$150,000		
5	Professional Services		265,000		
6	Notice/Publication		35,000		
7	Court Reporting		1,000		
8	Travel/Transportation/Misc.		125,000		
7	Total Rate Case Expense		$576,000		
8	Less: Staff adjustment for IHS Study		(50,000)		
9	Staff Recommended total Rate Case Expense		$526,000		
10	Staff Amortization Period (Years)		5		
11	Staff Annual Rate Case Expense		$105,200		
10	Company Amortized Rate Case Expense		144,000		
11	Adjustment		($38,800)		

REFERENCES:
Column [A]: Company Schedule C-2, Adjustment 12, sheet 1 of 1
Column [B]: Company response to RUCO 2-006 and Staff detail as shown above
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BKB-19

OPERATING ADJUSTMENT NO. 8 - INVESTOR RELATIONS

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Office Supplies and Expenses				
2	Direct	921	$0	$0	$0
3	System Allocable	921	8,423,284	(3,963)	8,419,321
4	**Total Office Supplies and Expenses**	921	$8,423,284	($3,963)	$8,419,321
5	Miscellaneous General				
6	Direct	930.2	$0	$0	$0
7	System Allocable	930.2	3,922,005	(100,473)	3,821,533
8	**Total Miscellaneous General**	930.2	$3,922,005	($100,473)	$3,821,533
9		**Total Adjustment**	$12,345,289	($104,435)	$12,240,854
10					
11		Act. No.	921	930.2	Total
12	Investor Relations Expense (Corporate)		$14,745	$373,831	$388,576
13	Paiute Allocation Rate		4.13%	4.13%	4.13%
14	Less: Paiute SG TC MMF Allocation (Line 8 * Line 9)		$609	$15,449	$16,058
15	After Allocations to FERC Jurisdictions (L8 - L10)		$14,135	$358,382	$372,518
16	Arizona Four Factor Allocation		56.07%	56.07%	56.07%
17	Test Year Invsestor Relations Expense (Arizona)		$7,926	$200,945	$208,871
18	Shareholder Allocation Percentage		50.00%	50.00%	50.00%
19	Investor Relations Expense Allocated to shareholders		$3,963	$100,473	$104,435

REFERENCES:
Column [A]: Company Schedule C-1 O&M Summary, Column e
Column [B]: Company response to RUCO DR 3-006
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation **Schedule BKB-20**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

OPERATING ADJUSTMENT NO. 9 - INCOME TAX

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Income Taxes	34,252,135	$3,249,319	$37,501,454
2				
3				
4				
5				
6				
7				
8		STAFF	STAFF	
9	**Calculation of Income Tax:**	ADJUSTED	RECOMMENDED	
10	Revenue (Sch BKB-10, Col. [C] Line 4, Col. [E] Line 4)	$481,681,406	$493,000,345	
11	Operating Expenses Excluding Income Taxes	350,188,048	$350,188,048	
12	Synchronized Interest (Sch BKB-2, L25)	$33,283,449	$33,283,449	
13	Arizona Taxable Income (L10 - L11 - L12)	$98,209,909	$109,528,848	
14	Arizona State Income Tax Rate (Sch BKB-2 L4)	4.90%	4.90%	
15	Arizona Income Tax (L13 x L14)	$4,812,286	$5,366,914	
16	Federal Taxable Income (L13 - L15)	$93,397,623	$104,161,934	
17	Total Federal Income Tax Rate (Sch BKB-2, L6)	35.00%	35.00%	
18	Total Federal Income Tax	$32,689,168	$36,456,677	
19	Combined Federal and State Income Tax (L15 + L18)	$37,501,454	$41,823,591	

REFERENCES:
Column [A]: Company Schedule C-1, sheet 1 of 18, Column e
Column [B]: Staff detail as shown above
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BKB-21

OPERATING ADJUSTMENT NO. 10 - DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	DESCRIPTION	[A] PLANT BALANCE	[B] NON-DEPRECIABLE/ FULLY DEPRECIATED	[C] STAFF RECOMMENDED DEPRECIATION RATE	[D] DEPRECIATION EXPENSE
1	*Direct*					
2	301	Organization	$42,653	$0	0.00%	$0
3	302	Franchise and Consents	2,131,095	0		69,261
4	303	Miscellaneous Intangible	1,968,623	0	0.00%	0
5	374	Land & Land Rights	405,666	405,666	0.00%	0
6	374	Rights of Way	2,580,656	0	1.37%	35,355
7	375	Structures & Improvements	110,557	0	3.35%	3,704
8	376	Mains	1,664,700,525	0	1.81%	30,131,080
9	378	Measuring and Reg. Stations	75,260,770	0	3.87%	2,912,592
10	380	Services	836,933,947	0	2.82%	23,601,537
11	381	Meters	292,374,234	0	4.15%	12,133,531
12	385	Industrial Measuring and Reg. Sta.	11,813,831	0	1.78%	210,286
13	387	Miscellaneous Equipment	432,098	0	0.00%	0
14	389	Land & Land Rights	16,211,030	16,211,030	0.00%	0
15	390	Structures & Improv - Co. Owned	50,485,778	0	2.79%	1,408,553
16	390	Structures & Improv - Leasehold	47,227	0	2.79%	1,318
17	391	Office Furniture & Fixtures	5,200,798	0	7.29%	379,138
18	391	Computer Software & Hardware	17,115,708	0	21.94%	3,755,186
19	392	Transportation Equipment - Light	23,644,116	0	14.37%	3,397,659
20	392	Transportation Equipment - Heavy	15,252,736	0	4.07%	620,786
21	393	Stores Equipment	845,802	0	3.73%	31,548
22	394	Tool, Shop, & Garage Equip.	9,863,065	0	10.39%	1,024,772
23	395	Laboratory Equipment	503,064	0	5.48%	27,568
24	396	Power-Operated Equipment	8,173,953	0	3.46%	282,819
25	397	Communication Equipment	2,209,647	0	-1.11%	(24,527)
26	397	Telemetry Equipment	569,911	0	21.96%	125,152
27	398	Miscellaneous Equipment	1,152,518	0	6.38%	73,531
28					**Total Direct Depreciation**	80,200,850
29					**Direct Depreciation as filed**	83,124,568
30					**Staff Recommended adjustment**	(2,923,718)
31						
32						
33	*System Allocable*					
34	301	Organization	34,660	0		0
35	303	Miscellaneous Intangible	122,666,985	0		9,301,683
36	389	Land & Land Rights	2,364,261	2,364,261	0.00%	0
37	390.1	Structures & Improv - Co. Owned	16,969,792	0	2.79%	473,457
38	390.2	Structures & Improv - Leasehold	2,546,644	0	2.79%	71,051
39	391	Office Furniture & Fixtures	5,025,979	0	7.29%	366,394
40	391.1	Computer Software & Hardware	9,530,290	0	21.94%	2,090,946
41	392.11	Transportation Equipment-Light	2,040,966	0	14.37%	293,287
42	392.12	Transportation Equipment-Heavy	0	0	4.07%	0
43	392.21	Transportation Equipment-Aircraft	0	0	0.00%	0
44	393	Stores Equipment	19,969	0	3.73%	745
45	394	Tool, Shop, & Garage Equip.	352,328	0	10.39%	36,607
46	395	Laboratory Equipment	546,398	0	5.48%	29,943
47	396	Power-Operated Equipment	6,594	0	3.46%	228
48	397	Communication Equipment	3,742,521	0	-1.11%	(41,542)
49	397.2	Telemetry Equipment	1,256	0	21.96%	276
50	398	Miscellaneous Equipment	685,621	0	6.38%	43,743
51		Rounding	0			0
52					**Total System Allocable Depreciation**	12,666,817
53					**Direct Depreciation as filed**	12,796,366
54					**Staff Recommended adjustment**	(129,549)
55						
56		Total Plant in Service	$3,206,564,272	$18,980,957	**Total Deprecation**	$92,867,667
57					**Direct Depreciation as filed**	$95,920,934
58					**Staff Recommended adjustment**	($3,053,267)

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BKB-22

OPERATING ADJUSTMENT NO. 11 - PROPERTY TAX

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Other Taxes	$41,628,621	$106,556	$41,735,177
2				
3				
4				
5	**Adjustment to Property Tax Expense**			
6	Adjusted Net Plant in Service	$1,754,880,282		
7	Add: Materials and Supplies	17,366,994		
8	Less: Transportation Equipment	(41,538,459)		
9	Less: Land Rights	(16,616,696)		
10	Estimated Full Cash Value	$1,714,092,122		
11	2016 Assessment Ratio	18.00%		
12	Assessed Value	$308,536,582		
13	Composite Property Tax Rate	14.11%		
14	Annualized Property Taxes	$43,522,170		
15	Capitalized Property Taxes	(1,831,351)		
16	Annualized Property Tax Expense	41,690,819		
17	Recorded Property Tax Expense	41,584,263		
18	Adjustment	$106,556		

REFERENCES:
Column [A]: Company Schedule C-1, sheet 15 of 18, Column f
Column [B]: Staff detail as shown above
Column [C]: Column [A] + Column [B]

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS	DOCKET NO. G-01551A-16-0107

DIRECT

TESTIMONY

OF

BLESSING NKIRUKA CHUKWU

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 30, 2016

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

This testimony provides Arizona Corporation Commission Utilities Division Staff's ("Staff") analysis and recommendations regarding Southwest Gas Corporation's ("SWG" or "Company") rate base in this rate case application.

The Company proposes a $31,926,894 or 4.25 percent revenue increase from the test year revenue of $481,681,406. The proposed revenue increase would produce an operating income of $108,844,799 for a 6.01 percent rate of return on a fair value cost rate base ("FVRB") of $1,812,414,666.

Staff recommends the following adjustments be made to SWG's proposed Original Cost Rate Base ("OCRB") and Reconstructed Cost New Depreciated Rate Base ("RCND"):

Summary of Staff Adjustments to Rate Base		**ORCB**		**RCND RB**	
Adj. No.	Description		Increase (Decrease)		Increase (Decrease)
1	Post Test Year Additions (Direct)	$	2,193,988	$	2,193,988
2	Post Test Year Additions (Allocable)	$	(1,892,895)	$	(1,892,895)
3	Airplane, Airplane Equipment and Hangar	$	(2,650,064)	$	(3,055,505)
4	Cash Working Capital	$	(388,000)	$	(388,000)
5	Material and Supplies	$	2,002,668	$	2,002,668
6	Prepaid Insurance	$	148,588	$	148,588
7	Customer Deposits	$	(173,954)	$	(173,954)
8	Customer Advances	$	(2,826,727)	$	(2,826,727)
9	Accumulated Deferred Income Tax –Bonus Tax Depreciation on Post Test Year Plant Additions	$	(7,560,471)	$	(7,560,471)
	Total of Staff Adjustments	$	(11,146,867)	$	(11,552,308)
	SWG Proposed Rate Base (Original Cost and RCND)	$	1,336,049,260	$	2,288,780,073
	Staff Proposed Rate Base (Original Cost and RCND)	$	1,324,902,393	$	2,277,227,765

I. INTRODUCTION

Q. Please state your name, business address, by whom and where you are employed and in what capacity.

A. My name is Blessing Nkiruka Chukwu. My business address is 1200 West Washington Street, Phoenix, Arizona 85007. I am employed by the Utilities Division ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission") as an Executive Consultant III.

Q. Please describe your educational and professional background.

A. I received a B.S. in Accounting and a M.B.A. in Finance from the University of Central Oklahoma. I was employed for over eight years by The City of Oklahoma City ("City") in various capacities. For approximately eight years of my employment with the City, I was an Administrative Aide with the responsibility of overseeing the various Environmental Protection Agency's mandates on Stormwater Quality within the Corporate City limits. Prior to being an Administrative Aide, I was a Budget Technician where I was responsible for reviewing, analyzing, and recommending budget requests and/or proposed budgets, fund transfers, appropriations and/or any other budget related issues proposed by assigned departments. Prior to joining the Commission, I was employed by the Oklahoma Corporation Commission ("OCC") for five years in the Public Utility Division, where I held various Public Utility Regulatory Analyst positions of increasing responsibilities. My responsibilities at the OCC included processing of applications consisting of rates and charges, streamline tariff revisions and requests for Certificates of Convenience and Necessity ("CC&N") filed by local exchange telecommunications companies, payphone providers, resellers, and operator service providers. I also reviewed mergers and acquisitions, Interconnection Agreements (including Arbitrations), and performed special projects as requested by the Director of Public Utility Division and/or the Commissioners.

Q. How long have you been employed with the ACC?

A. I have been employed with the ACC since May 27, 2003.

Q. What are your responsibilities as an Executive Consultant III?

A. My responsibilities include, but are not limited to, serving on the case teams; development of policies and procedures for appropriate regulatory oversight of public utilities; review of applications for CC&Ns, review of applications for rate cases and writing Staff Reports and Testimony.

Q. Have you testified previously before this Commission?

A. Yes, I have testified before this Commission.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Utilities Division Staff's ("Staff") analysis and recommendations regarding Southwest Gas Corporation ("Southwest" or "SWG" or "Company") rate base in this rate case application.

Q. What is the basis of your recommendations?

A. I performed a regulatory audit of the Company's application to determine whether sufficient, relevant, and reliable evidence exists to support the Company's requested rate base. The regulatory audit consisted of examining and testing the financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission-adopted National Association of Regulatory Utility Commissioners ("NARUC") Uniform System of Accounts ("USoA") and Generally Accepted Accounting Principles.

III. BACKGROUD

Q. Please provide a brief description of Southwest and the service it provides.

A. Southwest is an Arizona Class A utility engaged in the retail distribution, transportation, and sale of natural gas for domestic, commercial, agricultural, and industrial uses. Southwest currently serves over 1.9 million customers in the states of Arizona, California, and Nevada. Approximately 54 percent of the Company's customers are located in the state of Arizona, including portions of Cochise, Gila, Graham, Greenlee, La Paz, Maricopa, Mohave, Pima, Pinal, and Yuma counties. SWG's Central Arizona Division is headquartered in Phoenix and its Southern Arizona division is headquartered in Tucson. The current rates for the Company were approved in Decision No. 72723, dated January 6, 2012.

Q. What is the primary reason for Southwest's requested permanent rate increase?

A According to the Company, it has been more than five years since it filed its last general rate and currently its effective rates are based upon the level of operating expenses and capital investments made by the Company prior to June 30, 2010. Also, its authorized revenues need to be updated to reflect overall changes in the level of operating expenses currently being experienced by the Company and to reflect the significant amount of capital investments that have been made in the natural gas distribution system since its last rate case that are not presently included in rates.

As a result, the Company is seeking Commission approval for certain adjustments to its rates and charges for utility service so that the Company may recover its operating expenses and have a reasonable opportunity to earn a just and reasonable rate of return on the fair value of its property.

IV. SUMMARY OF PROPOSED RATE BASE

Q. Please summarize the Company's filing.

A. The Company proposes a $31,926,894 or 4.25 percent revenue increase from the test year revenue of $481,681,406. The proposed revenue increase would produce an operating income of $108,844,799 for a 6.01 percent rate of return on a fair value cost rate base ("FVRB") of $1,812,414,666. The Company's proposed rates represent a 2.8 percent increase to the average annual bill for residential customers.

Q. What test year did SWG utilize in this filing?

A. Southwest's test year is based on the twelve months ended November 30, 2015.

V. RATE BASE

Fair Value Rate Base

Q. Did the Company prepare schedules showing the elements of Reconstruction Cost New Rate Base?

A. Yes, the Company did. Southwest prepared schedules that show the Original Cost Rate Base ("OCRB"), the Reconstruction Cost New Rate Base ("RCRB") and averaged the two using equal weighting to calculate the FVRB.

Q. What is the difference between SWG's proposed rate base and Staff's recommended rate base?

A. Below is a comparison of Southwest's proposed rate base and Staff's recommended rate base:

Summary of Rate Base	Company		Staff		Difference	
Original Cost Rate Base	$	1,336,049,260	$	1,324,902,393	$	(11,146,867)
RCND Rate Base	$	2,288,780,073	$	2,277,227,765	$	(11,552,308)
Fair Value Rate Base	$	1,812,414,667	$	1,801,065,079	$	(11,349,588)

Rate Base Summary

Q. Please summarize Staff's rate base adjustments for Southwest.

A. Below is a summary of Staff adjustments for Southwest:

Summary of Staff Adjustments to Rate Base		**ORCB**		**RCND RB**	
Adj. No.	Description	Increase (Decrease)		Increase (Decrease)	
1	Post Test Year Additions (Direct)	$	2,193,988	$	2,193,988
2	Post Test Year Additions (Allocable)	$	(1,892,895)	$	(1,892,895)
3	Airplane, Airplane Equipment and Hangar	$	(2,650,064)	$	(3,055,505)
4	Cash Working Capital	$	(388,000)	$	(388,000)
5	Material and Supplies	$	2,002,668	$	2,002,668
6	Prepaid Insurance	$	148,588	$	148,588
7	Customer Deposits	$	(173,954)	$	(173,954)
8	Customer Advances	$	(2,826,727)	$	(2,826,727)
9	Accumulated Deferred Income Tax –Bonus Tax Depreciation on Post Test Year Plant Additions	$	(7,560,471)	$	(7,560,471)
	Total of Staff Adjustments	$	(11,146,867)	$	(11,552,308)
	SWG Proposed Rate Base (Original Cost and RCND)	$	1,336,049,260	$	2,288,780,073
	Staff Proposed Rate Base (Original Cost and RCND)	$	1,324,902,393	$	2,277,227,765

Rate Base Adjustments

Q. Please discuss Staff's adjustments to SWG's rate base shown on Schedules BNC-5, BNC-6, BNC-7a, BNC-7b, BNC-7c, BNC-7d, BNC-7e, BNC-8a, BNC-8b, and BNC-9.

A. Staff is recommending 9 adjustments to SWG's proposed rate base. Staff's adjustments to SWG's FVRB result in a net decrease of $11,349,588 from $1,812,414,667 to $1,801,065,079. These adjustments are discussed below.

Rate Base Adjustment No.1 - Post Test Year ("PTY") Plant Additions (Direct)

Q. Please explain the adjustment for Post Test Year Plant Additions (Direct).

A. This adjustment increases SWG's filed jurisdictional rate base by $2,193,988 and reflects the actual costs incurred for Post Test Year Plant (Direct) through August 31, 2016, as shown on Schedule BNC-5, line 16.

The Company's response to data request ("DR") STF 8-001 indicates that the costs on the work paper Schedule B-2 Post Test Year Plant as filed were those incurred through approximately March 25, 2016. In response to STF 8-001, the Company updated the worksheets comprising work paper Schedule B-2, Company's Adjustment 18, to include up-to date cost and in-service date information. Staff believes it is appropriate to include only actual costs incurred through August 31, 2016 in its post-test year adjustment.

Rate Base Adjustment No.2- Post Test Year Plant Additions (System Allocable)

Q. Please explain the Staff adjustment for Post Test Year Plant Additions (System Allocable).

A. This adjustment consists of two components: (1) a Miscellaneous Intangible Plant (Account 303) adjustment and (2) a General Plant adjustment.

As stated above, the Company's response to DR STF 8-001 indicates that the costs on the work paper Schedule B-2 Post Test Year Plant as filed were those incurred through approximately March 25, 2016. In response to STF 8-001, the Company updated the worksheets comprising work paper Schedule B-2, Company's Adjustment 18, to include up-to date cost and in-service date information. Staff believes it is appropriate to include only actual costs incurred through August 31, 2016 in its post-test year adjustment.

The total adjustment for Post Test Year Plant Additions (System Allocable) reduces SWG's filed jurisdictional rate base by $1,892,895 and reflects the actual costs incurred through August 31, 2016, as shown on Schedule BNC-6, line 14.

Q. Are there related adjustments that need to be considered?

A. According to Company's response to STF DR 2-004 and 2-017, and RUCO 2-011, "there are no accumulated depreciation associated with post-test year plant additions. Therefore, there are no book/tax depreciation differences and the associated deferred tax impact is $0."

However, in a subsequent DR, RUCO 8-007, the Company indicated that all post-test year plant additions are eligible for bonus depreciation and that the Company in fact takes bonus depreciation on all eligible plant additions. The bonus depreciation is discussed further with a related adjustment to Accumulated Deferred Income Tax.

Rate Base Adjustment No.3a – Airplane, Airplane Equipment and Hangar (Original Cost)

Q. Please explain the adjustment for Airplane, Airplane Equipment and Hangar (Original Cost).

A. This adjustment consists of two components: (1) Airplane adjustment and (2) Airplane Equipment and Hangar adjustment. Schedule BNC-7a shows the costs for corporate airplane, airplane equipment and hangar that were included in rate base as system allocable plant that were charged to Arizona jurisdiction. Those company-owned aircraft costs are removed from Arizona rate base, reducing rate base by a net amount of $2,650,064. Staff believes the company-owned airplane, airplane equipment and hangar are unnecessary for the provision of safe and reliable utility service to Arizona customers.

Q. Is there an adjustment to operating expenses related to this adjustment?

A. Yes. There is a related adjustment to test year depreciation expense, based on the adjustment to Plant in Service. The adjustment is addressed in Staff witness Brian K. Bozzo's testimony.

Rate Base Adjustment No.3b – Airplane, Airplane Equipment and Hangar (RCND)

Q. Please explain the adjustment for Airplane, Airplane Equipment and Hangar (RCND).

A. Just as Adjustment No. 3a, this adjustment consists of two components. Using information in the Company's application, Staff calculated an RCN factor of 1.55 for the airplane equipment and hangar, using the Handy-Whitman Index Methodology. The Airplane is the only item in Account No. 392.21 so Staff calculated the RCN factor using the Company's OCRB and RCRB reported balances. Schedule BNC-7b shows the costs that were charged to Arizona ratepayers. Those costs are removed from the Arizona rate base, reducing rate base by a net amount of $3,055,505. As stated above, the airplane, airplane equipment and hangar are unnecessary for the provision of safe and reliable utility service to Arizona customers.

Q. Is there an adjustment to operating expenses related to this adjustment?

A. Yes. There is a related adjustment to test year depreciation expense, based on the adjustment to Plant in Service. The adjustment is addressed in Brian K. Bozzo's testimony.

Working Capital Allowance

Q. What components are included in the Company's proposed working capital allowance?

A. The Company's proposed working capital allowance consists of three components. They are
(1) a thirteen-month average prepayments balance of $6.9 million;
(2) a thirteen-month average material and supplies balance of $15.4 million; and
(3) a negative cash working capital balance of $4.11 million based on a lead/lag study.

Q. Did Staff make working capital adjustments to rate base?

A. Yes, Staff made adjustments to prepayments, materials and supplies and cash working capital. The Staff adjustments are discussed below.

Rate Base Adjustment No.4 – Cash Working Capital

Q. Please describe Staff's cash working capital adjustment to rate base.

A. The calculation of a cash working capital requirement quantifies the amount of cash that a company needs to operate. Staff's recommended adjustments are based on Staff recommended revenue and expense levels in the schedules, and adjustments that Staff is recommending to the expense lag (lead) days for operating expense. As expenses were increased or decreased in the revenue requirement these were also increased or decreased in the cash working capital requirement.

Q. What basis did the Company use for its proposed allowance for cash working capital?

A. The Company's proposed allowance for cash working capital is based on a lead-lag study.

Q. What does the net result of the lead-lag factors suggest?

A. The net result from a lead-lag study indicates whether investors or ratepayers are being asked to provide the operating cash levels required to run recurring operations. The timing of the collection of revenues was compared to the timing of expenses SWG proposed. If the expense took longer to pay than to collect the revenue, SWG receives the benefit of cash working capital and the opposite is true if the expense is to be paid prior to the revenues being received. A net lead-lag factor was multiplied by the average daily operating expense applicable to each category of operating expense to calculate the positive or negative working capital required.

Q. What adjustments did Staff make to the revenue lag (lead) days?

A. On Schedule B-5, page 2, column C of the Company's application, the operating expense lag (lead) days were 40.68. Based on Staff recommended operating expense levels in the schedules Staff believes that the appropriate lag (lead) days is 40.95.

Q. What is Staff's recommendation?

A. Staff recommends a decrease to the allowance for cash working capital of $388,000 as shown on Schedule BNC-8a.

Rate Base Adjustment No.5 – Material and Supplies

Q. Please describe Staff's material and supplies' adjustment to rate base.

A. As mentioned above, the Company's proposed working capital allowance includes a thirteen-month average material and supplies balance of $15,364,326. In Company's response to Staff Informal DR 4_Attachment 1, SWG provided updated month end balances for the thirteen months ending September 30, 2016. The updated thirteen-month average material and supplies balance is $17,366,994. Staff reviewed the month end balances during the period and determined there is a need to normalize the balance included in the rate base.

Q. What is Staff's recommendation?

A. Staff recommends an increase to material and supply of $2,002,668 as shown on Schedule BNC-8b.

Rate Base Adjustment No.6 – Prepaid Liability Insurance

Q. Please explain Staff's Prepaid Liability Insurance adjustment to rate base.

A. This adjustment consists of two components: (1) a Prepaid Directors' and Officers' Liability Insurance adjustment and (2) an adjustment for updated thirteen-month average prepayments balance.

In data request responses to STF 9-002 and RUCO 5-012, SWG identified $290,653 as the level of Prepayments to include in rate base for Prepaid Directors' and Officers' Liability Insurance. This Staff adjustment removes $145,326 (one-half), of the rate base amount for Prepaid Directors' and Officers' Liability Insurance, to reflect a 50-50 sharing of such cost between shareholders and ratepayers, as shown on Schedule BNC-8c. The sharing of this cost is addressed further with a related adjustment to expense, in Brian K. Bozzo's testimony.

As indicated above, the Company's proposed working capital allowance includes a thirteen-month average prepayments balance of $6,885,291. In the Company's response to Staff Informal DRs 1-006 and 4_Attachment 1, SWG provided updated month end balances for the thirteen months ending September 30, 2016, and also corrected the amounts for October and November 2015. The updated thirteen-month average prepayments balance is $7,179,205. Staff reviewed the month end balances during the period and determined there is a need to normalize the balance included in the rate base. This adjustment would normalize the prepayments balance and would increase the rate base by $293,914.

Q. What is Staff's Net Prepayments recommendation?

A. Staff recommends a net increase to prepayments of $148,588 as shown on Schedule BNC-8c.

Rate Base Adjustment No.7 – Customer Deposits

Q. Please describe Staff's Customer Deposits adjustment to rate base.

A. This adjustment normalizes the balance included as a reduction to rate base. In Company's response to Staff Informal DR 4_Attachment 1, SWG provided updated month end balances for the thirteen months ending September 30, 2016. In the Company's application, the proposed thirteen-month average customer deposits balance is $39,253,787 while the updated amount is $39,427,741.

Q. What is Staff's recommendation?

A. Staff recommends an increase to customer deposits of $173,954 as shown on Schedule BNC-8d.

Rate Base Adjustment No.8 – Customer Advances

Q. Please describe Staff's Customer Advances adjustment to rate base.

A. This adjustment also normalizes the balance deducted from rate base. SWG had provided updated month end balances for the thirteen months ending September 30, 2016. In the Company's application, the proposed thirteen-month average customer advances balance is $38,815,661 while the updated amount is $41,642,388.

Q. What is Staff's recommendation?

A. Staff recommends an increase to customer advances of $2,826,727 as shown on Schedule BNC-8e.

Rate Base Adjustment No. 9 – Accumulated Deferred Income Taxes ("ADIT") - Bonus Tax Depreciation on PTY Plant Additions

Q. Please explain the adjustment for Accumulated Deferred Income Taxes for Bonus Tax Depreciation on Post Test Year Plant Additions.

A. In SWG's response to data request STF 2-017, regarding bonus income tax depreciation on any post-test year plant additions for which the Company is requesting rate base inclusion, the Company stated that "as of the end of the test year, there is no accumulated depreciation associated with post-test year plant additions. Therefore, there are no book/tax depreciation differences, and the associated deferred tax impact is $0."

However, in SWG's response to data request RUCO 8-007, the Company indicated that "all projects in the PTY plant adjustment are eligible for 50% bonus depreciation. The Company takes bonus depreciation on all eligible plant additions." The Company also stated that the amount related to bonus depreciation is 50% of each amount on the schedules provided, as follows:

WP B-2 PTY Dir: $12,407,289

WP B-2 PTY Sys 303: $11,644,662

WP B-2 PTY Sys Gen: $1,325,263

According to SWG's response to data request RUCO 8-007, the Company based its "response on the costs it is requesting for recovery in the post-test year plant adjustment, as updated in response to Staff 8.01." The Company further stated that, "there may be trailing charges after August 31, 2016, that will impact the final cost of each project, but will not be requested for recovery in this proceeding."

In its supplement to SWG updated response to STF 8-001, SWG revised the PTY Plant balance for System 303 (Miscellaneous Intangible Plant) from $23,289,325 to $23,931,832. Therefore, WP B-2 PTY Sys 303 should be $11,965,916.

To calculate the bonus tax depreciation impact on ADIT, based on the PTY Plant Addition (Direct), Staff multiplied 50% of the PTY Plant Additions' cost by the effective tax rate.

$24,814,579 x 50% x 38.0695% = $4,723,393

To calculate the bonus tax depreciation impact on ADIT, based on the PTY Plant Addition (System Allocable 303), Staff multiplied 50% of the PTY Plant Additions' cost by the four-factor allocator and by the effective tax rate.

$23,931,832 x 50% x 56.07% x 38.0695% = $2,554,193

To calculate the bonus tax depreciation impact on ADIT, based on the PTY Plant Addition (System Allocable General), Staff multiplied 50% of the PTY Plant Additions' cost by the four-factor allocator and by effective tax rate.

$2,650,526 x 50% x 56.07% x 38.0695% = $282,885

As shown on Schedule BNC-9, the total impact is $7,560,471 which is added to ADIT and it reduces SWG's as-filed rate base.

Q. What is the total reduction to Arizona jurisdictional rate base for the federal ADIT on the PTY Plant Additions amounts?

A. The total reduction to Arizona jurisdictional rate base for the ADIT on the PTY Plant Addition amounts is $7,560,471, as shown on Schedule BNC-4a, line 81

Adjustments to Reconstruction Cost New Depreciated Rate Base

Q. Please describe Staff's adjustments to RCND rate base.

A. Staff's adjustments to SWG's proposed RCND rate base are shown on Schedule BNC-4b (RCND). Except for Corporate Airplane, Airplane Equipment and Hangar costs, the RCND adjustment amounts are the same as Staff's adjustments to OCRB.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schdule BNC-3

ORIGINAL COST AND RCND ADJUSTED RATE BASE

		[A]	[B]	[C]	[D]	[E]	[F]
			Original Cost			RCND	
Line No.	Description	Company As Filed	Staff Adjustments	As Adjusted by Staff	Company As Filed	Staff Adjustments	As Adjusted by Staff
1	Gas Plant in Service						
2	Direct	$3,037,836,019	$2,193,988	$3,040,030,007	$4,996,152,529	$2,193,988	$4,998,346,517
3	System Allocable	173,566,230	(7,031,965)	166,534,264	183,692,132	(7,784,585)	175,907,546
4	Total Gross Plant	$3,211,402,249	($4,837,977)	$3,206,564,272	$5,179,844,661	($5,590,597)	$5,174,254,063
5							
6	Accumulated Depreciation						
7	and Amortization						
8	Direct	($1,285,149,725)	$0	($1,285,149,725)	($2,145,382,255)	$0	($2,145,382,255)
9	System Allocable	(99,705,173)	1,013,033	(98,692,140)	(103,103,563)	1,204,528	(101,899,035)
10	Total Accumulated Depreciation						
11	and Amortization	($1,384,854,898)	$1,013,033	($1,383,841,865)	($2,248,485,818)	$1,204,528	($2,247,281,290)
12							
13	Net Gas Plant in Service	$1,826,547,351	($3,824,944)	$1,822,722,406	$2,931,358,843	($4,386,070)	$2,926,972,773
14							
15	Other Rate Base						
16	Allowance for Working Capital						
17	Cash Working Capital	($4,113,676)	($388,000)	($4,501,676)	($4,113,676)	($388,000)	($4,501,676)
18	Materials and Supplies	15,364,326	2,002,668	17,366,994	15,364,326	2,002,668	17,366,994
19	Prepayments	6,885,291	148,588	7,033,879	6,885,291	148,588	7,033,879
20	Customer Deposits	(39,253,787)	(173,954)	(39,427,741)	(39,253,787)	(173,954)	(39,427,741)
21	Customer Advances	(38,815,661)	(2,826,727)	(41,642,388)	(38,815,661)	(2,826,727)	(41,642,388)
22	Deferred Taxes	(430,564,584)	(6,084,498)	(436,649,082)	(582,645,263)	(5,928,813)	(588,574,076)
23	Other		0			0	
24	Total Other Rate Base Items	($490,498,091)	($7,321,923)	($497,820,014)	($642,578,770)	($7,166,238)	($649,745,008)
25							
26	Total Rate Base	$1,336,049,260	($11,146,867)	$1,324,902,393	$2,288,780,073	($11,552,308)	$2,277,227,765
27							
28							
29	**Fair Value Calculation (Per Company)**						
30	Original Cost	$1,336,049,260					
31	RCND	2,288,780,073					
32	Total	$3,624,829,333					
33	Average (Fair Value)	$1,812,414,668					
34							
35	**Fair Value Calculation (Per Staff)**						
36	Original Cost	$1,324,902,393					
37	RCND	2,277,227,765					
38	Total	$3,602,130,158					
39	Average (Fair Value)	$1,801,065,079					

Notes and Source
Cols. A and D: SWG filing, Schedule B-1, Sheet 1 of 2

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BNC-4a

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

Line No.	Description	Act. No.	[A] COMPANY AS FILED	[B] ADJ #1 Post Test Year (Direct) Ref: Sch BNC-5	[C] ADJ #2 Post Test Year (Allocable) Ref: Sch BNC-6	[D] ADJ #3a Airplane, Airplane Equipment and Hanger Ref: Sch BNC-7a	[E] ADJ #4 Cash Working Capital Ref: Sch BNC-8a	[G] ADJ #5 Materials and Supplies Ref: Sch BNC-8b	[H] ADJ #6 Prepaid Insurance Ref: Sch BNC-8c	[I] ADJ #7 Customer Deposits Ref: Sch BNC-8d	[J] ADJ #8 Customer Advances Ref: Sch BNC-8e	[K] ADJ #9 Accumulated Deferred Income Taxes Ref: Sch BNC-9	[O] Staff Adjusted
1	**Direct**												
2	Intangible Plant												
3	Organization	301	$42,653	$0	$0	$0	$0	$0	$0	$0	$0	$0	$42,653
4	Franchise and Consents	302	2,131,095	0	0	0	0	0	0	0	0	0	2,131,095
5	Miscellaneous Intangible	303	1,968,623	0	0	0	0	0	0	0	0	0	1,968,623
6	Total Intangible Plant		$4,142,371	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,142,371
7													
8	Distribution Plant												
9	Land & Land Rights	374.1	$405,666	$0	$0	$0	$0	$0	$0	$0	$0	$0	$405,666
10	Rights of Way	374.2	2,580,656	0	0	0	0	0	0	0	0	0	2,580,656
11	Structures & Improvements	375	110,557	0	0	0	0	0	0	0	0	0	110,557
12	Mains	376	1,663,028,781	1,671,744	0	0	0	0	0	0	0	0	1,664,700,525
13	Measuring and Reg. Stations	378	75,084,241	176,529	0	0	0	0	0	0	0	0	75,260,770
14	Services	380	836,500,110	433,837	0	0	0	0	0	0	0	0	836,933,947
15	Meters	381	292,374,234	0	0	0	0	0	0	0	0	0	292,374,234
16	Industrial Measuring and Reg. Sta.	385	11,813,831	0	0	0	0	0	0	0	0	0	11,813,831
17	Miscellaneous Equipment	387	432,098	0	0	0	0	0	0	0	0	0	432,098
18	Total Distribution Plant		$2,882,330,173	$2,282,110	$0	$0	$0	$0	$0	$0	$0	$0	$2,884,612,283
19													
20	General Plant												
21	Land & Land Rights	389	$16,211,030	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,211,030
22	Structures & Improv - Co. Owned	390.1	50,485,778	0	0	0	0	0	0	0	0	0	50,485,778
23	Structures & Improv - Leasehold	390.2	47,227	0	0	0	0	0	0	0	0	0	47,227
24	Office Furniture & Fixtures	391	5,200,798	0	0	0	0	0	0	0	0	0	5,200,798
25	Computer Software & Hardware	391.1	17,113,211	2,497	0	0	0	0	0	0	0	0	17,115,708
26	Transportation Equipment - Light	392.11	23,680,551	(36,435)	0	0	0	0	0	0	0	0	23,644,116
27	Transportation Equipment - Heavy	392.12	15,252,736	0	0	0	0	0	0	0	0	0	15,252,736
28	Stores Equipment	393	888,168	(42,366)	0	0	0	0	0	0	0	0	845,802
29	Tool, Shop, & Garage Equip.	394	9,820,699	42,366	0	0	0	0	0	0	0	0	9,863,065
30	Laboratory Equipment	395	503,064	0	0	0	0	0	0	0	0	0	503,064
31	Power-Operated Equipment	396	8,228,137	(54,184)	0	0	0	0	0	0	0	0	8,173,953
32	Communication Equipment	397	2,209,647	0	0	0	0	0	0	0	0	0	2,209,647
33	Telemetry Equipment	397.2	569,911	0	0	0	0	0	0	0	0	0	569,911
34	Miscellaneous Equipment	398	1,152,518	0	0	0	0	0	0	0	0	0	1,152,518
35	Total General Plant		$151,363,475	($88,122)	$0	$0	$0	$0	$0	$0	$0	$0	$151,275,353
36													
37	Total Direct Gas Plant in Service		$3,037,836,019	$2,193,988	$0	$0	$0	$0	$0	$0	$0	$0	$3,040,030,007
38													
39	**System Allocable**												
40	Intangible Plant												
41	Organization	301	$34,660	$0	$0	$0	$0	$0	$0	$0	$0	$0	$34,660
42	Miscellaneous Intangible	303	124,525,748	0	(1,858,763)	0	0	0	0	0	0	0	122,666,985
43	Total Intangible Plant		$124,560,408	$0	($1,858,763)	$0	$0	$0	$0	$0	$0	$0	$122,701,644
44													$0
45	General Plant												
46	Land & Land Rights	389	$2,364,261	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,364,261
47	Structures & Improv - Co. Owned	390.1	17,533,775	0	(34,540)	(529,442)	0	0	0	0	0	0	16,969,792
48	Structures & Improv - Leasehold	390.2	2,550,008	0	(3,364)	0	0	0	0	0	0	0	2,546,644
49	Office Furniture & Fixtures	391	5,022,243	0	3,736	0	0	0	0	0	0	0	5,025,979
50	Computer Software & Hardware	391.1	9,530,290	0	0	0	0	0	0	0	0	0	9,530,290
51	Transportation Equipment-Light	392.11	2,040,966	0	0	0	0	0	0	0	0	0	2,040,966
52	Transportation Equipment-Heavy	392.12	0	0	0	0	0	0	0	0	0	0	0
53	Transportation Equipment-Aircraft	392.21	4,609,628	0	0	(4,609,628)	0	0	0	0	0	0	0
54	Stores Equipment	393	19,969	0	0	0	0	0	0	0	0	0	19,969
55	Tool, Shop, & Garage Equip.	394	352,328	0	0	0	0	0	0	0	0	0	352,328
56	Laboratory Equipment	395	546,398	0	0	0	0	0	0	0	0	0	546,398
57	Power-Operated Equipment	396	6,594	0	0	0	0	0	0	0	0	0	6,594
58	Communication Equipment	397	3,742,521	0	0	0	0	0	0	0	0	0	3,742,521
59	Telemetry Equipment	397.2	1,256	0	0	0	0	0	0	0	0	0	1,256
60	Miscellaneous Equipment	398	685,584	0	36	0	0	0	0	0	0	0	685,621
61	Total General Plant		$49,005,822	$0	($34,132)	($5,139,070)	$0	$0	$0	$0	$0	$0	$43,832,620
62													
63	Total System Allocable Gas Plant in Service		$173,566,230	$0	($1,892,895)	($5,139,070)	$0	$0	$0	$0	$0	$0	$166,534,264
64													
65	Total Gas Plant in Service		$3,211,402,249	$2,193,988	($1,892,895)	($5,139,070)	$0	$0	$0	$0	$0	$0	$3,206,564,272
66													
67	Accumulated Depreciation and Amortization												
68	Direct		($1,285,149,725)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,285,149,725)
69	System Allocable		(99,705,173)	0	0	1,013,033	0	0	0	0	0	0	(98,692,140)
70	Total Accumulated Depreciation and Amortization		($1,384,854,898)	$0	$0	$1,013,033	$0	$0	$0	$0	$0	$0	($1,383,841,865)
71													
72	Net Gas Plant in Service		$1,826,547,351	$2,193,988	($1,892,895)	($4,126,037)	$0	$0	$0	$0	$0	$0	$1,822,722,406
73													
74	Other Rate Base												
75	Allowance for Working Capital												
76	Cash Working Capital		($4,113,676)	$0	$0	$0	($388,000)	$0	$0	$0	$0	$0	($4,501,676)
77	Materials and Supplies		15,364,326	0	0	0	0	2,002,668	0	0	0	0	17,366,994
78	Prepayments		6,885,291	0	0	0	0	0	148,588	0	0	0	7,033,879
79	Customer Deposits		(39,253,787)	0	0	0	0	0	0	(173,954)	0	0	(39,427,741)
80	Customer Advances		(38,815,661)	0	0	0	0	0	0	0	(2,826,727)	0	(41,642,388)
81	Deferred Taxes		(430,564,584)	0	0	1,475,973	0	0	0	0	0	(7,560,471)	(436,649,082)
82	Other		0	0	0	0	0	0	0	0	0	0	0
83	Total Other Rate Base Items		($490,498,091)	$0	$0	$1,475,973	($388,000)	$2,002,668	$148,588	($173,954)	($2,826,727)	($7,560,471)	($497,820,014)
84													
85	Total Rate Base		$1,336,049,260	$2,193,988	($1,892,895)	($2,650,064)	($388,000)	$2,002,668	$148,588	($173,954)	($2,826,727)	($7,560,471)	$1,324,902,393

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BNC-4b

SUMMARY OF RECONSTRUCTION NEW LESS DEPRECIATION COST RATE BASE ADJUSTMENTS

Line No.	Description	Act. No.	[A] COMPANY AS FILED	[B] ADJ #1 Post Test Year (Direct) Ref: Sch BNC-5	[C] ADJ #2 Post Test Year (Allocable) Ref: Sch BNC-6	[D] ADJ #3b Airplane, Airplane Equipment and Hanger Ref: Sch BNC-7b	[E] ADJ #4 Cash Working Capital Ref: Sch BNC-8a	[G] ADJ #5 Materials and Supplies Ref: Sch BNC-8b	[H] ADJ #6 Prepaid Insurance Ref: Sch BNC-8c	[I] ADJ #7 Customer Deposits Ref: Sch BNC-8d	[J] ADJ #8 Customer Advances Ref: Sch BNC-8e	[K] ADJ #9 Accumulated Deferred Income Taxes Ref: Sch BNC-9	[F] Staff Adjusted
1	**Direct**												
2	Intangible Plant												
3	Organization	301	$42,653	$0	$0	$0	$0	$0	$0	$0	$0	$0	$42,653
4	Franchise and Consents	302	2,131,095	0	0	0	0	0	0	0	0	0	2,131,095
5	Miscellaneous Intangible	303	1,968,623	0	0	0	0	0	0	0	0	0	1,968,623
6	Total Intangible Plant		$4,142,371	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,142,371
7													
8	Distribution Plant												
9	Land & Land Rights	374.1	$405,666	$0	$0	$0	$0	$0	$0	$0	$0	$0	$405,666
10	Rights of Way	374.2	2,580,656	0	0	0	0	0	0	0	0	0	2,580,656
11	Structures & Improvements	375	1,003,245	0	0	0	0	0	0	0	0	0	1,003,245
12	Mains	376	2,825,838,544	1,671,744	0	0	0	0	0	0	0	0	2,827,510,288
13	Measuring and Reg. Stations	378	103,708,792	176,529	0	0	0	0	0	0	0	0	103,885,321
14	Services	380	1,337,008,146	433,837	0	0	0	0	0	0	0	0	1,337,441,983
15	Meters	381	514,798,726	0	0	0	0	0	0	0	0	0	514,798,726
16	Industrial Measuring and Reg. Sta.	385	21,481,716	0	0	0	0	0	0	0	0	0	21,481,716
17	Miscellaneous Equipment	387	1,235,844	0	0	0	0	0	0	0	0	0	1,235,844
18	Total Distribution Plant		$4,808,061,335	$2,282,110	$0	$0	$0	$0	$0	$0	$0	$0	$4,810,343,445
19													
20	General Plant												
21	Land & Land Rights	389	$16,211,030	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,211,030
22	Structures & Improv - Co. Owned	390.1	71,034,277	2,497	0	0	0	0	0	0	0	0	71,036,774
23	Structures & Improv - Leasehold	390.2	84,597	0	0	0	0	0	0	0	0	0	84,597
24	Office Furniture & Fixtures	391	6,644,540	0	0	0	0	0	0	0	0	0	6,644,540
25	Computer Software & Hardware	391.1	18,674,203	0	0	0	0	0	0	0	0	0	18,674,203
26	Transportation Equipment - Light	392.11	26,925,430	(36,435)	0	0	0	0	0	0	0	0	26,888,995
27	Transportation Equipment - Heavy	392.12	16,105,065	0	0	0	0	0	0	0	0	0	16,105,065
28	Stores Equipment	393	1,274,951	(42,366)	0	0	0	0	0	0	0	0	1,232,585
29	Tool, Shop, & Garage Equip.	394	11,729,250	42,366	0	0	0	0	0	0	0	0	11,771,616
30	Laboratory Equipment	395	673,899	0	0	0	0	0	0	0	0	0	673,899
31	Power-Operated Equipment	396	9,695,843	(54,184)	0	0	0	0	0	0	0	0	9,641,659
32	Communication Equipment	397	2,647,825	0	0	0	0	0	0	0	0	0	2,647,825
33	Telemetry Equipment	397.2	739,728	0	0	0	0	0	0	0	0	0	739,728
34	Miscellaneous Equipment	398	1,508,185	0	0	0	0	0	0	0	0	0	1,508,185
35	Total General Plant		$183,948,823	($88,122)	$0	$0	$0	$0	$0	$0	$0	$0	$183,860,701
36													
37	Total Direct Gas Plant in Service		$4,996,152,529	$2,193,988	$0	$0	$0	$0	$0	$0	$0	$0	$4,998,346,517
38													
39	**System Allocable**												
40	Intangible Plant												
41	Organization	301	$34,660	$0	$0	$0	$0	$0	$0	$0	$0	$0	$34,660
42	Miscellaneous Intangible	303	124,525,748	0	(1,858,763)	0	0	0	0	0	0	0	122,666,985
43	Total Intangible Plant		$124,560,408	$0	($1,858,763)	$0	$0	$0	$0	$0	$0	$0	$122,701,644
44													
45	General Plant												
46	Land & Land Rights	389	$2,364,261	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,364,261
47	Structures & Improv - Co. Owned	390.1	23,422,809	0	(34,540)	(821,100)	0	0	0	0	0	0	22,567,169
48	Structures & Improv - Leasehold	390.2	3,461,636	0	(3,364)	0	0	0	0	0	0	0	3,458,272
49	Office Furniture & Fixtures	391	6,421,391	0	3,736	0	0	0	0	0	0	0	6,425,127
50	Computer Software & Hardware	391.1	9,971,377	0	0	0	0	0	0	0	0	0	9,971,377
51	Transportation Equipment-Light	392.11	2,195,465	0	0	0	0	0	0	0	0	0	2,195,465
52	Transportation Equipment-Heavy	392.12	0	0	0	0	0	0	0	0	0	0	0
53	Transportation Equipment-Aircraft	392.21	5,070,591	0	0	(5,070,591)	0	0	0	0	0	0	0
54	Stores Equipment	393	23,969	0	0	0	0	0	0	0	0	0	23,969
55	Tool, Shop, & Garage Equip.	394	394,660	0	0	0	0	0	0	0	0	0	394,660
56	Laboratory Equipment	395	613,091	0	0	0	0	0	0	0	0	0	613,091
57	Power-Operated Equipment	396	7,451	0	0	0	0	0	0	0	0	0	7,451
58	Communication Equipment	397	4,369,968	0	0	0	0	0	0	0	0	0	4,369,968
59	Telemetry Equipment	397.2	1,282	0	0	0	0	0	0	0	0	0	1,282
60	Miscellaneous Equipment	398	813,774	0	36	0	0	0	0	0	0	0	813,810
61	Total General Plant		$59,131,724	$0	($34,132)	($5,891,690)	$0	$0	$0	$0	$0	$0	$53,205,902
62													
63	Total System Allocable Gas Plant in Service		$183,692,132	$0	($1,892,895)	($5,891,690)	$0	$0	$0	$0	$0	$0	$175,907,546
64													
65	Total Gas Plant in Service		$5,179,844,661	$2,193,988	($1,892,895)	($5,891,690)	$0	$0	$0	$0	$0	$0	$5,174,254,063
66													
67	Accumulated Depreciation and Amortization												
68	Direct		($2,145,382,255)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,145,382,255)
69	System Allocable		(103,103,563)	0	0	1,204,528	0	0	0	0	0	0	(101,899,035)
70	Total Accumulated Depreciation and Amortization		($2,248,485,818)	$0	$0	$1,204,528	$0	$0	$0	$0	$0	$0	($2,247,281,290)
71													
72	Net Gas Plant in Service		$2,931,358,843	$2,193,988	($1,892,895)	($4,687,163)	$0	$0	$0	$0	$0	$0	$2,926,972,773
73													
74	Other Rate Base												
75	Allowance for Working Capital												
76	Cash Working Capital		($4,113,676)	$0	$0	$0	($388,000)	$0	$0	$0	$0	$0	($4,501,676)
77	Materials and Supplies		15,364,326	0	0	0	0	2,002,668	0	0	0	0	17,366,994
78	Prepayments		6,885,291	0	0	0	0	0	148,588	0	0	0	7,033,879
79	Customer Deposits		(39,253,787)	0	0	0	0	0	0	(173,954)	0	0	(39,427,741)
80	Customer Advances		(38,815,661)	0	0	0	0	0	0	0	(2,826,727)	0	(41,642,388)
81	Deferred Taxes		(582,645,263)	0	0	1,631,658	0	0	0	0	0	(7,560,471)	(588,574,076)
82	Other												0
83	Total Other Rate Base Items		($642,578,770)	$0	$0	$1,631,658	($388,000)	$2,002,668	$148,588	($173,954)	($2,826,727)	($7,560,471)	($649,745,008)
84													
85	Total Rate Base		$2,288,780,073	$2,193,988	($1,892,895)	($3,055,505)	($388,000)	$2,002,668	$148,588	($173,954)	($2,826,727)	($7,560,471)	$2,277,227,765

Southwest Gas Corporation **Schedule BNC-5**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR ADDITIONS (DIRECT)

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Distribution Plant				
2	Mains	376	$12,124,818	$1,671,744	$13,796,562
3	Measuring and Reg. Stations	378	3,546,554	176,529	3,723,083
4	Services	380	2,822,622	433,837	3,256,459
5	Total Distribution Plant		$18,493,994	$2,282,110	$20,776,104
6					
7	General Plant				
8	Computer Software & Hardware	391.1	$28,003	$2,497	$30,500
9	Transportation Equipment - Light	392.11	1,921,601	(36,435)	1,885,166
10	Stores Equipment	393	106,981	(42,366)	64,615
11	Tool, Shop, & Garage Equip.	394	83,896	42,366	126,262
12	Power-Operated Equipment	396	349,269	(54,184)	295,085
13	Total General Plant		$2,489,750	($88,122)	$2,401,628
14					
15					
16	**Total Post-Test Year Additions (Direct)**		**$20,983,744**	**$2,193,988**	**$23,177,732**

REFERENCES:
Column [A]: Company Schedule B-2, page 1 and Workpaper Schedule B-2 Sheet 2
Column [B]: Company response to STF DR 8-001
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BNC-6

RATE BASE ADJUSTMENT NO. 2- POST TEST YEAR ADDITIONS (ALLOCABLE)

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED	
1	Intangible Plant					
2	Miscellaneous Intangible	303	$15,277,341	($1,858,763)	$13,418,578	
3	Total Intangible Plant		$15,277,341	($1,858,763)	$13,418,578	
4						
5						
6	General Plant					
7	Structures & Improv - Co. Owned	390.1	$951,958	($34,540)	$917,417	
8	Structures & Improv - Leasehold	390.2	107,532	(3,364)	104,167	
9	Office Furniture & Fixtures	391	287,479	3,736	291,215	
10	Miscellaneous Equipment	398	40,623	36	40,659	
11	Total General Plant		$1,387,591	($34,132)	$1,353,459	
12						
13						
14	**Total Post-Test Year Additions (Allocable)**		**$16,664,932**	**($1,892,895)**	**$14,772,037**	
15						
16						
17						
18	Arizona 4-Factor	56.07%				
19			COMPANY	Amount Allocated	STAFF	Amount Allocated
20	Intangible Plant		AS FILED	to Arizona	ADJUSTED	to Arizona
21	Miscellaneous Intangible	303	$27,246,908	$15,277,341	$23,931,832	$13,418,578
22	Total Intangible Plant		$27,246,908	$15,277,341	$23,931,832	$13,418,578
23						
24	General Plant					
25	Structures & Improv - Co. Owned	390.1	$1,697,802	$951,958	$1,636,200	$917,417
26	Structures & Improv - Leasehold	390.2	191,781	107,532	185,781	104,167
27	Office Furniture & Fixtures	391	512,714	287,479	519,377	291,215
28	Miscellaneous Equipment	398	72,450	40,623	72,515	40,659
29	Total General Plant		$2,474,747	$1,387,591	$2,413,873	$1,353,459

REFERENCES:
Column [A]: Company Schedule B-2, page 2 and Workpaper Schedule B-2 Sheets 1, 2, 7, and 8
Column [B]: Company response to STF DR 8-001
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BNC-7a

RATE BASE ADJUSTMENT NO. 3A AIRPLANE, AIRPLANE EQUIPMENT AND HANGAR

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED	
1	General Plant					
2	Structures & Improv - Co. Owned	390.1	$529,442	($529,442)	$0	
3	Transportation Equipment-Aircraft	392.21	4,609,628	(4,609,628)	0	
4	Total General Plant		$5,139,070	($5,139,070)	$0	
5						
6	Accumulated Depreciation and Amortization					
7	Direct		($1,285,149,725)	0	($1,285,149,725)	
8	System Allocable		(99,705,173)	1,013,033	(98,692,140)	
9	Total Accumulated Depreciation and Amortization		($1,384,854,898)	$1,013,033	($1,383,841,865)	
10						
11						
12	Deferred Taxes		(430,564,584)	1,475,973	(429,088,611)	
13						
14						
15			Airplane		Total	
16			Hangar and		Arizona	Staff
17			Equipment	Airplane	Allocation	Adjustment
18	Act. No.		390.1	392.21		
19	Original Cost		$529,442	$4,609,628	$5,139,070	($5,139,070)
20	Accumulated Depreciation		(200,035)	(812,998)	(1,013,033)	1,013,033
21	Accumulated Deferred Income Taxes		(17,938)	(1,458,035)	(1,475,973)	1,475,973
22	Net Arizona Rate Base		$311,469	$2,338,595	$2,650,064	($2,650,064)

REFERENCES:
Column [A]: Company Schedule B-2, page 7 and Workpaper Schedule B-2 Sheets 5 and 7
Column [B]: Company response to STF DR 9-001 AND RUCO DR 5.11
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation **Schedule BNC-7b**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

RATE BASE ADJUSTMENT NO. 3B AIRPLANE, AIRPLANE EQUIPMENT AND HANGAR

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	General Plant				
2	Structures & Improv - Co. Owned	390.1	$23,422,809	($821,100)	$22,601,709
3	Transportation Equipment-Aircraft	392.21	5,070,591	(5,070,591)	0
4	Total General Plant		$28,493,399	($5,891,690)	$22,601,709
5					
6	Accumulated Depreciation and Amortization				
7	Direct		($1,285,149,725)	0	($1,285,149,725)
8	System Allocable		(99,705,173)	1,204,528	(98,500,646)
9	Total Accumulated Depreciation and Amortization		($1,384,854,898)	$1,204,528	($1,383,650,371)
10					
11					
12	Deferred Taxes		(430,564,584)	1,631,658	(428,932,926)
13					
14					
15					
16			Staff's OCRB		Staff's RCRB
17			Adjustment		Adjustment
18			Airplane		Airplane
19			Hangar and	RCN	Hangar and
20			Equipment	Factor	Equipment
21	Original Cost	390.1	$529,442	1.55	$821,100
22	Accumulated Depreciation		(200,035)	1.55	(310,230)
23	Accumulated Deferred Income Taxes		(17,938)	1.55	(27,820)
24	Net Arizona Rate Base		$311,469		$483,050
25					
26					
27			Staff's OCRB		Staff's RCRB
28			Adjustment	RCN	Adjustment
29			Airplane	Factor	Airplane
30	Original Cost	392.21	$4,609,628	1.10	$5,070,591
31	Accumulated Depreciation		(812,998)	1.10	(894,298)
32	Accumulated Deferred Income Taxes		(1,458,035)	1.10	(1,603,839)
33	Net Arizona Rate Base		$2,338,595		$2,572,455
34					
35					
36			Total		
37			Arizona	Staff	
38			Allocation	Adjustment	
39	Original Cost		$5,891,690	($5,891,690)	
40	Accumulated Depreciation		(1,204,528)	1,204,528	
41	Accumulated Deferred Income Taxes		(1,631,658)	1,631,658	
42	Net Arizona Rate Base		$3,055,505	($3,055,505)	

REFERENCES:
Column [A]: Company Schedule B-2, page 7 and Workpaper Schedule B-2 Sheets 5 and 7
Column [B]: Company response to STF DR 9-001 AND RUCO DR 5.11
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BNC-8a

RATE BASE ADJUSTMENT NO. 4 CASH WORKING CAPITAL

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED	[D] Lag Days	[E] Dollar Days
1	Cost of Gas	$256,651,324	$0	$256,651,324	42.43	$10,889,715,677
2	Labor and Labor Loading	134,338,717	(3,763,866)	130,574,851	10.90	1,423,265,878
3	Provision for Uncollected Accounts	2,369,037	(96,592)	2,272,445	120.00	272,693,418
4	Other O & M Expenses	96,289,296	(1,237,611)	95,051,685	2.03	192,954,920
5	Total O & M Expenses	$489,648,374	($5,098,069)	$484,550,305	26.10	$12,778,629,893
6						
7	Interest	$33,627,705	($344,256)	$33,283,449	91.00	$3,028,793,859
8						
9	Taxes Other Than Income Taxes	$41,628,621	$106,556	$41,735,177	174.28	$7,273,606,711
10	Income Taxes-Current	46,530,675	(4,707,084)	41,823,591	37.00	1,547,472,852
11	Total Operating Expenses	$611,435,375	($10,042,853)	$601,392,522	40.95	$24,628,503,315
12						
13	Number of Days in Test Period	365		365		
14	Average Daily Operating Expense	$1,675,165		$1,647,651		
15						
16	Lag in Receipt of Payment of Cash Expenses	40.68			40.95	
17	Lag in Receipt of Revenue	38.22			38.22	
18	Net Difference Revenue-Expense Lag	(2.46)		(2.73)		
19						
20	Cash Working Capital:					
21	Per Staff			($4,502,140)		
22	Per Company	($4,113,676)		(4,113,676)		
23	Staff Adjustment			($388,464)		
24						
25	Staff Adjustment (rounded to thousands)			($388,000)		

REFERENCES:
Column [A]: Company Schedule B-2, page 7 and Workpaper Schedule B-2 Sheets 5 and 7
Column [B]: Staff recommended adjustments, per testimony.
Column [C]: Column [A] + Column [B]
Column [D]: Company Schedule B-5, page 2 of 4
Column [E]: Column [C] * Column [D]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BNC-8b

RATE BASE ADJUSTMENT NO. 5 MATERIALS AND SUPPLIES

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Materials and Supplies		$15,364,326	$2,002,668	$17,366,994
2					
3					
4					
5			13-Month Average	13-Month Average	Staff
6	Description	Account	Company as Filed	Updated	Adjustment
7		154	$14,924,229	$16,861,899	$1,937,670
		155	42,535	17,975	(24,560)
		163	407,395	508,134	100,739
	System Allocable		(9,833)	(21,014)	(11,181)
	Total Materials and Supplies		$15,364,326	$17,366,994	$2,002,668

REFERENCES:
Column [A]: Company Schedule B-2, page 1 and Workpaper Schedule B-2 Sheet 2
Column [B]: Company response to Staff Informal 4 attachment 1
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation **Schedule BNC-8c**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

RATE BASE ADJUSTMENT NO. 6 PREPAID LIABILITY INSURANCE

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Prepayments	165	$290,653	$148,588	$439,240
2					
3					
4					
5			Prepaid		
6			D&O Insurance	Staff	
7			In AZ Jurisdictonal	Allowance	Staff
8	Description	Account	Rate Base	(One-Half)	Adjustment
9	Prepayments	165	$290,653	$145,326	($145,326)
10					
11					
12			13-Month Average	13-Month Average	Staff
13	Description	Account	Company as Filed	Updated	Adjustment
14	Prepayments	165	$6,885,291	$7,179,205	$293,914

REFERENCES:
Column [A]: Company Schedule B-2, page 1 and Workpaper Schedule B-2 Sheet 2
Column [B]: Company response to STF DR 9-002, Staff Informal 4 attachment 1 and RUCO DR 5.12
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation **Schedule BNC-8d**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

RATE BASE ADJUSTMENT NO. 7 CUSTOMER DEPOSITS

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Customer Deposits	235	($39,253,787)	($173,954)	($39,427,741)
2					
3					
4					
5			13-Month Average	13-Month Average	Staff
6	Description	Account	Company as Filed	Updated	Adjustment
7	Customer Deposits	235	(39,253,787)	($39,427,741)	($173,954)

REFERENCES:
Column [A]: Company Schedule B-2, page 1 and Workpaper Schedule B-2 Sheet 2
Column [B]: Company response to Staff Informal 4 attachment 1
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation **Schedule BNC-8e**
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

RATE BASE ADJUSTMENT NO. 8 CUSTOMER ADVANCES

LINE NO.	DESCRIPTION	ACT. NO.	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Customer Advances	252	($38,815,661)	($2,826,727)	($41,642,388)
2					
3					
4					
5			13-Month Average	Most current balance	Staff
6	Description	Account	Company as Filed	as of September 2016	Adjustment
7	Customer Advances	252	($38,815,661)	($41,642,388)	($2,826,727)

REFERENCES:
Column [A]: Company Schedule B-2, page 1 and Workpaper Schedule B-2 Sheet 2
Column [B]: Company response to Staff Informal 4 attachment 1
Column [C]: Column [A] + Column [B]

Southwest Gas Corporation
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2015

Schedule BNC-9

RATE BASE ADJUSTMENT NO. 9 - ACCUMULATED DEFERRED INCOME TAXES ("ADIT") IMPACT RELATED TO POST-TEST YEAR PLANT

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJUSTMENT	[C] STAFF ADJUSTED
1	Deferred Taxes	($430,564,584)	($7,560,471)	($438,125,055)
2				
3				
4				
5				
6	WP B-2 PTY Direct: PTY Additions			
7	PTY Additions as of August 31, 2016	$24,814,579		
8	x 50%	50.00%		
9	Subtotal (L2 * L3)	12,407,290		
10	Combined Federal and State Income Tax Rate (L35)	38.0695%		
11	Total (L4 * L5)	$4,723,393		
12				
13	WP B-2 System 303: PTY Additions			
14	PTY Additions as of August 31, 2016	$23,931,832		
15	x 50%	50.00%		
16	Subtotal (L9 * L10)	11,965,916		
17	x 4 Factor Allocation Percentage	56.07%		
18	Subtotal (L11 * L12)	6,709,289		
19	Combined Federal and State Income Tax Rate (L35)	38.0695%		
20	Total (L13 * L14)	$2,554,193		
21				
22	WP B-2 System General: PTY Additions			
23	PTY Additions as of August 31, 2016	$2,650,526		
24	x 50%	50.00%		
25	Subtotal (L18 * L19)	1,325,263		
26	x 4 Factor Allocation Percentage	56.07%		
27	Subtotal (L20 * L21)	743,075		
28	Combined Federal and State Income Tax Rate (L35)	38.0695%		
29	Total (L22 * L23)	$282,885		
30				
31	Total Adjustment (L6 + L15 + L24)	$7,560,471		

REFERENCES:
[redacted]
Column [B]: Company response to RUCO DR 8-007
Column [C]: Column [A] + Column [B]

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS	DOCKET NO. G-01551A-16-0107

DIRECT

TESTIMONY

OF

YUE "NICK" LIU

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 30, 2016

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

My testimony provides an estimate of the cost of capital ("COC") for the current filing of Southwest Gas Corporation ("Southwest Gas" or "Company"). My overall cost of capital recommendation for Southwest Gas is summarized as follows:

Item	Percent	Cost	Weighted Cost
Long-Term Debt	48.31%	5.21%	2.52%
Common Equity	51.69%	9.00-9.50%	4.65-4.91%
Total	100.00%		7.17-7.43%
			(7.30% Midpoint)

I have used the Company's proposed end of test year capital structure in my COC analyses. Moreover, Southwest Gas' test year 5.21 percent cost rate for long-term debt is used.

My cost of equity recommendation is based upon my application of the following three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow ("DCF")	8.5%-9.0% (8.75% mid-point)
Capital Asset Pricing Model ("CAPM")	6.1%-6.2% (6.15% mid-point)
Comparable Earnings ("CE")	9.0%-10.0% (9.50% mid-point)

My recommendation of 9.25 percent cost of equity is the mid-point of the 9.0 percent to 9.5 percent range that reflects the upper end of the results for the DCF model and the mid-point for the CE model. My recommendation does not directly incorporate the CAPM results, which I believe to be somewhat low at this time, relative to the DCF and CE results. However, the CAPM results are an appropriate indicator of the continuing decline in the cost of capital, including the cost of equity.

I also provide a calculation of the Fair Value Rate of Return ("FVROR"). I recommend using the Company's proposed cost rate of 0.93 percent on the FVRB Increment and an overall FVROR of 5.61 percent.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Yue "Nick" Liu. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background and professional experience.

A. In 2013, I graduated with high distinction from the University of Minnesota, receiving a Bachelor of Arts degree in economics, mathematics and statistics. In 2014, after working as an investment-banking analyst for one year, I enrolled in the graduate program in statistics at the University of California Berkeley and received a Master of Arts degree in 2015. Before joining the Commission in December 2015, I worked on several research projects of various disciplines as a statistical consultant, offering clients advisory services on experimental designs, sampling methodologies, data analytics and statistical inferences. Moreover, I have passed Exam P/Probability Theory and FM/Financial Mathematics of Society of Actuaries ("SOA"), and I am currently a candidate for the Chartered Financial Analyst ("CFA") Level I Exam in June 2017.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I analyze and provide recommendations to the Commission on assigned cases.

Q. What is the purpose of your testimony in this case?

A. I evaluated the cost of capital ("COC") aspects of the current filing of Southwest Gas Corporation ("Southwest Gas" or "Company"). I have performed independent studies and am presenting Staff's recommendations of the current COC for Southwest Gas.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, made up of twelve schedules, identified as Schedule 1 through Schedule 12.

RECOMMENDATIONS AND SUMMARY

Q. What are your recommendations in this proceeding?

A. My overall cost of capital recommendations for Southwest Gas are (also shown on Schedule 1):

Item	Percent	Cost	Weighted Cost
Long-Term Debt	48.31%	5.21%	2.52%
Common Equity	51.69%	9.00-9.50%	4.65-4.91%
Total	100.00%		7.17-7.43%
			(7.30% Midpoint)

Southwest Gas' application requests a return on equity of 10.25 percent and a total cost of capital of 7.82 percent.

Q. Please summarize your cost of capital analyses and related conclusions for Southwest Gas.

A. This proceeding is concerned with Southwest Gas' regulated natural gas utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is to develop the appropriate capital structure. Southwest Gas proposes use of a capital structure (adjusted) at the end of the test year period, November 30, 2015, which reflects the removal of its equity investment in Centuri Construction Group (a non-regulated subsidiary of Southwest Gas). I have used the Company's proposed end of test year period capital structure in my COC analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of long-term debt. I have used a 5.21 percent cost for long-term debt which is contained is Southwest Gas' application.

The third step in the COC calculation is the estimation of the return on common equity ("ROE"). I have employed three recognized methodologies to estimate Southwest Gas' ROE. Each of these methodologies is applied to a proxy group of gas utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow ("DCF")	8.5%-9.0% (8.75% mid-point)
Capital Asset Pricing Model ("CAPM")	6.1%-6.2% (6.15% mid-point)
Comparable Earnings ("CE")	9.0%-10.0% (9.50% mid-point)

Based upon these findings, I conclude that Southwest Gas' ROE is within a range of 9.0 percent to 9.5 percent (9.25 percent mid-point), which is based upon the upper end of the range of the results for the DCF model and the mid-point for the CE model.[1] I recommend the mid-point of this range, 9.25 percent, as Southwest Gas' ROE.

Combining these three steps into the weighted COC results in an overall rate of return range of 7.17 percent to 7.43 percent (7.30 percent mid-point which incorporates a 9.25 percent ROE).

ECONOMIC PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to position the utilities to recover its costs, including capital costs. This is frequently referred to as "cost-of-service"

[1] As I indicate in a later section, my ROE recommendation does not directly incorporate the CAPM results, which I believe to be somewhat low at this time, relative to the DCF and CE results.

ratemaking. Rates for regulated public utilities traditionally have been established using the "rate base – rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e. rate base) in providing service to their customers.

The rate base is derived primarily from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. Thus, the revenue impact of the cost of capital is derived by multiplying the rate base by the rate of return, including income taxes.

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e. debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these values by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post facto (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante facto (before the fact) expected, or required, return on a capital base. In regulatory proceedings, however, the two terms are often used interchangeably, and I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Q. Is Southwest Gas requesting a "fair value" increment to this proceeding?

A. Yes, it is. Southwest Gas witness Hevert recommends a cost rate of 0.93 percent on the fair value increment, resulting in a 6.01 percent fair value rate of return.

Q. Does Staff agree with the Company's proposed cost rate on the fair value increment?

A. Yes. The analysis will be discussed in detail in a later section.

Q. How can economic principles and methodologies be employed to estimate the cost of capital for a utility?

A. Economic/financial theory has not developed exact mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the ROE, which is the capital structure item that is the most difficult to determine. These include the DCF, CAPM, CE and risk premium ("RP") methods. Each of these methods differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

I utilized three methodologies to determine Southwest Gas' cost of common equity: the DCF, CAPM, and CE methods. I have not directly employed a RP model in my analyses although, as discussed later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail in my testimony that follows.

GENERAL ECONOMIC CONDITIONS

Q. Are economic and financial conditions important in determining the costs of capital for Southwest Gas?

A. Yes. The costs of capital, for both fixed-cost (debt and preferred stock) components and for common equity are determined, in part, by current and prospective economic and financial conditions. At any given time, each of the following has an influence on the costs of capital:

- the level of economic activity (i.e., growth rate of the economy);
- the stage of the business cycle (i.e., recession, expansion, or transition);
- the level of inflation;
- the level and trend of interest rates; and
- current and expected economic conditions.

Q. What indicators of economic and financial activity have you evaluated in your analyses?

A. I examined several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over four full prior business cycles, allowing for an assessment of changes in long-term trends. Consideration of economic/financial conditions over a relatively long period of time allows assessment of how such conditions have had impacts on the level and trends of the costs of capital. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical influences (i.e., stage of business cycle) and thus permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframes of the four prior business cycles and the current cycle.

A. The four prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Mar. 1991-Mar. 2001	Apr. 2001-Nov. 2001
2001-2009	Nov. 2001-Nov. 2007	Dec. 2007-June 2009
Current	July 2009-	

Source: National Bureau of Economic Research, "Business Cycle Expansions and Contractions.[2]

Q. Do you have any general observations concerning the recent trends in economic conditions and their impact on capital costs over this broad period?

A. Yes. Until the end of 2007, the United States economy had enjoyed general prosperity and stability since the early 1980s. This period had been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs.

However, in 2008 and 2009, the economy declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and the related liquidity crisis in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline, initially based on a substantial increase in petroleum prices and a dramatic decline in the U.S. financial sector, culminating with the collapse and/or bailouts of a significant number of venerable institutions such as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Wachovia. The recession also witnessed the demise of national entities,

[2] http://www.nber.org/cycles/cyclesmain.html.

such as Circuit City, and the declared bankruptcy of automotive manufacturers, such as Chrysler and General Motors.

This decline has been described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." Beginning in 2008, the U.S. and other governments implemented unprecedented actions to attempt to correct or minimize its scope and effects.

It appears that the recession reached its low point in mid-2009 and that the economy has since begun to expand again, although at a slow and uneven rate. However, the length and severity of the recession, as well as a relatively slow and uneven recovery, indicate that the impacts of the recession have been and will be felt for an extended period of time.

Q. Please describe recent and current economic and financial conditions and their impact on the cost of capital.

A. Schedule 2 shows several sets of relevant economic and financial data for the cited time periods. Pages 1 and 2 contain general macroeconomic statistics; pages 3 and 4 show interest rates; and pages 5 and 6 contain equity market statistics.

Pages 1 and 2 show that the U.S. economy ended 2007 as the sixth year of an economic expansion, but it subsequently entered a significant decline. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product ("GDP"), industrial production, and an increase in the unemployment rate. This recession lasted until mid-2009, making it a longer-than-normal recession, as well as a much deeper recession. Since then, economic growth has been somewhat erratic and the economy has grown slower than the prior expansions.

The rate of inflation is also shown on Pages 1 and 2. As reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981, and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 4.1 percent or lower. Starting from 2008, the CPI has been 3 percent or lower, with 2013 being only 1.5 percent and 2014-2015 being below 1 percent. It is thus apparent that the rate of inflation has generally been declining over the past several business cycles. Recent and current levels of inflation are at the lowest levels of the past 35 years, which is reflective of lower capital costs.[3]

Q. What have been the trends in interest rates over the four prior business cycles and at the current time?

A. Pages 3 and 4 of Schedule 2 show several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates have declined substantially in conjunction with inflation since the early 1980's.

From 2008 to late 2015, the Federal Reserve System ("Federal Reserve") maintained the Federal Funds rate (i.e., short-term interest rate) at 0.25 percent, an all-time low. The Federal Reserve raised it slightly to 0.50 percent recently in December 2015. The Federal Reserve also purchased U.S. Treasury securities to stimulate the economy.[4] As seen on page 4 of Schedule 2, both U.S. and corporate bond yields have declined to their lowest levels in the past four business cycles and in more than 35 years. Even with the 2013-2014 "tapering" and eventual ending of the Federal Reserve's Quantitative Easing program, interest rates have remained

[3] The rate of inflation is one component of interest rate expectations of investors, who generally expect to receive a return in excess of the rate of inflation. Thus, a lower rate of inflation has a downward impact on interest rates and other capital costs.

[4] This is referred to as Quantitative Easing, in which the Federal Reserve initially purchased some $85 billion of U.S. Treasury Securities per month in order to stimulate the economy. The Federal Reserve eventually "tapered" its purchase of U.S. Treasury securities through October 2014, at which time Quantitative Easing ended.

low. Currently, both government and corporate lending rates remain at historically low levels, again reflective of lower capital costs.

Q. What does Schedule 2 show for trends of common share prices?

A. Pages 5 and 6 of Schedule 2 show several series of common stock prices and ratios. These indicate that stock prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. The 1983-1991 business cycle and the more recent cycles witnessed a significant upward trend in stock prices. The beginning of the recent financial crisis saw stock prices decline precipitously, as stock prices in 2008 and early 2009 were down significantly from peak 2007 levels, reflecting the financial/economic crisis. Beginning in the second quarter of 2009, prices recovered substantially and ultimately reached and exceeded the levels achieved prior to the "crash". On the other hand, recent equity markets have been somewhat volatile.

Q. What conclusions can be drawn from the discussion of economic and financial conditions depicted in your data?

A. It is apparent that recent economic and financial circumstances have been radically different from any that have prevailed since at least the 1930s. The late 2008-early 2009 deterioration in stock prices, the decline in U.S. Treasury bond yields, and an increase in corporate bond yields were evidenced in the then-evident "flight to safety." On the other side of this "flight to safety" is the negative perception of the concurrent decline in capital costs and returns, which significantly reduced the value of most retirement accounts, investment portfolios and other assets. One significant aspect of this has been a decline in investor expectations of returns, even with the return of stock prices to levels achieved prior to the "crash". Finally, as noted above, corporate bond interest rates are currently at levels below those prevailing prior to the financial crisis of late 2008 to early 2009 and are near the lowest levels in the past 35 years.

SOUTHWEST GAS' OPERATIONS AND RISKS

Q. Please describe Southwest Gas.

A. Southwest Gas is an operating gas distribution company. The Company is engaged in the business of purchasing, transporting and distributing natural gas to residential, commercial, and industrial customers in geographically diverse portions of Arizona, Nevada and California. Southwest Gas is the largest distributor of natural gas in both Arizona and Nevada.

Q. What are the current security ratings of Southwest Gas?

A. As is shown on Schedule 3, the current bond ratings of Southwest Gas are:

Moody's	A3
Standard & Poor's	BBB+
Fitch	A

Q. What has been the trend in Southwest Gas' debt ratings?

A. This is shown on Schedule 3. As this indicates, Southwest Gas' debt ratings were raised twice in 2012 and 2014 by Moody's, raised in 2013 and downgraded in 2014 by S&P, and raised twice in 2012 and 2013 by Fitch. Moreover, Southwest Gas' debt ratings from the three rating agencies have been stable since 2014.

Q. What are the cost of capital implications of the implementation of Southwest Gas' regulatory cost-recovery mechanisms?

A. Southwest Gas' most recent general rate case in Arizona resulted in a settlement agreement, with rates effective January 2012. Fitch considers that settlement agreement to have been constructive, supporting credit quality. The agreement includes an Energy Efficiency Enabling Provision ("EEP"), which provides for a full revenue decoupling mechanism with a monthly weather adjuster. This rate mechanism increases the stability and predictability of earnings and cash flows and provides for more timely cost recovery, since the Company's revenues, and income, are essentially insulated from variations due to weather and usage. The full revenue decoupling mechanism is risk-reducing, and the net effect of it is to transfer a significant portion of the Company's risks from its shareholders to its ratepayers.

CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in previous sections of my testimony, the purpose of determining the proper capital structure for a utility is to ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e. the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This occurs because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and (3) causes the most controversy since its cost cannot be precisely determined.

Q. How have you evaluated the capital structure of Southwest Gas?

A. I have examined the historic (2011-2015) capital structure ratios of Southwest Gas. Schedule 4 shows historical capital structure ratios of the Company. The respective common equity ratios over the past five years are as follows:

	Including S-T Debt	Excluding S-T Debt
2011	49.4%	49.4%
2012	49.8%	49.8%
2013	50.4%	50.4%
2014	47.6%	47.7%
2015	50.3%	50.6%

It is apparent that Southwest Gas has maintained a stable equity ratio around 50 percent over the past five years.

Q. How do these capital structure ratios compare to the gas distribution utility industry?

A. I have prepared Schedule 5 to make this comparison. Schedule 5 shows the common equity ratios (including short-term debt in capitalization) for the Value Line group of natural gas utilities. The average ratios are:

Year	Value Line Group	Southwest Gas
2011	50.7%	49.5%
2012	49.8%	49.9%
2013	47.4%	50.4%
2014	46.7%	47.3%
2015	46.4%	50.1%

These equity ratios are relatively lower than those of Southwest Gas.

Q. What capital structure has Southwest Gas requested in this proceeding?

A. Southwest Gas requests use of its adjusted test year capital structure as of November 30, 2015:

Capital Item	Percent
Long-Term Debt	48.31%
Common Equity	51.69%

The actual test period capital structure is adjusted for the removal of equity investment in Centuri Construction Group (a non-regulated subsidiary of Southwest Gas).

Q. What capital structure do you propose to use in this proceeding?

A. I have utilized the adjusted test year period capital structure of the Company in my analyses.

Q. What cost rate of long-term debt have you used in your analysis?

A. I have utilized the 5.21 percent cost of long-term debt shown in the Company's filing.

Q. Can the cost of common equity be determined with the same degree of precision as the cost of debt?

A. No. The cost rates of debt are largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. As discussed earlier, there are, however, several models that can be employed to estimate the cost of common equity. Three of the primary methods – DCF, CAPM, and CE – are developed in the following sections of my testimony.

SELECTION OF PROXY GROUP

Q. How have you estimated the ROE for Southwest Gas?

A. Southwest Gas is a publicly-traded company. Consequently, it is possible to directly apply ROE models to Southwest Gas. However, it is customary to analyze groups of companies, or "proxy" companies as a substitute for Southwest Gas to determine its ROE.

I have accordingly developed such a proxy group for comparison to Southwest Gas. My group of proxy companies is derived from the group of gas distribution companies followed by Value Line. Schedule 6 shows the criteria used to select my proxy group. The following criteria were employed for each company's selection in my proxy group:

(1) Inclusion in Value Line Natural Gas Utility Group;
(2) Currently pays dividends;
(3) Percent regulated gas revenues of 30 percent or greater;
(4) Common equity ratio of 40 percent to 60 percent;
(5) Value Line Safety rank of 1, 2, or 3;
(6) Standard & Poor's ("S&P") stock ranking of A or B; and,
(7) S&P and Moody's bond ratings of BBB or greater.[5]

In addition, I excluded Southwest Gas from the proxy group for the ROE analysis, although it meets all the above criteria.

DISCOUNTED CASH FLOW ANALYSIS

Q. What is the theoretical and methodological basis of the DCF model?

A. The DCF model is one of the oldest, as well as the most commonly-used, models for estimating the ROE for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate (the "constant growth" or "Gordon DCF model"). In this framework, the ROE is derived from the following formula:

[5] S&P and Moody's bond rating information of Chesapeake Utilities is not available.

$$K = \frac{D}{P} + g$$

where: K = discount rate (cost of capital)

P = current price

D = current dividend rate

G = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you have employed the DCF model.

A. I have utilized the constant growth DCF model. In doing so, I combine the current dividend yield for the proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; i.e., current versus future dividends or annual versus quarterly compounding of dividends. I have utilized the version listed below which is a quarterly version:

$$Yield = \frac{D_0(1 + 0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average of the high and low stock price for each proxy company for the most recent three month period (July-September, 2016). The D_0 is the current annualized dividend rate for each proxy company.

Q. How have you estimated the dividend growth component of the DCF equation?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock. Obviously, since two investors reach different decisions at the same market price, their expectations differ.

A wide array of indicators exists for estimating investors' growth expectations. As a result, it is evident that investors do not always use one single indicator of growth. It therefore is necessary to consider alternative dividend growth indicators in deriving the growth component of the DCF model. I have considered five indicators of growth in my DCF analyses. These are:

1. Years 2011-2015 (5-year average) earnings retention, or fundamental growth;
2. Five-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS);

3. Years 2016, 2017, and 2019-2021 projections of earnings retention growth (per Value Line);
4. Years 2013-2015 to 2019-2021 projections of EPS, DPS, and BVPS (per Value Line); and,
5. Five-year projections of EPS growth (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the group of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which would be expected to have some impact on their decision-making process.

Q. Please describe your DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e. prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rates for the group of proxy companies. Page 4 shows the DCF calculations, which are presented on several bases: mean, median, and high values. These results can be summarized as follows:

	Mean	Median	Mean Low[6]	Mean High[7]	Median Low[7]	Median High[8]
Proxy Group	7.6%	7.7%	7.0%	8.5%	7.1%	9.0%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy group; rather, the individual values shown should be interpreted as alternative information considered by investors.

[6] Using only the lowest growth rate.
[7] Using only the highest growth rate.

Q. What do you conclude from your DCF analyses?

A. The DCF rates resulting from the analysis of the proxy group falls into a range between 7.0 percent and 9.0 percent. The highest DCF rates are 8.5 percent to 9.0 percent (8.75 percent mid-point). I believe a 9.0 percent represents the current DCF-derived ROE for the proxy group. I recommend a cost of equity of 9.0 percent for Southwest Gas, which focuses on the upper end of the DCF range. I focus on the higher DCF results since recent financial conditions have had the effect of driving many of the DCF results to low levels relative to those of recent years. As such, my recommendation can be viewed as conservative.

CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Please describe the theory and methodological basis of the CAPM.

A. CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory ("MPT"), which studies the relationships among risk, diversification, and expected returns. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM is a variant of the RP method.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

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

where: K = cost of equity

R_f = risk free rate

Rm = return on market

β = beta

R_m-R_f = market risk premium

I believe the CAPM is generally superior to the simple RP method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple RP method assumes the same risk premium for all companies exhibiting similar bond ratings.

Q. What value do you use for the risk-free rate?

A. The first input of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any market risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component: short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three-month average yield (July-September 2016) for 20-year U.S. Treasury bonds. I use the yields on long-term Treasury bonds since this matches the long-term perspective of ROE analyses. Over this three month period, these bonds had an average yield of 1.91 percent.

Q. What is beta and what betas do you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas less than 1.0 are considered less risky than the market, whereas betas greater than 1.0 are more risky. Utility stocks traditionally have had betas below 1.0. I utilize the most recent Value Line betas for each company in my proxy group.

Q. How do you estimate the market risk premium component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or long-term government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the ROE for the S&P 500 group for the period 1978-2014. This schedule also indicates the annual yields on 20-year U.S. Treasury bonds and the annual differentials (i.e. risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that the risk premium from this analysis is 6.85 percent.

I next considered the total returns (i.e. dividends/interest plus capital gains/losses) for the S&P 500 group as well as for long-term (i.e., 20-year) government bonds, as tabulated by Morningstar (formerly Ibbotson Associates), using both arithmetic and geometric means. I considered the total returns for the entire 1926-2014 period, which are as follows:

	S&P 500	L-T Government Bonds	Risk Premium
Arithmetic	12.1%	6.1%	6.0%
Geometric	10.1%	5.7%	4.4%

I conclude from this analysis that the expected risk premium is about 5.75 percent (i.e. average of all three risk premiums (6.85 percent from Schedule 8; 6.0 percent arithmetic and 4.4 percent geometric from Morningstar).

Q. What are your CAPM results?

A. Schedule 9 shows my CAPM calculations. The results are:

	Mean	Median
Proxy Group	6.1%	6.2%

Q. What is your conclusion concerning the CAPM ROE?

A. The CAPM results indicate a ROE of 6.1 percent to 6.2 percent for the group of proxy utilities. I conclude that an appropriate CAPM ROE estimation for Southwest Gas is 6.2 percent.

COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is based upon the economic concept of opportunity cost. As previously noted, the ROE is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, it provides a direct measure of the fair return, since it translates into practice the competitive principle underlying regulation.

The CE method normally examines the experienced and/or projected return on book common equity. The logic for examining returns on book common equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base-rate of return methodology used to set utility rates.

Q. How have you employed the CE methodology in your analysis of Southwest Gas' ROE?

A. I conducted the CE methodology by examining realized returns on equity for the group of proxy companies, as well as unregulated companies, and evaluating investor acceptance of these returns by reference to the resulting market-to-book ratios ("M/B"). In this manner it is possible to assess the degree to which a given level of return equates to the COC. It is generally recognized for utilities that M/B of greater than one (i.e. 100 percent) reflects a situation where a company is able to attract new equity capital without dilution (i.e. above book value). As a result, one objective of a fair ROE is the maintenance of stock prices at or above book value. There is no regulatory obligation to set rates designed to maintain an M/B significantly above one.

It can be further noted that my CE analysis is based upon market data (through the use of M/B) and is thus essentially a market test. In addition, my CE analysis also uses prospective returns and thus is not backward looking.

Q. What time periods do you examine in your CE analysis?

A. My CE analysis first considers the experienced ROEs of the proxy group of utilities for the period 2002-2015 (i.e. the last fourteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current ROE, I focused on two periods: 2009-2015 (the current business cycle) and 2002-2008 (the most recent business cycle). I have also considered projected ROEs for 2016, 2017 and 2019-2021.

Q. Please describe your CE analysis.

A. Schedules 10 and 11 contain summaries of experienced ROEs for two groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the ROEs and M/B for the group of proxy utilities. These can be summarized as follows:

	Proxy Group
Historic ROE	
Mean	11.2-11.9%
Median	10.8-11.4%
Historic M/B	
Mean	183-188%
Median	174-179%
Prospective ROE	
Mean	9.9-10.4%
Median	10.0-11.0%

These results indicate that historic ROEs of 10.8 percent to 11.9 percent have been adequate to produce M/Bs of 174 percent to 188 percent for the group of proxy utilities. Furthermore, projected returns on equity for 2016, 2017 and 2019-2021 are within a range of 9.9 percent to 11.0 percent for the utility group. These relate to 2015 M/Bs of 186 percent or greater.

Q. Have you also reviewed earnings of unregulated firms?

A. Yes. As an alternative, I also examine the S&P's 500 Composite group. This is a well-recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned ROEs and M/Bs for the S&P 500 group over the past thirteen years (i.e., 2002-2014). As this schedule indicates, over the two business cycle periods, this group's average ROEs ranged from 12.4 percent to 13.6 percent, with average M/B ranging between 220 percent and 275 percent.

Q. How can the above information be used to estimate Southwest Gas' ROE?

A. The recent ROE of the proxy utilities and S&P 500 groups can be viewed as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the required ROE for the proxy utilities, however, it is necessary to compare the risk levels of the gas utilities and the competitive companies. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the gas utility group. The information in Schedule 12 indicates that the S&P 500 group is riskier than the gas utility proxy group.

Q. What ROE is indicated by your CE analysis?

A. Based on recent earnings and M/Bs, I believe the CE analysis indicates that the ROE for the proxy utilities is no more than 9.0 percent to 10.0 percent (9.5 percent mid-point). Recent ROEs of 10.8 percent to 11.9 percent have resulted in M/Bs of 174 percent and greater. Prospective ROEs of 9.9 percent to 11.0 percent have been accompanied by M/B over 186 percent. As a result, it is apparent that authorized ROEs below this level would continue to result in M/B of well above 100 percent. Accordingly, an earned return of 9.0 percent to 10.0 percent should result in a M/B of over 100 percent. As I indicated earlier, the fact that M/Bs substantially exceed 100 percent indicates that historic and prospective ROEs of 10 percent to 12 percent reflect earning levels that exceed the actual cost of equity for those regulated companies.

RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three ROE analyses.

A. My three ROE analyses produced the following findings and conclusions:

DCF	9.0%
CAPM	6.2%
CE	9.5%

These results indicate an overall broad range of 6.2 percent to 9.5 percent. I recommend a ROE range of 9.0 percent to 9.5 percent for Southwest Gas. This range includes my DCF result (9.0 percent), and my CE result (9.5 percent). For the purposes of this proceeding, I recommend the average of these values, which is 9.25 percent.

Q. It appears that your CAPM results are less than your DCF and CE results. Does this imply that the CAPM results should not be considered in determining the ROE for Southwest Gas?

A. No. It is apparent that the CAPM results are less than the DCF and CE results. There are two reasons for the lower CAPM results. First, risk premiums are lower currently than was the case in prior years. This is the result of lower equity market returns that have been experienced over the past several years. This is also reflective of a decline in investor expectations of equity returns and risk premiums. Second, the level of interest rates on U.S. Treasury bonds (i.e., the risk free rate) has been lower in recent years. This is partially the result of the actions of the Federal Reserve System to stimulate the economy. This also impacts investor expectations of returns in a negative fashion. It can be noted that, initially, investors may have believed that the decline in Treasury yields was a temporary factor that would soon be replaced by a rise in interest rates. However, this has not been the case as interest rates have remained low and continued to decline for the past five-plus years. As a result, it cannot be maintained that low interest rates (and low CAPM results) are temporary and do not reflect investor expectations. Consequently, the CAPM results should be considered as one factor in determining the cost of equity for Southwest Gas.

TOTAL COST OF CAPITAL

Q. What is the total cost of capital for Southwest Gas?

A. Schedule 1 reflects the COC for Southwest Gas using the adjusted test year capital structure and embedded cost of debt, as well as my ROE recommendations. The resulting total COC is a range of 7.17 percent to 7.43 percent with a 7.30 percent midpoint. I recommend a 7.30 percent total COC for Southwest Gas.

FAIR VALUE RATE BASE COST OF CAPITAL

Q. What is your understanding of Southwest Gas' position on the issue of fair value rate base ("FVRB") and related cost of capital implications?

A. It is my understanding that Southwest Gas is requesting that a 6.01 percent cost of capital be applied to the level of its FVRB. This 6.01 percent return incorporates a 0.93 percent cost rate of the "fair value increment" as well as a 10.25 percent cost of equity.

Q. Do you have any observations as to whether a cost of capital developed for application to an original cost rate base is consistent with a FVRB?

A. Yes. Conceptually, the cost of capital is designed to apply to an original cost rate base ("OCRB"). This is the case since the cost of capital is primarily derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet (i.e., OCRB). From a financial perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The amount of fair value rate base that exceeds original cost rate base is not financed with investor-supplied funds and, indeed, is not financed at all. As a result, a customary cost of capital analysis cannot be automatically applied to the fair value rate base since there is no financial link between the two concepts.

Q. Why is it important that there be a link between the concepts of rate base and cost of capital?

A. This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between cost of capital and rate base satisfies this financial objective.

Q. Do you have a suggestion as to how to account for the use of a FVRB in setting rates for Southwest Gas?

A. Yes. Since the increment between the FVRB and OCRB is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. Have you developed an alternative method with which to apply a FVROR to a FVRB?

A. Yes. Should the Commission determine that there should be a specific return (greater than zero) applied to the FVRB Increment, I have provided such a procedure.

Q. Why is it necessary to add a return on only the portion of FVRB that exceeds the OCRB?

A. The WCOC authorized by the Commission has already provided for a full cost of equity return and cost of debt on the portions of equity and debt capital that are supporting the OCRB portion of the FVRB. As a result, there is no need to provide any additional return on the portions of FVRB supported by common equity and debt.

Stated differently, both the cost of debt and the return on common equity (i.e., capital stock, paid-in capital, and retained earnings – the investment of common shareholders) are already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds OCRB ("Fair Value Increment") needs to have a specific return identified in order to reflect a return component on that Fair Value Increment ("FVI").

Q. What is the proper cost rate to apply to the FVI?

A. As indicated previously, from a financial perspective, it is not necessary to provide for any return on the FVI since this is not investor-supplied capital. However, I recognize that the Commission might choose to evaluate this issue from both a financial and a public policy perspective. I am aware that Southwest Gas may claim that the concept of fair value carries with it the notion that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost. It is possible that the Commission may determine that Arizona's fair value provision, which is somewhat unique, is not inconsistent with these concepts. Nonetheless, the idea that the Company should receive some benefit from the FVI does not mean that one should automatically apply to the FVRB a WCOC developed by reference to original cost rate base. If it is determined that it is desirable to provide an additional (non-zero) return on the FVI, the proper return should be no larger than the real (i.e., with inflation adjusted) risk-free rate of return.

Q. What is the "real" risk-free rate?

A. The concept of real risk-free rates involves the removal of the rate of inflation from the nominal risk-free rate. I propose to use the real risk-free rate recommended by Staff in the recent Tucson Electric Power ("TEP") rate case (Docket No. E-01933A-15-0322), which is 1.4 percent. This rate is calculated by subtracting the 2.3 percent inflation rate from the 3.7 percent nominal risk-free rate based on the yield of U.S. Treasury securities.

Q. Please explain why Southwest Gas' FVROR should consider the real risk-free rate, as opposed to the nominal risk-free rate.

A. The investors of Southwest Gas are already receiving an inflation factor due to the inclusion of inflation in the FVRB Increment. Specifically, the FVI incorporates inflation by considering the current value of assets, which reflect, in part, past inflation. It would be double-counting to also include the inflation components in the return to be applied to the FVI.

Q. What return on the FVI do you recommend in your alternative FVROR proposal?

A. My alternative FVROR proposal incorporates a return on the FVI with a maximum value of 1.4 percent, as developed above. In reality, any value between zero percent and 1.4 percent could be used as the cost rate on the FVI. The Company's proposed cost rate of 0.93 percent on FVI is well suited within this range. Therefore, I would propose 0.93 percent.

Q. What is the resulting impact of your alternative proposal in this proceeding?

A. I am proposing the following FVROR for Southwest Gas:

Capital Item	Percent[8]	Cost	Fair Value Return
Long-term Debt	35.46%	5.21%	1.85%
Common Equity	37.95%	9.25%	3.51%
FVRB Increment	26.59%	0.93%	0.25%
Total	100.00%		5.61%

As shown in the above table, this alternative proposal provides for a non-zero return on the FVI of Southwest Gas, and provides for an overall FVROR of 5.61 percent on the FVRB.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[8] As developed by Staff Witness Blessing Chukwu

Exhibit YL-1
Schedule 1

SOUTHWEST GAS CORPORATION
TOTAL COST OF CAPITAL

Item	AMOUNT	Percent 1/	Cost	Weighted Cost
Long-Term Debt		48.31%	5.21% 2/	2.52%
Common Equity		51.69%	9.00% 9.25% 9.50%	4.65% 4.78% 4.91%
Total		100.00%		7.17% 7.30% 7.43%

1/ Capital structure at the end of the test period, as contained in Company filing, Schedule D-1.

2/ Percents of Company test period costs of debt, as contained in Company filing, Schedule D-2.

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index
		1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%
1976	5.4%	10.8%	7.7%	4.8%
1977	5.5%	5.9%	7.0%	6.8%
1978	5.0%	5.7%	6.0%	9.0%
1979	2.8%	4.4%	5.8%	13.3%
1980	-0.2%	-1.9%	7.0%	12.4%
1981	1.8%	1.9%	7.5%	8.9%
1982	-2.1%	-4.4%	9.5%	3.8%
		1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%
1984	6.8%	9.3%	7.5%	3.9%
1985	3.7%	1.7%	7.2%	3.8%
1986	3.1%	0.9%	7.0%	1.1%
1987	2.9%	4.9%	6.2%	4.4%
1988	3.8%	4.5%	5.5%	4.4%
1989	3.5%	1.8%	5.3%	4.6%
1990	1.8%	-0.2%	5.6%	6.1%
1991	-0.5%	-2.0%	6.8%	3.1%
		1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%
1993	2.7%	3.4%	6.9%	2.7%
1994	4.0%	5.5%	6.1%	2.7%
1995	3.7%	4.8%	5.6%	2.5%
1996	4.5%	4.3%	5.4%	3.3%
1997	4.5%	7.3%	4.9%	1.7%
1998	4.2%	5.8%	4.5%	1.6%
1999	3.7%	4.5%	4.2%	2.7%
2000	4.1%	4.0%	4.0%	3.4%
2001	1.1%	-3.4%	4.7%	1.6%
		2002 - 2009 Cycle		
2002	1.8%	0.2%	5.8%	2.4%
2003	2.8%	1.2%	6.0%	1.9%
2004	3.8%	2.3%	5.5%	3.3%
2005	3.3%	3.2%	5.1%	3.4%
2006	2.7%	2.2%	4.6%	2.5%
2007	1.8%	2.5%	4.6%	4.1%
2008	-0.3%	-3.4%	5.8%	0.1%
2009	-2.8%	-11.3%	9.3%	2.7%
		Current Cycle		
2010	2.5%	5.6%	9.6%	1.5%
2011	1.6%	3.0%	8.9%	3.0%
2012	2.2%	2.8%	8.1%	1.7%
2013	1.5%	1.9%	7.4%	1.5%
2014	2.4%	2.9%	6.2%	0.8%
2015	2.4%	0.3%	5.3%	0.7%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index
2002				
1st Qtr.	2.7%	-3.8%	5.6%	2.8%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%
4th Qtr.	0.2%	1.4%	5.9%	1.6%
2003				
1st Qtr.	1.2%	1.1%	5.8%	4.8%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%
2004				
1st Qtr.	3.0%	2.8%	5.6%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%
2005				
1st Qtr.	4.1%	3.8%	5.3%	4.4%
2nd Qtr.	1.7%	3.0%	5.1%	1.6%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%
2006				
1st Qtr.	5.4%	3.4%	4.7%	4.8%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%
2007				
1st Qtr.	0.9%	2.5%	4.5%	4.8%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%
3rd Qtr.	2.3%	1.8%	4.6%	1.2%
4th Qtr.	2.9%	1.7%	4.8%	6.4%
2008				
1st Qtr.	-1.8%	1.9%	4.9%	2.8%
2nd Qtr.	1.3%	0.2%	5.3%	7.6%
3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%
4th Qtr.	-8.9%	6.0%	6.9%	-13.2%
2009				
1st Qtr.	-5.3%	-11.6%	8.1%	2.4%
2nd Qtr.	-0.3%	-12.9%	9.3%	3.2%
3rd Qtr.	1.4%	-9.3%	9.6%	2.0%
4th Qtr.	4.0%	-4.5%	10.0%	2.5%
2010				
1st Qtr.	1.6%	2.7%	9.7%	0.9%
2nd Qtr.	3.9%	6.5%	9.7%	-1.2%
3rd Qtr.	2.8%	6.9%	9.6%	2.8%
4th Qtr.	2.8%	6.2%	9.6%	2.8%
2011				
1st Qtr.	-1.5%	5.4%	9.0%	4.8%
2nd Qtr.	2.9%	3.6%	9.0%	3.2%
3rd Qtr.	0.8%	3.3%	9.1%	2.4%
4th Qtr.	4.6%	4.0%	8.7%	0.4%
2012				
1st Qtr.	2.3%	4.5%	8.3%	3.2%
2nd Qtr.	1.6%	4.7%	8.2%	0.0%
3rd Qtr.	2.5%	3.4%	8.1%	4.0%
4th Qtr.	0.1%	2.8%	7.8%	0.0%
2013				
1st Qtr.	1.9%	2.5%	7.7%	2.0%
2nd Qtr.	1.1%	2.0%	7.6%	1.2%
3rd Qtr.	3.0%	2.6%	7.3%	1.6%
4th Qtr.	3.9%	3.3%	7.0%	1.2%
2014				
1st Qtr.	-0.9%	3.2%	6.6%	1.6%
2nd Qtr.	4.6%	4.2%	6.2%	3.6%
3rd Qtr.	4.3%	4.7%	6.1%	0.0%
4th Qtr.	2.1%	4.5%	5.7%	-2.8%
2015				
1st Qtr.	0.6%	3.5%	5.6%	-1.2%
2nd Qtr.	3.9%	0.4%	5.4%	3.2%
3rd Qtr.	2.0%	0.1%	5.2%	-0.1%
4th Qtr.	1.4%	-1.6%	5.0%	0.0%
2016				
1st Qtr.	0.5%	-1.7%	4.9%	-0.4%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issue:

INTEREST RATES

Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Corporate Bonds Aaa	Corporate Bonds Baa
			1975 - 1982 Cycle		
1975	7.86%	5.84%	7.99%	8.83%	10.61%
1976	6.84%	4.99%	7.61%	8.43%	9.75%
1977	6.83%	5.27%	7.42%	8.02%	8.97%
1978	9.06%	7.22%	8.41%	8.73%	9.49%
1979	12.67%	10.04%	9.44%	9.63%	10.69%
1980	15.27%	11.51%	11.46%	11.94%	13.67%
1981	18.89%	14.03%	13.93%	14.17%	16.04%
1982	14.86%	10.69%	13.00%	13.79%	16.11%
			1983 - 1991 Cycle		
1983	10.79%	8.63%	11.10%	12.04%	13.55%
1984	12.04%	9.58%	12.44%	12.71%	14.19%
1985	9.93%	7.48%	10.62%	11.37%	12.72%
1986	8.33%	5.98%	7.68%	9.02%	10.39%
1987	8.21%	5.82%	8.39%	9.38%	10.58%
1988	9.32%	6.69%	8.85%	9.71%	10.83%
1989	10.87%	8.12%	8.49%	9.26%	10.18%
1990	10.01%	7.51%	8.55%	9.32%	10.36%
1991	8.46%	5.42%	7.86%	8.77%	9.80%
			1992 - 2001 Cycle		
1992	6.25%	3.45%	7.01%	8.14%	8.98%
1993	6.00%	3.02%	5.87%	7.22%	7.93%
1994	7.15%	4.29%	7.09%	7.96%	8.62%
1995	8.83%	5.51%	6.57%	7.59%	8.20%
1996	8.27%	5.02%	6.44%	7.37%	8.05%
1997	8.44%	5.07%	6.35%	7.26%	7.86%
1998	8.35%	4.81%	5.26%	6.53%	7.22%
1999	8.00%	4.66%	5.65%	7.04%	7.87%
2000	9.23%	5.85%	6.03%	7.62%	8.36%
2001	6.91%	3.44%	5.02%	7.08%	7.95%
			2002 - 2009 Cycle		
2002	4.67%	1.62%	4.61%	6.49%	7.80%
2003	4.12%	1.01%	4.01%	5.67%	6.77%
2004	4.34%	1.38%	4.27%	5.63%	6.39%
2005	6.19%	3.16%	4.29%	5.24%	6.06%
2006	7.96%	4.73%	4.80%	5.59%	6.48%
2007	8.05%	4.41%	4.63%	5.56%	6.48%
2008	5.09%	1.48%	3.66%	5.63%	7.45%
2009	3.25%	0.16%	3.26%	5.31%	7.30%
			Current Cycle		
2010	3.25%	0.14%	3.22%	4.94%	6.04%
2011	3.25%	0.06%	2.78%	4.64%	5.66%
2012	3.25%	0.09%	1.80%	3.67%	4.94%
2013	3.25%	0.06%	2.35%	4.24%	5.10%
2014	3.25%	0.03%	2.54%	4.16%	4.85%
2015	3.26%	0.60%	2.14%	3.89%	5.00%

Sources: Council of Economic Advisors, Economic Indicators, various issues; Federal Reserve.

INTEREST RATES

	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Corporate Bonds Aaa	Corporate Bonds Baa
2010					
Jan	3.25%	0.06%	3.73%	5.26%	6.25%
Feb	3.25%	0.10%	3.69%	5.35%	6.34%
Mar	3.25%	0.15%	3.73%	5.27%	6.27%
Apr	3.25%	0.15%	3.85%	5.29%	6.25%
May	3.25%	0.16%	3.42%	4.96%	6.05%
June	3.25%	0.12%	3.20%	4.88%	6.23%
July	3.25%	0.16%	3.01%	4.72%	6.01%
Aug	3.25%	0.15%	2.70%	4.49%	5.66%
Sept	3.25%	0.15%	2.65%	4.53%	5.66%
Oct	3.25%	0.13%	2.54%	4.68%	5.72%
Nov	3.25%	0.13%	2.76%	4.87%	5.92%
Dec	3.25%	0.15%	3.29%	5.02%	6.10%
2011					
Jan	3.25%	0.15%	3.39%	5.04%	6.09%
Feb	3.25%	0.14%	3.58%	5.22%	6.15%
Mar	3.25%	0.11%	3.41%	5.13%	6.03%
Apr	3.25%	0.06%	3.46%	5.16%	6.02%
May	3.25%	0.04%	3.17%	4.96%	5.78%
June	3.25%	0.04%	3.00%	4.99%	5.75%
July	3.25%	0.03%	3.00%	4.93%	5.76%
Aug	3.25%	0.05%	2.30%	4.37%	5.36%
Sept	3.25%	0.02%	1.98%	4.09%	5.27%
Oct	3.25%	0.02%	2.15%	3.98%	5.37%
Nov	3.25%	0.01%	2.01%	3.87%	5.14%
Dec	3.25%	0.02%	1.98%	3.93%	5.25%
2012					
Jan	3.25%	0.02%	1.97%	3.85%	5.23%
Feb	3.25%	0.08%	1.97%	3.85%	5.14%
Mar	3.25%	0.09%	2.17%	3.99%	5.23%
Apr	3.25%	0.08%	2.05%	3.96%	5.19%
May	3.25%	0.09%	1.80%	3.80%	5.07%
June	3.25%	0.09%	1.62%	3.64%	5.02%
July	3.25%	0.10%	1.53%	3.40%	4.87%
Aug	3.25%	0.11%	1.68%	3.48%	4.91%
Sept	3.25%	0.10%	1.72%	3.49%	4.84%
Oct	3.25%	0.10%	1.75%	3.47%	4.58%
Nov	3.25%	0.11%	1.65%	3.50%	4.51%
Dec	3.25%	0.08%	1.72%	3.65%	4.63%
2013					
Jan	3.25%	0.07%	1.91%	3.80%	4.73%
Feb	3.25%	0.10%	1.98%	3.90%	4.85%
Mar	3.25%	0.09%	1.96%	3.93%	4.85%
Apr	3.25%	0.06%	1.76%	3.73%	4.59%
May	3.25%	0.05%	1.93%	3.89%	4.73%
June	3.25%	0.05%	2.30%	4.27%	5.19%
July	3.25%	0.04%	2.58%	4.34%	5.32%
Aug	3.25%	0.04%	2.74%	4.54%	5.42%
Sept	3.25%	0.02%	2.81%	4.64%	5.47%
Oct	3.25%	0.06%	2.62%	4.53%	5.31%
Nov	3.25%	0.07%	2.72%	4.63%	5.38%
Dec	3.25%	0.07%	2.90%	4.62%	5.38%
2014					
Jan	3.25%	0.05%	2.86%	4.49%	5.19%
Feb	3.25%	0.06%	2.71%	4.45%	5.10%
Mar	3.25%	0.05%	2.72%	4.38%	5.06%
Apr	3.25%	0.04%	2.71%	4.24%	4.90%
May	3.25%	0.03%	2.56%	4.16%	4.76%
June	3.25%	0.03%	2.60%	4.25%	4.80%
July	3.25%	0.03%	2.54%	4.16%	4.73%
Aug	3.25%	0.03%	2.42%	4.08%	4.69%
Sept	3.25%	0.02%	2.53%	4.11%	4.80%
Oct	3.25%	0.02%	2.30%	3.92%	4.69%
Nov	3.25%	0.02%	2.33%	3.92%	4.79%
Dec	3.25%	0.04%	2.21%	3.79%	4.74%
2015					
Jan	3.25%	0.03%	1.88%	3.46%	4.45%
Feb	3.25%	0.03%	1.98%	3.61%	4.51%
Mar	3.25%	0.03%	2.04%	3.64%	4.54%
Apr	3.25%	0.02%	1.94%	3.52%	4.48%
May	3.25%	0.02%	2.20%	3.98%	4.89%
June	3.25%	0.04%	2.36%	4.19%	5.13%
July	3.25%	0.03%	2.32%	4.15%	5.20%
Aug	3.25%	0.09%	2.17%	4.04%	5.19%
Sep	3.25%	0.06%	2.17%	4.07%	5.34%
Oct	3.25%	0.01%	2.07%	3.95%	5.34%
Nov	3.25%	0.13%	2.26%	4.06%	5.46%
Dec	3.50%	0.26%	2.24%	3.97%	5.46%
2016					
Jan	3.50%	0.25%	2.09%	4.00%	5.45%
Feb	3.50%	0.32%	1.78%	3.96%	5.34%
Mar	3.50%	0.32%	1.89%	3.82%	5.13%
Apr	3.50%	0.23%	1.81%	3.62%	4.79%
May	3.50%	0.27%	1.81%	3.65%	4.68%
June	3.50%	0.29%	1.64%	3.50%	4.53%
July	3.50%	0.31%	1.50%	3.28%	4.22%
Aug	3.50%	0.30%	1.56%	3.32%	4.24%
Sep	3.50%	0.32%	1.63%	3.41%	4.31%

Sources: Council of Economic Advisors, Economic Indicators, various issues; Federal Reserve.

STOCK PRICE INDICATORS

	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	2,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		2002 - 2009 Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.54%
2009	948.05	1,845.38	8,876.15	2.40%	1.86%
		Current Cycle			
2010	1,139.97	2,349.89	10,662.80	1.98%	6.04%
2011	1,268.89	2,677.44	11,966.36	2.05%	6.77%
2012	1,379.35	2,965.56	12,967.08	2.24%	6.20%
2013	1,462.51	3,537.69	14,999.67	2.14%	5.57%
2014	1,930.67	4,374.31	16,773.99	2.04%	5.25%
2015	2,061.20	4,943.49	17,590.81	2.10%	4.59%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDA Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
2010					
1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
2011					
1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
3rd Qtr.	1,237.12	2,613.11	11,671.47	2.15%	7.69%
4th Qtr.	1,225.65	2,600.91	11,798.65	2.25%	6.91%
2012					
1st Qtr.	1,347.44	2,902.90	12,839.80	2.12%	6.29%
2nd Qtr.	1,350.39	2,928.62	12,765.58	2.30%	6.45%
3rd Qtr.	1,402.21	3,029.86	13,118.72	2.27%	6.00%
4th Qtr.	1,418.21	3,001.69	13,142.91	2.28%	6.07%
2013					
1st Qtr.	1,514.41	3,177.10	14,000.30	2.21%	5.59%
2nd Qtr.	1,609.77	3,369.49	14,961.28	2.15%	5.66%
3rd Qtr.	1,675.31	3,643.63	15,255.25	2.14%	5.61%
4th Qtr.	1,770.45	3,960.54	15,751.96	2.06%	5.42%
2014					
1st Qtr.	1,834.30	4,210.06	16,170.26	2.04%	5.38%
2nd Qtr.	1,900.37	4,195.81	16,603.50	2.06%	5.26%
3rd Qtr.	1,975.95	4,483.51	16,953.85	2.02%	5.37%
4th Qtr.	2,012.04	4,607.88	17,368.36	2.03%	4.97%
2015					
1st Qtr.	2,063.46	4,821.99	17,806.47	2.02%	4.80%
2nd Qtr.	2,094.37	5,029.47	18,007.48	2.05%	4.60%
3rd Qtr.	2,026.14	4,921.81	17,065.52	2.16%	4.72%
4th Qtr.	2,053.17	5,000.69	17,482.97	2.16%	4.23%
2016					
1st Qtr.	1,948.32	4,609.47	16,635.76	2.31%	4.20%
2nd Qtr.	2,074.99	4,845.55	17,763.85	2.19%	4.14%
3rd Qtr.	2,161.36	5,165.06	18,367.92	2.13%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit YL-1
Schedule 3

SOUTHWEST GAS CORPORATION
HISTORY OF CREDIT RATINGS

Year	UNSECURED DEBT RATINGS		
	Moody's	S&P	Fitch
2011	Baa2	BBB+	BBB+
2012	Baa1	BBB+	A-
2013	Baa1	A-	A
2014	A3	BBB+	A
2015	A3	BBB+	A
2016 1/	A3	BBB+	A

1/ As of July 7, 2016.

Source: Response to STF 3.7.

Exhibit YL-1
Schedule 4

SOUTHWEST GAS CORPORATION
CAPITAL STRUCTURE RATIOS
2011 - 2015
($ in thousands)

YEAR	COMMON EQUITY /1	LONG-TERM DEBT 2/	SHORT-TERM DEBT
2011	$1,225,031	$1,253,476	$0
% Total Capital	49.4%	50.6%	0.0%
% Permanent Capital	49.4%	50.6%	
2012	$1,308,498	$1,318,510	$0
% Total Capital	49.8%	50.2%	0.0%
% Permanent Capital	49.8%	50.2%	
2013	$1,412,523	$1,392,432	$0
% Total Capital	50.4%	49.6%	0.0%
% Permanent Capital	50.4%	49.6%	
2014	$1,506,308	$1,650,566	$5,000
% Total Capital	47.6%	52.2%	0.2%
% Permanent Capital	47.7%	52.3%	
2015	$1,608,433	$1,570,679	$18,000
% Total Capital	50.3%	49.1%	0.6%
% Permanent Capital	50.6%	49.4%	

1/ Includes redeemable noncontrolling interest.
2/ Includes current maturities of long-term debt.

Note: Percentage may not total 100.0% due to rounding.

Source: Response to STF 3.6.

Exhibit YL-1
Schedule 5

PROXY COMPANIES
COMMON EQUITY RATIOS

COMPANY	2011	2012	2013	2014	2015	2011-2015 Average
Southwest Gas	49.5%	49.9%	50.4%	47.3%	50.1%	49.4%
Proxy Group						
Atmos Energy	46.6%	46.5%	45.8%	50.5%	50.4%	48.0%
Chesapeake Utilities	Not reported in AUS Utility Reports					
Laclede Group (Spire Inc.)	55.3%	58.1%	51.5%	40.5%	41.8%	49.4%
New Jersey Resources	52.0%	48.1%	44.7%	52.7%	51.7%	49.8%
Northwest Natural Gas	46.5%	45.4%	44.7%	46.1%	47.3%	46.0%
South Jersey Industries	45.5%	43.3%	43.9%	42.6%	41.4%	43.3%
WGL Holdings	58.1%	57.1%	53.6%	47.5%	45.8%	52.4%
Average	50.7%	49.8%	47.4%	46.7%	46.4%	**48.2%**
Median	49.3%	47.3%	45.3%	46.8%	46.6%	**48.7%**

Note: Percentages include short-term debt.

Source: AUS Utility Reports

PROXY COMPANIES
BASIS FOR SELECTION

COMPANY	Market Capitalization ($000)	Percent Reg Gas Revenues	Common Equity Ratio	Value Line Safety	S&P Stock Ranking	S&P Bond Rating	Moody's Bond Rating
Southwest Gas	$3,400,000	57%	52.7%	3	A-	A-	A3
Proxy Group							
Atmos Energy	$7,800,000	72%	52.6%	1	A-	A-	A2
Chesapeake Utilities	$1,000,000	53%	53.0%	2	A	NR	NR
Laclede Group (Spire Inc.)	$3,000,000	101%	48.0%	2	B+	A+	A3
New Jersey Resources	$3,000,000	32%	48.9%	1	B+	A+	Aa2
Northwest Natural Gas	$1,700,000	97%	51.7%	1	B	AA-	A1
South Jersey Industries	$2,400,000	50%	51.1%	2	A-	A	A2
WGL Holdings	$3,300,000	45%	47.2%	1	B+	A+	A1

Sources: AUS Utility Reports, Value Line Investment Survey.

PROXY COMPANIES
DIVIDEND YIELD

COMPANY	Qtr DPS	July - September, 2016				YIELD
		DPS	HIGH	LOW	AVERAGE	
Southwest Gas	$0.450	1.8	79.58	67.97	73.775	2.4%
Proxy Group						
Atmos Energy	$0.420	$1.68	$81.97	$71.61	$76.79	2.2%
Chesapeake Utilities	$0.305	$1.22	$67.88	$59.12	$63.50	1.9%
Laclede Group (Spire Inc.)	$0.490	$1.96	$71.21	$61.96	$66.59	2.9%
New Jersey Resources	$0.255	$1.02	$38.92	$32.27	$35.60	2.9%
Northwest Natural Gas	$0.468	$1.87	$66.17	$57.96	$62.07	3.0%
South Jersey Industries	$0.264	$1.06	$32.03	$28.17	$30.10	3.5%
WGL Holdings	$0.488	$1.95	$72.18	$60.27	$66.23	2.9%
Average						**2.8%**

Source: Yahoo! Finance.

PROXY COMPANIES
RETENTION GROWTH RATES

COMPANY	2011	2012	2013	2014	2015	Average	2016	2017	2019-'21	Average
Southwest Gas	5.3%	6.1%	6.1%	5.0%	4.0%	5.3%	4.0%	4.5%	6.0%	4.8%
Proxy Group										
Atmos Energy	3.3%	2.8%	4.0%	4.7%	4.9%	3.9%	5.5%	5.5%	5.5%	5.5%
Chesapeake Utilities	6.6%	6.4%	7.1%	7.4%	6.8%	6.9%	7.0%	7.0%	8.0%	7.3%
Laclede Group (Spire Inc.)	4.9%	4.3%	1.0%	1.5%	3.7%	3.1%	3.5%	4.0%	5.0%	4.2%
New Jersey Resources	6.2%	6.2%	5.2%	11.0%	6.8%	7.1%	4.5%	5.5%	4.5%	4.8%
Northwest Natural Gas	2.4%	1.6%	1.5%	1.1%	0.6%	1.4%	1.0%	1.0%	3.5%	1.8%
South Jersey Industries	6.7%	5.8%	4.8%	4.3%	2.8%	4.9%	1.0%	1.5%	1.5%	1.3%
WGL Holdings	3.4%	4.8%	2.6%	4.3%	5.4%	4.1%	4.0%	4.5%	3.5%	4.0%
Average						**4.5%**				**4.1%**

Source: Value Line Investment Survey.

PROXY COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '13-'15 to '19-'21 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Southwest Gas	10.0%	9.0%	5.5%	8.2%	7.0%	8.5%	3.0%	6.2%
Proxy Group								
Atmos Energy	7.0%	2.5%	5.0%	4.8%	6.5%	6.5%	3.5%	5.5%
Chesapeake Utilities	10.0%	5.0%	8.0%	7.7%	8.5%	6.0%	6.5%	7.0%
Laclede Group (Spire Inc.)	-1.0%	3.0%	8.0%	3.3%	9.0%	3.5%	4.5%	5.7%
New Jersey Resources	6.5%	7.0%	6.5%	6.7%	1.0%	3.0%	6.5%	3.5%
Northwest Natural Gas	-5.0%	3.0%	2.5%	0.2%	7.0%	2.0%	2.5%	3.8%
South Jersey Industries	4.0%	9.5%	8.5%	7.3%	3.0%	6.5%	8.0%	5.8%
WGL Holdings	2.5%	3.5%	2.5%	2.8%	3.5%	2.5%	6.0%	4.0%
Average				**4.7%**				**5.0%**

Source: Value Line Investment Survey.

PROXY COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Southwest Gas	2.5%	5.3%	4.8%	8.2%	6.2%	4.0%	5.7%	8.2%
Proxy Group								
Atmos Energy	2.2%	3.9%	5.5%	4.8%	5.5%	7.3%	5.4%	7.7%
Chesapeake Utilities	2.0%	6.9%	7.3%	7.7%	7.0%	3.0%	6.4%	8.4%
Laclede Group (Spire Inc.)	3.0%	3.1%	4.2%	3.3%	5.7%	4.7%	4.2%	7.2%
New Jersey Resources	2.9%	7.1%	4.8%	6.7%	3.5%	6.5%	5.7%	8.7%
Northwest Natural Gas	3.1%	1.4%	1.8%	0.2%	3.8%	4.0%	2.3%	5.3%
South Jersey Industries	3.6%	4.9%	1.3%	7.3%	5.8%	6.0%	5.1%	8.7%
WGL Holdings	3.0%	4.1%	4.0%	2.8%	4.0%	8.0%	4.6%	7.6%
Mean	2.8%	4.5%	4.1%	4.7%	5.0%	5.6%	4.8%	**7.6%**
Median	3.0%	4.1%	4.2%	4.8%	5.5%	6.0%	5.1%	**7.7%**
Composite - Mean		7.3%	**7.0%**	7.5%	7.9%	**8.5%**	7.6%	
Composite - Median		**7.1%**	7.2%	7.8%	8.5%	**9.0%**	8.1%	

Note: negative values not used in calculations.

Sources: Prior pages of this schedule, Yahoo! Finance.

Exhibit YL-1
Schedule 8

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$18.86	$149.74	12.22%	7.29%	4.93%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$216.51	16.58%	7.60%	8.98%
1996	$38.73	$237.08	17.08%	6.18%	10.90%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.70	$338.37	7.44%	5.53%	1.91%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.17	$529.59	12.80%	4.86%	7.94%
2008	$14.88	$451.37	3.03%	4.45%	-1.42%
2009	$50.97	$513.58	10.56%	3.47%	7.09%
2010	$77.35	$579.14	14.16%	4.25%	9.91%
2011	$86.95	$613.14	14.59%	3.81%	10.78%
2012	$86.51	$666.97	13.52%	2.40%	11.12%
2013	$100.20	$715.84	14.49%	2.86%	11.63%
2014	$102.31	$726.96	14.18%	3.33%	10.85%
Average					**6.85%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

Exhibit YL-1
Schedule 9

PROXY COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Proxy Group				
Atmos Energy	1.91%	0.75	5.75%	6.2%
Chesapeake Utilities	1.91%	0.60	5.75%	5.4%
Laclede Group (Spire Inc.)	1.91%	0.70	5.75%	5.9%
New Jersey Resources	1.91%	0.80	5.75%	6.5%
Northwest Natural Gas	1.91%	0.65	5.75%	5.6%
South Jersey Industries	1.91%	0.80	5.75%	6.5%
WGL Holdings	1.91%	0.75	5.75%	6.2%
Mean				**6.1%**
Median				**6.2%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

20-year Treasury Bonds	
Month	Rate
July 2016	1.82%
August 2016	1.89%
September 2016	2.02%
Average	1.91%

PROXY COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2002-2008 Average	2009-2015 Average	2016	2017	2019-21
Proxy Group																			
Atmos Energy	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	9.0%	8.5%	9.1%	9.2%	8.2%	9.2%	10.0%	9.9%	9.7%	9.2%	10.5%	11.5%	11.5%
Chesapeake Utilities	8.5%	14.1%	12.3%	12.6%	11.1%	11.3%	11.7%	10.6%	11.8%	11.7%	11.5%	12.2%	12.4%	12.2%	11.7%	11.8%	12.0%	12.0%	13.0%
Laclede Group (Spire Inc.)	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	12.6%	12.9%	10.3%	11.5%	10.7%	6.9%	7.0%	8.9%	11.4%	9.7%	9.0%	9.0%	10.0%
New Jersey Resources	16.0%	16.7%	15.8%	16.1%	14.5%	10.2%	16.5%	14.2%	14.4%	14.2%	14.2%	13.4%	18.8%	14.5%	15.1%	14.8%	11.5%	12.5%	11.0%
Northwest Natural Gas	8.7%	9.2%	9.3%	10.1%	10.9%	12.4%	11.1%	11.6%	10.7%	9.1%	8.2%	8.1%	7.7%	6.9%	10.2%	8.9%	7.5%	8.0%	9.5%
South Jersey Industries	13.9%	13.0%	13.4%	13.3%	17.2%	13.4%	13.6%	13.4%	14.5%	14.6%	13.8%	12.5%	11.9%	10.2%	14.0%	13.0%	7.5%	7.5%	8.0%
WGL Holdings	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.0%	11.8%	10.2%	9.7%	11.1%	9.4%	11.0%	12.9%	11.3%	10.9%	11.5%	11.0%	9.5%
Average	10.3%	12.9%	11.9%	12.1%	12.5%	11.4%	12.4%	11.9%	11.6%	11.4%	11.1%	10.2%	11.3%	10.8%	**11.9%**	**11.2%**	**9.9%**	**10.2%**	**10.4%**
Median	8.7%	13.0%	11.9%	12.1%	11.1%	11.3%	12.0%	11.8%	10.7%	11.5%	11.1%	9.4%	11.0%	10.2%	**11.4%**	**10.8%**	**10.5%**	**11.0%**	**10.0%**

Source: Calculations made from data contained in Value Line Investment Survey.

PROXY COMPANIES
MARKET TO BOOK RATIOS

COMPANY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2002-2008 Average	2009-2015 Average
Proxy Group																
Atmos Energy	150%	152%	147%	145%	146%	136%	110%	109%	121%	130%	132%	151%	173%	186%	141%	143%
Chesapeake Utilities	236%	271%	272%	212%	205%	190%	159%	141%	152%	165%	171%	192%	226%	240%	221%	184%
Laclede Group (Spire Inc.)	145%	169%	179%	179%	184%	168%	209%	171%	145%	153%	154%	147%	148%	155%	176%	153%
New Jersey Resources	221%	245%	252%	275%	246%	223%	201%	214%	226%	248%	232%	212%	244%	249%	238%	232%
Northwest Natural Gas	145%	144%	153%	172%	177%	208%	201%	173%	181%	168%	170%	157%	166%	167%	171%	169%
South Jersey Industries	185%	170%	195%	222%	209%	231%	196%	205%	245%	254%	236%	232%	215%	183%	201%	224%
WGL Holdings	152%	162%	175%	183%	168%	172%	146%	149%	159%	172%	168%	172%	189%	238%	165%	178%
Average	176%	188%	196%	198%	191%	190%	175%	166%	176%	184%	180%	180%	194%	203%	**188%**	**183%**
Median	152%	169%	179%	183%	184%	190%	196%	171%	159%	168%	170%	172%	189%	186%	**179%**	**174%**

Source: Calculations made from data contained in Value Line Investment Survey.

Exhibit YL-1
Schedule 11

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 2002 - 2014

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
2002	8.4%	295%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
2008	3.0%	224%
2009	10.6%	187%
2010	14.2%	208%
2011	14.6%	207%
2012	13.5%	214%
2013	14.5%	237%
2014	14.2%	268%
Averages:		
2002-2008	12.4%	275%
2009-2014	13.6%	220%

Source: Standard & Poor's Analyst's Handbook, 2015 edition.

RISK INDICATORS

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Proxy Group						
Atmos Energy	1	0.75	A	4.00	A-	3.67
Chesapeake Utilities	2	0.60	B++	3.67	A	4.00
Laclede Group (Spire Inc.)	2	0.70	B++	3.67	B+	3.33
New Jersey Resources	1	0.80	A+	4.33	B+	3.33
Northwest Natural Gas	1	0.65	A	4.00	B	3.00
South Jersey Industries	2	0.80	A	4.00	A-	3.67
WGL Holdings	1	0.75	A	4.00	B+	3.33
	1.4	0.72	A	3.95	B+/A-	3.48

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B
Proxy Group	1.4	0.72	A	B+/A-

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS	)	DOCKET NO. G-01551A-16-0107

DIRECT

TESTIMONY

OF

KIRK S. BALCOM

OH BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 30, 2016

TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

In support of the Arizona Corporation Commission's review of Southwest Gas Corporation's rate application, we examined and analyzed Southwest's depreciation studies. To conduct our assessment, we:

- Reviewed the analysis of the year life and the Iowa Curve dispersion for each FERC account.
- Evaluated the net salvage analysis including salvage, cost of removal, and that salvage rate.
- Determined whether recent and future salvage and cost of removal experience support the analysis for each FERC account.
- Confirmed the accuracy and completeness of figures used in the calculation of the $74,607,780 distribution plant and general plant structures and improvements depreciation and the $6,864,744 million general plant amortization.
- Verified the accuracy and completeness of the comparison of existing and proposed depreciation and amortization rates.

As a result of our review and analysis, we developed four recommendations with regard to Southwest's depreciation studies:

1. Approve the distribution plant and general plant structures and improvements revised depreciation rates based on revised depreciation reserve balances recorded from book reserves, the elimination of the theoretical reserve allocation of book reserves, and increase of the average remaining life for mains. This recommendation decreases the annual depreciation accrual by $4,275,831.

2. Approve the general plant revised annual amortization rate based on establishing a deficiency reserve calculated from a theoretical reserve, amortize the deficiency reserve, and amortize plant in service net of the theoretical reserve calculated for general plant. This recommendation increases the annual amortization accrual by $1,009,715.

3. Approve a distribution and general plant annual expense accrual of $78, 206,408 based on distribution and general plant in service at December 31, 2015 totaling $3,000,903,439. This recommendation decreases the previous authorized annual expense accrual by $45,270,354.

4. We recommend that, before the next rate case, a detailed independent and objective cost of removal study be performed to determine the validity of significant increases

in cost of removal charges recorded in 2015, and for any that may occur after 2015 and before the next rate case. In the meantime, we recommend that Southwest Gas Corporation review the cost of removal charges recorded in mains and services accumulated depreciation accounts in 2015 to determine whether charges, if any, should be transferred to operations, maintenance, or other accounts. This review would help ensure the account balances of mains and services accumulated depreciation are fairly stated going forward into the next rate case. When filing for its next rate case, Southwest Gas shall provide the Commission with results of such study and review.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Kirk Balcom. I work for Rehmann Robson LLC ("Rehmann Robson"), a subsidiary of Rehmann LLC ("Rehmann"). My business address is 675 Robinson Road, Jackson, Michigan 49203.

Q. What is your current position at Rehmann Robson?

A. I am currently a Principal.

Q. Please describe your background and qualifications for your testimony in this proceeding.

A. Examples of accounting systems internal audits pertinent to this rate case include:

- Construction Management System – the system that accounts for electric distribution and gas main construction.
- Distribution Management System – the system that accounts for electric and gas service construction.
- Construction Work in Progress System – the system that accounts for major electric and gas construction and equipment.
- Integrated Plant In-Service System – the system that accounts for in-service electric and gas real property and electric and gas personal location property.
- Mass Property System – the system that accounts for in-service electric and gas personal mass property and unitization of personal mass property.

I have audited components of accumulated depreciation reserve including cost of removal and valuing vintage retirement units based on statistical aging programs. My most recent utility experience includes auditing a Distribution Capital Investment Rider of Duke Energy Ohio, a Management Audit of United Illuminating Company, and an investigative audit of three Ohio Gas Utilities.

A copy of my resume, which includes a list of clients, is attached to this testimony as Exhibit KSB-1 – Kirk Balcom Resume.

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

A. The Arizona Corporation Commission ("Commission"), Utilities Division ("Staff"), contracted with Overland Consulting to review and assess certain aspects of the Southwest Gas Corporation ("SWG" or "Company") rate application filed with the Commission on May 2, 2016. Rehmann Consulting is acting as a subcontractor to Overland Consulting.

Q. What is Overland's scope of work with respect to reviewing and assessing SWG's rate application?

A. Overland was asked to examine and analyze SWG's depreciation studies.

Q. Can you summarize the approach that Overland utilized in carrying out its assessment?

A. Overland employed a workflow process to accomplish its investigation in an efficient manner by reviewing relevant filings, orders, and statutes; initiating discovery requests; evaluating discovery responses, and providing follow-up with additional discovery as needed.

Q. What specifically did you review in the SWG depreciation study?

A. Specifically, we reviewed the depreciation rate study as follows:

- For each Federal Energy Regulatory Commission ("FERC") account, we reviewed the analysis of the year life and the Iowa Curve dispersion.

- For each FERC account, we reviewed the net salvage analysis including salvage, cost of removal, and the salvage rate. We also determined whether recent and future salvage and cost of removal experience support the analysis for each FERC account.

- We verified the accuracy and completeness of figures used in the calculation of the \$74,607,780 million distribution plant and general plant structures and improvements depreciation and the \$6,864,744 million general plant amortization.

- We verified the accuracy and completeness of the comparison of existing and proposed depreciation and amortization rates.

Q. Who assisted you in this review?

A. This independent investigation was performed under my direct supervision with the assistance of two other subcontractors, Frank DiPalma and Thomas Simonsen. Copies of their respective resumes are included in Exhibit-KSB-2 – Frank DiPalma Resume and Exhibit KSB-3 – Thomas Simonsen Resume.

SUMMARY OF RECOMMENDATIONS

Q. As a result of your review and analysis, summarize your recommendations with regard to SWG's depreciation studies.

A. Our recommendations can be summarized as follows:

1. Approve the distribution plant and general plant structures and improvements revised depreciation rates based on revised depreciation reserve balances recorded from book

reserves, eliminate the theoretical reserve allocation of book reserves, and increase the average remaining life for mains. This recommendation decreases the annual depreciation accrual by $4,275,831.

2. Approve the general plant revised annual amortization rate based on establishing a deficiency reserve calculated from a theoretical reserve, the amortization of the deficiency reserve, and the amortization of plant in service net of the theoretical reserve calculated for general plant. This recommendation increases the annual amortization accrual by $1,009,715.

3. Approve a distribution and general plant annual expense accrual of $78,206,408 based on distribution and general plant in service at December 31, 2015, totaling $3,000,903,439. This recommendation decreases the previous authorized annual expense accrual by $45,270,354.

4. We recommend that, before the next rate case, a detailed independent and objective cost of removal study be performed to determine the validity of significant increases in cost of removal charges recorded in 2015, and for any that may occur after 2015 and before the next rate case. In the meantime, we recommend that Southwest Gas Corporation review the cost of removal charges recorded in mains and services accumulated depreciation accounts in 2015 to determine whether charges, if any, should be transferred to operations, maintenance, or other accounts. This review would help ensure the account balances of mains and services accumulated depreciation are fairly stated going forward into the next rate case. When filing for its next rate case, Southwest Gas shall provide the Commission with results of such study and review.

SUPPORTING ANALYSIS

Q. Please describe the SWG depreciation rate study.

A. The depreciation rate study[1] was completed as of December 31, 2015, and used the straight-line, Average Life Group ("ALG"), and remaining life depreciation system to calculate annual and accrued depreciation for Distribution Plant FERC accounts 374.20 Rights-of-Way, 375.00 Structures and Improvements, 376.00 Mains, 378.00 Measuring and Regulating Station Equipment – General, 380.00 Services, 380.00 Meters, and 385.00 Industrial Measuring and Regulating Station Equipment. The depreciation system was also used for General Plant FERC account 390.10 Structures and Improvements. A vintage year accounting method approved by the FERC in Accounting Release Number 15 ("AR-15") was used to amortize General Plant FERC accounts 391.00 Office Furniture and Equipment, 391.10 Computer Equipment, 392.11 Transportation Equipment – Light, 392.12 Transportation Equipment – Heavy, 393.00 Stores Equipment, 394.00 Tools, Shop, and Garage Equipment, 395.00 Laboratory Equipment, 396.00 Power Operated Equipment, 397.00 Communication Equipment, 397.20 Telemetering Equipment, and 398.00 Miscellaneous Equipment. AR-15 excluded General Plant account 390.10 Structures and Improvements.

Q. What did the depreciation rate study recommend?

A. The study recommends an overall depreciation decrease of $42.0 million annually to $81.5 million from $123.5 million. FERC account 376.00 Mains and account 380.00 Services accounted for a $45 million decrease in depreciation, while all other Distribution Plant accounts and all General Plant accounts accounted for a $3.0 million increase in depreciation and amortization. Both the increases in services lives and reductions of the negative net salvage resulted in the $45 million decrease in depreciation for mains and services.

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[1] Generally in preparation for a rate case, utilities will often prepare depreciation rate studies. Depreciation is a key factor in the final revenue rate calculation, as utilities get recovery of their investment through depreciation.

Q. Did the SWG depreciation rate study suggest a change in the average remaining life for mains and services?

A. Yes, the approved life for account 376.00 Mains that was previously used was 45 years with a R4 dispersion,[2] and for account 380.00 Services was previously 42 years and an L0 dispersion. The current study moves to a 53-year life and to a R1.5 dispersion for mains and a 44-year life and an L1 dispersion for services.

Q. Did the depreciation rate study suggest a change in the net salvage value?

A. Yes, the previously authorized net salvage[3] for FERC account 376.00 Mains was a negative 60 percent. The study recommended a decrease to negative 35 percent due to 5- to 10-year trends. The previously authorized net salvage for FERC account 380.00 Services was a negative 96 percent. The study recommended a decrease to negative 55 percent due to recent trends excluding 2015 which had a net salvage of negative 266 percent.

Q. Was the depreciation rate study supported by a detailed analysis?

A. The depreciation rate study was supported by detailed analysis of plant in service records by vintage year, retirement data by vintage year and activity year, salvage credits, and cost of

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[2] Average life and retirement pattern shape define the characteristics of an Iowa-type survivor curve. The L series designates left-moded curves, the S series designates symmetrical-moded curves, and the R series designates right-moded curves. The left-moded curves describe life expectancy characteristics whereby the greatest retirement frequency occurs prior to the average service life. The right-moded curves show the greatest retirement frequency after the average service life has been achieved. In the symmetrical-moded curves, the greatest retirement frequency occurs at the average service life. There is also an O series that designates origin-moded curves, whereby the highest rate of retirement occurs in the year of placement. Naming conventions for the Iowa-type curves specify a letter (L, S, R, or O), indicating the type of retirement pattern as well as a number designating the width of the dispersion pattern. A low number indicates a wide dispersion pattern and a high number indicates a narrow dispersion pattern.

[3] Net salvage is also recorded in the depreciation reserve. Net salvage is credits received from removal of plant retired less the cost of removal. Salvage credits increase the depreciation reserve and cost of removal decreases the depreciation reserve.

removal data. It was also supported by numerous Iowa Curves[4] used to determine the curve that best fits the existing life of the plant in service.

DEPRECIATION RESERVE

Q. What is depreciation reserve?

A. Depreciation reserve or accumulated provision for depreciation means the summation of charges for retirements, net salvage, and the annual provision for depreciation accrual(s) recorded by the utility under an approved method of depreciation accounting.

Q. Do you have any concerns with regard to the depreciation reserve in the rate study?

A. The Company reported[5] that Accumulated Provision for Depreciation and Amortization Detail at $1,290,046,943 for Distribution Plant and General Plant Structures and Improvements FERC accounts and ($7,408,140) for all other General Plant FERC accounts was included in the depreciation study. Since distribution plant and general plant structures and improvements depreciation expense were based on allocated accumulated depreciation reserve of $1,249,336,609 and general plant had been allocated (before assigning retirement of fully accrued assets) accumulated depreciation reserve of $33,179,209, we are concerned that distribution plant and general plant structures and improvements have not been allocated enough accumulated depreciation reserve based on subsidiary records.[6] We also believe allocating book reserve based on theoretical depreciation reserve is not appropriate since actual plant records were maintained at the FERC account level. Allocating an additional $40,708,333 of accumulated depreciation to distribution plant and general plant structures

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[4] Iowa curves are survivor curves developed in a study at the University of Iowa. The curves comprise a set of standardized patterns of asset retirement dispersion and are the most widely used standardized survivor curves in the utility industry.
[5] In response to Data Request No. Staff 4.43, a schedule WP-B-2 AZ ADA provided accumulated provision for depreciation and amortization as of December 31, 2015.
[6] Subsidiary records are required to be maintained according to the Uniform System of Accounts Prescribed for Natural Gas Companies subject to the provisions of the Natural Gas Act.

and improvements and using book depreciation reserve increases distribution plant and general plant structures and improvements depreciation expense by $1,167,624 from the depreciation study, when using the same average service lives in the study. See Exhibit KSB-4 Revised Depreciation Reserve.

Furthermore, general plant has a depreciation reserve of ($7,408,140); therefore, we are concerned that it can never be trued-up so that each asset will be fully amortized at the end of their recommended amortization period, where the amortization reserve will be sufficient to cover future additions.

Q. In view of your concerns for general plant, what do you recommend?

A. We recommend that a deficiency reserve be established for $33,516,328 and amortized $4,061,646, annually. We also recommend an additional amortization of net plant of $3,812,813 for a total of $7,874,458 for annual general plant amortization. This change results in an increase of $1,009,715 for general plant amortization from the depreciation study. See Exhibit KSB-5 Revised General Plant. We recommend that general plant be amortized under AR-15 going forward in 2016 and that the Company continue to use amortization based on a deficiency reserve and net plant, for general plant placed in service before January 1, 2016.

COST OF REMOVAL

Q. What was the cost of removal in 2015 and how does it compare with the previous year?

A. Cost of removal[7] in 2015 for mains totaled $5,230,681 and for services totaled $27,096,366 and were 2.8 and 9.1 times higher, respectively, than the 2014 cost of removal.

[7] Cost of removal refers to the costs associated with taking an asset out of service. Cost of removal reduces accumulated depreciation and therefore increases net plant value used in calculating the annual depreciation accrual.

Q. Does this dramatic increase in cost of removal give you cause for concern?

A. Yes, although an increase in cost of removal could be anticipated, the magnitude of the increase is significant. Initially, we were advised that the increase was related to the Customer-Owned Yard Line ("COYL") Program[8]; subsequently, we received a corrected discovery response stating that the increases are related to ongoing Distribution Integrity Management Program ("DIMP") work.[9] Based on this revised response, we have a concern that errors could have been made and COYL Program work charged to cost of removal.

Q. With regard to cost of removal, do you have any other concerns?

A. Yes, SWG uses a retirement unit of feet for both mains and services. This makes work on mains or services for smaller footages a capital expenditure instead of maintenance, resulting in higher cost of removal percentages.

Q. Could you please provide examples that would illustrate both of these cost of removal concerns?

A. Examples that would illustrate both accidental errors and use of feet as a retirement unit can be seen by comparing the cost of removal per unit for a variety of work orders in the following table.[10]

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[8] Responses to data requests Staff 4.18 and Staff 4.19 stated that the increases are related to the COYL Program.
[9] Revised responses were received in Supplemental Staff 4-018 and Supplemental Staff 4-019.
[10] Response to data request Staff 5.08 Attachment 1.

KSB-1

Type of Work Order	Work Order Number	Retirement Amount	Quantity Removed (Feet)	Cost of Removal Amount	Cost of Removal Per Unit (Feet)
Main	0042W1796371	$3.33	1	$26,398	$26,398
Main	0042W1860136	$86.34	3	$21,233	$7,078
Main	0042W1864750	$5.73	1	$1,256	$1,256
Main	0042W1985835	$347.40	20	$2,055	$103
Main	0042W1988840	$63.56	7	$4,573	$653
Service	0034RB02600	$38,036.67	5,457	$2,937,568	$583
Service	0036RB02600	$395,712.13	40,490	$4,388,218	$108

Q. Can you estimate the potential impact of cost of removal being overstated?

A. Without doing a detailed cost of removal study, we cannot estimate the impact of cost of removal being overstated. However, any overstatement of cost of removal would add to the accumulated depreciation reserve for mains and services. In addition, the current net salvage percent, which is the net of cost of removal expense and salvage credits, could result in a lower negative percentage. Both adjustments would lower the annual depreciation accrual.

Q. Can you provide an example as to what would be the impact of cost of removal being overstated by, say, 50 percent in 2015 for both mains and services?

A. Yes, if a further study disclosed a 50 percent overstatement of mains and services actual cost of removal in 2015, then an additional $2,615,341 would be added to the depreciation reserve for mains and $13,548,183 would be added to accumulated depreciation for services. This change reduces annual depreciation accrual for mains by $50,952 and by $414,444 for services when using Exhibit KSB-8 Computation of Revised Depreciation Accrual Rates as a baseline. The significant increase in cost of removal was not factored into the net salvage calculation for services but was for mains. Reducing mains net salvage from negative 35 percent to negative 30 percent reduces the annual depreciation accrual for mains by another $1,618,042. The total impact of a 50 percent overstatement of cost of removal and a 5 percent reduction in net salvage is a $2,083,438 additional reduction from the annual distribution plant and general plant structures and improvements depreciation accrual described in Exhibit KBS-8 Computation of Revised Depreciation Accrual Rates. Exhibit KSB-9 Impact of Cost of Removal on Mains and Services details the cost of removal impact, should the results of an actual detailed analysis result in the 50 percent overstatement in this hypothetical estimate of cost of removal for both mains and services.

REMAINING LIFE CALCULATIONS

Q. How is remaining life of an asset predicted?

A. The remaining life of an asset is difficult to predict as it can be lengthened or shortened by a variety of potential contributing factors including materials used, maintenance techniques employed, installation or design standards changes, and varied system operating conditions. However, using the Iowa Survivorship Curves standardized patterns of asset retirements dispersion can be identified.

Q. Did you review the remaining life calculations for all distribution plant and general plant structures and improvements?

A. Overland reviewed the average remaining life calculations for all distribution plant and general plant structures and improvements. For example, the Iowa Curve analysis for mains moves to a 53-year life and to a R1.5 dispersion.

Q. Do you agree with the remaining life calculation as contained in the SWG depreciation study?

A. While Overland understands that judgment plays a significant factor in assigning the best fit for the Iowa Curve, we believe a 6-year life and L1 dispersion is a better fit. See Exhibit KSB-7 Survivor Curve for Account 376.00 Mains. We base our opinion on three factors:

SWG's historical retirements, consideration of the early vintage plastic replacement program which began in 2007, and benchmarks more closely aligned to the life curves of other utilities.

Q. What is the impact of using a 61-year life and L1 dispersion?

A. Using a 61-year life and L1 dispersion (see Exhibit KSB-7), produces an average remaining life for mains of 51.33, as noted in Exhibit KSB-6 Revised Main Average Service Life L1 61. The revised average remaining life reduces the studies' annual depreciation for mains by another $5,443,455, or a total main reduction of $8,034,887 (see Exhibit KSB-8) after considering the change in depreciation reserve for mains noted in Exhibit KSB-4.

Q. Please summarize your testimony.

A. As a result of our review and assessment of the SWG depreciation study, we have four recommendations, as follows:

1. Approve the distribution plant and general plant structures and improvements revised depreciation rates based on revised depreciation reserve balances recorded from book reserves, eliminate the theoretical reserve allocation of book reserves, and increase in the average remaining life for mains. This recommendation decreases the annual depreciation accrual by $4,275,831.

2. Approve the general plant revised annual amortization rate based on establishing a deficiency reserve calculated from a theoretical reserve, amortizing the deficiency reserve, and amortizing plant in service net of the theoretical reserve calculated for general plant. This recommendation increases the annual amortization accrual by $1,009,715.

3. Approve a distribution and general plant annual expense accrual of $78,206,408 based on distribution and general plant in service at December 31, 2015 totaling $3,000,903,439. This recommendation decreases the previous authorized annual expense accrual by $45,270,354.

4. We recommend that, before the next rate case, a detailed independent and objective cost of removal study be performed to determine the validity of significant increases in cost of removal charges recorded in 2015, and for any that may occur after 2015 and before the next rate case. In the meantime, we recommend that Southwest Gas Corporation review the cost of removal charges recorded in mains and services accumulated depreciation accounts in 2015 to determine whether charges, if any, should be transferred to operations, maintenance, or other accounts. This review would help ensure the account balances of mains and services accumulated depreciation are fairly stated going forward into the next rate case. When filing for its next rate case, Southwest Gas shall provide the Commission with results of such study and review.

Q. How do your recommendations compare to the previous authorized study?

A. The previous authorized annual accrual rates and the recommended annual accrual rates are described in Exhibit KSB-10 Comparison of Previous Authorized Rates to Recommended Authorized Rates. The previous authorized annual accrual expense was $123,476,762 and the recommended annual accrual expense is $78,206,408. This recommendation decreases the annual accrual expense by $45,270,354.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Name: **Kirk S. Balcom**

Title: **Principal, CIA, CISA, CFE**

Education: B.S. Accounting, Iowa State University

Membership in Professional Societies:
Institute of Internal Auditors
Information Systems Audit & Control Association
Association of Certified Fraud Examiners

Career Synopsis:

Professional consultant with 40 years' experience in evaluating internal controls. Areas of expertise include Sarbanes-Oxley, operational auditing, information systems auditing, risk assessments, service organization controls, and quality assessments of Internal Audit Departments. Expertise spans numerous industries with 27 years in the utility industry. Performed operational, financial, information technology, joint venture, and international auditing for the utility. Most recent experience includes investigative and management audits of two utilities. Experienced in using the 2013 Committee of Sponsoring Organization's (COSO) Internal Control-Integrated Framework and the Control Objectives for Information and related Technology (COBIT) Framework to evaluate and document internal controls. Skilled at using flow charts to document processes and evaluate the effectiveness and efficiency of the process flow.

Selected Consulting Responsibilities:

Management Audits, Sarbanes-Oxley, Internal Audits, Risk Assessments & Service Organization Controls Exams

- 2015 – Principal Team Member of a Public Utilities Regulatory Authority management audit of a Connecticut electric utility.
- 2014 – Principal Team Member of a Public Utilities Commission of Ohio investigative audit of three Ohio natural gas utilities.
- 2008/2014 – Principal in Charge of Rehmann's Service Organization Controls (SOC) Practice that attests to service organization internal controls that affect their user organizations internal controls over financial reporting (SOC 1) and attests to internal controls over security, availability, processing integrity, confidentiality, and privacy of service organization operations (SOC 2 and SOC 3).

- 2009/2014 – Principal in Charge of internal audits at Ferris State University. These internal audits cover all areas of university operations.
- 2004/2011 – Principal in Charge of risk assessments and start up internal audit consulting at Allegiance Health Systems. These risk assessments coved all areas of health systems operations.
- 2004/2010 – Principal in Charge of Sarbanes-Oxley external financial reporting evaluations for Caraco Pharmaceutical Company's, a generic drug manufacturer, assertion on the effectiveness of internal controls over financial reporting.
- 2005/2013 – Principal in Charge of Sarbanes-Oxley documentation for Fremont Insurance Company's and Monarch Bank's senior management's assertion on the effectiveness of internal controls over financial reporting.
- 2008/2010 – Principal in Charge of the Committee of Sponsoring Organizations (COSO) risk assessments for Demmer Corporation, a large manufacturing firm.
- 2008/2012– Principal in Charge of External Quality Assessments of Internal Audit Departments of the Lansing Board of Water and Light, Wolverine World Wide, and JSJ Corporation that assessed their Internal Audit Department's compliance with the International Standards for the Professional Practice of Internal Auditing.
- 2003 – Team leader for Sarbanes-Oxley documentation for Consumers Energy Company, a $18 billion combination natural gas and electric utility, and subsidiary of CMS Energy Corporation. Responsibilities focused on all systems that provided financial reporting support.
- 1999/2003 – Supervised information technology and financial audits of Consumers Energy Company.
- 1998/1999 – Lead International Auditor for CMS Enterprises Company, a non-regulated company of parent company CMS Energy Corporation. International audits were located in Australia, Chile, Argentina, and Morocco.
- 1987/1998 – Supervised operational internal audits for Consumers Energy Company. These audits resulted in cash recoveries and cost savings for numerous natural gas and electric utility operations.
- 1980-1987 – Lead auditor for application system audits for Consumers Energy Company. These audits covered the numerous applications that impacted internal controls over financial reporting.
- 1978/1979 – Team member of the Foreign Corrupt Practices Act internal controls documentation project for Consumers Energy. This documentation covered all operations of Consumers Energy Company and its subsidiaries.
- 1977 – Team member of natural gas and electric utility distribution financial audits for Consumers Energy Company.
- 1976 – Team member for Electric Utility Generating Plant financial audits for Consumers Energy Company.

Recent Publications and Presentations:

- "Fraud and Theft " K.S. Balcom presented to the Audit and Assurance Group of Rehmann Robson, 2016.
- "COSO 2013" K.S. Balcom presented to the Audit and Assurance Group of Rehmann Robson, 2015.
- "The New COSO and its Relationship with COBIT 5," K S Balcom presented at the ISACA and IIA Joint Seminar, 2014
- "What's New With COSO," K S Balcom presented at the Governmental Accounting & Auditing Conference, 2013
- "Internal Auditing," K.S. Balcom presented to the Association of Government Accountants, 2011.
- "Service Organization Controls," K.S. Balcom presented to the Audit and Assurance Group of Rehmann Robson, 2011.
- "Service Organization Control Reports Updated Reporting Standards," K.S.Balcom published article in Business Wisdom Delivered, A Rehmann Publication, 2011.
- "Internal Audit Reporting," K.S. Balcom presented to the Institute of Internal Auditors, 2010.
- "Internal Controls – What Do They Look Like," K.S. Balcom presented to Michigan Association of County Administrators Organization, 2010.
- "Service Organizations Internal Controls," K.S.Balcom published article in Business Wisdom Delivered, A Rehmann Publication, 2010.

Employment History:

Rehmann	2003 - Present
Consumers Energy Company	1976 – 2003

Name: **FRANK T. DiPALMA**

Title: **Partner/Principal**

Education: Fairleigh Dickinson University, MBA Management/Finance
New Jersey Institute of Technology, BS Mechanical Engineering
University of Michigan, Executive Development Program

Professional Affiliations: American Gas Association
Society of Gas Operators
Southern Gas Association
University of West Virginia, Institute of Technology (Adjunct Professor)

Career Synopsis:

An operations oriented engagement/project manager who leads teams of consultants to resolve complex business problems in power generation and transmission and distribution entities; skilled at directing, planning and implementing approach and objectives for client's project; experienced in engineering and operations management, process improvement, project management, construction, business development, marketing, continuous improvement, strategic alliances, labor relations, strategic planning, change management, organization assessments and regulatory compliance. Consulting expertise supports both management and technical projects, with assignments grouped in the following categories: Operations Reviews, Merger Due Diligence, Safety and Reliability Reviews, Emergency Response, Integrity Management, Benchmarking, Regulatory Assessments and Various Studies.

Selected Consulting Assignments:

Management Audit of United illuminating (2015-2016) Public Utility Regulatory Authority
Served as Jacobs' responsible officer and project manager we are conducting a comprehensive diagnostic review the major functions of UI. The scope of the audit includes: organization and management, financial systems and controls, marketing, engineering and operations, information technology, customer-service operations, and relationships with parent company.

Gas Infrastructure Filing - Public Service Electric and Gas Company (2015)
PSE&G wanted to initiate a gas infrastructure filing to replace approximately 4,000 miles of cast iron and bare steel, while recovering all associated costs in a timely manner. To address requirements for a comprehensive filing, Jacobs analyze and developed: a

Safety case, a Business case and a Program execution plan. The analysis resulted in Jacobs preparing direct testimony that was filed with the NJ Board of Public Utilities on February 27, 2015.

Operational Due Diligence Consulting in Connection with the Exelon - Pepco Holdings Incorporated Merger (2015) Maryland Public Service Commission and Delaware Public Service Commission

Analyzed and testified as to the potential impacts on Pepco Holdings' two operating utilities in Maryland and Delaware. Jacobs' role was to assist the Maryland and Delaware Public Service Commission's (MDPSC) and (DEPSC) Staff in determining if the transaction was in the public interest by assessing how it could affect the reliability, adequacy and safety of electric service in Maryland and gas and electric service in Delaware. Specific support activities included: analysis of pre-filed materials, participate in discovery, provide expert analysis, provide expert testimony, develop cross examination, assist in brief preparation, and support settlement discussions.

Public Service New Hampshire Clean Air Project at Merrimack Station (2010 – 2014) The New Hampshire Public Utilities Commission

PSNH was installing a wet scrubber at Merrimack Power Generating Station, originally the project was estimated to cost $250M, at the time Jacobs was assigned to the project the cost estimate had increased to $457M. Acting as both responsible officer and project manager, our scope of work included: due diligence on completed portions of the project, monitoring of the ongoing portion of the project, quarterly reports to track the progress and summarization of project completion. The project due diligence was summarized in testimony and presented at a New Hampshire Commission cost of service hearing.

Electric Reliability Reporting Metrics of the New York State Electric Utilities (2014-2015) New York State Public Service Commission

The objective of the audit was to verify that the data provided by the six major New York State electric utilities to the NYSPSC is sound and accurate, and reflects the appropriate levels of reliability. Serving as project manager, we reviewed the completeness and accuracy of data collected by various systems, identified opportunities for improvements and recommend best practices metrics.

Technical Reliability Study of Curaçao Refinery Utilities (2014) Refineria Isla Curaçao B.V.

Prior to deciding on possible investment strategies, it was important to determine the reliability of the supply of the steam, water, air, electricity utilities from Curaçao Refinery Utilities (CRU) to Refineria Isla. Accordingly, Jacobs was contracted to: review equipment maintenance schedules and operating data, configuration and integration; perform a physical site visit to examine the condition of the equipment and review operating logs; perform life-expectancy estimation on the main equipment; benchmark the performance and reliability of the equipment; evaluate CRU using a SWOT analysis; Identify significant gaps and mitigation requirements, and prepare recommendations.

Root Cause Analysis of Weld Failure (2014) Enbridge Pipeline Inc.

A tie-in weld failure was detected while conducting a commissioning hydrostatic test on a new 36-inch pipeline. In view of the nature and complexity of the weld failure, Enbridge wanted to have an independent third-party opinion identify the events or causes that resulted in the defective girth weld. Acting as project manager and facilitator, Jacobs SME's conducted a root cause analysis (RCA) conducted interviews; utilized knowledge gained through our operations risk management assessments; participated in a facilitated RCA session; and conducted the facilitation effort.

Conduct Comprehensive Review of UGI's Penn Natural Gas, Inc Gas Program and Activities (2014)

UGI Corporation

Conducted a comprehensive review of UGI PNG's Natural Gas Distribution programs and activities based on their operating policies, processes, standards, procedures, systems, records, culture, staffing levels, and training programs. Serving as responsible officer, specific areas of focus were organizational silos, decision-making, knowledge sharing in the areas of leak management, corrosion management, transmission integrity management, and emergency response.

Conduct Technical Due Diligence Power Generation Assets (2013) Elliott Management Corp.

Elliott was interested in acquiring fossil and renewable power generation assets located in Latin America. Serving as responsible officer and project manager, Jacobs performed a technical, organizational, environmental, and power market assessment. In addition we provided assumptions for Elliott's cash flow spreadsheet and develop a Dispatch/Market Analysis Model.

Conduct Operational Risk Management Assessments (2013 to 2014) Enbridge Pipeline Inc.

Enbridge wanted to determine ongoing conformance with project management systems and to identify current good practices and improvement opportunities to achieve industry leadership in pipeline construction. Serving as project manager, Jacobs conducted a number of Operational Risk Management Assessments for both pipelines and major facility construction that focused on organizational design, delegations of authority, and knowledge sharing within the 2000 person field organization structure.

Investigation into the Performance of Connecticut's Electric and Gas Distribution Companies in Restoring Service Following Storm Sandy (2013) Connecticut Public Utilities Regulatory Authority

Serving as responsible officer, Jacobs provided technical expertise to PURA's staff in areas pertaining to electric distribution company and gas company preparation for and action in response to significant outages that occurred as a result to Hurricane Sandy.

Assessment of Safety Policies and Emergency Response Procedures (2013) NiSource

In response to a gas related incident, NiSource sought an independent review of its safety policies and emergency response procedures. Included in the projects scope of work was a review of the pertinent policies, processes and procedures; identification of opportunities for improvement; and development of roadmap for how these opportunities should be prioritized for implementation. Serving as project manager, our analysis involved assessing policies, practices and procedures in the categories of emergency response, facility damage prevention, and leak management and leak investigation. In each category, unclear decision-making, communication barriers, poor organization structure were contributing factors contributing factors.

Transmission and Growth Strategy Assignments (2012 to 2015) Central Alberta Rural Electric

Serving as responsible officer, Jacobs performed the following assignments:

- Operational Capabilities Report to support right to serve all new customers within its territory.
- Transmission Report to support having costs allocated directly for existing transmission lines.
- Load Settlement Report to determine the feasibility of taking over the existing lines.
- Independent Operating Agreement with Fortis.
- Fortis-AB Rate Case Phase 2 Assistance for CAREA as merged with North Parkland.

Responding to the Requirements of Public Act No. 12-148, An Act Enhancing Emergency Preparedness and Response (2012) Connecticut Public Utilities Regulatory Authority

In the aftermath of Tropical Storm Irene and the October 2011 Snow Storm, Connecticut recognized the need to enhance emergency preparedness and response and establish electric and gas company performance standards for emergency preparation and service restoration. Acting as project manager, Jacobs facilitated an interactive process with five utilities, Rate Council and Commission Staff.

Technical Analysis of the New Jersey Natural Gas Company's Safety Acceleration Facility Enhancement Program (2012) New Jersey Division of Rate Counsel

Working as project manager, Jacobs performed an assessment of NJNG proposal to undertake a five year $204 million capital investment program for the replacement of existing cast iron and unprotected steel distribution mains and services; and achieve cost recovery through annual rate adjustment filings.

Assessment of Pacific Gas & Electric Co. Pipeline Safety Enhancement Plan (2011-2012) CPUC

The PSEP is a multiphase, multiyear, multibillion dollar program that is in addition to PG&E's existing transmission pipeline maintenance and integrity management programs. Jacobs was asked by the CPUC to review the PSEP, supporting work papers and testimony filed by PG&E, as well as interveners.

Management Audit of Public Service Electric and Gas Company (2010-2011) NJBPU

Jacobs Consultancy participated in an independent management audit of PSE&G mandated by The State of New Jersey's Board of Public Utilities (BPU). Serving as Jacobs' project manager, the technical and management practices of PSE&G were assessed in the areas of electric transmission and distribution, gas transmission and distribution, gas procurement and supply and contractor performance.

Energy Reliability Consulting Exelon - Constellation Energy Merger (2011) Maryland PSC

Analyzed the potential impacts on BGE in connection with the Exelon and Constellation Energy Merger; my role was to assist the Maryland Public Service Commission's (MDPSC's) Staff in determining if the transaction was in the public interest by assessing how it could affect the reliability, adequacy and safety of electric and gas service in the State of Maryland.

Assessment Study of Project Execution of Major Gas Pipeline Project (2011) Spectra Energy

Performed a Critical Assessment study of project execution for the New Jersey-New York Pipeline Expansion Project. As project manager coordinated a review the risk mitigation areas already recognized, and identified additional issues that may arise, which could impede permitting and construction of the Project. In total, 13-risk mitigation areas and strategies already recognized were expanded, six additional risk mitigation issues were identified, and four additional project management tools were suggested.

Report of the Independent Review Panel, San Bruno Explosion (2010-2011) CPUC
Jacobs was retained by the an Independent Review Panel to gather and review facts and suggest recommendations for the improvement and safe management of PG&E's natural gas transmission lines. Serving as project manager our investigation identified multiple weaknesses in PG&E's management and oversight, as well as in the CPUC's resources and organizational focus.

Management Audit of Fitchburg Gas and Light Company d/b/a Unitil (2010-2011) Massachusetts Department of Public Utilities
Jacobs Consultancy was asked to conduct an independent management audit of FG&E. Serving as engagement director and project manager, the management practices of both FG&E and Unitil were assessed in the areas of strategic planning, staffing and workforce management, management and control, customer and public relations and emergency preparedness and response planning.

Develop an Economic Model and Provide Testimony for Rockford Eclipse Valve Replacement (2009-2010) South Jersey Gas Company
Developed an economic model for estimating the cost of replacing approximately 70,000 Rockford Eclipse (RE) valves, currently in South Jersey's distribution system. Advanced how actual costs would be accumulated and tracked against the RE valve replacement estimate developed to assure that all RE placement costs are tracked, and that only RE replacement costs are tracked. Served as an expert witness presenting testimony for the RE valve replacement in South Jersey Gas Company's 2010 base rate case. Testimony resulted in establishing an activity-based tracker for annual cost recovery throughout the multiyear replacement program.

Operations and Energy Reliability Consulting in Connection with the merger of First Energy Corp. and Allegheny Energy, Inc. (2010) Maryland Public Service Commission
Analyzed from a reliability and operations perspective the problem areas, deficiencies, and merits of the proposed acquisition of AYE by FE. My role was to serve as the Maryland Public Service Commission's expert electric witness testifying as to the potential impact on AYE's Potomac Edison reliability and safety in a post-merger environment.

Service Response and Communications of CL&P and UI following the Outages from the Severe Weather (2010) Connecticut Department of Public Utility Control

The scope of this assignment entailed: analysis of pre-filed testimony, preparation of discovery requests, auditing CL&P's and UI's procedures, examination of the evidence, cross-examination at public hearings and providing the DPUC with a report containing. Serving as project manager, Jacobs conducted its investigation in seven focus areas: Emergency Planning, Preparedness, Restoration Performance, Mutual Assistance, Post-storm Activities, Best Practices and Other.

Energy Reliability Consulting in Connection with the Electricité de France Purchase of Constellation Energy Group's Nuclear Holdings (2009) MD PSC
Analyzed the potential impacts on BGE in connection with Electricité de France's proposed purchase of half of Constellation Energy Group's Nuclear Holdings. Serving as the MDPSC's expert electric and gas witness, I testified to: overall electric reliability performance, effectiveness of the vegetation management program and other maintenance and inspection programs, adequacy of funding for capital asset replacement and operations & maintenance needs, need for contemplated cast-iron replacement program, need to re-examine service replacement policy and assessment of customer satisfaction surveys.

Workforce Study Analysis of Illinois Electric Utilities (2008) Illinois Commerce Commission
The Illinois Commerce Commission retained Jacobs Consultancy to conduct a workforce study analysis of the five major Illinois electric utilities. The intent of the analysis was to determine the adequacy of in-house staffing in each job critical to maintaining quality reliability and restoring service. The study also included: assessment of asset management practices, use of technology, operational practices, system maintenance and condition, call center, safety and training.

Technical Evaluation of New Connecticut Peaking Generation Units (2008) Connecticut DPUC
Coordinated a technical evaluation and review of 11 proposals to build 500 MW of new peaking generation units in the state of Connecticut. Our work included: land site costs, insurance, capital costs, operating costs, starting capacities, type of fuel, proximity and availability of electric and gas connections, inclusion of Nox controls, heat rate, permit schedule, and other critical path items.

Energy Reliability Consulting Services in Connection with the Exelon-PSEG Proposed Merger (2005-2006) New Jersey Board of Public Utilities
Jacobs Consultancy completed 14 month engagement analyzing the problem areas, deficiencies, and merits of the proposed acquisition of PSEG by Exelon, with specific emphasis on how the proposed merger may affect New Jersey ratepayers.

Organization Assessment and Work Force Analysis (2006-2007)
City of Atlanta, Department of Water Management
Served as Jacobs' project manager, conducting an Organization Assessment and Work Force Analysis of City of Atlanta DWM, Safety and Security Division. The Division is responsible for securing approximately 57 water management related facilities and 1400 DWM employees. The analysis covered: strategic direction, DWM expectations, ongoing operations, workforce management practices, determination of areas of strength, as well as areas of potential improvement. Benchmarking was utilized to help expand horizons and to identify gaps. In addition, a workforce analysis was conducted to quantify the effort associated with position responsibilities, communications, and knowledge.

Industry Assignments:

Operations-Responsible for the installation, operations and maintenance of the gas distribution system, managed workforces between 500 and 1000 employees.
Engineering- Managed the planning, budgeting, design, measurement and engineering support services.
Quality Management/Process Improvement-Designed, implemented and promoted quality and organizational activities including organization design, culture change, knowledge transfer, workforce staffing, communications and process improvement.
Technical Support and Regional Performance-Developed a technology and performance focus to improve performance, reduce costs and improve customer service

Designated Expert Witness:

- Exelon-Pepco Holdings merger (Delaware Public Service Commission), 2015
- Exelon - Pepco Holdings merger (Maryland Public Service Commission), 2015
- New Hampshire Clean Air Project at Merrimack Station cost of service (New Hampshire Public Utilities Commission), 2014
- Exelon and Constellation Energy merger (Maryland Public Service Commission), 2011
- First Energy Corp. and Allegheny Energy, Inc. merger (Maryland Public Service Commission), 2010
- Rockford Eclipse valve replacement cost of service (South Jersey Gas Company), 2010
- Electricité de France purchase of Constellation Energy Group's Nuclear Holdings (Maryland Public Service Commission), 2009
- Exelon and PSEG merger (New Jersey Public Utilities Commission), 2006
- Ductile iron pipe failure - Larkhall, Scotland (Transco), 2002

Employment History:

Williams Consulting Inc. (2015 – present) *Partner/Principal*
Jacobs Consultancy Inc. (2002 – 2015) *Director*
Stone & Webster Consultants (2000 – 2002) *Associate Director*
Mountaineer Gas Company (1996 – 2000) *Vice President of Operations and Engineering*
Public Service Electric & Gas Company (1968 – 1996) various senior management positions

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Name: **THOMAS L. SIMONSEN**

Title: **Consultant**

Education: Michigan State University, MBA Accounting
Lawrence Institute of Technology, BS Electrical Engineering
Western Michigan University Institute of Technological Studies, Various Depreciation Courses
George Washington University, Depreciation for Managers and Regulators of Public Utilities Course

Professional Affiliations: (Past) American Gas Association, Chairman of the Depreciation Committee
Edison Electric Institute, Property Accounting and Evaluation Group
Institute of Electrical and Electronic Engineers

Career Synopsis:

A senior accounting executive who has over 30 years of varied utility accounting experience. He has in-depth expertise in all aspects of book and tax depreciation. While with Consumers Energy Company he held a number of positions with increasing responsibility, including: Accounting Analyst, Supervisory Accountant, Corporate Tax Supervisor, Senior Corporate Tax Supervisor, Corporate Tax Manager and Director of Depreciation and the Commission. As Director of Depreciation and Decommission, Mr. Simonsen was responsible for the preparation and control of depreciation accounting records and systems for both book and tax depreciation.

Expert Witness Appearances:

Mr. Simonsen has filed testimony and/or testified before the Michigan Public Service Commission in the following cases:

U-6041 (Reopened) - (Campbell No. 3) Accounting and Ratemaking Approval of Depreciation Practices for Electric and Common Utility Plant (1982)

U-7564 - Discontinuance of Service in Areas of the City of Holland (1983)

U-9197 - Accounting and Ratemaking Approval of Depreciation Practices for Gas Utility Plant (1989)

U-9493 - Accounting and Ratemaking Approval of Depreciation Practices for Electric and Common Utility Plant (1990)

U-9668 - Adjustment of Surcharges for Nuclear Power Plant Decommissioning (1991)

U-10342 - Accounting and Ratemaking Approval of Depreciation Practices for Ludington Pump Storage Plant (1993) (This case was resolved by settlement prior to my testifying)

U-10800 - Adjustment of Surcharges for Nuclear Power Plant Decommissioning (1995)

U-11662 - Adjustment of Surcharges for Nuclear Power Plant Decommissioning (1999)

U-13000 - To increase its rates for the distribution of natural gas and for other relief (2002)

U-12999 - Accounting and Ratemaking Approval of Depreciation Practices for Gas Utility Plant (2004)

LA- 14292 - Statement of Financial Accounting Standards number 143 (2005)

Mr. Simonsen has also filed testimony and testified before the Federal Energy Regulatory Commission:

Docket No. ER89-256-000 - Palisades Generating Company, on the subject of Nuclear Power Plant Decommissioning (1991).

Employment History:

ACRO Services Corporation (2005 – 2006) Consultant
Consumers Energy Company (1975 – 2005) variety of senior accounting positions including Director of Depreciation and Decommission
National Steel Corporation (1969 – 1975) Electric Maintenance Foreman

Southwest Gas Corporation
Revised Depreciation Reserve
As of December 31, 2015

Plant	Plant at 12/31/2015	Book Dep Reserve	Theoretical Reserve	Allocated Book Dep Reserve	Salvage %	Avg Remaining Life	Recommended Dep Expense	Recommended Dep Rate	Study Annual Dep Expense	Study Annual Dep Rate	Dep Expense Change from Study	Dep Rate Change from Study
Distribution Plant and General Plant												
Rights of Way	$2,694,946	$738,369	$498,420	$750,485	0	52.98	$36,702	1.36%	$37,159	1.38%	-$457	-0.02%
Structures & Improvements	$110,557	$73,851	$90,629	$136,463	0	9.91	-$2,614	-2.36%	$334	0.30%	-$2,948	-2.66%
Mains	$1,661,082,834	$701,792,441	$403,956,349	$608,249,200	-0.35	43.45	$37,611,338	2.26%	$38,049,876	2.29%	-$438,538	-0.03%
Meas. & Reg Station Equip	$74,903,202	$13,826,055	$15,581,825	$23,462,022	-0.25	27.51	$2,550,599	3.41%	$2,575,407	3.44%	-$24,808	-0.03%
Services	$835,721,110	$524,093,399	$332,935,912	$501,311,597	-0.55	32.69	$24,290,490	2.91%	$24,734,185	2.96%	-$443,695	-0.05%
Meters	$293,267,849	$35,160,083	$85,979,074	$129,461,273	0	21.2	$7,726,725	2.63%	$7,974,744	2.72%	-$248,019	-0.09%
Industrial M&R Station	$11,809,530	$6,954,650	$4,093,902	$6,164,310	-0.15	31.44	$235,899	2.00%	$243,148	2.06%	-$7,249	-0.06%
General Plant												
Structures & Improvements	$50,104,315	$7,408,140	$13,622,387	$20,511,637	0	30.58	$967,713	1.93%	$992,927	1.98%	-$25,214	-0.05%
Total	**$2,929,694,343**	**$1,290,046,988**	**$856,758,498**	**$1,290,046,988**			**$73,416,852**		**$74,607,780**		**-$1,190,928**	
Theoretical Reserve Allocation Factor				**1.5057300172**								

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Southwest Gas Corporation
Revised General Plant
As of December 31, 2015

General Plant Amortized	Plant at 12/31/2015	Book Dep Reserve	Theoretical Reserve	Reserve Deficiency	Assets Moved to Retirement	Revised Plant at 12/31/2015	Revised Book Dep Reserve	Revised Theoretical Reserve	Revised Reserve Deficiency	Recommended Amort Reserve Def
Office Furniture & Equipment	$5,098,148	-$1,569,391	$2,239,651	-$3,809,042	-$76,489	$5,021,659	-$1,645,880	$2,163,162	-$3,809,042	$211,613
Computer Equipment	$14,138,270	-$1,277,144	$7,965,571	-$9,242,715	-$949,785	$13,188,485	-$2,226,929	$7,015,786	-$9,242,715	$1,848,543
Transportation Equipment - Light	$21,953,490	-$7,790,173	$8,103,704	-$15,893,877	-$2,464,889	$19,488,601	-$10,255,062	$5,638,815	-$15,893,877	$1,986,735
Transportation Equipment - Heavy	$14,850,037	$4,510,295	$5,817,658	-$1,307,363	-$1,255,644	$13,594,393	$3,254,651	$4,562,014	-$1,307,363	$108,947
Stores Equipment	$799,109	$43,032	$397,144	-$354,112	-$162,725	$636,384	-$119,693	$234,419	-$354,112	$14,164
Tools, Shop, & Garage	$9,594,419	-$4,624,317	$4,322,961	-$8,947,278	-$1,316,592	$8,277,827	-$5,940,909	$3,006,369	-$8,947,278	$596,485
Laboratory Equipment	$499,163	-$183,694	$194,415	-$378,109	-$1,480	$497,683	-$185,174	$192,935	-$378,109	$15,124
Power Operated Equipment	$7,990,811	$1,618,105	$2,845,778	-$1,227,673	-$486,683	$7,504,128	$1,131,422	$2,359,095	-$1,227,673	$87,691
Communication Equipment	$2,134,699	$1,989,578	$567,328	$1,422,250	-$395,131	$1,739,568	$1,594,447	$172,197	$1,422,250	-$109,404
Telemetering Equipment	$211,611	-$224,767	$137,806	-$362,573	-$23,624	$187,987	-$248,391	$114,182	-$362,573	$36,257
Miscellaneous Equipment	$1,133,346	-$22,650	$587,193	-$609,843	-$60,965	$1,072,381	-$83,615	$526,228	-$609,843	$38,115
Total	**$78,403,103**	**-$7,531,126**	**$33,179,209**	**-$40,710,335**	**-$7,194,007**	**$71,209,096**	**-$14,725,133**	**$25,985,202**	**-$40,710,335**	**$4,834,272**

General Plant Amortized	Salvage %	Remaining Life	Recommended Annual Amortization	Recommended Total Amortization	Recommeded Amort Rate	Study Annual Amortization	Study Annual Amort Rate	Amortization Change from Study	Dep Rate Change from Study
Office Furniture & Equipment	0	18	$158,805	$370,419	7.38%	$278,981	5.56%	$91,438	1.82%
Computer Equipment	0	5	$1,234,540	$3,083,083	23.38%	$2,637,697	20.00%	$445,386	3.38%
Transportation Equipment - Light	0.25	8	$1,122,204	$3,108,939	15.95%	$1,827,056	9.38%	$1,281,883	6.57%
Transportation Equipment - Heavy	0.18	12	$548,782	$657,729	4.84%	$928,950	6.83%	-$271,221	-1.99%
Stores Equipment	0	25	$16,079	$30,243	4.75%	$25,455	4.00%	$4,788	0.75%
Tools, Shop, & Garage	0	15	$351,431	$947,916	11.45%	$551,855	6.67%	$396,061	4.78%
Laboratory Equipment	0	25	$12,190	$27,314	5.49%	$19,907	4.00%	$7,407	1.49%
Power Operated Equipment	0.3	14	$206,700	$294,391	3.92%	$375,206	5.00%	-$80,815	-1.08%
Communication Equipment	0	13	$120,567	$11,163	0.64%	$133,813	7.69%	-$122,650	-7.05%
Telemetering Equipment	0	10	$7,381	$43,638	23.21%	$18,799	10.00%	$24,839	13.21%
Miscellaneous Equipment	0	16	$34,135	$72,250	6.74%	$67,024	6.25%	$5,226	0.49%
Total			**$3,812,813**	**$8,647,084**		**$6,864,743**		**$1,782,341**	

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Depreciation
Revised Main Average Service Life L1 61

Account	Activity Year	Vintage Year	Ending Balance	Remaining Life	Weigted Investment	Average Service Life Calculated
ARIZ - 376.00 Mains	2015	2015	115,389,566.70	60.5	6981068785	
ARIZ - 376.00 Mains	2015	2014	123,079,546.51	59.6	7335540972	
ARIZ - 376.00 Mains	2015	2013	88,727,745.42	58.7	5208318656	
ARIZ - 376.00 Mains	2015	2012	86,849,448.70	57.7	5011213190	
ARIZ - 376.00 Mains	2015	2011	121,040,839.05	56.9	6887223742	
ARIZ - 376.00 Mains	2015	2010	62,296,511.11	56	3488604622	
ARIZ - 376.00 Mains	2015	2009	39,790,851.38	55.1	2192475911	
ARIZ - 376.00 Mains	2015	2008	48,031,319.65	54.3	2608100657	
ARIZ - 376.00 Mains	2015	2007	71,552,317.32	53.4	3820893745	
ARIZ - 376.00 Mains	2015	2006	59,938,066.71	52.6	3152742309	
ARIZ - 376.00 Mains	2015	2005	65,667,906.55	51.8	3401597559	
ARIZ - 376.00 Mains	2015	2004	70,601,234.91	51	3600662980	
ARIZ - 376.00 Mains	2015	2003	53,633,531.11	50.2	2692403262	
ARIZ - 376.00 Mains	2015	2002	61,594,101.50	49.5	3048908024	
ARIZ - 376.00 Mains	2015	2001	57,621,884.84	48.8	2811947980	
ARIZ - 376.00 Mains	2015	2000	51,703,162.57	48	2481751803	
ARIZ - 376.00 Mains	2015	1999	47,253,851.93	47.4	2239832581	
ARIZ - 376.00 Mains	2015	1998	39,334,958.13	46.7	1836942545	
ARIZ - 376.00 Mains	2015	1997	34,676,269.54	46	1595108399	
ARIZ - 376.00 Mains	2015	1996	38,765,156.00	45.4	1759938082	
ARIZ - 376.00 Mains	2015	1995	41,878,836.08	44.8	1876171856	
ARIZ - 376.00 Mains	2015	1994	33,960,567.70	44.2	1501057092	
ARIZ - 376.00 Mains	2015	1993	28,096,713.04	43.6	1225016689	
ARIZ - 376.00 Mains	2015	1992	15,035,494.16	43.1	648029798.3	
ARIZ - 376.00 Mains	2015	1991	10,805,499.38	42.5	459233723.7	
ARIZ - 376.00 Mains	2015	1990	24,378,139.50	42	1023881859	
ARIZ - 376.00 Mains	2015	1989	17,818,749.66	41.5	739478110.9	
ARIZ - 376.00 Mains	2015	1988	22,029,604.03	41	903213765.2	
ARIZ - 376.00 Mains	2015	1987	20,276,291.22	40.5	821189794.4	
ARIZ - 376.00 Mains	2015	1986	18,832,646.91	40.1	755189141.1	
ARIZ - 376.00 Mains	2015	1985	6,759,607.31	39.6	267680449.5	
ARIZ - 376.00 Mains	2015	1984	8,409,769.12	39.2	329662949.5	
ARIZ - 376.00 Mains	2015	1983	6,303,234.40	38.8	244565494.7	
ARIZ - 376.00 Mains	2015	1982	3,571,343.88	38.4	137139605	
ARIZ - 376.00 Mains	2015	1981	4,662,486.17	37.9	176708225.8	
ARIZ - 376.00 Mains	2015	1980	2,477,140.65	37.6	93140488.44	
ARIZ - 376.00 Mains	2015	1979	1,782,228.40	37.2	66298896.48	
ARIZ - 376.00 Mains	2015	1978	1,529,878.21	36.8	56299518.13	
ARIZ - 376.00 Mains	2015	1977	1,866,334.92	36.4	67934591.09	
ARIZ - 376.00 Mains	2015	1976	1,045,730.35	36	37646292.6	
ARIZ - 376.00 Mains	2015	1975	2,396,618.06	35.7	85559264.74	
ARIZ - 376.00 Mains	2015	1974	4,122,454.50	35.3	145522643.9	
ARIZ - 376.00 Mains	2015	1973	3,784,192.07	34.9	132068303.2	
ARIZ - 376.00 Mains	2015	1972	5,132,593.61	34.5	177074479.5	
ARIZ - 376.00 Mains	2015	1971	3,250,822.06	34.1	110853032.2	
ARIZ - 376.00 Mains	2015	1970	1,411,288.24	33.8	47701542.51	
ARIZ - 376.00 Mains	2015	1969	2,464,565.04	33.4	82316472.34	
ARIZ - 376.00 Mains	2015	1968	1,156,916.20	33.1	38293926.22	
ARIZ - 376.00 Mains	2015	1967	2,033,628.42	32.7	66499649.33	
ARIZ - 376.00 Mains	2015	1966	2,421,441.46	32.4	78454703.3	
ARIZ - 376.00 Mains	2015	1965	1,934,125.84	32	61892026.88	
ARIZ - 376.00 Mains	2015	1964	1,987,452.09	31.7	63002231.25	
ARIZ - 376.00 Mains	2015	1963	1,638,230.25	31.3	51276606.83	
ARIZ - 376.00 Mains	2015	1962	2,041,266.15	31	63279250.65	
ARIZ - 376.00 Mains	2015	1961	1,734,494.48	30.7	53248980.54	
ARIZ - 376.00 Mains	2015	1960	1,622,985.15	30.3	49176450.05	
ARIZ - 376.00 Mains	2015	1959	1,647,994.34	30	49439830.2	
ARIZ - 376.00 Mains	2015	1958	1,752,625.65	29.7	52052981.81	
ARIZ - 376.00 Mains	2015	1957	1,092,790.81	29.4	32128049.81	
ARIZ - 376.00 Mains	2015	1956	1,114,366.68	29	32316633.72	
ARIZ - 376.00 Mains	2015	1955	2,612,130.74	28.7	74968152.24	
ARIZ - 376.00 Mains	2015	1954	589,586.46	28.4	16744255.46	
ARIZ - 376.00 Mains	2015	1953	411,214.28	28.1	11555121.27	
ARIZ - 376.00 Mains	2015	1952	634,177.13	27.8	17630124.21	
ARIZ - 376.00 Mains	2015	1951	668,283.12	27.5	18377785.8	
ARIZ - 376.00 Mains	2015	1950	727,615.91	27.2	19791152.75	
ARIZ - 376.00 Mains	2015	1949	495,516.25	26.9	13329387.13	
ARIZ - 376.00 Mains	2015	1948	668,335.34	26.6	17777720.04	
ARIZ - 376.00 Mains	2015	1947	205,520.63	26.3	5405192.569	
ARIZ - 376.00 Mains	2015	1946	9,584.08	26	249186.08	
ARIZ - 376.00 Mains	2015	1945	48,522.67	25.7	1247032.619	
ARIZ - 376.00 Mains	2015	1944	13,269.01	25.4	337032.854	
ARIZ - 376.00 Mains	2015	1943	26,812.68	25.1	672998.268	
ARIZ - 376.00 Mains	2015	1942	17,554.10	24.8	435341.68	
ARIZ - 376.00 Mains	2015	1941	30,443.09	24.6	748900.014	
ARIZ - 376.00 Mains	2015	1940	182.23	24.4	4446.412	
ARIZ - 376.00 Mains	2015	1938	19,897.44	24.2	481518.048	
ARIZ - 376.00 Mains	2015	1937	14,239.72	24	341753.28	
ARIZ - 376.00 Mains	2015	1936	0.27	23.8	6.426	
ARIZ - 376.00 Mains	2015	1935	7,532.59	23.6	177769.124	
ARIZ - 376.00 Mains	2015	1934	2,239.76	23.4	52410.384	
ARIZ - 376.00 Mains	2015	1931	2,459.06	23.2	57050.192	
ARIZ - 376.00 Mains	2015	1930	64,590.15	23	1485573.45	
ARIZ - 376.00 Mains	2015	1929	215.25	22.8	4907.7	
ARIZ - 376.00 Mains	2015	1928	829.34	22.6	18743.084	
ARIZ - 376.00 Mains	2015	1927	353.77	22.4	7924.448	
ARIZ - 376.00 Mains	2015	1926	26.33	22.2	584.526	
ARIZ - 376.00 Mains	2015	1924	120.29	21	2526.09	
ARIZ - 376.00 Mains	2015	1923	2,166.42	21.8	47227.956	
Total			1,661,082,833.93	3,217.30	85,258,923,030.35	51.33

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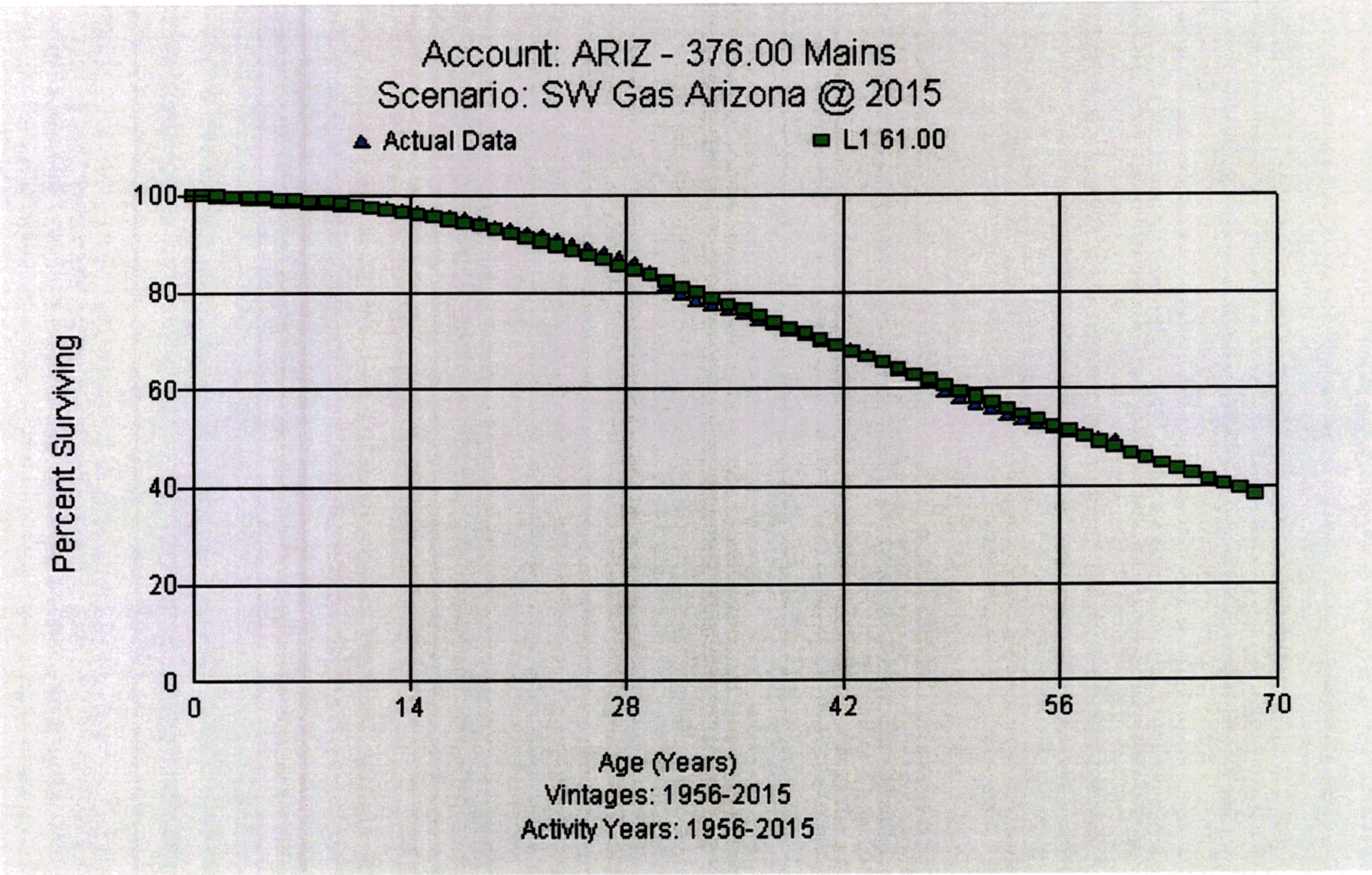
Account: ARIZ - 376.00 Mains
Scenario: SW Gas Arizona @ 2015
Actual Data
L1 61.00
Percent Surviving
100
80
60
40
20
0
0
14
28
42
56
70
Age (Years)
Vintages: 1956-2015
Activity Years: 1956-2015

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Southwest Gas Corporation
Computation of Revised Depreciation Accrual Rates
as of December 31, 2015

Plant	Plant at 12/31/2015	Cost of Removal Impact on Dep Reserve	Revised Book Dep Reserve	Cost of Removal Reduction to Net Salvage	Salvage %	Avg Remaining Life	Recommended Dep Expense	Recommended Dep Rate	Hypothetical Study Annual Dep Expense	Hypothetical Study Annual Dep Rate	Dep Expense Change from Hypothetical Study
Distribution Plant											
Rights of Way	$2,694,946		$738,369		0%	52.98	$36,930	1.37%	$37,159	1.38%	-$229
Structures & Improvements	$110,557		$73,851		0%	9.91	$3,704	3.35%	$334	0.30%	$3,370
Mains	$1,661,082,834	$2,615,341	$704,407,782	5%	-30%	51.33	$28,345,995	1.71%	$38,049,876	2.29%	-$9,703,881
Meas. & Reg Station Equip	$74,903,202		$13,826,055		-25%	27.51	$2,900,871	3.87%	$2,575,407	3.44%	$325,464
Services	$835,721,110	$13,548,183	$537,641,582		-55%	32.69	$23,179,142	2.77%	$24,734,185	2.96%	-$1,555,043
Meters	$293,267,849		$35,160,038		0%	21.2	$12,174,897	4.15%	$7,974,744	2.72%	$4,200,153
Industrial M&R Station	$11,809,530		$6,954,650		-15%	31.44	$210,760	1.78%	$243,148	2.06%	-$32,388
Distribution Plant Subtotal	$2,879,590,028		$1,298,802,327				$66,852,298		$73,614,853		-$6,762,555
General Plant											
Structures & Improvements	$50,104,315		$7,408,140		0%	30.58	$1,396,212	2.79%	$992,927	1.98%	$403,285
Total	$2,929,694,343		$1,306,210,467				$68,248,511		$74,607,780		-$6,359,269

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Southwest Gas Corporation
Impact of Cost of Removal on Mains and Services
as of December 31, 2015

Plant	Plant at 12/31/2015	Cost of Removal Impact on Dep Reserve	Revised Book Dep Reserve	Cost of Removal Reduction to Net Salvage	Revised Salvage %	Avg Remaining Life	Recommended Dep Expense	Recommended Dep Rate	Study Annual Dep Expense	Study Annual Dep Rate	Dep Expense Change from Study
Distribution Plant											
Rights of Way	$2,694,946		$738,369		0%	52.98	$36,930	1.37%	$37,159	1.38%	-$229
Structures & Improvements	$110,557		$73,851		0%	9.91	$3,704	3.35%	$334	0.30%	$3,370
Mains	$1,661,082,834	$2,615,341	$704,407,782	5%	-30%	51.33	$28,345,995	1.71%	$38,049,876	2.29%	-$9,703,881
Meas. & Reg Station Equip	$74,903,202		$13,826,055		-25%	27.51	$2,900,871	3.87%	$2,575,407	3.44%	$325,464
Services	$835,721,110	$13,548,183	$537,641,582		-55%	32.69	$23,179,142	2.77%	$24,734,185	2.96%	-$1,555,043
Meters	$293,267,849		$35,160,038		0%	21.2	$12,174,897	4.15%	$7,974,744	2.72%	$4,200,153
Industrial M&R Station	$11,809,530		$6,954,650		-15%	31.44	$210,760	1.78%	$243,148	2.06%	-$32,388
Distribution Plant Subtotal	$2,879,590,028		$1,298,802,327				$66,852,298		$73,614,853		-$6,762,555
General Plant											
Structures & Improvements	$50,104,315		$7,408,140		0%	30.58	$1,396,212	2.79%	$992,927	1.98%	$403,285
Total	$2,929,694,343		$1,306,210,467				$68,248,511		$74,607,780		-$6,359,269

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Southwest Gas Corporation
Comparison of Previous Authorized Rates to Recommended Rates
as of December 31, 2015

Plant	Plant at 12/31/2015	Recommended Annual Expense	Recommended Rate	Previous Authorized Annual Expense	Previous Authorized Rate	Annual Expense Change	Rate Change
Distribution Plant							
Rights of Way	$2,694,946	$36,930	1.37%	$57,941	1.38%	-$21,011	-0.01%
Structures & Improvements	$110,557	$3,704	3.35%	$1,271	1.15%	$2,433	2.20%
Mains	$1,661,082,834	$30,014,989	1.71%	$63,453,364	3.82%	-$33,438,375	-2.11%
Meas. & Reg Station Equip	$74,903,202	$2,900,871	3.87%	$3,086,012	4.12%	-$185,141	-0.25%
Services	$835,721,110	$23,593,586	2.77%	$44,293,219	5.30%	-$20,699,633	-2.53%
Meters	$293,267,849	$12,174,897	4.15%	$5,806,703	1.98%	$6,368,194	2.17%
Industrial M&R Station	$11,809,530	$210,760	1.78%	$508,991	4.31%	-$298,231	-2.53%
Distribution Plant Subtotal	$2,879,590,028	$68,935,737		$117,207,501		-$48,271,764	
General Plant							
Structures & Improvements	$50,104,315	$1,396,212	2.79%	$921,919	1.84%	$474,293	0.95%
Office Furniture & Equipment	$5,021,659	$366,169	7.29%	$137,091	2.73%	$229,078	4.56%
Computer Equipment	$13,188,485	$2,893,126	21.94%	$1,961,128	14.87%	$931,998	7.07%
Transportation Equipment - Light	$19,488,601	$2,800,828	14.37%	$1,490,878	7.65%	$1,309,950	6.72%
Transportation Equipment - Heavy	$13,594,393	$553,092	4.07%	$1,039,971	7.65%	-$486,879	-3.58%
Stores Equipment	$636,384	$23,734	3.73%	$13,237	2.08%	$10,497	1.65%
Tools, Shop, & Garage	$8,277,827	$860,143	10.39%	$179,629	2.17%	$680,514	8.22%
Laboratory Equipment	$497,683	$27,255	5.48%	$19,559	3.93%	$7,696	1.55%
Power Operated Equipment	$7,504,128	$259,627	3.46%	$291,160	3.88%	-$31,533	-0.42%
Communication Equipment	$1,739,568	-$19,232	-1.11%	$154,474	8.88%	-$173,706	-9.99%
Telemetering Equipment	$187,987	$41,275	21.96%	$11,636	6.19%	$29,639	15.77%
Miscellaneous Equipment	$1,072,381	$68,439	6.38%	$48,579	4.53%	$19,860	1.85%
General Plant Subtotal	$121,313,411	$9,270,671		$6,269,261		$3,001,410	
Total	$3,000,903,439	$78,206,408		$123,476,762		-$45,270,354	

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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS	DOCKET NO. G-01551A-16-0107

DIRECT

TESTIMONY

OF

HOWARD E. LUBOW

OH BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 30, 2016

TABLE OF CONTENTS

EXHIBIT

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

The gas procurement function is generally managed on an efficient and cost effective basis. However, at least over the review period, Southwest Gas Corporation's ("Southwest Gas" or "Company") hedging program has resulted in a significant incremental cost to Arizona customers, without necessarily achieving the intended benefit of reducing price volatility. The costs and benefits of the hedging program are not currently quantified in internal managerial reports or reported to the Arizona Corporation Commission ("Commission") in Southwest Gas' Annual Gas Procurement Plan.

As a result of Overland Consulting's review, and recognizing the current and intermediate-term market conditions for gas supply at stable prices, we recommend that the Commission adopt the following:

- Southwest Gas should continue to manage its hedging program based on its discretion. However, it should limit the amount of gas hedged to not more than 25 percent, subject to the consent of the Commission to do otherwise.

- The Company should file additional information about the effect of its hedging program on the cost of gas in its Annual Gas Procurement Plan filed with the Commission, including:

    - Hedging activity by month such that it reflects the volume and percent of gas hedged.

    - Hedging gains and losses incurred.

    - Summary of the 12-month gas price volatility with and without hedging.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Howard E. Lubow. My business address is Overland Consulting, 11551 Ash Street, Suite 215, Leawood, Kansas 66211.

Q. What is your current position at Overland?

A. I am President of the firm.

Q. Please describe Overland Consulting and your role in the firm.

A. Overland Consulting generally provides management, finance, regulatory policy, and accounting services to clients in or associated with the electric, gas, telecommunications, and railroad industries. I typically participate in these services as project director or project manager in the firm's major engagements, providing testimony on regulatory policy, finance, management practices, and ratemaking issues.

Q. Please describe your professional experience.

A. For most of the last 40 years, I have provided consulting services in the subject areas identified above either on behalf of industry clients or state regulators such as the Arizona Corporation Commission ("ACC" or "Commission"). I have testified on many occasions in state and federal administrative proceedings before state commissions and the Federal Energy Regulatory Commission ("FERC"). On occasion, I have also testified in state and federal courts on utility and valuation matters. Aside from this consulting experience, I have also served as Chief Financial Officer and Chief Operating Officer of a gas utility located in the Midwest. A more detailed description of my professional experience is contained in my resume, attached to this testimony as Exhibit HEL-1.

Q. Would you please characterize your experience as it relates to the fuel procurement function?

A. I have sponsored testimony on fuel procurement practices in proceedings focused solely on this subject, as well as in rate filings. These testimonies have generally focused on procurement portfolios, hedging programs, transactions with affiliates, load forecasting, pipeline, and operational issues. I have also reviewed the procurement function in connection with utility management audit reviews conducted by the firm.

Q. What is the scope of your testimony in this proceeding?

A. Overland was retained by Corporation Utilities Division Staff ("Staff") to address certain elements of the Southwest Gas Corporation ("Southwest Gas" or "Company") rate application filed with the Commission on May 2, 2016. Specifically, the areas for review included:

- Conducting a Gas Procurement Review.
- Analyzing the Depreciation Study and Proposed Depreciation Rates.
- Reviewing the Rate Design and Decoupling measures proposed by Southwest Gas.
- Reviewing the Class Cost of Service Study contained in the Southwest Gas filing.

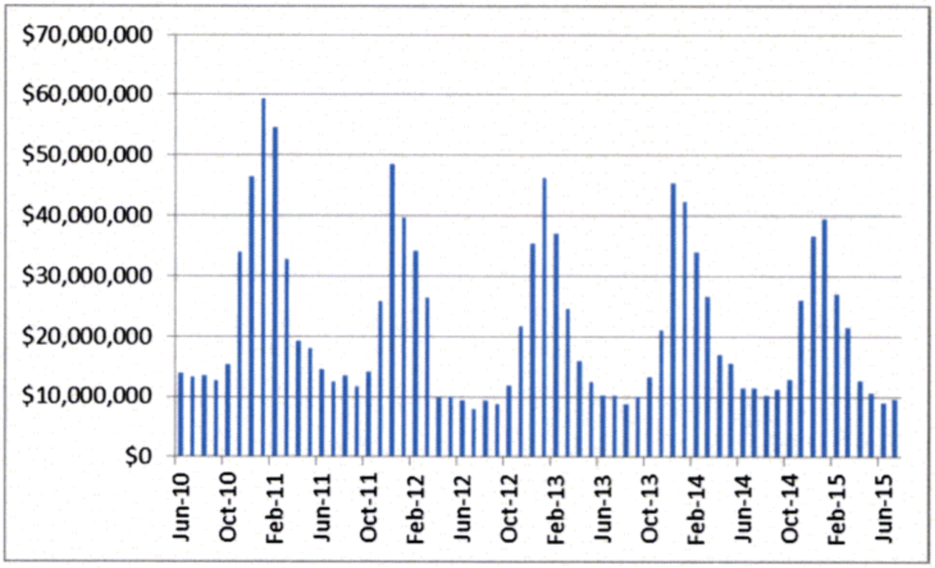
This testimony addresses the firm's review of Gas Procurement for the period June 2010 to November 2015, the "review period" identified in the Utilities Division request for proposal dated May 19, 2016.

FUEL PROCUREMENT

Q. What were Southwest Gas' gas costs in Arizona during the time period audited?

A. For the time period from June 2010 to July 2015, the Company reported $1.338 billion in gas costs. Details of the monthly gas costs are presented in Exhibit HEL-2. A graph showing the cyclical nature of these costs is shown in the following figure:[1]

Figure HEL-1



Q. What is the Company's policy with respect to the acquisition of natural gas?

A. According to Southwest Gas, it "... endeavors to acquire the best-cost portfolio of natural gas supplies considering price, reliability, flexibility, and protection from short-term market volatility while still providing security of supply to meet sales customer demands."[2]

[1] Obtained from the Annual Gas Procurement Plans filed with the Arizona Corporation Commission. Data for August 2015 through October 2015 would have been included in our summary but was not available since these months will be included in the next Annual Gas Procurement Plan which is expected to be filed in late November or early December 2016.

[2] Response to Staff 4-48, Attachment 5, p. 1.

Q. Did this policy change between June 2010 and November 2015?[3]

A. The actual policy statement did not change. However, the manner in which it was implemented by Southwest Gas did change.[4]

Q. Please describe what change was implemented.

A. In Arizona, Southwest Gas builds a portfolio of gas supplies using three different programs. The first program includes Arizona Price Stability Purchases ("APSP") which consist of either fixed-price firm gas supplies or term first-of-month indexed price purchases coupled with fixed-for-floating index swaps. All other things being equal, both of these strategies achieve the same short-term market price volatility mitigation goal. Between 2010 and 2015, Southwest Gas chose to decrease the use of the APSP from approximately 50 percent of total gas year demand to a range of 25 to 40 percent.[5] This was done primarily to reduce operational issues associated with APSP supplies exceeding minimum daily demand and to reduce the risk of penalties and imbalance charges from upstream interstate pipelines.[6]

The second program employed by Southwest Gas in Arizona is term purchases selected during an annual solicitation. These term purchases range for one or more gas years and typically have prices based on a market index. Term purchases are designed to provide the flexible firm peaking supplies that Southwest Gas must have available to provide reliable service to its sales customers.[7] As the use of the APSP has waned somewhat in more recent years, term purchases have filled the void, increasing as a percentage of the total gas year demand supplied. On a calendar year basis, term purchases have ranged from approximately

[3] The audit period considered by Overland was June 2010 through November 2015.
[4] Responses to Staff 4-48, Attachments 1-5, and Staff 4-55.
[5] The Company's gas year runs from November through the subsequent October. In its procedures, the quantities are expressed as "fifty-percent of the annual average forecasted portfolio volume" in 2010 to "about thirty-percent to about 40-percent" of the annual average forecasted portfolio volume in 2015 (see response to Staff 4-48, Attachments 1 and 5). The range of 25%-40% was obtained from the response to Staff 4-55.
[6] Response to Staff 4-55, p. 3.
[7] Response to Staff 4-48, Attachment 5, pp. 2 and 4.

one-third to nearly one-half of all volumes acquired between 2011 and 2015 with the highest percentages occurring in more recent years.[8]

The final program used by Southwest Gas to build its gas supply portfolio is spot purchases. These short-term supplies of one month or less may be firm or interruptible and are intended to fill daily requirements or serve as an alternative to higher cost term purchases. Spot purchases may have either fixed or indexed pricing.[9] The use of spot purchases has generally ranged from 15 to 20 percent of total gas supply on a calendar year basis between 2011 and 2015.[10]

Q. Did you attempt to test the reasonableness of any of Southwest Gas' past purchases of natural gas in Arizona?

A. Yes, we did.

Q. What purchases did you test?

A. We tested the spot purchases made by the Company because this pricing could be independently verified. Unlike term purchases which are made using a computer model that is designed to secure a "...best cost portfolio considering price, reliability, and resource mix" or purchases made under the APSP which are based on a competitive solicitation process, spot purchases were made at market prices.[11]

Q. Please describe the testing you performed.

A. The Company initially provided us a summary listing of the natural gas market prices for monthly and daily spot purchases during the time period from June 2010 to November

[8] Computed from data provided in response to Staff 4-55.
[9] Response to Staff 4-48, Attachment 5, p. 2.
[10] Computed from data provided in response to Staff 4-55.
[11] Responses to Staff 4-48, Attachment 19, pp. 2-3; Staff 7-16; and Staff 7-17.

2015.[12] We judgmentally selected ten months and 25 days during this time period and traced the prices summarized on the Company's listing to Platts *Inside FERC's Gas Market Report* and Platts *Gas Daily*, noting no exceptions.

Having gained assurance that the Company's market price listing is accurate, we then chose the five largest spot purchases from each calendar year, along with five other judgmentally selected spot purchases from each calendar year, and compared the prices paid by the Company to the market price listing.[13] This review of 60 transactions indicated that the prices paid by the Company for Arizona spot purchases were all within two percent of the index prices attributed to Platts by the Company.

Q. What conclusion can you draw from this testing?

A. Since we did not identify any significant differences between prices paid by the Company and market pricing in our testing of Arizona spot purchases, we believe the Company's representation that this portion of its gas supply portfolio is based on market prices to be true.

Q. Is Arizona the only state in which Southwest Gas has reduced its hedging of the price of gas supplies to mitigate price volatility?

A. No. In 2013, the Nevada Bureau of Consumer Protection ("BCP") approached the Company with questions regarding the level of volatility mitigation program ("VMP") purchases made in Nevada. After performing studies on the matter, which included the impacts on the deferred accounting adjustment mechanism, Southwest Gas presented its findings to the BCP and the staff of the Public Utilities Commission of Nevada ("Nevada

[12] Response to Staff 7-18.

[13] Actual spot purchases were provided in response to Staff 4-56. The largest purchases were based on the Nominal Gross Volumes listed in this report. In response to Staff 11-4, Southwest Gas explains how the listed delivery points in Staff 4-56 can be associated with the pricing provided in Staff 7-18.

Commission"). Later in 2013, the Nevada Commission approved a stipulation between the BCP, the staff, and the Company to suspend VMP purchases effective November 2013 with the understanding that on a quarterly basis Southwest Gas would both revisit the continuation of the suspension and present its recommendation on the matter.[14] The suspension of the price hedging program in Nevada continued through late 2015.[15] It is our understanding that the suspension has continued in 2016.[16]

Q. Was the decision to suspend the VMP purchases in Nevada in late 2013 communicated to the Staff or the Commission?

A. According to the Company, it met with Staff on January 9, 2014 to discuss the agreement to suspend the Nevada VMP. Also according to the Company, it was at that meeting that Southwest Gas informed the Staff that it intended to reduce the APSP to approximately 20 to 25 percent of the overall Arizona gas supply portfolio. The Company reported that the Staff "... understood the Company's intention to reduce the APSP and did not express any concern with it."[17]

Q. On an incremental basis, how much does Southwest Gas spend to conduct the APSP?

A. Southwest Gas cannot quantify either the transaction costs associated with APSP activities or the specific gains or losses it incurs as a result of hedging the price of natural gas. However, since purchases for the APSP are representative of market prices at the time of purchase, the Company provided its estimate of the difference between the actual APSP prices paid and the first-of-month market indices.[18] This data is presented in the table below for the five gas years ended October 31, 2015:

[14] Response to Staff 7-8.
[15] Response to Staff 4-48, Attachment 13.
[16] Interview of John Olenick, Director of Gas Supply, and Steve Williams, Manager of Gas Resource Planning, dated September 1, 2016.
[17] Response to Staff 7-8.
[18] Responses to Staff 7-11 and Staff 7-13.

Table HEL- 1

Time Period	APSP Cost (Higher)/Lower Than First-of-Month Index
November 2010 – October 2011	($43,300,000)
November 2011 – October 2012	(30,900,000)
November 2012 – October 2013	(8,100,000)
November 2013 – October 2014	4,600,000
November 2014 – October 2015	(10,300,000)
Grand Total	**($88,000,000)**
Source: Obtained or derived from response to Staff 7-13.	

Based on the data presented in this table, Southwest Gas has incurred at least $88 million of costs over and above what it would have cost if purchases of natural gas had been made at first-of-month indices.[19] While some of these purchases would likely have been made historically on a term basis rather than a spot basis, this data is the only surrogate for actual gains and losses realized as a result of the APSP that the Company produced.

Q. The goal of the APSP is to mitigate short-term market price volatility. How effective was the program in achieving this goal in recent years in Arizona?

A. The results are mixed. Southwest Gas defines short-term gas price volatility as the month-to-month changes in monthly natural gas prices. It suggested that one way it would quantify the effectiveness of the APSP would be to compare the historical volatility (i.e., the standard deviation) in the month-to-month percentage change in the Company's monthly weighted average cost of gas that includes the APSP to a hypothetical monthly weighted average cost of gas that replaces the APSP with monthly index price gas supplies.[20] The following table summarizes the Company's computations for the five gas years ended October 2015:

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[19] The cost is actually slightly more than the amounts reported in the table since transaction costs have been ignored in the analysis.

[20] Monthly index prices would be set to the San Juan first of month index price as reported in Platts *Inside FERC* (see response to Staff 4-60).

Table HEL-2

Time Period	Historical Volatility with APSP	Historical Volatility without APSP
November 2010 – October 2011	8.8%	10.4%
November 2011 – October 2012	13.1%	12.0%
November 2012 – October 2013	6.3%	6.2%
November 2013 – October 2014	11.4%	14.1%
November 2014 – October 2015	9.6%	8.4%
Source: Response to Staff 7-12.		

This table demonstrates that in less than half the gas years (two of five), short-term natural gas price volatility was reduced because Southwest Gas employed APSP. In the two years where volatility was reduced, the reduction was in the range of 15 – 20 percent.

Q. To what does Southwest Gas attribute these results?

A. The Company suggests that the unprecedented overall reduction in gas price volatility in the market during this time period had the effect of either reducing or reversing the price-stabilizing effect that the APSP was intended to have.[21]

Q. Has quantitative data regarding the recent effectiveness of the APSP identical or similar in nature to that in the preceding table ever been communicated to the Chief Executive Officer or board of directors of Southwest Gas?

A. As of mid-September 2016, no – it has not.[22]

Q. To reiterate, what forms of hedging did Southwest Gas employ in Arizona for the time period from June 2010 to November 2015 to carry out the APSP?

A. Fixed price gas purchases and fixed-for-floating index swaps.[23]

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[21] Response to Staff 4-60.
[22] Response to Staff 7-21.
[23] Response to Staff 7-10.

Q. And during that same time period, did the Company ever enter into any derivative transactions on a speculative basis pursuant to the programmatic APSP hedge program?

A. According to the Company, no.[24]

Q. Do you have any recommendations as to the prospective use of the APSP?

A. Past data suggests that the Company and, more specifically, its customers are paying a high price to obtain results which frequently run counter to the intent of the program, which is to reduce the short-term market price volatility of natural gas. I recommend that Southwest Gas consider reducing its reliance on APSP even more than it has when market price volatility is low. In the future, if short-term natural gas price volatility were to reverse and increase significantly, the percentage of the natural gas supply hedged by Southwest Gas should be similarly increased.

More specifically, I recommend that a 25 percent guideline be set for Southwest's ASPS (or similar) hedging. If Southwest chooses to hedge above that limit, it would be required to send a letter to Staff indicating it would be hedging above the 25 percent level with the ASPS (or similar) hedging program.

Q. Should the Commission be able to monitor the SWG hedging program and activity, aside from looking at it as part of a rate filing review?

A. Yes. The Company currently files an Annual Gas Procurement Plan with the Commission. I recommend that SWG be required to provide its hedging activity by month such that it reflects the volume and percent of gas hedged. Further, the Company should report the gains or losses incurred as a result of the hedging practice and procedures employed in Arizona.

[24] Response to Staff 7-15.

Finally, SWG should provide a summary of the 12-month gas price volatility with and without APSP.

Q. For the time period from June 2010 to November 2015, how diverse was Southwest Gas' Arizona supply?

A. During this time period, the Company purchased from approximately 30 to 40 different gas suppliers. The maximum percentage purchased from any one gas supplier for various calendar periods during this time frame ranged from 13 percent to 27 percent.[25] This data, as well as the identity of the largest supplier for each period, is summarized in the following table:

Table HEL-3

Time Period	No. of Suppliers	Maximum % from a Single Supplier	Largest Supplier
Jun 2010 – Dec 2010	29	26%	BP Energy
Jan 2011 – Dec 2011	38	13%	Tenaska
Jan 2012 – Dec 2012	31	17%	Tenaska
Jan 2013 – Dec 2013	32	19%	ConocoPhillips
Jan 2014 – Dec 2014	31	21%	BP Energy
Jan 2015 – Nov 2015	30	27%	ConocoPhillips
Source: Response to Staff 4-55.			

Q. During this same time period, what was the peak day demand in Arizona for Southwest Gas?

A. The following table provides the specific data for each month:

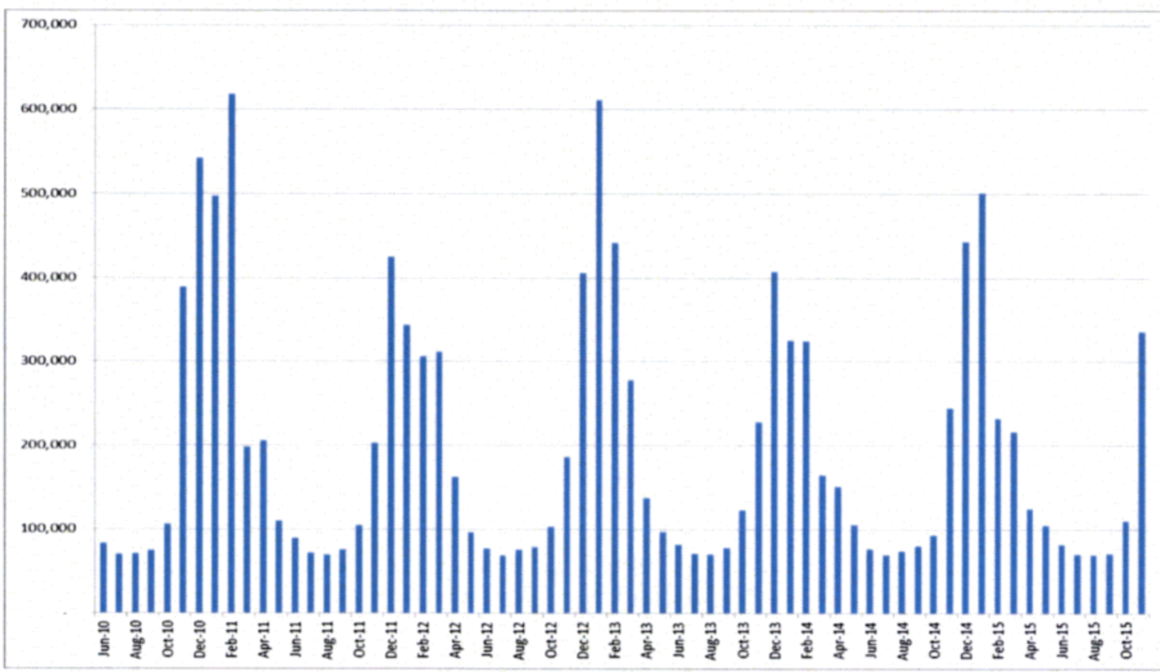
[25] Response to Staff 4-55.

Table HEL-4

Month	2010	2011	2012	2013	2014	2015
January		497,204	342,910	611,206	324,949	500,913
February		618,422	306,153	441,748	324,092	232,012
March		198,421	311,415	277,451	164,505	216,344
April		205,610	162,572	136,949	150,881	124,548
May		109,650	96,511	97,192	105,610	104,859
June	83,302	89,634	77,648	81,921	76,306	81,791
July	70,407	72,208	68,789	71,497	69,671	70,174
August	71,213	69,419	75,435	70,862	73,958	69,359
September	75,418	75,874	79,058	78,270	80,272	71,502
October	106,045	104,374	103,058	122,831	93,374	109,736
November	389,417	202,512	185,712	227,799	244,570	335,181
December	541,989	425,416	406,067	407,535	443,383	
Source: Response to Staff 4-54.						

When graphed, the data above shows the seasonality of the peak day demand as customers take more gas during the typically colder months of the year and scale back their demand during the warmer months:

Figure HEL-2



Q. What was the interstate capacity utilization of the Company during this time period?

A. When grouped by calendar year, Southwest Gas experienced the following utilization:

Table HEL- 5

Time Period	Utilization %
Jun 2010 – Dec 2010	67.85%
Jan 2011 – Dec 2011	73.77%
Jan 2012 – Dec 2012	73.78%
Jan 2013 – Dec 2013	77.10%
Jan 2014 – Dec 2014	62.59%
Jan 2015 – Nov 2015	49.02%
Source: Response to Staff 4-57. Utilization percentage based on Total Available MDQ (Dth).	

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit HEL-1

Howard E. Lubow, President

Overland Consulting | 11551 Ash Street, Suite 215 | Leawood, KS 66211 | 913-599-3323
hlubow@overlandconsulting.com

General

Mr. Lubow is President of Overland Consulting. He has more than 30 years of experience as a public utility consultant. His consulting engagements have encompassed a broad spectrum of management, finance, and regulatory issues for electric, gas, water, pipeline, and telephone utilities. Recent project experience includes focused management audits, analysis of utility diversification and acquisition plans, prudence studies, accounting systems design, cost-of-service determination and allocation, utility property valuation, rate of return determinations, and rate design issues. Mr. Lubow has testified in more than 100 regulatory and civil litigation proceedings and has testified in approximately 20 jurisdictions through the county.

Professional Work History

Overland Consulting *1991 – Present*
President

Responsible for administration and review of management auditing, regulatory consulting, and litigation support services. Provide expert witness services in projects involving decision analysis, damages assessment, ratemaking, valuation, and accounting.

Kansas Pipeline Company *1997 – 1999*
Executive Vice President, Chief Operating and Financial Officer

Responsible for the day-to-day operations of this natural gas pipeline, as well as direct responsibilities associated with the financial, accounting, and regulatory functions of the Company. Implemented a reengineering and downsizing program that resulted in a major reduction in operating expenses. Negotiated new gas supply and transportation contracts. Renegotiated credit lines on more favorable terms. Responsible for the negotiation and acquisition of a natural gas marketing company. Developed and implemented a management incentive program for senior executives. Developed due diligence and presentation materials relied upon by potential buyers of Kansas Pipeline assets.

Amerifax, Inc. (Americonnect) *1990 – 1991*
Chief Executive Officer

Directed the IPO for this telecommunications switchless rebiller. The company implemented a national marketing program, focusing primarily in the Midwest. After five years, the company was acquired for approximately three times its IPO valuation.

LMSL, Inc. *1983 – 1990*
President

Responsible for administration and review of regulatory services projects and research studies. Expert witness in regulatory proceedings. Director of special projects including management audits, financing feasibility studies, property acquisition and merger feasibility studies, and development of innovative solutions to current regulatory issues.

Drees Dunn Lubow & Company *1976 – 1982*
Managing Partner

Responsible for projects for utility clients. Responsibility included financial and managerial analysis of public utility companies and the presentation of expert testimony before regulatory commissions.

Troupe, Kehoe, Whiteaker & Kent *1972 – 1976*
Senior Regulatory Consultant

Responsible for special services work for utility clients, including accounting systems design, cost-of-service determination and allocation, budgeting, and rate designs. Performed fair value determinations, developed cost analysis studies, curtailment requirements analysis, and forecasts of utility operations.

Kansas City Power & Light Company *1968 – 1972*
Senior Accountant

Analyzed accounting and reporting procedures, taxes, and costs of operations. Assisted in the preparation of Federal and State income tax returns and the Annual Report to stockholders. Assisted with rate filings in Kansas and Missouri. Developed tax basis property accounting system.

PROFESSIONAL EXPERIENCE

ELECTRIC AND GAS

- Engagement Director in a comprehensive management and operations audit of Central Hudson, on behalf of the New York State PSC. The audit includes a comprehensive assessment of the utility's construction program planning processes and an evaluation of the efficiency of the utility's operations with a focus on opportunities to improve performance.
- Project Director in a focused review of the general rate application of Southwest Gas Corporation, on behalf of the Arizona Corporation Commission. The review addresses procurement activities, depreciation studies, rate design and revenue decoupling, and a class cost of service study.
- Project Director in the review of the proposed merger between Exelon Corporation and Pepco Holdings, Inc., on behalf of the Maryland PSC. Appeared as the lead policy witness, addressing financial, governance, and rate issues implicit in the merger review.
- Project Director in the review of the proposed merger between Exelon Corporation and Pepco Holdings, Inc., on behalf of the Delaware PSC. Prepared written testimony, addressing financial, governance, and rate issues implicit in the merger review.
- Project Director in a focused audit of all major electric and gas utilities in the State of New York. The audit addressed the reliability and comparability of operating metrics reported to the Commission concerning electric reliability, gas safety, and customer service.
- Project Manager in a management audit of South Jersey Gas Company and its parent, South Jersey Industries. The audit addressed compliance with affiliate transaction rules, as well as all primary functional areas of utility and corporate operations. Specifically addressed corporate governance, finance, gas operations, gas safety, and gas procurement functions within the audit. Reviewed implications of diversification on utility risk.
- Project Director in a focused review of PG&E practices associated with their gas transmission system. This project arose from the San Bruno incident, which led to intense investigations at the state and federal level. Overland was retained by the California PUC to audit the management operations and financial commitments of PG&E necessary to assess the adequacy of resources

supporting gas safety policies and procedures. In this context, capital expenditures and operating budgets were reviewed in relation to regulatory commitments reflected in customer rates over time. Provided testimony on the financial capacity of PG&E to support capital investments needed to upgrade gas safety and reliability across the transmission system, as well as to consider the implications of potential fines under review by the CPUC.

- Project Director in a focused review of PG&E gas distribution gas safety and reliability financial commitments and operations procedures. Considered the adequacy of financial commitments and management practices, as well as consequences of resource restrictions on safety and reliability metrics. Results were provided in a report filed with the CPUC on behalf of the Public Safety Division.
- Project Director in a focused audit of National Grid service and parent company charges to New York jurisdictional utilities. The audit included a review of internal control procedures, as well as an in-depth review of transactions over a 20-month period, ultimately associated with jurisdictional cost-of-service implications. The scope of charges considered in the audit exceeded $5.0 billion. Overland sampled the total population of costs through direct and statistical analysis.
- Project Director in the review of the proposed merger between Exelon Constellation Energy on behalf of the Maryland PSC. Appeared as the lead policy witness, addressing financial, governance, and rate issues implicit in the merger review. Considered the implications of market power and cost-benefit analyses in making recommendations concerning proposed settlement options.
- Project Manager in a management audit of Connecticut Natural Gas and its parent, Iberdrola USA. The audit scope included all significant functions of the company including a review of corporate governance and executive management, accounting and finance, conservation activities, and operations. A number of special topics were also addressed including: customer demand metering, billing determinates, and billing procedures.
- Project Director in the review of the proposed merger of FirstEnergy and Allegheny on behalf of the Maryland PSC. Appeared as the lead policy witness, addressing financial, governance, and rate issues implicit in the merger review. Proposed conditions necessary to comply with statutory criteria. Provided a set of ring-fencing conditions appropriate to maintain financial and governance policies necessary to protect Potomac Edison, the Maryland regulated utility under review.
- Project Director in the review of the proposed transaction between Constellation Energy and EDF involving, among other things, the sale of a 50% interest in Constellation's nuclear facilities. Lead witness on behalf of the Maryland Staff addressing various transaction issues including: impact on Baltimore Gas & Electric customers, corporate governance and financial implications, ring-fencing measures, and cost-benefit analysis.
- Project Manager of the management audit of Atlantic City Electric and its parent PHI Holdings. The audit covered a detailed review of the corporate governance, strategic planning, executive management, and finance functions. Other key areas of review included affiliate transactions, generation and transmission planning, service quality, and system reliability.
- Project Manager in the review of long-term financial projections prepared by Midland Cogeneration Venture Limited Partnership to be used in regulatory proceedings concerning proposed modifications to a power purchase agreement. The engagement included the sensitivity testing of major variables in the partnership's financial model.

- Project Manager in the review of accounting and finance issues raised by Connecticut utilities in connection with proceedings on long-term capacity measures. Addressed the implications of new generation facilities and DSM projects on regulated electric utilities.
- Project Director for a multi-disciplinary consulting team that reviewed the proposed Exelon/PSEG merger on behalf of the New Jersey Board of Public Utilities. Also the primary expert witness in areas of finance and regulatory policy; responsible for analysis of the merger's financial impacts, in particular the impact on PSE&G, the New Jersey utility. Responsible for recommendations to insure that if the merger is approved, the transaction price, terms, and conditions are fair and reasonable in light of applicable standards for review, and that the New Jersey utility remains financially secure.
- Performed a financial and market feasibility study of a fiber optic network designed to provide SCADA requirements for a large multi-state electric utility interested in selling capacity to telecommunications carriers and high volume customers.
- Sponsored the overall development of utility revenue requirements, jurisdictional, and class cost-of-service studies and rate design issues in numerous electric, gas, water, and telecommunication cases throughout the country.
- Conducted an analysis of the adequacy of depreciation rates for a large independent telephone company located in Texas in order to assess the relationship of capital recovery in light of technological obsolescence.
- Directed and developed a two-day training seminar for the Kentucky Public Service Commission addressing energy and telecommunications issues raised in rate filings, utility planning, and forecast models required in considering the use of projected test year data.
- Supervised and directed a group of PSC Staff members in the review of a rate filing relying upon the use of a projected test year.
- Directed a comprehensive financial and regulatory base period audit of a large gas transmission and distribution company in connection with implementation of an incentive regulation plan. Reviewed savings resulting from force reductions of 1,200 employees and implementation of aggressive cost reduction programs.
- Performed a study of a LDC's gas supply and transportation procurement practices in a post-Order 636 operating environment, where the LDC's transportation and supply services continued to be provided by affiliated companies. The parent reorganized its pipeline transmission and gas supply services into a separate company, transferring jurisdiction from state regulators to the FERC. Developed a model to quantify an optimal supply and transportation mix for state ratemaking purposes.
- Performed a review of intrastate pipeline issues including the use of a straight fixed-variable cost methodology, regulatory treatment of stranded costs, pipeline competition issues, and the merits of a corporate restructuring and related effects on cost-of-service and changes in corporate operations.
- Developed a revenue requirement analysis of an intrastate gas transmission pipeline company addressing issues including: proper recognition of net operating loss carryforwards for ratemaking purposes, treatment of deferred start-up costs, application of criteria for consideration of acquisition premium in rates, and the recognition and relationship of financial criteria in the rate-setting process.

- Directed a comprehensive review of the $850 million PG&E gas transmission pipeline expansion project. This study included a review of regulatory considerations in recognizing construction and operating costs in light of competition in the California pipeline markets and, based upon the Commission intended allocation of risks among regulated customers, project shippers, and the pipeline owner.
- Directed a review of gas procurement policies and procedures and addressed the impact of FERC Order 636 for three Wyoming LDC's. This study addressed the relationship of gas pipeline and LDC affiliate organizations associated with the gas supply and transportation functions and the impact of the affiliated organizational structures on gas prices measured against other utilities in the region.
- Reviewed impacts of FERC Order 636 on gas utility distribution companies including staffing and other operating requirements, changes in gas procurement and storage policies, and effects on marketing plans. Also reviewed various pipeline compliance filings, analyzing impacts on firm and non-firm customers.
- Reviewed electric and gas utility fuel procurement policies and procedures, organization, and internal controls in various engagements. Developed recommendations resulting in significant benefits to utilities under review.
- Performed fuel audit investigations in several jurisdictions addressing such issues as economic dispatch procedures, fuel acquisition policies, affiliated mine or pipeline operations, captive mine development, and compliance with Commission rules and regulations. These studies included the review of prices and returns produced from affiliated operations versus third-party options and market prices available.
- Reviewed gas supply issues including procurement policies, supply mix, affiliate transactions, and contract provisions in the context of both cost-of-service and management review proceedings. Provided policy analysis regarding considerations and benefits of increased gas supply and pipeline competition.
- Participated in three FERC interstate pipeline rate proceedings addressing cost-of-service issues, including appropriate classification and allocation methodologies. Also addressed construction costs, overhead, and pipeline operations issues in a major oil pipeline docket.
- Performed a detailed analysis and presented testimony regarding the relative economic benefits of the operation of a LNG plant versus meeting seasonal peak demands through pipeline contract commitments.
- Developed gas transportation pricing criteria and implementation guidelines in the development of tariff service offerings for several gas LDC's.
- Developed numerous gas cost service studies and related rate design recommendations for local distribution companies, as well as pipeline suppliers. Testimony regarding such studies was presented before various state commissions, as well as the FERC.
- Responsible for gas distribution company revenue requirements in over 25 cases addressing accounting, cost allocation, operations, and rate design issues. These cases generally included an analysis of gas production, gathering, and transmission systems owned by the LDC parent.
- Developed a damages model for a gas utility in civil litigation arising from acquisition of a defective distribution system caused by improper installation practices. Measured incremental construction and operating costs associated with pipe replacement program.

- Developed a risk analysis model used to associate the relationship between cost recovery and changes in class consumption patterns for a gas distribution company.
- Developed a quantitative model to estimate jurisdictional and class-peak consumption for distribution gas companies.
- Performed an overview of regulatory considerations in the oversight of holding company formations and operations. This project was conducted on behalf of a PUC to analyze issues associated with holding company formations, utility diversification, and affiliated interest oversight and controls. The four largest electric utilities in the state were included in the study. The final report covered policy issues, as well as more detailed discussions of monitoring procedures and recommended filing requirements.
- Developed diversification guidelines for utilities in several jurisdictions. Addressed regulatory concerns and limits that might be implemented to control contingent adverse consequences to utility ratepayers.
- Performed an overview of regulatory considerations in the oversight of holding company formations and operations. This study addressed appropriate regulatory guidelines and oversight policies for utility and non-utility operations.
- Directed reviews of two major utility subsidiary gas intrastate pipeline systems, addressing cost-of-service, operating issues, and appropriate accounting for overheads and affiliated transactions from regulated electric utility parent companies.
- Developed a financing plan and reorganization of corporate structure for an electric utility having gas properties and a separate gas subsidiary. This project included preparation of SEC U-1 filings, filings with regulatory agencies, and testimony to address the impact of the proposed financing and reorganization on cost of capital and rates.
- Responsible for the independent analysis of the feasibility and economics of consolidation of two major electric utilities. The project focused primarily on the quantification of merger benefits associated with consolidated operations. This in-depth 12-month study also included a detailed review of the scope of services and basis of pricing such services among affiliates. The study addressed a number of affiliate interest issues including: the basis of pricing and level of capacity and/or energy supplied by affiliate versus third parties, the services provided by an affiliate "service" company versus internal resources or purchases from third parties, and the consideration of management resources devoted to non-utility functions and the basis of compensation for such resource transfers.
- Reviewed American Electric Power System Agreement to assess the reasonableness of fuel and purchased power costs incurred and allocated to its utility operating companies. The analysis also considered system dispatch and related fuel accounting issues associated with energy requirements of regulated customers versus wholesale transactions.
- Responsible for the development and implementation of phase-in plans utilized to defer initial costs of new generation facilities. Developed assessment criteria and related models to assign capacity from new plant additions between jurisdictional and non-regulated service.
- Developed and conducted a training program on the measurement of relative and absolute fuel productivity measures in ranking utility's effectiveness in fuel procurement and generation system operations.

- Developed a framework for implementation of competitive pricing for an electric utility facing higher costs due to nuclear plant additions. The analysis also encompassed an incentive rate program designed to induce greater use of excess capacity, as well as to improve the utility load factor.
- Analyzed and implemented economic dispatch models used to evaluate the effects of changes in generation capacity and fuel use.
- Conducted several comprehensive nuclear management and prudence reviews addressing construction, management, planning, and economics issues.
- Directed a two-year study of the impacts on and options available to an electric utility due to the abandonment of a nuclear plant near completion. Presented a workout plan to regulators. Study involved a five-year forecast of financial results including construction expenditures and operating costs.
- Developed commercial operation date criteria and guidelines for nuclear power plants which were supported by a national industry survey.
- Developed a financial analysis of a major municipal utility facing an extended outage of its nuclear power plant, with alternative pricing strategies, recognizing competitor pricing in adjacent service areas. Developed multi-year cost-of-service and revenue requirements models and presented results to the Utility Board.
- Performed studies for municipalities to determine the feasibility of acquiring street lighting facilities or, in the alternative, pricing options other than PSC-regulated tariffs.
- Conducted an industry survey of the effectiveness and relative benefits achieved from the use of uniform filing requirements in utility rate applications. The findings were published and distributed to the utility industry and regulatory commissions.
- Developed class cost-of-service studies including identification of direct assignments and review of distribution facilities, methodologies, and criteria for the allocation of generation and bulk power facilities and risk differentials associated with various classes of service.
- Project Director of a review of Kentucky current statutes, regulations, and policies governing integrated resource planning. The project addressed recommendations necessary to mitigate impediments to the development of appropriate demand-side management programs, energy efficiency, renewables, and new generation technology options available within the state.

WATER

- Senior Auditor on two financial audits of a large Kansas City area water utility. Lead Consultant working with this client on an engagement to develop an improved model to forecast water consumption. Provided consulting services to the client in the development of inverted rate design structure.
- Project Director in revenue requirement, cost-of-service, and rate design studies for a Kansas area water utility. Responsible for the filing of two cases before the Kansas Corporation Commission. Also advised this client on the going concern valuation of the utility, relied upon in a transaction for the sale of the utility assets.
- Developed a class cost-of-service analysis involving a St. Louis area water utility and submitted the study in rate proceedings before the Missouri Public Service Commission.

- Addressed tax issues impacting the revenue requirements of a large Indiana water company before the Indiana Utility Regulatory Commission.
- Developed rate filings on behalf of several water companies within the state of Missouri. Responsible for revenue requirement, cost-of-service, and rate design evidence in two applications on behalf of this client.
- Project Manager of a regulatory audit of California American Water Company's general office activities and costs, including unregulated activities, cost allocations, and affiliate transactions.
- Project Manager in a rate design analysis of Cal Am Water Phase 2 Rate proceedings. Addressed appropriate rate design considerations in a market area highly constrained by available supply. Proposed use of inverted rates and other conservation mechanisms to address limited supply conditions. Reviewed price elasticity implications on usage, metering options for irrigation customers, cost-of-service analysis, and pricing of service charge component of customer tariffs.

VALUATION

- Conducted a feasibility study regarding the sale of a utility power plant used to provide steam heat and process steam to commercial customers through a downtown area distribution system. The feasibility study addressed energy alternatives and pricing options, cogeneration, and a financial and operating forecast assuming alternative case scenarios based upon various potential ownership structures.
- Performed a valuation analysis on behalf of an investor group for the construction and operation of a high-capacity fiber network between Seattle and Vancouver, designed to serve large commercial companies and telecommunications providers. Provided due diligence analysis of market demand and pricing assumptions, competition, and anticipated construction and operation costs.
- Performed a valuation analysis of an electric utility in the southwest on behalf of a private investor group interested in making a tender offer for the shareholder interests of this public company. Also participated in presentations to investment bankers and commercial banks who were to fund the acquisition.
- Performed a valuation study regarding two natural gas distribution affiliates in the Midwest, whose electric utility parent was seeking offers for a sale of the assets and related securities. Developed analysis of the impact of regulation on property values.
- Performed a valuation analysis of a gas transmission company used to evaluate offers for the company. Developed due diligence and information materials provided to interested parties. Participated in presentations to interested parties with investment bankers.
- Developed a valuation analysis used in litigation proceedings to support the reasonableness of the acquisition price for a rural electric company acquired by an investor-owned electric utility company.
- Developed and applied a model for the determination of the value of helium extracted from natural gas relied upon in litigation cases in federal courts in Oklahoma and Kansas. Analysis required the determination of extraction costs at plants involving four major pipeline systems in the Midwest. Developed studies of construction and operating costs associated with helium extraction plants, as well as the analysis of incremental costs and revenues related in by-product liquid extractions.
- Performed an analysis of the value of long-term gas transportation contracts relied upon in civil litigation and by regulators. The studies included the development of construction cost and operations estimates, as well as discount rates to be employed.

- Performed a reproduction cost study for a cable television company located in the west. As part of the project, developed a continuing property records system. The company used the results in the negotiation of the sale of its assets.
- Represented a member of a consortium formed to build a satellite network for cellular services with commercial applications throughout the United States. Developed a valuation analysis and business plan used in a private placement for equity financing. Acted as a co-investment advisor with a large Wall Street firm in providing these services and making presentations to potential investors.
- Developed a valuation analysis of nuclear facilities which included a detailed study of assets, and their costs, required for environmental protection as defined by state statutes and federal regulations. The study was relied upon in determining the proper classification and valuation of nuclear assets for property tax purposes.
- On behalf of a state department of revenue, developed a review of property tax rules and definitions as applied to telephone, cellular, and cable companies. The study included a national survey of valuation practices relied upon by each state department of revenue.
- Developed appraisals of telecommunications properties for property tax purposes using standard valuation methods. Presented studies in administrative and civil proceedings. Developed cost of capital analysis based upon applications of the DCF and CAPM models.
- Developed appraisals relied upon in property tax cases involving telecommunications properties where subject sales were involved within two years of the date of property assessment.
- Prepared appraisals for a natural gas transmission company in appeals of property tax assessments in administrative proceedings in Kansas and Oklahoma.
- Prepared appraisals of two investor-owned utilities on behalf of the Iowa Department of Revenue. The appraisals included a subject sale analysis and a review of economic obsolescence.
- Developed appraisals of two Class I railroad companies in contested property tax valuation in civil proceedings in New York. Valuation studies included the review of the cost method based on RCNLD.
- Assisted an electric G&T coop in valuation and due diligence analysis of electric and gas properties offered for sale by a large independent telephone company.
- Developed a manual for "Alternative Valuation Procedures" on behalf of the Virginia State Corporation Commission – Public Service Taxation Division in a state that otherwise relies on the cost method.
- Developed a business plan and other financial advisory services to the National Homebuilders Association joint venture subsidiary, "Smarthouse," in connection with securities offerings.
- Developed a complete appraisal of a cogeneration facility on behalf of the Virginia State Corporation Commission – Public Service Taxation Division. The study included "Subject Sale" and "Comparable Company" analyses, as well as a review of capacity and energy forecast prices in the PJM market area.
- Prepared a complete appraisal of CSX Railroad operating property on behalf of the Florida Department of Revenue.
- Prepared a complete appraisal of Qwest Corporation on behalf of the Iowa Department of Revenue. The appraisals included "Subject Sale" and "Comparable Company" market analyses.

- Developed a complete appraisal of the Dickerson Electric Generation Plant located in Dickerson, Maryland, on behalf of the Maryland State Department of Assessments and Taxation and Montgomery County, Maryland. The plant was comprised of three coal and three gas units with a total capacity of approximately 900 Mw. The ultimate owner of these facilities was Mirant Corporation, now known as GenOn Energy.
- Retained by the Virginia Public Service Taxation Division to perform a valuation of the Portsmouth Genco and James River Genco, both coal-fired generation units. The units were owned and operated by Cogentrix Energy, whose ultimate owner was the Carlyle Group.

Telecommunications

- Developed and directed a three-day nationally attended conference entitled, "Competitive Strategies in the Local Exchange Marketplace."
- Directed audits of RBOCs regarding compliance with regulatory accounting requirements, procedures to allocate costs between regulated and non-regulated activities, policies and rules for pricing transactions among affiliates, and monitoring reports filed with regulators.
- Conducted a review of depreciation rates for local exchange telecommunications property of the central division of a national carrier.
- Directed a comprehensive review of the operation of a RBOC telecommunications incentive plan, based upon a revenue sharing mechanism, over a three-year period. The study reviewed quality of service measures, capital expansion programs, workforce reductions, and other major elements of operating expense for the review period. Provided policy options regarding modifications to the incentive plan for prospective consideration.
- Developed a business plan and other related materials for a telecommunications reseller in its initial public offering. Provided ongoing financial and regulatory services, including development of all SEC filings.
- Directed an analysis of switching and other LEC facilities required and costs of providing inter-exchange services to an alternative service provider in the Phoenix, AZ, area.

Income Tax

- Expert witness in numerous regulatory proceedings addressing the proper recognition of investment tax credits and accelerated depreciation for accounting and ratemaking purposes. Provided guidance on intent of IRS regulations in use of tax benefits in the rate-setting process. Such testimony was provided in a number of jurisdictions including: Arizona, Oklahoma, Missouri, Indiana, Kansas, and Mississippi.
- Addressed the implications of utility net operating loss carryforwards for GAAP and ratemaking purposes before the Kansas Corporation Commission and the FERC.
- Provided expert analysis and testimony on the proper recognition of tax benefits arising from participation of subsidiary utilities in consolidated tax returns that include regulated and unregulated affiliates.
- Expert witness testimony and analysis of tax timing differences arising from utility operations as considered for income tax, accounting, and ratemaking purposes. Provided an assessment of proper application of normalization or flow-through of tax timing differences for accounting and ratemaking purposes. These issues were addressed in over 20 cases in various jurisdictions throughout the U.S.

Education and Professional Certification

- **University of Missouri – Kansas City,** Kansas City, MO
  Bachelor of Business Administration – Accounting, Economics Minor, May 1968.
- **University of Missouri – Kansas City,** Kansas City, MO
  Graduate studies in quantitative and systems analysis, 1968 – 1970.

PUBLICATIONS AND PRESENTATIONS

- *Utility Merger Review – Training Workshop for Regulators and Consumer Stakeholder Representatives.* An advanced course discussion of utility M&A technical and policy issues. Presented to Regulators and Staff in Dover, DE, and Trenton, NJ, May 2015.
- *Systematic Ring Fencing: A Quantitative Approach to Balancing the Interests of Utilities and Regulation.* Presented at the NARUC Accounting & Finance Spring Meeting, Jacksonville, FL, March 2014.
- *CPUC Knowledge Transfer Workshop – Executive Summary.* A presentation for senior staff and policy makers, February 2014.
- *California Public Utilities Commission Staff Workshop.* An overview of management, financial, and regulatory considerations associated with the PG&E San Bruno incident, November 2013.
- *How to Build a Fence (and When);* Co-authors. *Public Utilities Fortnightly,* October 2013.
- *Constellation/EDF Nuclear Joint Venture: Regulatory Issues and Subsequent Resolutions.* Co-author. Published in the *Electricity Journal*, March 2010. Also presented at the Western States Association of Tax Administrators Annual Meeting, February 2010.
- *Rating Agencies – Current Methods Employed and Recognition of Imputed Debt.* WSATA Unitary Appraisal School, Advanced Class, Logan, UT, January 2008.
- *Accounting Pronouncements Impacting Financial Reporting Associated with Utility Purchase Power Agreements.* WSATA Unitary Appraisal School, Advanced Class, Logan, UT, January 2008.
- *Accounting and Finance Issues Associated with Contracts for Differences – Generation/DSM Projects.* Gregory Oetting, co-presenter. Connecticut Department of Public Utility Control, September 2007.
- *Overview of FIN 46(R), SFAS No.* 133, and SFAS No. 71. Gregory Oetting, co-presenter. Connecticut Department of Public Utility Control, May 2007.
- *The Yield Capitalization Method – Application Issues.* WSATA Unitary Appraisal School, Advanced Class, Logan, UT, January 2007.
- *Blue Chip Method Overview.* 21st Conference of Unit Value States, Memphis, TN, October 2004.
- *Appraisers Find Help in Recent Accounting Rules.* Gregory Oetting, co-author. *Fair & Equitable,* August 2003.
- *Impact of Deregulation and Competition On Property Tax Valuation Within the Utility Industry.* Western States Association of Tax Administrators, Austin, TX, September 1995.
- *Considerations Associated with the Review of Rate Applications Based Upon Projected Test Periods.* A two-day training seminar conducted on behalf of the Kentucky Public Service Commission, December 1992.
- *Competitive Strategies in the Local Exchange Marketplace.* A three-day telecommunications conference sponsored by Overland Consulting and the University of Missouri – Kansas City, September 1991.
- *Framework for a Competitive Strategy.* Southeastern Regional Public Utilities Conference, Atlanta, GA, September 1988.

- *Regulatory Considerations Inherent in Assessing Utility Culpability.* Richard Ganulin, co-author. *Public Utilities Fortnightly,* 1987.
- *On the South Texas Project and Other Cases.* Published in *The Advisory,* March 1987.
- *Regulatory Implications Associated with the Prudence Audit Process.* NARUC Biennial Regulatory Information Conference, September 1986.
- *Review of The Proposed Amendment to FASB Statement No. 71.* Presentation to the Financial Accounting Standards Board, June 1986.
- *Rate Moderation Plan Considerations.* Presented at the Public Utilities Accounting and Ratemaking Conference, sponsored by the Texas Society of CPAs, April 1985.
- *Regulatory and Accounting Implications of Phase-in Plans.* Presented at the NARUC Biennial Regulatory Information Conference with Gary Harpster, co-presenter, September 1984.
- *The Use of Uniform Filing Requirements by State Regulatory Commissions – An Industry Survey.* May 1980.

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Southwest Gas Corporation Cost of Gas Summary							
Month	Year	Spot Purchases ($)	Firm Purchases ($)	Storage Charges ($)	Total Gas Purchases ($)	Tranportation Charges ($)	Total Gas Costs ($)
Jun	2010	646,127	10,032,925		10,679,052	3,263,000	13,942,052
Jul	2010	771,298	9,364,744		10,136,042	3,167,012	13,303,054
Aug	2010	688,373	9,711,267		10,399,640	3,171,055	13,570,695
Sep	2010	1,560,337	7,840,826		9,401,163	3,280,421	12,681,584
Oct	2010	1,654,483	10,226,612		11,881,095	3,516,078	15,397,173
Jun-Oct	**2010**	**5,320,618**	**47,176,374**	**-**	**52,496,992**	**16,397,566**	**68,894,558**
Nov	2010	6,720,167	20,173,246		26,893,413	7,126,417	34,019,830
Dec	2010	3,190,740	34,656,430		37,847,170	8,631,234	46,478,404
Jan	2011	11,612,732	38,690,995		50,303,727	9,010,400	59,314,127
Feb	2011	11,051,088	35,394,332		46,445,420	8,144,951	54,590,371
Mar	2011	831,988	24,323,695		25,155,683	7,643,951	32,799,634
Apr	2011	5,833,409	8,968,361		14,801,770	4,524,461	19,326,231
May	2011	6,308,116	7,269,429		13,577,545	4,420,411	17,997,956
Jun	2011	3,962,596	7,057,456		11,020,052	3,508,971	14,529,023
Jul	2011	1,708,495	7,290,779		8,999,274	3,390,208	12,389,482
Aug	2011	2,776,797	7,286,911		10,063,708	3,391,822	13,455,530
Sep	2011	2,448,801	7,054,177		9,502,978	2,119,983	11,622,961
Oct	2011	2,291,812	9,589,375		11,881,187	2,172,741	14,053,928
Nov-Oct	**2010-2011**	**58,736,741**	**207,755,186**	**-**	**266,491,927**	**64,085,550**	**330,577,477**
Nov	2011	7,635,518	11,943,151		19,578,669	6,166,934	25,745,603
Dec	2011	5,713,893	34,632,013		40,345,906	8,137,845	48,483,751
Jan	2012	1,622,806	29,628,184		31,250,990	8,413,893	39,664,883
Feb	2012	1,591,942	25,104,768		26,696,710	7,464,669	34,161,379
Mar	2012	2,075,762	17,351,249		19,427,011	6,967,054	26,394,065
Apr	2012	4,793,849	2,714,836		7,508,685	2,252,991	9,761,676
May	2012	4,522,680	3,311,877		7,834,557	2,089,302	9,923,859
Jun	2012	4,510,640	2,709,287		7,219,927	2,139,888	9,359,815
Jul	2012	3,068,886	2,799,879		5,868,765	2,144,029	8,012,794
Aug	2012	4,366,383	2,800,447		7,166,830	2,152,854	9,319,684
Sep	2012	3,881,054	2,708,105		6,589,159	2,134,248	8,723,407
Oct	2012	6,714,029	2,806,983		9,521,012	2,268,848	11,789,860
Nov-Oct	**2011-2012**	**50,497,442**	**138,510,779**	**-**	**189,008,221**	**52,332,555**	**241,340,776**
Nov	2012	611,369	14,770,134		15,381,503	6,237,664	21,619,167
Dec	2012	1,487,722	26,011,816		27,499,538	7,893,505	35,393,043
Jan	2013	1,862,056	36,266,398		38,128,454	8,066,581	46,195,035
Feb	2013	1,427,738	28,356,833		29,784,571	7,350,528	37,135,099
Mar	2013	1,111,344	16,690,820		17,802,164	6,797,938	24,600,102
Apr	2013	10,642,170	2,871,328		13,513,498	2,389,859	15,903,357
May	2013	8,047,465	2,398,925		10,446,390	2,114,732	12,561,122
Jun	2013	6,440,933	1,665,911		8,106,844	2,173,871	10,280,715
Jul	2013	5,922,117	2,717,548	(775,873)	7,863,792	2,279,502	10,143,294
Aug	2013	5,403,837	1,811,424	(775,873)	6,439,388	2,273,637	8,713,025
Sep	2013	5,957,106	2,426,517	(697,188)	7,686,435	2,271,602	9,958,037
Oct	2013	7,181,657	3,873,518	(157,749)	10,897,426	2,445,889	13,343,315
Nov-Oct	**2012-2013**	**56,095,514**	**139,861,172**	**(2,406,683)**	**193,550,003**	**52,295,308**	**245,845,311**

Month	Year	Spot Purchases ($)	Firm Purchases ($)	Storage Charges ($)	Total Gas Purchases ($)	Tranportation Charges ($)	Total Gas Costs ($)
Nov	2013	648,352	13,676,026	82,977	14,407,355	6,676,891	21,084,246
Dec	2013	146,751	36,941,879		37,088,630	8,313,508	45,402,138
Jan	2014	435,644	33,146,961	84,870	33,667,475	8,640,688	42,308,163
Feb	2014	41,031	26,340,233		26,381,264	7,578,889	33,960,153
Mar	2014	245,817	19,150,456		19,396,273	7,148,827	26,545,100
Apr	2014	11,551,990	2,986,026		14,538,016	2,482,835	17,020,851
May	2014	10,444,241	2,798,624		13,242,865	2,237,084	15,479,949
Jun	2014	6,818,158	2,205,236		9,023,394	2,460,018	11,483,412
Jul	2014	6,606,352	2,601,223	(153,436)	9,054,139	2,463,710	11,517,849
Aug	2014	5,301,019	2,550,521		7,851,540	2,462,502	10,314,042
Sep	2014	6,483,791	2,327,300		8,811,091	2,449,246	11,260,337
Oct	2014	7,657,364	2,588,550	(35,030)	10,210,884	2,731,965	12,942,849
Nov-Oct	**2013-2014**	**56,380,510**	**147,313,035**	**(20,619)**	**203,672,926**	**55,646,163**	**259,319,089**
Nov	2014	561,541	18,408,267		18,969,808	6,971,132	25,940,940
Dec	2014	301,105	27,660,807		27,961,912	8,765,274	36,727,186
Jan	2015	451,015	29,278,407	(14,181)	29,715,241	9,878,828	39,594,069
Feb	2015	224,025	18,050,231		18,274,256	8,805,155	27,079,411
Mar	2015	68,798	13,008,933		13,077,731	8,338,182	21,415,913
Apr	2015	6,005,268	2,771,121		8,776,389	3,808,249	12,584,638
May	2015	4,822,854	2,467,461		7,290,315	3,399,729	10,690,044
Jun	2015	3,393,757	2,122,896		5,516,653	3,452,807	8,969,460
Jul	2015	3,286,271	2,750,370		6,036,641	3,458,723	9,495,364
Aug	2015				-		-
Sep	2015				-		-
Oct	2015				-		-
Nov-Jul	**2014-2015**	**19,114,634**	**116,518,493**	**(14,181)**	**135,618,946**	**56,878,079**	**192,497,025**
Total		**246,145,459**	**797,135,039**	**(2,441,483)**	**1,040,839,015**	**297,635,221**	**1,338,474,236**

Source: Southwest Gas Annual Gas Procurement Plans.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS	DOCKET NO. G-01551A-16-0107

DIRECT

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 30, 2016

TABLE OF CONTENTS

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

Staff's testimony concerns the following Southwest Gas Corporation ("Southwest" or "Company") proposals: (i) to expand its Customer Owned Yard Line ("COYL") program to include customers who are not experiencing leaks or living in the vicinity of a planned replacement; (ii) to increase flexibility by inspecting each COYL once every three years instead of inspecting a third of known COYLs once a year; (iii) to "rebrand" or expand the COYL adjustor mechanism, thereby modifying it to become a "Gas Infrastructure Modernization" ("G.I.M.") mechanism; (iv) to use the G.I.M. mechanism to recover the costs of accelerated replacement of vintage steel pipe ("VSP") in its Arizona territory; and (v) to change the way in which L.N.G. facility costs are recovered.

Staff's testimony also addresses proposed changes to Southwest's Rules, with the exception of those relating to line extensions and Southwest's request to move to a four month winter and eight month summer.

Staff's recommendations are the following:

1. Staff recommends that Southwest be allowed to expand its COYL program to include customers who are not experiencing leaks or living in the vicinity of a planned replacement.

2. Staff recommends that Southwest be allowed to inspect each COYL once every three years instead of inspecting a third of known COYLs once a year.

3. Staff recommends that the COYL adjustor mechanism not be rebranded as the G.I.M. adjustor and that it not be modified to recover the costs of accelerated replacement of Vintage Steel Pipe in addition to recovering the cost of the COYL program.

4. Staff recommends denial of Southwest's proposed VSP program at this time.

5. Staff recommends that the Company, at its discretion, file to request Commission approval to initiate an accelerated VSP replacement program and address cost recovery in a future filing or through a separate docket. In a future filing Southwest should include a detailed explanation of any pipeline replacement projects it wishes to fund, including information on why replacement is required, how projects are prioritized, and what the projected costs and timelines will be. A proposal for recovering the costs arising from extraordinary pipe replacements should be included and the Company should include a detailed Plan of Administration.

6. Staff recommends that Southwest's L.N.G. costs be recovered in the manner specified in Decision No. 74875 (December 23, 2014), with the exception that the authorization to defer costs be extended from November 1, 2017 to December 31, 2020.

7. Staff recommends that Southwest discontinue the Field Collection Fee, as proposed.

8. Staff recommends that the language of the Rules be revised, if necessary, to reflect the testimony of Staff Witness Howard Lubow regarding Line Extensions and Southwest's proposal to move to an eight month summer and four month winter.

9. Staff recommends that the proposed changes to Rules 7 and 11 which potentially limit the Company's legal costs and liability be allowed.

10. Staff recommends with respect to Rule 7, Section H, that the current language regarding the requirement for notification should be deleted and replaced with language describing what type of incidents require notification and referring the reader to the Arizona Administrative Code R14-5-203.

11. Staff recommends that, in future rate cases, Southwest provide a redline of its Rules showing the changes it is proposing.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Julie McNeely-Kirwan. I am a Utilities Analyst V employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. My duties include reviewing and analyzing applications filed with the Commission, and drafting staff reports and proposed orders for Open Meeting. In addition, my duties include performing rate case sufficiency reviews, preparing written testimony in rate cases, and testifying during related hearings. I have also assisted in the management of rate cases.

Q. Please describe your educational background and professional experience.

A. I have a Master's Degree in Political Science from the University of Wisconsin, Madison. Prior to that, I graduated Magna Cum Laude from Arizona State University, with a Bachelor of Arts degree. I have been employed by the Commission as a Utilities Analyst since September of 2006. During that time, I have attended the Annual Regulatory Studies Program, given by the Institute of Public Utilities at Michigan State University, and a number of regulatory courses taught by the New Mexico Center for Public Utilities. In addition, I attend seminars and classes on regulatory issues on an ongoing basis as part of my work for the Commission.

SCOPE OF TESTIMONY

Q. What is the scope of your testimony in this case?

A. I will address Southwest Gas Corporation's ("Southwest" or "Company") proposed changes to its Customer Owned Yard Line ("COYL") program and Southwest's proposed "rebranding" or expansion of the COYL adjustor mechanism, which would be known as the "Gas Infrastructure Modernization" ("G.I.M.") mechanism. My testimony will also cover Southwest's proposal to replace vintage steel pipe ("VSP") in its Arizona territory on an accelerated basis. (The costs of the VSP accelerated replacement program, along with the costs of the COYL program, would be recovered by the G.I.M. mechanism.) In addition, my testimony covers Southwest's proposals to alter the way in which it would recover the costs for its L.N.G. facility. Lastly, my testimony addresses changes to Southwest's Rules.

Q. Have you reviewed testimony submitted by the Company in this case?

A. Yes. I reviewed the testimony of Christy M. Berger, particularly as it pertains to proposed changes to Southwest's Rules. My review has also included the testimonies of Edward Gieseking, Theodore K. Wood, and Kevin M. Lang, primarily as they pertain to the COYL program and the G.I.M.

Proposed Expansion and Revision of the COYL Program

Q. Please describe the changes to the COYL program proposed by Southwest.

A. Southwest proposes to expand the COYL program to allow replacement regardless of whether or not a customer's COYL is leaking. With the requested change, customers will not need to have leaks or live in the vicinity of a planned replacement in order to participate in the COYL program. The Company estimates that this proposed expansion would allow Southwest to eliminate all COYLs in a more timely fashion.

Southwest also proposes to change its leak survey frequency. Instead of a third of known COYLs being inspected once a year, as required by Decision No. 72723, Southwest proposes that each known COYL be inspected once every three years. This latter change would allow Southwest greater flexibility in managing its leak surveys.

Q. Please describe the current status of the COYL program.

A. Approximately 86,205 COYLs remained as of the end of 2015. Southwest is projected to complete 3,000 COYLs in 2016, 4,500 in 2017, and 6,000 in 2018 and going forward. The higher numbers projected for 2017 and beyond are based on the assumption that the Commission will approve the changes requested by Southwest in this rate case.

Q. What is the approximate total budget of the COYL program?

A. The current total budget of the COYL program is approximately $256 million over the life of the program.

Q. Will there be a limit on how much Southwest will be able to spend on the COYL program?

A. Yes. The amount Southwest can recover through the COYL surcharge is limited to an increase of $0.01 per therm per year.

Q. What does Staff recommend with respect to the changes to the COYL program proposed by Southwest?

A. The changes proposed by Southwest will enhance the COYL program's ability to reach customers and improve program efficiency. Staff recommends that the Commission approve the changes to the COYL requested by Southwest.

Gas Infrastructure Modernization Mechanism

Q. What is the G.I.M. Mechanism proposed by Southwest?

A. The G.I.M. mechanism is what Southwest refers to as a "rebranding" of the COYL adjustor mechanism. As proposed by Southwest, the existing COYL adjustor mechanism would be used to recover the costs associated with both the COYL and the VSP replacement programs. These costs are characterized by Southwest as "investments in the modernization of the natural gas delivery system infrastructure," and would include the capital costs (pre-tax return on investment and depreciation expense, net of associated retirements).

Q. Please describe the proposed VSP program.

A. The VSP program would involve accelerated replacement of vintage steel pipe installed in Arizona prior to January 1, 1970. Vintage steel pipe is already replaced by Southwest as part of normal operations when there is a safety or other issue with a given segment of pipe. The VSP program would be in addition to business-as-usual pipe replacement activities. Southwest indicates that the accelerated replacement of VSP would represent a proactive avoidance of future pipeline problems and higher future costs, particularly steel costs, and would result in Southwest having improved documentation for its system. Southwest also asserts that approval of the G.I.M. would increase the likelihood of Southwest improving its credit ratings and assist in avoiding future rate shock.

Q. What is the projected cost of the VSP replacement program?

A. Southwest has estimated the total cost of the VSP replacement program at $3.7 billion. This amount does not include interest. Given interest, the long timeframe for the project (30-40 years), the volatility of steel prices, and other variables, the final cost of the project is unknown and is likely to be higher than $3.7 billion. The estimated $3.7 billion cost of the VSP replacement is more than Southwest's most recent market capitalization. The approximate annual cost of the VSP project, as proposed by Southwest, would range from $100 to $140 million per year.

Q. What would be the bill impact on an average residential customer of the proposed G.I.M. surcharge?

A. Based on average monthly usage of 26 therms and the $0.03 per therm surcharge level allowed under Southwest's G.I.M. surcharge, an average residential bill would increase approximately $0.78 a month or approximately a 1.9 percent, in comparison to the $41.33 average residential bill under current rates cited by Southwest in Schedule H. If the G.I.M. surcharge increases by the allowed $.03 per therm each year for five years, residential customers would be paying an additional $3.90 monthly or $46.80 annually under the G.I.M. surcharge or a total 9.4 percent increase over current rates. Significant additional increases would result over the projected 30-40 year lifetime of the program.

Q. Please briefly discuss the physical size of the proposed VSP project.

A. There are approximately 6,000 miles of VSP in Southwest's Arizona territory. There are 193 miles of transmission pipeline and 5,741 miles of distribution pipeline.

Q. Is VSP replacement necessary for safety and the public welfare?

A. No. Southwest indicates that it is not proposing to accelerate replacement of VSP because there is an existing safety issue. Southwest states: "[P]re-1970's vintage steel distribution or transmission pipe in Southwest Gas' system do not present an immediate safety concern and the Company maintains vigorous programs to ensure the distribution system is operated in a safe and reliable manner." Southwest also testifies that "[u]nsafe pipe, regardless of age or pipe type, is replaced immediately in accordance with the Company's Operations Manual."

Also, as Staff Witness Alan Bourne confirms in his testimony, Southwest's Distribution Integrity Management Plan ("DIMP") does not mandate accelerated replacement of any pre-1970's pipeline.

Q. If Southwest's G.I.M. mechanism were approved, would there be a cap on the G.I.M. surcharge?

A. Yes. The annual adjustment to the G.I.M. Surcharge would be limited to $0.03 per therm. If the adjustment would result in an increase in excess of $0.03 per therm, then the excess is deferred for recovery to a subsequent G.I.M. Surcharge. (Deferred amounts will be the first amounts recovered in the following year.) Interest would be applied to the deferred balance equal to the one-year nominal Treasury constant maturities rate.

Q. Is the cap on the G.I.M. surcharge cumulative?

A. Yes. As proposed by Southwest, the G.I.M. surcharge can increase by $0.03 each year. For example, if the surcharge were approved and increased by the maximum each year, after five years the G.I.M. surcharge rate would be $0.15 per therm.

Q. What are the concerns related to the proposed VSP replacement program?

A. Two related concerns are the very high cost and size of the proposed VSP accelerated replacement program and the cumulative nature of the proposed cap. The potential three cent per therm per year increase could result in large per-therm increases and significant bill impacts over time.

Other related concerns are whether the accelerated replacement program as proposed by Southwest is necessary at this time and whether it would result in significant replacement of VSP that is still used and useful.

Q. Has Southwest demonstrated the need for an accelerated VSP replacement program?

A. No. Staff does not believe Southwest has demonstrated the need for an accelerated VSP replacement program at this time.

Q. What are Staff's recommendations?

A. Staff recommends that the COYL adjustor mechanism not be rebranded as the G.I.M. adjustor and that it not be modified to recover the costs of accelerated replacement of Vintage Steel Pipe in addition to recovering the cost of the COYL program.

The safety of Southwest's pipeline system is of primary and critical concern. However, Southwest in its direct testimony stated that the distribution system is already being run in a safe and reliable manner. Based on the Company's information, it is not reasonable to conclude that $3.7 billion or more in additional spending is necessary for purposes of improving the safety of a system where integrity management already meets or exceeds current federal and state pipeline safety requirements. There is also insufficient information to demonstrate that the future costs avoided through the VSP accelerated replacement program, or the potential improvements to its credit rating should G.I.M. be approved, would equal or outweigh the extremely high cost of the VSP program itself and the loss of useful remaining life of existing steel pipe. Staff recommends denial of Southwest's proposed VSP program at this time.

Q. Does Staff's recommendation to deny Southwest's proposed VSP program in this proceeding mean Staff would always oppose such a program?

A. No. Staff believes the Company's management needs to decide on the level of investment necessary to provide safe and reliable services. In addition, Staff Witness Alan Bourne has testified that "[i]f safety concerns related to vintage steel pipeline throughout the state increase in the future, an accelerated replacement program may be warranted." If Southwest were to seek approval of such a program in the future, Staff would evaluate such a proposal on its merits. Staff could support a program in the future if there is a clear demonstrated need and the program details are properly designed.

Q. If such an accelerated replacement program becomes warranted in the future, how should the Company seek approval of such a program and recovery of the related costs?

A. In such an event, Staff recommends that the Company, at its discretion, file to request Commission approval to initiate an accelerated VSP replacement program and address cost recovery in a future filing or through a separate docket.

In a future filing, Southwest should include a detailed explanation of any pipeline replacement projects it wishes to fund, including information on why replacement is required, how projects are prioritized, and what the projected costs and timelines will be. A proposal for recovering the costs arising from extraordinary pipe replacements should be included and the Company should include a detailed Plan of Administration.

Q. What could make accelerated replacement necessary, as opposed to replacement made necessary for safety reasons?

A. Changes in policy by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") could also result in the need to replace VSP on an accelerated basis. It is Staff's understanding that PHMSA has not currently made any changes requiring such accelerated replacement.

Q. If the Commission does not approve the Company's proposals regarding accelerated replacement of VSP, would this mean that VSP cannot be replaced in the normal course of business, for example, for safety reasons?

A. No. As is currently the case, any pipeline requiring replacement in the normal course of business can be continue to be replaced as part of Southwest's ongoing integrity management practices.

Recovery of L.N.G. Costs

Q. Has Southwest made any other proposals with respect to the G.I.M. mechanism?

A. Yes. Southwest has proposed that the costs of the L.N.G. facility be recovered through the G.I.M. mechanism. The Company indicates that adding these costs to the G.I.M. would ensure timely recovery and would not take place until the L.N.G. facility was placed into service. Southwest has also asked that, if the Property Tax True-Up mechanism is approved, the revenue requirement associated the L.N.G. facility investment be modified to include depreciation expense, operations and maintenance expense, and carrying costs.

Q. What are Staff's recommendations regarding Southwest's proposals to alter the manner in which the Company recovers its costs related to the L.N.G. project?

A. The L.N.G. facility was pre-approved in Decision No. 74875 (December 23, 2014), without liquefaction. The project is in its early stages. Staff does not believe that Southwest has demonstrated a need to change the way in which the Company would recover the costs related to the L.N.G. project. This is particularly the case in light of language in Decision No. 74785 which indicates a need for L.N.G. costs to be considered in the context of a future rate case.

Staff recommends that Southwest's L.N.G. costs be recovered in the manner specified in Decision No. 74875 (December 23, 2014), with the exception that the authorization to defer costs be extended from November 1, 2017 to December 31, 2020.

RULES

Q. Did Southwest propose any changes to its Rules Section of its Tariff?

A. Yes. Southwest has proposed various changes to its Rules. My testimony will cover the discontinuance of the Field Collector's Fee and a number of changes relating to Southwest's liability.

Q. Are you testifying about all the proposed substantive changes to the Rules?

A. No. Staff Witness Howard Lubow will testify with respect to Service and Main Extensions, as addressed in Rule 6. Staff recommends that all language in the Rules regarding Service and Main Extensions should be changed to reflect Mr. Lubow's testimony, if necessary.

In addition, Staff Witness Howard Lubow will testify regarding Staff's position on Southwest's proposal to redefine winter as a four-month period from December through March, as shown in Rule 1. Staff recommends that all language in the Rules regarding the length of summer and winter should be made to reflect Mr. Lubow's testimony, if necessary.

Q. What is the Field Collector's Fee and why has Southwest proposed to discontinue it?

A. Currently, Southwest's Rules allow their employees to accept payments by check in the field. However, Southwest has now has a variety of payment methods available to customers, including the ability to pay with a check over the phone and without a service fee. Customers using this method of payment can also pay their bills after business hours and on weekends. Given that customers can now pay with a check over the phone and at their convenience, Southwest has proposed to remove the language that allows customers to pay by check in the field.

Q. What is Staff's recommendation regarding discontinuance of the Field Collection Fee?

A. Staff recommends that Southwest be allowed to discontinue the Field Collection Fee. With a more convenient method now available, the Field Collection Fee is redundant and unnecessary. Discontinuing the Field Collection Fee also allows Southwest to eliminate an unneeded administrative cost.

Q. Are there any other changes Staff wishes to discuss?

A. Please see below:

- In Rule No. 7, Section B Southwest is proposing changes to clarify which test the utility should perform to determine whether customers have a leak tight system for receiving gas. The proposed changes also codify long-established practices. This change may also reduce the utility's litigation costs, because it narrows the Company's duties and liabilities.

- There are other changes to Rule 7 which are designed to reduce Southwest's risk of liability for litigation costs and damages.

- Proposed changes to Rule 11 clarify and/or establish that disputes arising out of the Tariff shall be adjudicated by the Commission, reducing potential legal costs for the Company and customers.

Q. What is Staff's recommendation regarding this changes?

A. The changes proposed by Southwest potentially limit the Company's liability and litigation costs, thereby potentially lowering costs to ratepayers. Staff believes these revisions to the Rules are reasonable and that they be allowed.

Q. Is Staff concerned by any of the changes proposed by Southwest?

A. Yes. In Rule 7, there are deletions in Section H which remove language discussing the requirement for notification to the Commission following certain pipeline incidents. Southwest considers the language proposed for removal redundant, because this requirement is addressed more comprehensively in Arizona Administrative Code ("A.A.C.") R14-5-203. Staff believes there is value in having information regarding notification requirements available in the Rules. To address Staff's concern, the current language regarding the requirement for notification should be deleted and replaced with language describing what type of incidents require notification and referring the reader to A.A.C. R14-5-203.

Q. Do you have any other recommendations?

A. Yes. In the future, when filing a rate case, Southwest should provide a redline of its Rules showing the changes it is proposing. A redline provides a clear and exact indication of the changes being proposed and will more easily allow Staff to evaluate whether or not changes are substantive.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are the following:

- Staff recommends that Southwest be allowed to expand its COYL program to include customers who are not experiencing leaks or living in the vicinity of a planned replacement.

- Staff recommends that Southwest be allowed to inspect each COYL once every three years instead of inspecting a third of known COYLs once a year.

- Staff recommends that the COYL adjustor mechanism not be rebranded as the G.I.M. adjustor and that it not be modified to recover the costs of accelerated replacement of VSP in addition to recovering the cost of the COYL program.

- Staff recommends denial of Southwest's proposed VSP program at this time

- Staff recommends that the Company, at its discretion, file to request Commission approval to initiate an accelerated VSP replacement program and address cost recovery in a future filing or through a separate docket. In a future filing, Southwest should include a detailed explanation of any pipeline replacement projects it wishes to fund, including information on why replacement is required, how projects are prioritized, and what the projected costs and timelines will be. A proposal for recovering the costs arising from extraordinary pipe replacements should be included and the Company should include a detailed Plan of Administration.

- Staff recommends that Southwest's L.N.G. costs be recovered in the manner specified in Decision No. 74875 (December 23, 2014), with the exception that the authorization to defer costs be extended from November 1, 2017 to December 31, 2020.

- Staff recommends that Southwest discontinue the Field Collection Fee, as proposed.

- Staff recommends that the language of the Rules be revised, if necessary, to reflect the testimony of Staff Witness Howard Lubow regarding Line Extensions and Southwest's proposal to move to an eight month summer and four month winter.

- Staff recommends that the proposed changes to Rules 7 and 11 which potentially limit the Company's legal costs and liability be allowed.

- Staff recommends with respect to Rule 7, Section H, that the current language regarding the requirement for notification should be deleted and replaced with language describing what type of incidents require notification and referring the reader to A.A.C. R14-5-203.

- Staff recommends that, in future rate cases, Southwest provide a redline of its Rules showing the changes it is proposing.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS	DOCKET NO. G-01551A-16-0107

DIRECT

TESTIMONY

OF

ALAN BORNE

LEAD PIPELINE SAFETY INSPECTOR

ARIZONA CORPORATION COMMISSION

NOVEMBER 30, 2016

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

The Direct Testimony of Staff witness Alan Borne addresses the following issues from the perspective of the Arizona Corporation Commission Office of Pipeline Safety:

1. Southwest Gas Corporation ("Southwest Gas") request to extend customer owned yard line ("COYL") replacement program to include all COYLs throughout the state.

2. Southwest Gas request to begin accelerated replacement of all pre 1970s vintage steel pipeline ("VSP") throughout the state.

3. Southwest Gas use and usefulness issues.

Staff makes the following recommendations:

1. Extension of the COYL program be allowed to include all COYLs throughout the state.

2. Disapproval of the proposed accelerated replacement of pre 1970s VSP throughout the state.

3. That Southwest Gas continue with the replacement of VSP per its existing replacement plans and programs.

Staff concludes that all projects and equipment reviewed to date are used and useful.

Q. Please state your name and business address?

A. My name is Alan Borne. My business address is 1300 West Washington Avenue, Phoenix, Arizona.

Q. What is your current position and how long have you been employed by the Arizona Corporation Commission?

A. I am a Lead Pipeline Safety Inspector. I have been employed by the Arizona Corporation Commission ("Commission") for over 13 years.

Q. Please describe briefly your duties as a Lead Pipeline Safety Inspector.

A. Briefly, my duties include conducting annual pipeline safety inspections, conducting investigations into the causes of pipeline failures, conducting pipeline construction inspections, conducting inspections and/or investigations with respect to the Underground Facilities Law (Blue Stake), completing required reports associated with each inspection or investigation, managing the master meter inspection program and providing testimony on behalf of the Commission.

Q. Please describe your education, training and pertinent work experience.

A. I have over 13 years' experience as a Pipeline Safety Inspector with the Commission. During my time with the Commission I have attended and successfully completed all required training classes required by the Commission and Department of Transportation to execute my duties. Prior to my time with the Commission I have 20 years' experience in the field of gas processing and oil refining plant operations and maintenance and held the title of Environmental, Health and Safety Regional Advisor. I have an A. S. in Electrical Engineering Technology.

Q. What is the purpose of your testimony in these proceedings?

A. The purpose of my testimony is to address the following issues from the perspective of the Commission's Office of Pipeline Safety ("Staff"):

1. Discuss any outstanding probable non-compliance items with Southwest Gas Corporation ("SWG" or "Southwest Gas").

2. Help to determine use and usefulness of Southwest Gas's projects and equipment.

3. Provide a technical perspective on Southwest Gas's proposal of extending the Customer Owned Yard Line ("COYL") program.

4. Present a technical perspective on Southwest Gas's proposed accelerated replacement of pre-1970 vintage steel pipe ("VSP").

Q. Are there any outstanding non-compliance items on file with the Arizona Corporation Commission Office of Pipeline Safety?

A. No.

Q. Has your office examined SWG's gas distribution system and equipment with regard to used and useful?

A. Yes, during the 2016 Standard Annual Audit conducted by our office, inspectors visited the SWG's offices in Tucson, Bullhead City, Yuma, Phoenix, Sierra Vista, Casa Grande, and Globe and visited numerous field locations and projects.

Q. Did your office find any of the SWG's gas system or equipment not to be used and useful?

A. No, I consulted with the inspectors and all projects and equipment were found to be used and useful.

Q. What is your Office's determination from a technical standpoint in regard to extending SWG's COYL program to include all COYLs within the state?

A. It is our understanding that this program, from its inception, was going to be extended from replacement of leaking COYLs only to include all COYLs within the state at some point. Our office believes that the extension of this program is well justified in that it transfers ownership of a COYL from the customer to SWG thereby also transferring all responsibility for maintenance of the COYL to SWG as well and that in the interest of public safety will be the best course of action.

Q. What is your Office's determination from a technical standpoint in regard to an accelerated replacement of pre 1970s VSP throughout the state?

A. Pre 1970's VSP is addressed in the SWG Distribution Integrity Management Program ("DIMP"). Threat evaluation and assessment, and risk mitigation processes integral to the SWG distribution pipeline integrity process determine when replacement is mandated or other risk control practices should be implemented. The SWG DIMP presently does not mandate an accelerated replacement of any pre 1970s vintage pipeline. If safety concerns related to VSP throughout the state increase in the future, an accelerated replacement program may be warranted.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
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ANDY TOBIN
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IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORTATION DEVOTED TO ITS ARIZONA OPERATIONS	DOCKET NO. G-01551A-16-0107

DIRECT

TESTIMONY

OF

RANELLE PALADINO

EXECUTIVE CONSULTANT

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 30, 2016

TABLE OF CONTENTS

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

Ranelle Paladino's testimony presents the results of the Utilities Division Staff's ("Staff") review of the proposed Property Tax True-Up mechanism. This testimony also addresses the elimination of the Gas Research Fund ("GRF") Surcharge and the need for a comprehensive Plan of Administration ("POA") for all of Southwest Gas Corporation's ("Southwest Gas" or "Company") current adjustor mechanisms.

Staff recommends that Southwest Gas be allowed to defer the difference between the actual property tax expense incurred compared to the level of property tax expense included in the test year data for the rate case. The deferral is not a recommendation for the creation of a Property Tax True-Up Mechanism, but an opportunity for the Company to defer the costs until the next Southwest Gas rate case filing.

Staff also recommends that Southwest Gas eliminate the GRF surcharge and recover $820,000 for GRF through base rates.

Staff recommends that Southwest Gas be ordered to work with Staff to implement POA documents for all of its existing adjustor mechanisms.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Ranelle Paladino. I am an Executive Consultant employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant.

A. In my capacity as an Executive Consultant, I review and analyze utility applications filed with the Commission, and prepare memoranda and proposed orders for Open Meetings. I also assist in the management of rate cases and track monthly fuel adjustor reports.

Q. Please describe your educational background and professional experience.

A. In 1992, I graduated magna cum laude from Creighton University, receiving a Bachelor of Science degree in Business Administration. In 1999, I received a Master's Degree in Business Administration from Creighton University. I have been employed by the Commission since November of 2011.

Prior to working at the Commission, I was employed by UtiliCorp United, Inc. and Aquila Energy in various departments including the Gas Supply Operations Department and the Gas Accounting Department in both a regulated and non-regulated capacity. After leaving Aquila Energy, I was employed by Northern Natural Gas, an interstate pipeline company, as a Regulatory Analyst and Marketing Analyst.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. G-01551A-16-0107?

A. Yes.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to discuss Staff's review of Southwest Gas Corporation's ("Southwest Gas" or "Company") request for a Property Tax True-Up Mechanism and the status of Plan of Administration ("POA") documents for all of its existing adjustors.

Q. Have you reviewed testimony submitted by the Company in this case?

A. Yes. I reviewed the testimony of Byron C. Williams and Edward Gieseking, particularly as it pertains to the scope of my testimony.

PROPERTY TAX TRUE-UP MECHANISM

Q. What is the Company requesting regarding property tax deferral?

A. Southwest Gas is requesting authority to track 100 percent of the Arizona property taxes above or below the test year level and implement a property tax true-up mechanism. According to the testimony of Mr. Williams, this mechanism would track the dollar level of change in the Arizona property tax expense above or below the level established in the current rate case.[1] Mr. Gieseking further explains the Company would track the dollar level change in a balancing account. The Company would plan to file annually with the Commission for approval to put in place a surcharge or credit adjustor which reflects the recovery or refund associated with the balancing account.[2]

Q. Why is the Company asking for a property tax deferral and the implementation of a Property Tax True-Up Mechanism?

A. Property taxes are a function of property values. As property values decrease, taxing authorities must raise tax rates to maintain revenues. Southwest Gas indicated in its application that as a result of declines in net assessed property values, property tax rates have

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[1] Williams Direct page 2 lines 8-10.
[2] Gieseking Direct page 5 lines 14-18.

increased in Maricopa, Pima, and Pinal counties. Over 90 percent of the Company's Arizona plant is located in these three counties as of November 30, 2015.[3] For most taxpayers, lower values and higher tax rates may not necessarily change the taxpayer's tax payment. However, for Southwest Gas, the assessed value is based primarily on the net book value of its fixed assets, a value which is typically rising. As a result, when a taxing authority raises tax rates, Southwest Gas' property tax liability also increases.

In addition, Southwest Gas specified that an increase in capital expenditures, mostly for the replacement of natural gas infrastructure, have resulted in an increase in property tax liability from the last Arizona rate case (Decision No. 72723, dated January 6, 2012).[4] Overall, the Company believes that the volatility in the actual property tax liability and that the amount recovered in the last rate case will continue.[5]

Q. Has the Commission granted other property tax deferrals?

A. Yes. The Commission approved the rate case settlement agreement that provided a property tax deferral for Arizona Public Service Company ("APS") in Decision No. 73183, dated May 24, 2012. The Commission also recently approved a property tax deferral for future recovery in the UNS Electric, Inc. ("UNSE") rate case Decision No. 75697, dated August 18, 2016.

Q. How is Southwest Gas' property tax deferral different from that which the Commission approved for APS and UNSE?

A. For its property tax deferral, Southwest Gas proposes recovery of 100 percent of any property tax increase or decrease, which is similar to the deferral for UNSE. The APS Decision included provisions for deferral if property tax rates increased over varying

[3] Williams Direct page 2 lines 17-19.
[4] Williams Direct page 4 lines 23-25.
[5] Williams Direct page 5 lines 16-19.

percentage levels (an increase of 25% the first year, 40% the second year, and 75% all subsequent years or decreased any percentage). Recovery in the APS settlement was spread over ten years for a positive balance and refunds spread over three years for a negative balance. In addition, the Company is also requesting authority to implement a Property Tax True-Up Mechanism. As explained above, this adjustor would utilize a balancing account and the Company would file annually with the Commission a request for approval to put in place a surcharge or credit based on the balance in the account.

Q. How is Southwest Gas recommending that the property tax deferral be calculated?

A. The Company has proposed the following calculation be performed for each tax year (this is a hypothetical example)[6].

A	Current Year Taxable Property	$1,700,000,000	(A)
B	Current Year Statutory Assessment Ratio	18.0%	(B)
C	Assessed Value	$306,000,000	(C = A x B)
D	Current Year Composite Property Tax Rate	14.0%	(D)
E	Current Year Property Tax Liability	$42,840,000	(E = C x D)
F	Capitalized Property Tax	$1,831,351	(F)
G	Current Year Property Tax Expense	$41,008,649	(G = E – F)
H	Test Year Annualized Property Tax Expense	$41,584,263	(H)
I	Property Tax Deferral	($575,614)	(I = G – H)

Q. What is Staff's recommendation regarding the proposed property tax deferral and the implementation of a property tax true-up mechanism?

A. Staff recommends accepting Southwest Gas' proposed property tax deferral and the methodology for calculating that deferral amount. However, Staff is hesitant to introduce another adjustor mechanism to customers' bills without first knowing the magnitude of such an adjustor.

[6] Gieseking Direct page 6 lines 1-9.

While Staff recognizes that volatility in property taxes are beyond the control of the Company and that a deferral balances the interests of consumers and shareholders, Staff believes it is more appropriate to defer the variances and include those variances in the next rate case rather than implement another adjustor mechanism.

EXISTING ADJUSTOR MECHANISMS

Q. What adjustor mechanisms does Southwest Gas currently have in place?

A. Southwest Gas has the following adjustors currently in place:

- Low Income Ratepayer Assistance ("LIRA Adjustor")
- Demand Side Management ("DSM Adjustor")
- Department of Transportation ("DOT Adjustor")
- Customer Owned Yard Line Cost Recovery Mechanism ("COYL CCRM")
- Gas Research Fund ("GRF")
- Energy Efficiency Enabling Provision ("EEEP")
- Purchased Gas Adjustor ("PGA") (including the Balancing Account)

Q. What is the purpose of an adjustor mechanism?

A. The purpose of an adjustor mechanism is to recover certain types of costs between rate cases. The LIRA Adjustor recovers the low income discounts provided during the prior winter heating season. The DSM Adjustor recovers Southwest Gas' costs associated with Southwest Gas's Demand-Side Management portfolio. The DOT adjustor recovers Southwest Gas' costs associated with the Transmission Integrity Management Program mandated by the Federal Pipeline Safety Improvement Act of 2002. The COYL CCRM recovers the costs with the replacement of customer-owned yard lines. The GRF adjustor recovers Southwest Gas' costs associated with research and development. The EEEP rate recovers the true-up associated with Southwest Gas' revenue decoupling mechanism. The PGA rate recovers the costs associated with purchased gas.

Q. Is Southwest Gas proposing any changes to its adjustor mechanisms?

A. Yes. Southwest Gas is proposing to eliminate the GRF surcharge and recover the funding through base rates. The total funding for GRF proposed to be included in base rates is \$820,000 per year. The current surcharge funding level for the GRF is \$688,712.

Southwest Gas is also proposing a new adjustor mechanism to replace the COYL CCRM. The new adjustor mechanism is being referred to as the Gas Infrastructure Modernization Mechanism ("GIM") and is explained further by Mr. Gieseking.[7]

Q. Does Staff agree with the changes Southwest Gas has proposed for its adjustor mechanisms?

A. Staff agrees with the inclusion of the GRF funding into base rates and the slight increase in funding. Staff recognizes that the need for natural gas research funding has not declined over time, but in fact is more imperative now with an increase in dependence upon natural gas over the last few years. The Company indicated that it will continue to file its annual plan detailing the programs to be funded by the Company through the GRF so that Staff will be able to maintain oversight of this program.[8]

Staff's position with regard to the implementation of the GIM is discussed in more detail in the Direct Testimony of Staff Witness Julie McNeely-Kirwan.

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[7] Gieseking Direct pages 7-12.
[8] Cunningham Direct page 30 lines 6-8.

Q. Is Staff proposing any changes to the Southwest Gas' adjustor mechanisms?

A. Yes. In the direct Rate Design testimony of Howard Lubow, Staff will be proposing changes to the EEEP. Staff is also proposing that Southwest Gas file a Plan of Administration ("POA") for each of its adjustor mechanisms.

Q. Why is Staff proposing that Southwest Gas file a POA for each of its adjustor mechanisms?

A. With respect to adjustor mechanisms, the purpose of a POA is to create a record describing the intended functioning of the adjustor, including how the adjustor rate is reset. This provides for transparency and ease of implementation for both existing and future Commission Staff and Company employees. In particular, POAs for adjustor mechanisms should include a specific list of the types of costs permitted to be recovered through each adjustor ensuring no inappropriate costs are recovered through the adjustor.

Q. Does Southwest Gas currently have any POAs approved for its adjustors?

A. Southwest Gas does not currently have any approved POAs for its adjustors. The Company did include in its rate case application two draft POAs for review: a POA for the EEEP and a POA for the proposed Gas Infrastructure Modernization Mechanism ("GIM" adjustor).

Q. Should the Company create POAs for all of its existing adjustor mechanisms?

A. Yes. Staff recommends that Southwest Gas be ordered to work with Staff to compile draft POAs for all of its adjustors to be included in the Company's Rejoinder Testimony. Staff requests that Southwest Gas outline the scope, type of eligible costs to be recovered, and method of calculation in its draft POAs.

Q. Does this conclude your direct testimony?

A. Yes, it does.