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AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE - Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

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; APPROVAL OF DEFERRED ACCOUNTING ORDERS; AND FOR APPROVAL OF AN ENERGY EFFICIENCY AND RENEWABLE ENERGY RESOUCE TECHNOLOGY PORTFOLIO IMPLEMENTATION PLAN.	DOCKET NO. G-01551A-10-0458 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY (EXCEPT RATE DESIGN)**

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Staff Witnesses Ralph C. Smith, David C. Parcell, Robert G. Gray, Bryan Frye and Julie McNeely-Kirwan in the above-referenced matter.

A confidential version of Ralph C. Smith's Direct Testimony has also been provided under seal to the Commissioners, their Assistants, the assigned Administrative Law Judge, and the parties that have signed the Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 10th day of June, 2011.

Arizona Corporation Commission
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JUN 10 2011
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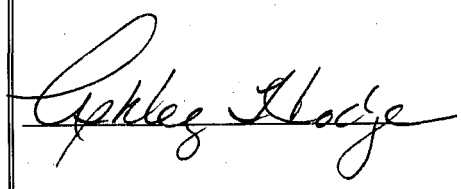

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
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 ITS PROPERTIES THROUGHOUT ARIZONA	)	DOCKET NO. G-01551A-10-0458

PUBLIC

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 10, 2011

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

My testimony addresses the following issues, and responds to the testimony of Southwest Gas Corporation ("Company," "Southwest," or "SWG") witnesses Mashas, Aldridge, Schmitz and Gaffin on these issues:

- The Company's proposed revenue requirement
- Adjustments to test year data
- Rate base
- Test year revenues, expenses, and net operating income
- The Company's request for special accounting and deferrals
- The need for an updated depreciation rate study from Southwest in its next Arizona rate case

My findings and recommendations for each of these areas are as follows:

- The Company's proposed revenue requirement of a base rate increase of $73.2 million is overstated. On original cost rate base ("OCRB") Staff's calculations show a jurisdictional revenue deficiency of $47.0 million. Staff recommends a base rate increase of not more than $54.9 million on adjusted fair value rate base ("FVRB"). This recommended increased amount is a percentage increase of 13.4 percent on adjusted base rate revenue at current rates of $410.9 million, and is based on Staff's second alternative for the revenue requirement on FVRB ("Alternative 2"). On adjusted FVRB under Staff's first alternative ("Alternative 1"), which uses a fair value rate of return ("FVROR") of 6.69 percent, Staff recommends a base rate increase of $47.0 million. Under Alternative 2, Staff's alternative method to calculate the FVROR, the FVROR for SWG is 7.02 percent as recommended by Staff witness David Parcell, and the jurisdictional revenue deficiency is approximately $54.9 million. The testimony of Staff witness Parcell addresses the determination of the FVROR. In its filing, Southwest did not calculate a revenue deficiency for OCRB and based its recommended revenue increase solely on FVRB. Southwest has requested an additional rate increase on FVRB of approximately $7.8 million. Staff's FVROR "Alternative 2" produces an additional rate increase on FVRB of approximately $7.9 million.

- The following adjustments to Southwest's proposed OCRB and Reconstructed Cost New Depreciated ("RCND") rate base should be made:

Summary of Staff Adjustments to Rate Base		OCRB	RCND RB
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
B-1	Corrections to Completed Construction Not Classified	$ (1,066,657)	$ (1,066,657)
B-2	Yuma Manors Pipe Replacement	$ (225,445)	$ (225,445)
B-3	Cash Working Capital	$ (468,000)	$ (468,000)
B-4	Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC	$ (1,286,985)	$ (1,286,985)
B-5	Remove Corporate Aircraft Costs	$ (352,892)	$ (352,892)
B-6	Remove One-Half of Prepaid D&O Insurance	$ (185,097)	$ (185,097)
	Total of Staff Adjustments	**$ (3,585,076)**	**$ (3,585,076)**
	SWGas Proposed Rate Base (Original Cost and RCND)	$ 1,073,700,633	$ 1,839,334,300
	Staff Proposed Rate Base (Original Cost and RCND)	**$ 1,070,115,558**	**$ 1,835,749,225**

- Staff is recommending the following adjustments to Southwest's proposed revenues, expenses and net operating income:

Summary of Staff Adjustments to Net Operating Income		Pre-Tax Adj. to Revenue or Expense	Net Operating Income
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
C-1	CCNC Correction Depreciation and Property Tax Expense	$ (102,079)	$ 61,728
C-2	Yuma Manors Pipe Replacement	$ (17,447)	$ 10,550
C-3	Management Incentive Program	$ (1,899,807)	$ 1,148,828
C-4	Restricted Stock/Unit Plan	$ (1,033,723)	$ 625,101
C-5	Supplemental Executive Retirement Expense	$ (1,725,839)	$ 1,043,629
C-6	American Gas Association Dues	$ (90,898)	$ 54,967
C-7	Loss on Sale of Employee Homes for Relocation Expense	$ (503,620)	$ 304,543
C-8	Test Year Rent Charged to Affiliate IntelliChoice Energy LLC	$ (13,156)	$ 7,956
C-9	Gas Heat Pump Development Expenses	$ (711,287)	$ 430,121
C-10	Interest Synchronization	$ -	$ (56,377)
C-11	Directors' and Officers' Liability Insurance	$ (386,402)	$ 233,660
C-12	Self-Insurance Retention Expense	$ (579,774)	$ 350,594
C-13	Leased Aircraft Operating Costs	$ (193,893)	$ 117,249
C-14	COYL Leak Detection Survey	$ 1,000,000	$ (604,708)
Total of Staff's Adjustments to Net Operating Income		$ (6,257,925)	$ 3,727,841
	Adjusted Net Operating Income per Southwest Gas		$ 65,065,829
	Adjusted Net Operating Income per Staff		**$ 68,793,670**

Southwest has requested to modify the write-off requirements related to the replacement of AHD pipe established in Decision No. 58693. Staff recommends that such requested modification be denied. Southwest projects it will have completed the AHD pipe replacements by mid-year 2013. Consequently, leaving the Settlement and Order that had been in place from Decision No. 58693 for one additional rate case cycle should alleviate the need to modify the previous write-off percentages for replacement of AHD pipe. Should the Commission allow the modification, Staff recommends that the modification should become effective as of the date of the Commission's Order in this case. Southwest should continue to comply with Decision No. 58693 from July 1, 2010 through the date of the Commission's final decision in this case.

Staff recommends that the Company's proposal to defer depreciation expense, carrying costs, and property taxes resulting from removing the remainder of AHD pipe from July 1, 2010 through mid-year 2013 be denied.

Staff recommends that the Company's request for accounting authority to defer $10 million of cost for replacing 5,000 customer owned yard lines ("COYL") with Southwest Gas owned facilities be denied at this time. Staff recommends that the Company perform a leak detection survey and, if necessary, request a deferral order upon completion.

The Company has not conducted a depreciation study for its Arizona utility plant in approximately 23 years. Staff recommends that the Company be ordered to file updated depreciation rate studies in its next general rate case. Any changes to System Allocable plant depreciation rates should not be instituted for book purposes until such depreciation rates have been authorized by the Arizona Corporation Commission. Southwest should also file an updated depreciation study for System Allocable plant in its next Arizona rate case.

I. INTRODUCTION

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("CPA") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed CPA and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and

Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 31 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorney generals, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington D.C.,

West Virginia, and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified before the Commission previously on a number of occasions. Recently, I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS"), and concerning APS's proposed depreciation rates in Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, a proceeding involving APS base rates and other matters. I also testified before the Commission in the a recent UNS Gas, Inc. rate case, Docket Nos. G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831, and in the a recent UNS Electric, Inc. rate case Docket No. E-04204A-06-0783. In addition, I testified before the Commission in Southwest Gas Corporation's ("Southwest" or "SWG" or "Company") last base rate case, Docket No. G-01551A-07-0504.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the rate base, adjusted net operating income and revenue requirement proposed by Southwest.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 through RCS-5 contain the results of my analysis and copies of selected documents that are referenced in my testimony.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

Q. What revenue increase has been requested by SWG?

A. SWG is requesting an increase in base rate revenues of $73.2 million, or approximately 17.8 percent, based on adjusted base rate revenues at current rates of $410.91 million. The revenue amount is from Company Schedule C-1 in Southwest's filing and is also shown on Staff Schedule C on Attachment RCS-2.

Q. What revenue increase does Staff recommend?

A. Staff recommends a revenue increase of not more than $54.9 million on adjusted fair value rate base using the alternative fair value rate of return ("FVROR") recommendation of Staff witness Parcell. As shown on Schedule A, on original cost rate base ("OCRB") my calculations show a jurisdictional revenue deficiency of $47.0 million. On adjusted fair value rate base ("FVRB") under Staff's proposed fair value rate of return of 7.02 percent, Staff recommends a base rate increase of $54.9 million. Attachment RCS-2, Schedule D, shows the development of Staff's recommended FVROR to be applied to FVRB. The testimony of Staff witness David Parcell addresses the determination of the FVROR.

A. Test Year

Q. What test year is being used in this case?

A. SWG's filing is based on the historic test year ended June 30, 2010. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are annualized based on end of test year levels. This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in a company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

B. Summary of Company Proposed and Staff Adjusted Revenue Requirement

Q. What did your review of SWG's filing indicate?

A. My review of SWG's filing indicated that the Company's request for a revenue increase is overstated. As shown on Attachment RCS-2, Schedule A, based on the FVROR recommended by Staff witness David Parcell and the adjustments to SWG's rate base and net operating income, Staff has calculated a jurisdictional base rate revenue requirement deficiency on FVRB of $54.9 million using the FVROR of 7.02 percent. SWG should be authorized a base rate increase of not more than $54.9 million in this case.

C. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-4 and net operating income adjustment Schedules C-1 through C-14.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary reflecting the recommended adjustments. This schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on Staff's proposed OCRB and FVRB. The rate base and operating income amounts are taken from Schedules B and C, respectively. The weighted average cost of capital ("WACC") for OCRB of 9.08 percent, as presented in the prefiled testimony of Staff witness Parcell, is provided on Schedule D for convenience, as are the

derivation of Staff's recommended FVROR alternatives. Column D of Schedule A presents Staff's determination of the base rate revenue deficiency on FVRB using Staff's recommended fair value rate of return. Schedule D presents the original cost and fair value rate of return recommended in the prefiled testimony of Mr. Parcell.

The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the income deficiency by the gross revenue conversion factor ("GRCF"). The derivation of the GRCF is shown on Schedule A-1.

Q. How does the GRCF recommended by Staff compare with the GRCF contained in SWG's filing?

A. As shown on Schedule A-1, Staff recommends a GRCF of 1.6579. This is the same as the GRCF of 1.6579 used in SWG's filing.

Q. What is shown on Schedule B?

A. Schedule B presents SWG's proposed adjusted test year OCRB and FVRB and Staff's proposed adjusted test year OCRB and FVRB. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically SWG Schedule B-1. Staff's recommended adjustments to rate base are summarized on Schedule B.1. Schedule B.1 presents the adjustments to Southwest's proposed OCRB base, and another Schedule B.1 for Reconstruction Cost New Depreciated ("RCND") rate base adjustments.

Schedules B-1 through B-6 provide further support and calculations for the rate base adjustments Staff is recommending.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is SWG's adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to SWG's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments is discussed in my testimony.

Schedules C-1 through C-14 provide further support and calculations for the net operating income adjustments Staff is recommending.

Q. What is shown on Schedule D?

A. Schedule D summarizes the capital structure and cost of capital that was proposed by SWG and the capital structure and cost of capital that is recommended by Staff witness Parcell. Schedule D also presents the derivation of Staff's recommended FVROR for use with the Staff's adjusted FVRB.

D. Return on Fair Value Rate Base

Q. How was the fair value basis of rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the FVRB was determined by averaging OCRB and RCND. For purposes of this presentation, the Company's RCND information was used as the starting point for Staff's derivation of the FVRB. Adjustments were made to the RCND rate base as shown on Attachment RCS-2, Schedule B.1 (RCND).

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

A. In SWG's filing, as shown on Schedule A-1, the Company applied its proposed FVROR to its adjusted FVRB. On that Schedule in the Fair Value column, Southwest calculates an increase in gross revenue requirements of $73.2 million.

Q. Describe the change in the Commission method of calculating operating income as it relates to the calculation of the FVROR.

A. Prior to a recent Arizona Court of Appeals decision,[1] the Commission had determined operating income by multiplying the WACC by the OCRB. The resulting product was then divided by the FVRB to determine a FVROR. The Arizona Court of Appeals found that the Commission did not comply with Article 15, Section 14 of the Arizona Constitution when it set rates based original cost instead of fair value. However, the Court noted: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." The Commission, in Decision No. 70441 adopted a FVROR based on the WACC modified to reflect a 2.00 percent reduction to the cost of equity, but not to the cost of debt. In Decision No. 71308, the Commission calculated the FVROR by subtracting an inflation factor from both the debt and equity components of the WACC.

Q. How has Staff calculated the FVROR and addressed the ruling in the Court of Appeals decision for purposes of the current SWG rate case?

A. Staff is presenting two alternatives for the FVROR as shown on Schedule D. The results of each of those alternatives for the FVROR are shown on Schedule A in columns D1 and D2. Schedule D of Attachment RCS-2 shows the derivation of the fair value rate of return

[1] *Chaparral City Water* Co *v Ariz Corp. Comm'n*, 1 CA-CC 05-0002 (Ariz. App. Feb. 13,2007)

for application to the FVRB. On Schedule A of Attachment RCS-2, Staff's adjustment to the weighted cost of capital as described by Mr. Parcell in his Direct Testimony was applied. Based on Staff witness Parcell's recommendation concerning the FVROR, Staff recommends a revenue requirement increase of not more than the $54.9 million shown on Schedule A in column D2. This equates to an increase of not more than 13.4 percent over Southwest's current base rate revenues.

III. RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to SWG's proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis is presented below:

Summary of Rate Base	Company	Staff	Difference
Original Cost Rate Base	$ 1,073,700,633	$ 1,070,115,558	$ (3,585,076)
RCND Rate Base	$ 1,839,334,300	$ 1,835,749,225	$ (3,585,076)
Fair Value Rate Base	$ 1,456,517,468	$ 1,452,932,391	$ (3,585,077)

Adjustments To Original Cost Rate Base

Q. Please discuss Staff's adjustments to Southwest's proposed original cost rate base.

A. Staff has made six adjustments to Southwest's proposed original cost rate base. These have been designated as Staff Adjustments B-1 through B-6:

Summary of Staff Adjustments to Rate Base		OCRB	RCND RB
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
B-1	Corrections to Completed Construction Not Classified	$ (1,066,657)	$ (1,066,657)
B-2	Yuma Manors Pipe Replacement	$ (225,445)	$ (225,445)
B-3	Cash Working Capital	$ (468,000)	$ (468,000)
B-4	Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC	$ (1,286,985)	$ (1,286,985)
B-5	Remove Corporate Aircraft Costs	$ (352,892)	$ (352,892)
B-6	Remove One-Half of Prepaid D&O Insurance	$ (185,097)	$ (185,097)
	Total of Staff Adjustments	**$ (3,585,076)**	**$ (3,585,076)**
	SWGas Proposed Rate Base (Original Cost and RCND)	$ 1,073,700,633	$ 1,839,334,300
	Staff Proposed Rate Base (Original Cost and RCND)	**$ 1,070,115,558**	**$ 1,835,749,225**

Each adjustment is discussed below.

B-1 Corrections to Completed Construction Not Classified

Q. Please explain the adjustment for Completed Construction Not Classified.

A. This adjustment consists of two components, (1) a direct adjustment and (2) a system allocable adjustment.

The Company's filing included an adjustment (No. 17) to include in rate base Completed Construction Not Classified ("CCNC") of $2,806,169 of distribution and general plant that was supposed to be in service by June 30, 2010, the end of the test year. In response to Staff discovery, including STF-6-7(a) and (c), the Company indicated that two work orders have not closed and should be removed from the Company's original adjustment, which should be reduced to $2,695,762. The reduction of $110,407 is shown on Schedule B-1, line 3.

The Company's response to data request STF-6-7(d) stated that: "The Company is removing the $1,700,000 cost of the SCADA system originally included in Adjustment 17 in System Allocable Account 303." The Company's response to data request STF-6-19(a) states that: "The … SCADA System, has not yet been placed into service; therefore, the

Company is no longer requesting that this item be included in rate base or amortization expense in this proceeding, reducing the plant in service increase to $4,139,131." The second part of the adjustment removes the $1.7 million. Applying the four-factor allocator of 56.25 percent, this reduces rate base by $956,250, as shown on Schedule B-1, line 8.

The total adjustment for CCNC reduces Southwest's filed jurisdictional rate base by $1,066,657, as shown on Schedule B-1, line 11.

Q. Is there a related adjustment to expenses?

A. Yes. The related adjustment to Depreciation Expense is presented on Schedule C-1, page 1, and the related adjustment for property taxes is presented on Schedule C-1, page 2. Those adjustments are discussed, below, in the section on net operating income adjustments.

B-2 Yuma Manors Pipe Replacement

Q. Please explain the adjustment for the Yuma Manors Pipe Replacement.

A. Staff's concerns regarding Southwest's deficient pipe maintenance were originally addressed in the testimony of Staff engineer Corky Hanson in Southwest's last rate case, Docket No. G-01551A-07-0504. The Commission's Decision No. 70665 in that case at page 8 found that:

> Based on all of the evidence and arguments presented by the parties, we find that in this proceeding $546,224 should be removed from rate base of which the cost for expediting the Yuma Manors pipeline replacement ($320,779) should be permanently disallowed from inclusion in the Company's rate base. The remaining $225,445 will be potentially included in rate base in the Company's next general rate case. We believe this disallowance gives appropriate recognition and weighting to the competing arguments presented by the Company and Staff and presents a reasonable resolution of this issue.

As described in the Direct Testimony of SWG witness Mashas at page 21, Southwest wrote off $320,779 of that disallowed amount and has permanently removed that from rate base. Southwest is requesting inclusion in rate base of the remaining $225,445. The testimony of Staff witness Frye presents reasons for why Staff believes the $225,445 should continue to be excluded from Southwest's rate base. On Schedule B-3, I have reflected the continued exclusion of the $225,445 from jurisdictional rate base.

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

A. Yes. Staff Adjustment C-2 is related to this adjustment and reduces test year Depreciation Expense and Property Tax Expense, based on the adjustment to Plant in Service and Net Plant, respectively.

B-3 Working Capital

Q. Have you reviewed the Company's request for a working capital allowance?

A. Yes. The Company's proposed working capital request of approximately $10.19 million consists of three separate subcomponents. The subcomponents are:

(1) a negative cash working capital balance of $4.47 million based on a lead/lag study;
(2) a thirteen-month average materials and supplies balance of $9.9 million; and
(3) a thirteen-month average prepayments balance of $4.7 million.

Q. How does that compare with the Company's request for a working capital allowance in its last rate case, Docket No. G-01551A-07-0504?

A. It is substantially higher than the Company's proposed working capital request of approximately $5.68 million from its last rate case, Docket No. G-01551A-07-0504. In its last case, the Company's negative cash working capital balance was $10.38 million based

on a lead/lag study. In that prior case, SWG had also proposed a thirteen-month average materials and supplies balance of $12.39 million, and a thirteen-month average prepayments balance of $3.68 million.

B-3.1 Cash Working Capital

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does SWG have a positive or negative cash working capital requirement?

A. SWG has a negative cash working capital requirement. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company. On average, revenues from ratepayers are received prior to the time when the utility pays the associated expenditures.

Q. Did SWG present a lead/lag study in support of its cash working capital requirement?

A. Yes, SWG performed a lead/lag study to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with the work papers provided in the case.

Q. Has SWG made any revisions to the cash working capital calculation included in its filing?

A. No, none of which I am aware.

Q. Are you recommending any revisions to SWG's cash working capital request?

A. Yes. At this time, as shown on Schedule B-3, I have reflected the impact of Staff's adjustments to operating expenses and impacts on revenue based taxes. I also propose to synchronize the calculation of cash working capital with Staff's recommended revenue increase.[2]

Q. What is the result of your cash working capital calculation?

A. As shown on Schedule B-3, at this time I have decreased SWG's filed cash working capital by approximately $468,000.

Q. What revenue lag does Southwest propose and what are its components?

A. Southwest proposes a total revenue lag of 38.22 days, based on the following three components:

Description	Lag Days
Cycle	15.21
Read to Bill	2.90
Bill to Collection	20.12
Total revenue lag days	38.22

Q. Do you have any concerns about apparent omissions in Southwest's lead-lag study?

A. Yes. It appears that Southwest has omitted reflecting the additional cash payment lag associated with revenue-based taxes and assessments. I have reviewed lead-lag studies for

[2] Such synchronization has not yet been reflected at this time, but would be incorporated in Staff's Surrebuttal filing.

other Arizona utilities, including UNS Gas, UNS Electric and Tucson Electric Power Company. Those lead-lag studies have included a component for the additional cash payment lag related to the payment of revenue-based taxes and assessments. During the period between (1) when the utility collects the revenue based taxes from ratepayers and (2) when the utility remits those funds to the taxing or assessing authority, the Company has use of the ratepayer-provided funds. Because the revenue based taxes are directly related to the provision of utility service and because there is a cash payment and the utility typically has the use of ratepayer-provided funds for some period, it is appropriate to reflect the payment lag associated with such taxes in the determination of cash working capital using a lead-lag study.

Q. How did Southwest consider revenue-based taxes in its lead-lag study?

A. Southwest considered revenue-based taxes in its lead-lag study by adding such taxes to billed revenues in order to calculate the 20.12 day billing to collection lag. However, based on my review to date, it does not appear that Southwest reflected the additional payment lag associated with such taxes as a source of ratepayer-provided funds. Consequently, at a later point in this proceeding, such as with Staff's Surrebuttal Testimony, it may be necessary to incorporate an adjustment to cash working capital for the impact of the payment lag associated with revenue-based taxes and assessments.

<u>B-4 Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC</u>

Q. Please explain the adjustment for Accumulated Deferred Income Taxes for Bonus Tax Depreciation on CCNC.

A. As described above, the Company's rate base has been adjusted to include only CCNC that was in service by June 30, 2010, the end of the test year. As described in Southwest's response to data request STF-6-7(d), the Company forgot to include the impact on

Accumulated Deferred Income Taxes ("ADIT") for the related income tax depreciation. The Company's response to data request STF-1-26 calculated the bonus tax depreciation related to the CCNC to be $704,030. The Company's response to data request STF-6-7(d) states:

> In preparing the response to this data request, it came to the Company's attention that the $704,030 was not included. The Company's Schedule B-6, Sheet 3 of 3, Line 4, Col. (c) should be increased by $704,030 to $211,498,218. This correction is needed only if the Commission accepts the Company's adjusted proposed $2,771,114 CCNC Adjustment No. 17.

As shown on Schedule B-2, ADIT in Account 282 has been increased to reflect the tax depreciation (in this case bonus tax depreciation) on the CCNC that has been included in rate base. Because the amount of CCNC included in rate base was approximately 3.93 percent lower than Southwest's as-filed amount, I reduced the Company's calculated $704,030 amount similarly by 3.93 percent. As shown on Schedule B-2, line 3, this adjustment increases federal ADIT (which is cost-free, ratepayer-provided capital) and reduces Southwest's as-filed rate base by $676,330.

There is a similar adjustment for the System Allocable amount of federal ADIT. As described in the Company's response to data request STF-6-7(d):

> Not reflected was the impact of bonus depreciation on the Corporate CCNC reflected in Adjustment No. 17. Schedule B-6, Sheet 3 of 3, Line 7, Col. (c) should be increased by $1,085,609 to $16,668,826 which is an amount before allocation to Arizona. Again, this adjustment is only appropriate if the $4,139,131 adjusted CCNC Adjustment No. 17, is accepted by the Commission.

As shown on Schedule B-2, lines 6-8, when the four-factor allocator of 46.25 percent is applied to the increase in federal ADIT of $1,085,609, the reduction to Arizona jurisdictional rate base is $610,655.

Q. What is the combined reduction to Arizona jurisdictional rate base for the federal ADIT on the CCNC amounts?

A. As shown on Schedule B-2, line 11, the total reduction to Arizona jurisdictional rate base for the federal ADIT on the CCNC amounts is $1,286,985.

B-5 Corporate Aircraft Costs

Q. Please explain the adjustment for Corporate Aircraft Costs.

A. As shown on Schedule B-5, the costs included in rate base as system allocable plant charged to Arizona for a corporate aircraft hanger and equipment are removed from Arizona rate base, reducing rate base by a net amount of $352,892. The hanger and aircraft equipment is located at 155 E. Reno, Suite D-12, Las Vegas, Nevada, and is unnecessary for the provision of utility service to Arizona customers.

B-6 Prepaid Directors' and Officers' Liability Insurance

Q. Please explain the adjustment for Prepaid Directors and Officers' Liability Insurance.

A. This adjustment, as shown on Schedule B-6, removes one-half, or $185,097, of the rate base amount for Prepaid Directors and Officers' Liability Insurance that Southwest identified in its response to data request STF 6-9, to reflect a 50-50 sharing of such cost between shareholders and ratepayers. The sharing of this cost is addressed in additional detail in conjunction with a related adjustment to expense, Staff Adjustment C-11, below.

Adjustments To Reconstruction Cost New Depreciated Rate Base

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

A. Staff's adjustments to Southwest's proposed RCND rate base are shown on Attachment RCS-2, Schedule B.1 (RCND). In each instance, the RCND adjustment amounts are the same as Staff's adjustments to OCRB.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Schedule C summarizes Staff's recommended net operating income. Schedule C.1 presents Staff's recommended adjustments to Arizona test year revenues and expenses. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. SWG's proposed adjusted test year net operating income is $65.066 million, whereas Staff's recommended adjusted net operating income is $69.794 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1 CCNC Correction Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-1.

A. This adjustment is related to Adjustment B-1. As shown on Schedule C-1, page 1, it removes $99,843 of Depreciation Expense and, on page 2 of that schedule, $21,603 of Property Tax Expense related to the adjustment to the correction for Completed Construction Not Classified.

C-2 Yuma Manors Depreciation and Property Tax Expense

Q. Please explain the adjustment for Yuma Manors Depreciation and Property Tax Expense.

A. This adjustment is shown on Schedule C-2 and reduces Depreciation Expense by $10,053 and Property Tax Expense by $4,566 related to the removal from rate base of $225,445 for Yuma Manors plant that was discussed above in conjunction with Staff Adjustment B-2.

C-3 Management Incentive Program Expense

Q. Please explain Staff Adjustment C-3.

A. This adjustment provides for the allocation of 50 percent of the test year expense for the Management Incentive Program ("MIP") to shareholders. Test year expense for the MIP proposed by Southwest is reduced by $1.768 million. Related payroll tax expense is decreased by $131,558.

Q. Please explain why a 50 percent allocation to shareholders is appropriate for an incentive compensation program, such as Southwest's MIP.

A. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50 percent of the MIP expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

Q. What changes has SWG made to its MIP since the end of the test year in its last Arizona rate case?

A. The Company's response to data request STF-6-1 indicates that SWG made two modifications to the MIP since the end of the test year (April 30, 2007) in its last Arizona rate case, Docket No. G-01551A-07-0504: (1) in 2008, the five performance measures of the MIP were replaced with four; and (2) in 2009, the eligibility threshold for the non-officer (30 percent) tier was increased and a level for technical managers (10 percent tier) was created.

Q. What are the four performance measures used in the Southwest Gas MIP?

A. The Company's response to data request STF-6-1 describes the four performance measures as follows:

> 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. Has the Company indicated that these performance measures are designed to address the interests of both customers and shareholders?

A. Yes. For example, SWG's response to STF-11-10(a) states in part that:

> **... 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. (Emphasis supplied.)

Q. What is the current tier structure used in the Southwest Gas MIP and how does that compare with the previous tier structure that was in place at the time of the Company's last rate case?

A. The Company's response to data request STF-6-1 compares the previous and current MIP participant tier structure in the following table:

Position	Previous	Current [1]
CEO	115%	115%
President	100%	100%
Executive Officers	90%	90%
Sr. Officers	75%	75%
Officers	50%	50%
Non-Officers [2]	30%	30%
Technical Manager [3]		10%

[1] Effective beginning in the 2009 plan year
[2] Eligibility threshold increased to positions with 775 Hay Points versus 700 Hay Points
[3] New tier added for Technical Managers, encompassing positions between 677 and774 Hay Points

Q. Please briefly discuss the key provisions of the MIP.

A. SWG's MIP provides variable compensation to executives for the achievement of specific goals and performance objectives important to both the short-term and long-term success of the Company. A summary of the MIP award triggers is presented in the following table:

[redacted]

As described above, the MIP award is at risk each year based on performance relative to four measures. These annual performance measures, which are equally weighted, include (1) customer satisfaction, (2) customer to employee ratio, (3) return on equity ("ROE"), and (4) operating costs. Each of these measurements has a threshold, target and a maximum. At target, each measurement contributes 25 percent towards the total award for the year. An award under a specific criterion may be given within a range from 70 percent at threshold to 140 percent at maximum. There is no award under specific criteria for performance under the threshold, and there is no incremental value for performance over the maximum for any of the four criteria.

Q. How much of the MIP is cash and how much is stock?

A. The Company's MIP provides that:

[redacted]

In summary, subject to the restriction period on the long-term component, the MIP is 40 percent cash and 60 percent stock.

Q. How are the MIP awards related to shareholder dividends?

A. As noted above, one of the four MIP award criteria relates to return on equity. Additionally, no annual incentive awards will be payable unless the Company's dividends

equal or exceed the prior year's dividends. This is an important factor because, if shareholder dividends are decreased from the prior year, there is no incentive award under the MIP for that year.

Q. What Southwest management personnel are eligible for the MIP award, and how is it distributed?

A. According to SWG's response to STF-1-50[3], the MIP award opportunity is measured as a percentage of base salary and varies by title as follows:

Position	Percentage of Base Salary
CEO	115%
President	100%
Executive VP	90%
Senior VP	75%
Vice President	50%
Non-Officers	
Director/Senior Manager	30%
Key Management Employees	10%

Forty percent of the total award earned under the MIP is paid in cash immediately following the financial close of the most current calendar year. The remaining 60 percent is awarded through the issuance of performance shares, which are issued to the executives and key management employees three years into the future.

Q. Does Southwest recognize that its proposed treatment of MIP expense in the current case represents a conscious deviation from principles and policies established in prior Commission Orders?

A. Yes. Data request STF 1-92 asked[4]:

[3] See Attachment RCS-3.
[4] Id.

> Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

Southwest's response to this data request referred to STF 1-56 and STF 1-57. STF 1-57 states in part that "Southwest is requesting full cost recovery of its Management Incentive Program and Supplemental Executive Retirement Plan."[5]

Q. What reasoning does SWG give for its request to recover 100 percent of its MIP costs despite prior Commission Orders?

A. In her Direct Testimony at page 19, Company witness Gaffin stated that the Company's compensation packages are designed to maintain a dedicated and consistent executive team to ensure the implementation of the operations and strategic plans of the organization. Ms. Gaffin also states that the compensation packages are reasonable and well-balanced with below market base salaries, and competitive.

Additionally, as described in Ms. Gaffin's Testimony at pages 2-3, SWG employed Towers Watson to assess the competitiveness of SWG's compensation packages with peer group companies. Towers Watson compared the total compensation (base salary, bonus, other, restricted stock awards, options awards, non-equity incentive plan, long term incentive payout and all other compensation) and concluded that its management and executive employees are compensated within a reasonable range. Based in part on the analysis shown in her Confidential Exhibit__SLG-1, Ms. Gaffin concludes that Southwest's executive compensation package is prudent and reasonable.

[5] I discuss Staff's recommended adjustment for the SERP, below, in conjunction with Staff Adjustment C-5.

Q. Does the methodology for comparing the executive compensation used by Ms. Gaffin address the criteria that the Commission has found important in deciding issues concerning utility incentive compensation in recent cases?

A. No. Her methodology ignores the criteria the Commission has found important in deciding this issue in recent cases. In Decision No. 68487 (February 23, 2006), the Commission adopted Staff's recommendation for an equal sharing of costs associated with the Company's MIP expense. For example, in reaching its conclusion regarding SWG's MIP, the Commission stated in part on page 18 of Decision No. 68487 that:

> We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendations to be a reasonable solution.

Additionally, in Decision No. 70665 (December 24, 2008), at page 16, the Commission stated that:

> In the last Southwest Gas rate case, as well as several subsequent cases, we disallowed 50 percent of management incentive compensation on the basis that such programs provided approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:
>
> In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is

> little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendations to be a reasonable resolution.
>
> (Id.) We believe the same rationale exists in this case to adopt the position ... to disallow 50 percent of the Company's proposed MIP costs.
>
> (Footnotes omitted)

Ms. Gaffin has not refuted the fact that both shareholders and ratepayers derive some benefit from such incentive goals.

Q. Do SWG's shareholders and customers both benefit from its MIP goals?

A. Yes. In referencing the SWG's executive compensation philosophy, Ms. Gaffin states in her Direct Testimony at page 4, lines 25-27 that:

> "...executives are not paid in excess of what their performance merits and aligns the interests of executives with the customers and shareholders..."

Additionally, as noted above, SWG's response to STF-11-10(a) states in part that:

> **... 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. (Emphasis supplied.)

Shareholders benefit from the achievement of financial goals. Additionally, shareholders benefit from the achievement of expense reduction and expense containment goals between rate cases. Shareholders and ratepayers can both benefit from the achievement of customer service goals.

Q. Have the facts changed materially since the last two Southwest Gas rate cases that a different result concerning the sharing of MIP expense should occur?

A. No, I don't believe so. The rationale for the 50 percent allocation to shareholders of the MIP expense in the current case appears to be consistent with the Commission's findings concerning MIP in Decision Nos. 68487 and 70665.

Q. Should the 50/50 ratepayer/shareholder sharing that the Commission has applied to utility incentive compensation in SWG's last rate case be modified to a 100 percent ratepayer responsibility for such cost based on the analysis presented by Ms. Gaffin?

A. No. The 50/50 sharing of Southwest's MIP program cost ordered by the Commission in Decision Nos. 68487 and 70665 should continue to apply in the current Southwest Gas rate case.

Q. Was an equal sharing of utility incentive compensation expense also ordered in the Commission's recent decision in the two most recent rate cases involving another Arizona gas distribution utility?

A. Yes, it was. In Decision No. 70011 (November 27, 2007), in a UNS Gas rate case, Docket No. G-04204-06-0463 et al, the Commission stated in part on page 27 that:

> We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

Similarly, in Decision No. 71623 (April 14, 2010), in the most recent UNS Gas rate case, Docket No. G-04204-08-0571, the Commission stated in part on page 30 that:

> We believe that the Staff and RUCO recommendations to require a 50/50 sharing of incentive compensation costs provides a reasonable balancing of the interests between ratepayers and shareholders.

Q. Is a significant portion of Southwest's MIP expense related to stock-based compensation?

A. Yes. SWG's response to data request STF 17-2(a) identifies $3.536 million as MIP compensation expense charged to Arizona jurisdictional operations.[6] [redacted]

Q. Has the Commission disallowed other utilities' stock based compensation in other recent decisions?

A. Yes. In Decision No. 69663, from an APS rate case, the Commission adopted a Staff recommendation in that case where cash-based incentive compensation expense was allowed and stock-based compensation was disallowed. Additionally, page 36 of Decision No. 69663 indicates that the Commission rejected an argument by APS that the Commission not look at how compensation is determined or its individual components:

> APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost.
>
> We agree with Staff that APS' stock-based compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate." As testified to by Staff witness Dittmer and set out in

[6] See Attachment RCS-3.

> Staff's Initial brief, "enhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. ... For example, some maintenance can be temporarily deferred, thereby boosting earnings. ... But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." [cite omitted] To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation."

Thus, in Decision No. 69663, the Commission made an adjustment to disallow a portion of that utility's incentive compensation expense, specifically the stock-based compensation.

Additionally, in Decision No. 71448 (December 30, 2009), the most current APS rate case, the Commission adopted a settlement reached between the parties which had restricted the inclusion of cash and stock based incentive compensation in rates to the amounts recommended by Staff.

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

A. Staff recommends continuing the 50 percent allocation to shareholders ordered for Southwest by the Commission in Decision Nos. 68487 and 70665. This results in a reduction to test year expense of $1,768,249 for MIP expense and $131,558 for related payroll tax expense for a total reduction to operating expenses of $1,899,807.

C-4 Stock-Based Compensation (Other than MIP)

Q. Please describe Southwest's stock-based compensation plans.

A. Southwest has two stock-based compensation plans: (1) the Restricted Stock/Unit Plan ("RSUP") and the MIP. The Restricted Stock/Unit Plan replaced the stock-option based

compensation in May 2007. As described above, Southwest's MIP incentive compensation also includes a stock-based component. However, in this section of testimony I will address only Southwest's Stock-Based Compensation (Other than MIP).

Q. Please describe Southwest's Restricted Stock/Unit Plan.

A. The RSUP is available to officers and other key management employees, with the purpose of "enhancing the competitive position of the total direct compensation and to further align customer, management, and shareholder interests, while sustaining a strong commitment to the long-term financial success of the Company and further encouraging management with ownership of Company stock." The three-year average of the MIP percent of target achieved is used to calculate the RSUP distribution. The amounts granted range from 50 to 150 percent of target. The minimum three-year average MIP achievement of 90 percent is required for RSUP distribution. The distribution is converted to restricted share units based on the current market price of the date the distribution is approved.

Q. What Southwest management personnel are eligible for the RSUP, and how is it distributed?

A. As stated above, the RSUP is available to officers and other key management employees. According to SWG's response to STF-1-50, the RSUP award opportunity 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

These units, similar to MIP, have a three-year vesting period, with 40 percent for the first year, and 30 percent for years two and three.

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

A. Yes, but it was replaced since then with the RSUP.

Q. Please explain Staff Adjustment C-4.

A. 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.[7] 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.

C-5 Supplemental Executive Retirement Plan Expense

Q. Please explain Staff Adjustment C-5.

A. This adjustment removes 100 percent of the expense for the Supplemental Executive Retirement Plan ("SERP"). The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such

[7] See, SWG's response to STF-6-5; this amount for RSUP is after the allocation to Arizona.

that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

The response to STF 1-50 states that benefits will equal 60 percent of annual compensation for senior executives and 50 percent for all other officers, when added to the benefits received under the basic retirement plan. The amount of compensation is calculated as the 12-month average of the highest 36 months of salary. Officers must be at least 55 years of age and have a minimum of 20 years of service with SWG. Being an unqualified plan, payments of SERP are not guaranteed. Workpaper C-2, Adjustment No. 3, Sheet 5, states that SWG is requesting $1.42 million for recovery in the test year, but that is only for a portion of the SERP cost charged and allocated to Southwest's Arizona jurisdictional operations. The Company's response to data request STF-17-1 shows estimated SERP expense charged to Arizona jurisdictional operations of $1.726 million.

Q. Is participation in the SERP limited to a select group of highly paid executives?

A. Yes. The Company's confidential response to data request STF-6-3 lists the SERP participants and their respective salary levels. The list provided in response to STF-6-3 by Southwest includes information for two executives who retired during the test year. Southwest's labor annualization adjusted test year expenses to remove the salaries for the retired executives.

Q. Did Southwest provide test year SERP information by participant?

A. No. The Company's response to data request STF-6-4, which had requested that information, provided an actuarial report and stated that SERP expense is a total company amount that is allocated to each ratemaking jurisdiction using the labor loading process.

Additionally: "Test year SERP expense by participant is not information that is used by the Company, and is not readily available to the Company."

Q. Does the actuarial report provided by the Company indicate the number of active participants and their average compensation?

A. Yes. Page 5 of the Hewitt Associates actuarial report for the Southwest Gas SERP for 2010 shows that as of August 1, 2008 there were 17 active participants with average compensation of $240,802. At August 1, 2009, there were 20 active participants with average compensation of $255,494.[8]

Q. Was Southwest's SERP expense disallowed by the Commission in the Company's last two rate cases?

A. Yes. In Decision No. 68487, the Commission adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Decision No. 68487 that:

> Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

[8] The actuarial report at page 5 also indicates that, as of August 1, 2008 and 2009, respectively, there were 29 and 31 retirees/beneficiaries, with average annual benefits of $80,180 and $74,215, respectively.

Similarly, SERP was disallowed by the Commission in Decision No. 70665, based on the discussion at pages 16-18. At page 18, the Commission stated that: "... we agree with the recommendations of Staff and RUCO that the request for inclusion of SERP expenses should be denied. We therefore adopt the recommendations of Staff and RUCO on this issue."

Q. Has Southwest indicated that its SERP has changed since the Commission ruled on this expense in Decision No. 70665?

A. No. In fact, Southwest's response to data request STF-6-2 states that: "No changes have been made to the Supplemental Executive Retirement Plan since SWG's last rate case, Docket No. G-01551A-07-0504."

Q. Was SERP expense also disallowed in the Commission's two most recent decisions in the rate case involving UNS Gas, Inc?

A. Yes, it was. See Decision No. 70011 at pages 27-29. Notably, at page 28 of that Decision, the Commission stated:

> ... the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rational on this issue in the most recent Southwest Gas rate case [*See also Arizona Public Service Co.,* Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.], and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

Similarly, in Decision No. 71623, at page 34, the Commission stated:

> We see no reason to depart from the rationale on this issue ..., that ratepayers should not be required to fund the retirement benefits of a few select executives whose salaries exceed current IRS limits. ... as has been stated in prior cases, the Company's shareholders may provide these additional benefits but ratepayers should not be subject to this additional burden.

Q. What adjustment related to SWG's SERP expense do you recommend?

A. I recommend the adjustment to remove SWG's expense for the SERP, which is shown on Schedule C-5 and reduces O&M expense by $1.726 million.

C-6 American Gas Association Dues

Q. Please explain Staff's proposed adjustment for American Gas Association ("AGA") dues.

A. This adjustment is shown on Schedule C-6 and reduces test year expense by $80,138 to reflect the removal of 40 percent of AGA dues.

Q. How does Staff's proposed adjustment for AGA dues compare with SWG's proposed treatment of such dues?

A. As noted above, Staff's adjustment reflects the removal of 40 percent of AGA core dues while SWG's filing reflected the removal of only 6.09 percent of the AGA dues. Southwest proposes to only remove the lobbying portion of AGA dues.

Q. Do you agree with Southwest's adjustment to remove only 6.09 percent of AGA dues?

A. No. While the marketing and lobbying-related portion of the AGA dues should be removed from rates, SWG should continue to demonstrate that the remainder of the dues are legitimate test year expenses. Decision No. 68487 also provided a clear directive from

that "in its next rate case filing the Company should provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona ratepayers." In Southwest's most recent Arizona rate case, Docket No. G-01551A-07-0504, the issue of AGA dues was addressed at some length. In Decision No. 70665, the Commission found at page 12 that:

> ... Staff's recommended disallowance of 40 percent of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit. The documentation offered by the Company to justify the AGA dues, including the alleged monetary savings to members, consists primarily of information provided by the AGA itself and must be viewed in that context. As Staff witness Ralph Smith indicated, several other states have disallowed AGA dues in substantially higher amounts than the amount proposed by Southwest Gas. Mr. Smith also pointed out that Staff's recommended disallowance is approximately the same percentage as that attained by totaling up AGA activities for Public Affairs, Corporate Affairs, half of General Counsel expenses, and marketing under a 2005 NARUC audit. Further, application of the 2007 and 2008 AGA dues would result in even greater disallowances under these categories. We therefore adopt Staff's recommendation to disallow 40 percent of the Company's AGA dues.

Q. What information did Southwest provide concerning the specific benefits of AGA activities to the Company and Arizona ratepayers?

A. Southwest witness Randi Aldridge addresses AGA activities in her Direct Testimony at pages 13-17. However, she did not provide any quantification of claimed savings, or the source document from which such claimed benefits were taken, and it is not clear whether AGA claimed benefits have ever been independently audited or verified.

Q. Please comment on the support for AGA dues reflected by Southwest in this current rate case.

A. The information provided by Company witness Aldridge in direct testimony to support the Company's claim for AGA dues is even less than what was provided by the Company in its last rate case. In Southwest's last Arizona rate case, SWG provided an Exhibit RLA-2 containing a one-page listing and description of the AGA's functions as listed in the March 2005 Annual Audit report to the National Association of Regulatory Utility Commissioners ("NARUC"). In the last case and in the current case, however, the Company did not include the percentage of AGA activities related to each function.

Q. Does the information provided by Southwest show that 93.91 percent (100 percent minus the Company's 6.09 percent disallowance for lobbying) of AGA dues-funded activities are beneficial to the Company and/or to its Arizona ratepayers?

A. No. Southwest has demonstrated that there is some benefit of AGA membership to the Company and to Arizona ratepayers from some of the AGA's functions. However, the Company has failed to demonstrate that ratepayers should fund activities conducted through an industry organization that would be subject to disallowance if conducted directly by the utility. The Company has failed to demonstrate that a disallowance of AGA dues of only 6.09 percent is adequate. Other jurisdictions have used a significantly higher disallowance percentage for gas utility AGA dues than Southwest is proposing here.

Q. To your knowledge, what percentage disallowance for utility AGA dues has been used in other recent utility rate cases?

A. In a recent UNS Gas rate case, as described on pages 32-33 of Decision No. 70011, UNS Gas had initially included $41,854 for AGA dues, and RUCO witness Moore

recommended a partial disallowance of $1,523, based on an ABA/NARUC Oversight Committee Report indicating that 1.54 percent of AGA dues were for marketing and 2.10 percent of dues were for lobbying activities. UNS Gas agreed with that adjustment, and it was ultimately adopted by the Commission. At pages 33-34 of Decision No. 70011, however, the Commission also stated that:

> Mr. Smith raises a valid point regarding the nature of AGA dues and whether a higher percentage of such dues should be disallowed as related to activities that are not necessary for the provision of services to UNS customers. However, we believe it is reasonable, in this case, to allow $40,311 ($41,854 - $1,523), in accordance with RUCO's recommendation. As we indicated in the Southwest Gas Order, however, we expect UNS in its next rate case to provide more detailed support for the allowance of AGA dues and how the AGA's activities benefit the Company's customers aside from marketing and lobbying efforts.

AGA dues disallowances have been made in gas utility rate cases in Michigan and California. In California, it appears that a disallowance of 25 percent of Pacific Gas and Electric Company's AGA dues was made by the Company itself in its filing in Application 05-12-002 (filed 12/2/05) as related to lobbying in the broader sense. In a more recent California rate case, Application No. 06-12-009, involving San Diego Gas and Electric, that utility appears to have proposed a 2 percent AGA dues disallowance for lobbying in the narrowest sense; DRA proposed that the entire cost of SDG&E's AGA dues be excluded; and UCAN supported either the full disallowance or a 25 percent disallowance based on the result from the PG&E rate case and their review of AGA activities information.

In a Michigan case involving Consumers Energy Company's gas utility operations[9], that utility conceded to a PSC Staff adjustment to disallow 16.17 percent of the AGA dues.

Q. How did you determine the percent disallowance for AGA dues?

A. This was based upon a review of information in the two most recent NARUC sponsored Audit Reports of the Expenditures of the American Gas Association, as well as the components by function of the AGA's 2007 and 2008 budgets, that were used in Southwest's last Arizona rate case, plus a review of subsequent AGA budget information that Southwest provided in response to data requests in the current rate case, including the Company's response to data request STF 6-21. I also relied upon a Florida PSC Staff memorandum, discussed in more detail below, which contained a 40 percent AGA dues disallowance. Copies of relevant pages from the NARUC-sponsored audit reports are provided in Attachment RCS-3. AGA 2007 and 2008 budget information, by component, is summarized on Schedule C-6, page 2, which is similar to the analysis I had filed in Southwest's last rate case, Docket No. G-01551A-07-0504, in support of the recommended adjustment to AGA dues. Additionally, Schedule C-6, page 3, presents information on AGA actual expenditure information from 2001 through 2009, and for forecast 2010, which was provided by Southwest in response to data request STF-6-21. Page 3 also shows the percentages by category, before and after the allocation of AGA administrative and general expenditures, and shows calculated disallowance percentages. This supports the reasonableness of the continuation of the 40 percent AGA dues disallowance.

[9] Michigan PSC Case No. U-13000.

Q. What is the purpose of the NARUC-sponsored audits of AGA expenditures?

A. The purpose of the NARUC-sponsored audits of AGA expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. As stated in the June 2001 memo to the Chairs and Chief Accountants of the State Regulatory Commissions included with the NARUC-sponsored audit of 1999 AGA expenditures: "Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities." The NARUC-sponsored audit categorizes the AGA expenditures and, as stated in the aforementioned memo, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit."

Q. Have other regulatory commissions required similar adjustments to utility-incurred AGA dues, based on the results of the NARUC-sponsored audits?

A. Yes. As an example, I have included in Attachment RCS-3 an excerpt from a Florida Public Service Commission Staff Memorandum (dated 12/23/03) in a City Gas Company rate case addressing this issue. As stated in that document:

> In City Gas's last rate case, *In re: Request for rate increase by City Gas Company of Florida*, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. *In re: Application for a rate increase by City Gas Company of Florida*, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No.

PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.
From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

Q. What amount of AGA membership dues expense has Staff removed from test year expense?

A. As shown on Schedule C-6, Staff has removed $90,898 in test year expense for AGA membership dues.

C-7 Loss on Sale of Employee Homes for Relocation Expense

Q. Please explain Staff Adjustment C-7.

A. During the test year ending June 30, 2010, the Company charged to Arizona operations expense of $503,620.[10] As shown on Schedule C-7, page 2, that amount is abnormally high in comparison with all prior years other than 2008 and with a five-year average. As shown on Schedule C-7, page 1, Staff Adjustment C-7 adjusts expense in two phases.

First, the test year amount is adjusted to a more normal level, based on a five-year average. The Company's Arizona jurisdictional operating expense is reduced by $243,931.

Second, the remaining expense related to losses incurred on the sale of employee homes is removed from the test year, reducing test year expense by $259,688. The total reduction to test year expense is $503,620.

Q. What is Staff's reason for totally removing the expense related to losses incurred on the sale of employee homes?

A. The Company should not be incurring cost related to losses on the sale of employee homes related to relocation expense unless there is a net benefit being produced by the relocation, and the incurrence of this additional relocation expense. Staff sees no evidence that these additional relocation costs related to losses on the sale of employee homes have produced any net cost savings for Arizona ratepayers.

[10] Southwest Gas' response to data request STF-6-29.

C-8 Test Year Rent Charged to Affiliate IntelliChoice Energy LLC

Q. Please explain Staff Adjustment C-8.

A. IntelliChoice Energy LLC ("ICE") is a non-regulated affiliate of Southwest Gas that is using space in a Southwest Gas building. ICE should be reimbursing SWG for rent and utilities. Per SWG's response to data request STF-11-1(n), due to a billing error, ICE was not billed for its portion of rent and utilities during the test year. SWG identified the amount of rent that was not reimbursed in that response. The Arizona jurisdictional amounts identified in that response, which total $13,156 are removed from test year expense.

C-9 Gas Heat Pump Development Expenses

Q. Have Southwest Gas' ratepayers been funding gas heat pump development?

A. Yes. Southwest Gas' ratepayers been funding gas heat pump ("GHP") development by the inclusion of research and development ("R&D") costs in operating expenses which are included in Southwest Gas' base rates, and also by R&D costs related to gas heat pump development which have been recovered by the Company in the R&D surcharge.

Q. Has Southwest Gas recently transferred virtually all of its assets related to gas heat pump development into a non-regulated subsidiary?

A. Yes. A new non-regulated subsidiary of Southwest's wholly owned subsidiary Northern Pipe Line Company ("NPLC") was formed. The new non-regulated subsidiary, IntelliChoice Energy LLC, is two-thirds owned by NPLC and one-third owned by Tommis Young, a non-affiliated contractor, who, under various company names had been receiving funding from Southwest Gas related to GHP research. Upon the formation of ICE, Southwest Gas transferred assets and intellectual property to ICE. The purpose of

ICE is to commercially develop and sell GHP, including gas engine driven air conditioning ("GEDAC").

Q. What department at Southwest had been involved in gas heat pump development?

A. Southwest's Energy Efficient Technology Department ("EETD") had been involved in the development of gas heat pumps.

Q. Did Staff ask Southwest Gas to identify all rate base and income statement amounts related to gas heat pump development?

A. Yes. Data request STF-11-1(b) requested Southwest Gas to identify all rate base and income statement amounts, by account, related to gas-fired heat pump technology, for the test year as well as calendar years, 2008, 2009 and 2010.

Q. What information did Southwest Gas provide?

A. Southwest Gas provided its EETD expenditures, by account, for each period in an attachment to its response to data request STF-11-1, along with the following explanation:

[redacted]

The information provided by Southwest Gas is summarized on Schedule C-9, page 2. As shown there, for the three years, the Company expended over [redacted] on GHP project activities.[11] Southwest Gas' response to data request STF-11-1(h) shows the amounts for

[11] Of this total, approximately [*BEGIN CONFIDENTIAL*] $3 million [*END CONFIDENTIAL*] appears to be from Arizona, using information supplied by Southwest in response to data request STF-11-1, and Arizona allocations derived from Southwest's response to data request STF-11-21.

GHP development that it estimates were included in rates charged to Arizona ratepayers. That information provided by the Company plus a cumulative column is shown in the following table:

[redacted]

According to the information provided by Southwest in response to data request STF-11-1(h), Arizona ratepayers have funded approximately [redacted] for GHP development through 2010.

Q. Why is the funding of GHP development by Southwest Gas' Arizona ratepayers a concern?

A. It is a concern because the funding has gone toward the development of gas-fired equipment that will be sold in a competitive market to compete with non-regulated electric equipment. Ratepayer funding for gas-on-electric competition or commercial development of competitive products has generally been disfavored. Additionally, and

perhaps more importantly in this instance, under Southwest's recent arrangements, the GHP equipment will be commercialized and sold by a non-regulated subsidiary, without any apparent compensation to Southwest Gas or its ratepayers for the significant development funding incurred to date.

Q. Has Staff asked Southwest to explain how the Company and its subsidiaries, including but not limited to NPLC and IntelliChoice Energy LLC will account for the revenue produced by commercialization of gas heat pumps?

A. Yes. This request was made in data request STF-11-1(g).

Q. What was Southwest's response?

A. Southwest's response to data request STF-11-1(g) stated that:

[redacted]

To date, Staff is unaware of Southwest Gas proposing a methodology or plan for sharing any benefits of GHP commercialization or royalties from the sale of GEDAC units with Arizona ratepayers.

Q. Has Southwest Gas provided other information concerning the development of GHP and the transfer of assets and intellectual property to ICE?

A. Yes. Southwest Gas has provided other information in response to a number of Staff data requests including STF-1-98, STF-7-17, and STF-11-1. Copies of those non-confidential and confidential responses are included in Attachments RCS-3 and RCS-4 to my Direct Testimony, respectively.

Q. What is Staff's recommendation?

A. Staff has the following recommendation:

1) Because Southwest Gas has elected to transfer commercial development of GHP into a non-regulated subsidiary without compensation to Arizona ratepayers who have funded a substantial portion of the development costs to date, all GHP development costs should be removed from the Company's test year operating expenses in the current Southwest Gas rate case.

2) No additional GHP development costs should be recoverable by Southwest Gas via the R&D surcharge.

3) Southwest Gas should be ordered to prepare an accounting for all GHP development costs that have been funded by Arizona ratepayers through base rates and the R&D surcharge through the date of the Commission's final order in this case; that accounting should be filed by the Company within 30 days of the final order.

4) Southwest should record the Arizona ratepayer funding for GHP development as a regulatory liability, to be returned to ratepayers, as commercial development occurs and revenues and royalties are received.

5) Southwest Gas should be ordered to prepare a plan to reimburse Arizona ratepayers for their funding of GHP development costs, and a methodology to share the benefit of commercialization revenues and royalties from the development of GEDAC units with Southwest's Arizona ratepayers. Southwest's plan and sharing methodology should be subject to comment from interested parties to the current rate case.

Q. Please explain Staff Adjustment C-9.

A. This adjustment removes the GHP development cost from test year operating expenses, using the information provided by SWG in response to data requests STF-11-1 and STF-11-21 to identify the amounts. Test year expenses are reduced by $711,287, as shown on Schedule C-9, page 1.

Q. How was the issue of Southwest Gas' funding of GHP development and commercialization addressed in the Company's most recent Nevada rate case?

A. In Southwest Gas' most recent Nevada rate case, Docket No. 09-04003, the issue is addressed at pages 19-21 of the Nevada Commission's October 28, 2009 Order. Page 19 describes the Nevada Staff's alternative recommendation to remove the test year costs of Southwest's EETD. The Nevada Staff proposed removing Southwest's internal R&D costs from ratemaking because Southwest's competitive ventures should be separated from its monopoly services to prevent cross-subsidization of competitive products by utility customers. The Nevada Staff referenced statements made by Southwest concerning

the function of the EETD and its role in development of products that are commercially viable. Pages 20-21, at paragraph 71, of the Nevada Commission's Order state that:

> The Commission finds that Staff's alternative recommendation, that Southwest's EETD costs should be removed from the cost of service, should be granted. Ratepayers generally should not subsidize the competitive activities of a regulated monopoly. Southwest demonstrated that the EETD's research efforts are directed at developing competitive products that do not fit the Commission's definition of energy efficiency pursuant to [citations omitted] because they are not directed at the end result of a reduction to the use of natural gas. Additionally, Southwest was not able to provide information regarding how EETD activities might dovetail with the Conservation and Energy Efficiency Plan.

Q. Do some of the concerns identified in Southwest's last Nevada rate case also exist in the current Southwest Arizona rate case regarding EETD costs and gas heat pump development costs?

A. Yes. Similar concerns that ratepayers generally should not subsidize the competitive activities of a regulated monopoly and that Southwest's (and now the non-regulated affiliate, ICE's) research efforts are directed at developing competitive products that are not directed at the end result of a reduction to the use of natural gas, also exist in the current SWG Arizona rate case.

Q. How does the removal of the Company's EETD costs in the most recent Nevada rate case compare with the Staff's recommendation in the current Southwest Arizona rate case?

A. As shown on Schedule C-9, page 1, of the total $2,015,843 EETD expenses in the test year (before jurisdictional allocation), Staff's recommendation is to remove the portion of that related to GHP development and commercialization, which Southwest has quantified at 65 percent. Consequently, 65 percent of the $2,015,843 EETD expenses, or

$1,310,298, is being removed. Of the $1,310,298 being removed for GHP development, the Arizona jurisdictional amount shown on Schedule C-9, page 1, column C, is $711,287.

C-10 Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, Staff's proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-10. This adjustment increases income tax expense by the amount shown on Schedule C-10 and decreases the Company' achieved operating income by a similar amount.

C-11 Directors and Officers Liability Insurance Expense

Q. Please explain the adjustment for Directors and Officers Liability Insurance Expense.

A. As shown on Schedule C-11, this adjustment allocates 50 percent of the cost of Directors and Officers Liability Insurance (D&O Insurance) to shareholders, reducing test year expense by $386,403.

Q. Why should the cost of this expense be shared between shareholders and ratepayers?

A. 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 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.

Q. Was this adjustment made in Southwest Gas' last Arizona rate case?

A. To my knowledge it was not; however, it was made in Southwest's most recent Nevada rate case, Nevada PSC Docket No. 09-04003, order dated October 29, 2009, which was more recent. Southwest's D&O Insurance expense is a "system allocable" expense, meaning that it is incurred at Southwest's corporate headquarters and the cost is allocated to the divisions. Thus, a portion of the same Southwest D&O Insurance expense that was recently disallowed in Nevada is being allocated to Arizona.

Q. Have other regulatory commissions besides Nevada made a similar adjustment for sharing of D&O Liability Insurance Expense between shareholders and ratepayers?

A. Yes. The Nevada Commission order in Southwest's last rate case, at page 47, paragraph 157, cites two states (Arkansas and California) that have required a sharing of D&O Liability Insurance Expense between ratepayers and shareholders on a 50-50 basis.[12] We are aware that at least two other commissions (Connecticut and Florida) that have made adjustments for a ratepayer and shareholder sharing of D&O Insurance expense. Connecticut has also required shareholders to share a portion of the cost of D&O Insurance expense, with the shareholder portion varying from 50 percent to 75 percent in different cases.

[12] To date, we have not located the Arkansas and California commission orders which required that sharing.

Q. Have you included an attachment with excerpts from to the orders of which you are aware which have made such findings concerning sharing of D&O Insurance Expense between shareholders and ratepayers?

A. Yes. Attachment RCS-5 contains excerpts from such orders that we have currently located.

Q. Please summarize your adjustment to expense for D&O Insurance sharing between shareholders and ratepayers.

A. As shown on Schedule C-11, 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.

Q. Is there a related adjustment to rate base?

A. Yes. A related adjustment to rate base is shown on Schedule B-6 to remove 50 percent of the prepaid amount for D&O Insurance.

C-12 Self Insurance Expense

Q. Please explain your adjustment for Self-Insurance expense.

A. This adjustment is shown on Schedule C-12, and reduces Southwest's proposed expense for self-insurance expense in Account 925 by $579,774.

As shown on Schedule C-12, page 1, line 1, during the test year, Southwest recorded an expense for self insurance in two parts: (1) $537,500 for Arizona direct and (2) $275,000 for System Allocable. After allocations, this equates to a total Arizona expense of $686,263, as shown in column F.

As shown on Schedule C-12, page 1, line 2, Southwest is requesting an expense for self insurance of: (1) $834,961 for Arizona direct and (2) $1 million for System Allocable, for a total Arizona expense of $1,375,917. As shown on line 3, Southwest's request for Arizona direct, System Allocable and total Arizona, equate to increases over the respective test recorded amounts of 55.3 percent, 263.6 percent, and 100.5 percent. Southwest's pro forma adjustment would thus effectively increase the test year recorded expense allocated to the Arizona jurisdiction by over 100 percent.

In contrast with SWG's proposals, as shown on Schedule C-12, page 1, line 5, Staff recommends a normalized allowance for self-insurance of $796,143. This represents an increase of $109,880 or approximately 16.0 percent, over the test year recorded amount, on an Arizona jurisdictional basis.

Q. How was this issue addressed in Southwest's last Arizona rate case?

A. In Southwest's last rate case, Docket No. G-01551A-07-0504, there was an issue with Southwest's derived pro forma requested self insurance expense, because it had included an extremely abnormal cost relating to a May 2005 incident. Southwest's current request has not removed that impact. Because of a May 2005 leaking gas line fire that resulted in significant injuries and property loss, for which Southwest incurred an abnormal and extremely high payment to settle the related litigation, even the ten-year average for the "common" reserve for self-insurance expense proposed by Southwest is not representative. Ratepayers should pay for a normalized level of insurance expense, but should not be required to pay for extremely high litigation payments that the utility incurred related to the May 2005 leaking gas line fire.

In response to data request STF-6-12, Southwest provided a calculation of the allowance for self-insurance similar to the one presented by Staff and accepted by the Commission in Southwest's last rate case. That Southwest calculation shows an adjustment to decrease the amount of self-insurance reserve expense requested by the Company in the current rate case by $507,121. For the normalized "common" amount, however, it used an annual allowance of $275,000 per year, which is considerably higher than the 2010 amount of $150,000, and is considerably higher than the ten-year average (excluding the extreme May 2005 leaking gas line fire) of $51,363. Rather than use $275,000 as the "common" amount, therefore, as shown on Schedule C-12, page 2, column F, Staff used a $150,000 annual allowance for the "common" reserve for self-insurance expense. The $150,000 equals the Company's recorded amount in 2010. It compares with the ten-year average of $57,450 shown on Schedule C-12, page 2, column D, which is without the massive impact of the May 2005 leaking gas line fire litigation settlement. As one can see from the annual amounts listed on Schedule C-12, columns B and D, the annual expense rates from a negative $300,000 in years 2003 and 2008, to a positive $275,000 in years 2004 and 2009. The $10.367 million in 2005 relating to the May 2005 leaking gas line fire (listed for 2005 in Column B) is an extreme anomaly in comparison with all of the other amounts.

Q. Please explain why Southwest's Arizona ratepayers should not be responsible for the impact on Injuries and Damages expense relating to the Company's settlement of litigation related to the May 2005 leaking gas line fire.

A. Arizona ratepayers should not be responsible for the massive expense incurred by the Company to settle litigation related to the May 2005 leaking gas line fire, because the expense is abnormal and was incurred in a prior period. Rates in the current case are being established for prospective application. While historical information may be useful to address normalized expenses, an extremely abnormal event like the May 2005 leaking

gas line fire-related settlement expense, is not expected to reoccur and should therefore not be built into pro forma operating expenses. Second, the Company has not demonstrated that the May 2005 leaking gas line fire was not due to its own negligence. Ratepayers should not be burdened with extra costs that may have been incurred as the result of negligence by the utility.

Q. Please explain the other information shown on Schedule C-12, page 2.

A. Lines 17-19 show a derivation of the adjustment to Southwest's proposed reserve for self-insurance expense, as filed, under three scenarios: (1) using a 10-year average, without adjustment for the May 2005 leaking gas line fire; (2) using a 10-year average, with the extreme and abnormal amount of over $10 million related to the May 2005 leaking gas line fire removed; and (3) using normalized self-insurance expense of $713,828 for Arizona Direct and $150,000 for common allocated. Line 19 shows the approximate net adjustment to Southwest's as-filed pro forma expense, under each of the above.

Q. Please summarize Staff's adjustment for Injuries and Damages Expense.

A. As shown on Schedule C-12, page 1, column G, Southwest's as-filed pro forma expense for self-insurance (Account 925) should be reduced by $579,774.

C-13 Leased Aircraft Operating Costs

Q. Please explain your adjustment for Leased Aircraft Operating Costs.

A. This adjustment normalizes the expense for Southwest's leased aircraft operating costs. Southwest does not own aircraft, but does lease aircraft for its business operations. The expense for the test year of $873,055 (before allocations) is significantly higher than for any year in the four-year period, 2004 through 2007, and is 74 percent higher than the four-year average. As shown on Schedule C-13, the test year expense for leased aircraft is

adjusted downward by $174,261 to a normalized amount. Additionally, depreciation expense on an aircraft hanger and equipment of $19,632 is removed, for a total adjustment to reduce test year operating expense by $193,893.

Q. How was the normalized amount determined?

A. I used the four-year period, 2004 through 2007, which was the basis for the leased aircraft cost allowance from Southwest's last rate case. The amount from that case was adjusted upward by 10 percent.

Q. Has Southwest demonstrated that it needs to lease aircraft or that the other expenses relating to such aircraft are cost-justified?

A. No. Had a normalized amount for leased aircraft expense not been allowed in Southwest's last rate case, I would probably be recommending an adjustment to remove all such leased aircraft related cost from the test year.

C-14 COYL Leak Detection Survey

Q. Please explain your adjustment for a Customer Owned Yard Line ("COYL") Leak Detection Survey.

A. A detailed discussion of the COYL issue and Southwest's proposed $10 million pilot program related to replacing COYL with facilities owned by Southwest is presented in a subsequent section of my testimony[13], and is also addressed in Staff witness Frye's Testimony. This adjustment reflects Staff witness Frye's recommendation that, instead of implementing the Company's proposed pilot program, that the Company be required to conduct a leak detection survey of the COYL. It provides for an annual expense of $1 million, based on the Company's estimate of a total cost for a COYL leak detection survey

[13] See section V-C, below.

of $3 million, that was provided in Southwest's response to data request STF 20-3. Southwest's interval between rate cases is three years, so the annual allowance for ratemaking purposes is based on one-third of the total survey cost estimate. As shown on Schedule C-14, this adjustment increases operating expenses by $1 million.

V. THE COMPANY'S REQUESTS FOR SPECIAL ACCOUNTING APPROVALS AND DEFERRALS

Q. What special accounting approvals and deferrals has Southwest asked the Commission to approve?

A. Southwest witness Mashas' Direct Testimony identifies the following special accounting approvals and deferrals which the Company is asking the Commission to approve.

1) At pages 16-17 of his Direct Testimony, the Company is requesting that the Commission to reconsider the write-off requirements for AHD pipe replacement by permitting Southwest Gas to discontinue the write-offs beginning with the end of the test year in this proceeding.

2) At pages 18-19 of his Direct Testimony, Mr. Mashas states that the replacement of all AHD pipe is expected to be completed by mid-year 2013 and he presents a Company proposal to defer depreciation expense, carrying costs, and property taxes resulting from removing the remainder of AHD pipe from July 1, 2010 through mid-year 2013.

3) At pages 19-21 of his Direct Testimony, Mr. Mashas presents a Company proposal to defer depreciation expense, carrying costs, property taxes and incremental expenses related to the Company's proposed installation of Southwest facilities to

replace COYL. Southwest witness Schmitz presents testimony describing Southwest's proposed COYL pilot program.

Staff is also presenting a witness from its Pipeline Safety Section to present Staff's non-accounting related analysis of these Company proposals.

A. Write-off Requirements for AHD Pipe Replacement

Q. What types of early vintage plastic pipe ("EVPP") has Southwest Gas had in its distribution system?

A. The Direct Testimony of Company witness Schmitz at page 6 states that Southwest characterizes the following pipe types as EVPP:

- ABS – Acrylonitrile Butadiene Styrene pipe;
- AA – Aldyl A pipe;
- AHD – Aldyl High Density pipe; and
- PVC – Polyvinyl Chloride pipe.

Q. What was the genesis of Southwest's pipe replacement write-offs?

A. A series of prior Commission orders dating back to the 1980s and early 1990s addressed issues with respect to the deficient installation and maintenance of pipe by predecessors to Southwest. As a result of the problems relating primarily to the initial installation of such pipe by the predecessors, the Commission has required Southwest to write-off specified percentages of the replacement costs for such pipe. Decision No. 57075 (August 31, 1990), for example, at pages 31-45 addresses issues with pipe replacements for Southwest after Southwest acquired the Southern Arizona gas distribution system from Tucson Gas

and Electric Company[14] in 1979 and the Central Arizona gas distribution system from Arizona Public Service Company ("APS") in 1984. Additionally, Decision No. 58693 (July 7, 1994) approved a settlement between Staff, RUCO and Southwest Gas concerning, among other things, write-offs of Plant in Service for pipe replacements related to defective materials and/or installation. The agreement approved by the Commission in Decision No. 58693 specified as follows, as it applied to Aldyl A ("AA") and Aldyl HD ("AHD") pipe replacements in future Southwest Gas rate cases:

> In future Southwest rate cases for the Southern Division gas properties, Southwest shall exclude from rate base an additional portion of capitalized expenditures associated with replacements of Aldyl A, [and] Aldyl HD ... pipe related to defective materials and/or installation. For such capitalized expenditures during the period July 1, 1993 through June 30, 1994, the rate base exclusion shall be based on the following percentages: 36 percent for Aldyl A, 75 percent for Aldyl HD .... During each successive twelve month period following June 1994, the foregoing percentages shall be reduced incrementally by one percent.

Q. What has Southwest Gas proposed in the current rate case for ending the Commission's write-off requirements for AHD pipe replacements?

A. At page 15 of his Direct Testimony, Mr. Mashas states that with respect to the replacement of its early vintage plastic pipe ("EVPP"):

> Two of the EVPP materials (AHD and AA) carry a legacy pipe write-off practice emanating from Commission decisions from nearly twenty years ago. Southwest Gas has written-off $8,176,962, or approximately 27 percent, of the $29,898,711 spent to replace AHD pipe from 2007 through June 2010. The Company has also written-off $274,000, or approximately 5.5 percent, of the $5,002,307 spent to replace AA. Since the write-off percent for AA goes to zero in 2013, and given the priority of its replacement, the directives from prior Commission decisions regarding AA will have a very small future impact on the Company.

[14] Now Tucson Electric Power Company ("TEP").

At pages 15-16, Mr. Mashas addresses various write-off scenarios with respect to four different AHD replacement time periods. At page 16, he states that: "The Company is not requesting the Commission's prior decision concerning AHD write-off to be changed retroactively, and understands that AHD replacement from 2007 through the end of the test year has resulted in an unavoidable $8,177,675 write-off." At pages 16-17, he nevertheless asks the Commission "to reconsider the write-off requirements for AHD pipe replacement by permitting Southwest Gas to discontinue the write-offs beginning with the end of the test in this proceeding, and finding that the $8,177,675 that has already been written-off should be permanently removed from rate base, representing a reasonable sharing of these replacement costs between shareholders and customers." At page 17, Mr. Mashas states that the pipe has continued to age in the 20 years since the Commission first considered this issue, and its removal would no longer be considered premature.

Q. Does another Southwest witness also address the Company's proposal with respect to pipe replacement?

A. Yes. Southwest witness Schmitz presents testimony from an operations perspective supporting the Company's request for rate relief for its pipe replacement program. At page 2, lines 10-11, he states that: "Southwest Gas is requesting specific rate treatment consistent with its distribution pipeline integrity management program and its EVPP." He discusses Southwest's EVPP, its distribution pipeline integrity management program, and the federal regulations for a Distribution Integrity Management Program ("DIMP"), and leaves the details of Southwest's request for specific rate treatment to Mr. Mashas.

Q. What does Mr. Schmitz state concerning Southwest's overall strategy for pipe replacement?

A. At page 7 of his testimony Mr. Schmitz states that:

> Southwest Gas' overall risk-based strategy is based on evaluating threats to the integrity of its pipeline system so that it can apply available resources to mitigate risk in a cost-effective and efficient manner. Since 1986, Southwest Gas has been monitoring leak rates of various distribution pipe types. While this leak analysis has provided performance measures for all types of pipe in the overall [Distribution Pipeline Integrity] DPI process, it has provided the basis for the pipe replacement strategy for the 20-year plan to replace all EVPP. ABS pipe was a top priority pipe based on its historically poor performance. All of the ABS pipe has now been replaced. Considering all risk factors including leak rates AHD pipe has the highest replacement priority of the remaining EVPP. Both AA and PVC pipe will continue to be replaced as well, driven by DPI assessments. Once the AHD pipe replacement is completed, the AA and PVC pipe replacement will occur similar to the AHD replacement based on the relative risk of each of those pipe types at that time.

Q. Where does Southwest present information on the amount of Arizona pipe it has replaced under its 20-year plan?

A. Southwest presents information in Exhibit No. __(RAM-5) attached to Mr. Mashas' testimony.

Q. Is this Southwest's first attempt at ending or modifying prior Commission orders relating to write-off requirements for replacing plastic pipe?

A. No. Decision No. 68487 (February 23, 2006), at pages 7-9, addressed a previous attempt by Southwest to modify Decision No. 58693 to stop the pipe write-off schedule required by that Decision to allow the affected write-offs to cease when the specific type of pipe reached an average life of 40 years.

Q. Did the Commission adopt Southwest's request in Decision No. 68487?

A. No. Decision No. 68487, at page 7, noted that:

> In Decision No. 58693 (July 7, 1994), the Commission adopted a Settlement Agreement between Southwest Gas, Staff and RUCO which

> required Southwest to write-off a certain percentage of the replacement cost of defective pipe, and provided that the pipe replacement percentage write-off amounts would decline annually until the amounts reached zero (Decision No. 58693, at 3-4 ...)

Decision No. 68487 states further at page 8 that:

> ... both the Settlement and the Order specifically state that 'In future Southwest rate cases for the Southern Division gas properties, Southwest shall exclude from rate base an additional portion of capitalized expenditures associated with replacements of Aldyl A, Aldyl HD, ... related to defective materials and/or installation.' (Decision No. 58693, at 3).

At page 9, Decision No. 68487 states that:

> The Company may not unilaterally alter the terms of a Settlement Agreement and Commission Order simply because it has an understanding of the terms of the agreement that may differ from the belief of another party. Rather, the Company could seek an amendment to the requirements of the prior Order if it believed the terms are no longer applicable, which it has properly done in this docket. However, we agree with RUCO that Southwest Gas must continue to comply with the requirements of the prior Order until such a time as those requirements are modified by the Commission.

Based on the evidence in that case (Docket No. G-01551A-04-0876), the Commission did not adopt Southwest's request to modify the Settlement and Order that had been in place from Decision No. 58693.

Q. Has Southwest presented a compelling need in the current rate case to modify the Settlement and Order that had been in place from Decision No. 58693?

A. No. Lacking compelling evidence or a compelling reason for modifying that Settlement and Order, would suggest that it should continue unmodified.

Q. Do you have any other comments?

A. Yes. First, to the extent that Southwest is replacing AHD pipe in 2011 or 2012, the replacements will presumably qualify for bonus federal income tax depreciation applicable in those years. The availability of this additional tax benefit, which will be enjoyed by Southwest between rate cases, will alleviate the burden of the write-offs.

Second, Southwest can influence and control to some extent the remaining write-offs related to AHD pipe by determining when they are made.

Third, much of the pipe replacement and installation work is contracted by Southwest to its non-regulated affiliate, NPLC, which is a wholly owned subsidiary of Southwest. So, even though Southwest is still incurring write-offs with respect to the replacement of AHD pipe that relates back to the initial defective materials and/or installation that was addressed in Decision No. 58693, et al, Southwest receives a benefit from having much of the pipe replacement work done by its affiliate.

Fourth, Southwest projects it will have completed the AHD pipe replacements by mid-year 2013. Consequently, leaving the Settlement and Order that had been in place from Decision No. 58693 for one additional rate case cycle should alleviate the need to modify the previously write-off percentages for replacement of AHD pipe.

Finally, if the Settlement and Order that had been in place from Decision No. 58693 were to be modified in the current Southwest gas rate case, the modification should become effective as of the date of the Commission's Order in this proceeding. Southwest should continue to comply with Decision No. 58693 from July 1, 2010 through the date of the Commission's final decision in this case.

B. Company's Accounting Deferral Proposal Related to Removing the Remainder of AHD Pipe

Q. What is the Company's accounting deferral proposal related to removing the remainder of AHD pipe?

A. As noted above, at pages 18-19 of his direct testimony, Mr. Mashas states that the replacement of all AHD pipe is expected to be completed by mid-year 2013 and he presents a Company proposal to defer depreciation expense, carrying costs, and property taxes resulting from removing the remainder of AHD pipe from July 1, 2010 through mid-year 2013.

Q. What rationale has Southwest presented as the basis for this accounting proposal?

A. At pages 18-19, Mr. Mashas' presents the Company's rationale for requesting that deferral as follows:

> The capital expenditures required to replace the AHD, as part of its plan to replace EVPP, are non-revenue producing. The carrying costs, depreciation and property taxes associated with these replacement costs contribute to the Company's inability to earn its Commission authorized ROR, which in turn has a negative impact on the Company's credit ratings and ultimately impacts the terms the Company is able to receive when refinancing and issuing debt.
>
> The deferral of depreciation expense is justified for another reason. Depreciation expense is accumulated in Account 108, Accumulated Provision for Depreciation, which in turn is an offset to rate base. The Company does not earn a return on amounts included in Account 108 under the presumption that the customer has provided the funds accumulated in this account. This deferred depreciation represents amounts that the customer did not provide in this case, or any other case, unless the deferral and subsequent recovery is authorized by the Commission. Therefore, without the deferral it would be unfair to use the depreciation expense accumulated in Account 108, as a rate base offset unless these amounts are ultimate recovered from the customer.

Q. What is the effect of accounting deferrals in general?

A. In general, accounting deferrals do not impact current rates, but could cause future rates to be higher than they otherwise would be.

Q. What is the general policy with respect to accounting deferrals?

A. Because they represent a deviation from traditional ratemaking practice, accounting deferrals should generally be discouraged unless a compelling need for such extraordinary treatment has been demonstrated.

Q. Has the Company justified its requested accounting deferral for AHD pipe replacements?

A. No. The rationale presented by the Company is not specific to AHD pipe replacements but is a general rationale that could presumably be applied to any additions by any utility of non-revenue producing plant between rate cases. Moreover, the Company's reasoning as it relates to Depreciation expense does not withstand scrutiny for a number of reasons.

First, there is a concern that the depreciation rates currently being used by Southwest Gas for its Arizona jurisdictional assets are outdated and may not be accurate. The current depreciation rates being used by the Company are based upon a depreciation study of Arizona plant at December 31, 1988. The Company has not had a depreciation rate study for Arizona in approximately 23 years. Without periodic depreciation rate studies, it is difficult to judge whether the depreciation rates being applied by the Company are accurate. Without a recent depreciation rate study for its Arizona jurisdictional gas distribution systems, it is difficult to know whether the Company is over- or under-depreciating its assets. An under-depreciating situation would suggest that the Company

may effectively be deferring depreciation that should be receiving current recognition into future years.

Second, the Company's claim that the customer does not pay for depreciation expense between rate cases lacks support. Customers pay rates that are based upon a revenue requirement. Many factors change between rate cases; however, as long as the utility is earning a positive amount of net income, it is generally assumed that the rates that ratepayers are paying covers all of the Company's operating expenses, which are subtracted from revenues in the determination of net income.

Third, the cost of installing non-revenue producing plant in the second half of 2010, as well as in 2011 and 2012, could be significantly offset by the availability of bonus federal income tax depreciation. Bonus tax depreciation in this period is available at levels of 50 percent and 100 percent, depending on when the plant is installed.

Q. At page 19, lines 16-23, Southwest witness Mashas quotes from Decision No. 57075, page 93, as purported justification for Southwest's proposed accounting deferral. What language appears in Decision No. 57075 immediately preceding the passage quoted by Mr. Mashas when that same language appears on page 43 of that Decision?

A. Pages 43-44 of Decision No. 57075 contain the following language surrounding the quoted passage primarily relied upon by Mr. Mashas (which is shown in italics below):

> **For the Southern division, the uncontroverted record evidence establishes that the inordinately high leak rates have primarily resulted from imprudent actions and improper installation techniques by TEP. The record also establishes that Southwest failed to adequately investigate and test the condition of the system prior to purchase. In these circumstances, it would clearly be unfair and**

> **unreasonable to include in rate base any costs of the replacement program, whether for remedial work or repairs and betterments, which may be related to imprudence or which may be offset by the damages recovered by TEP.**
>
> Although neither the Staff nor RUCO have challenged the full program cost, the amount in dispute at the time of hearing, between $52.5 million and $59.3 million, does exceed the capitalized program costs included in test year plant balances. **The Commission will, accordingly, eliminate all of the program costs from the calculation of the revenue requirement and defer rate recognition to the next rate proceeding, at which time the settlement can be taken into consideration. This adjustment reduces Applicant's adjusted rate base for the Southern division by approximately $20.6 million.** *Until the allowable portion of costs is ultimately determined by the Commission and reflected in rates, Southwest should capitalize in a deferred asset account all interest costs, taxes, and depreciation expense incurred on the Southern division pipeline replacement program. A weighted average interest rate of 10.99%, equal to the approved cost of debt for the Southern division in these proceedings,* should be used to accrue interest on the deferred balance. The extent to which the accumulated interest is a reasonable and allowable cost for ratemaking purposes will be determined by the Commission in the next rate case.
>
> (**Emphasis supplied in bold**; *italics used to indicate passage containing language similar to that relied upon by Southwest witness Mashas at page 19, lines 16-23 of his direct testimony.*)

As can be seen from the above passages, the deferral from Decision No. 57075 was in the context of findings that it would be unfair and unreasonable to include in rate base any costs of the replacement program, whether for remedial work or repairs or betterments, which may be related to imprudence or which may be offset by damages that Southwest recovered from Tucson Electric Power ("TEP"). The deferral was also in the context of removing approximately $20.6 million of pipe replacement program costs from the calculation of the revenue requirement in that prior Southwest Gas rate case. In summary, the passage relied upon by Mr. Mashas has been taken out of context, and certainly does not support a prospective deferral in the current Southwest rate case.

Q. Please summarize Staff's recommendation regarding Southwest's request for accounting deferrals for AHD pipe replacement costs incurred between rate cases.

A. For the reasons stated above, this request by Southwest for an exceptional regulatory treatment of deferring depreciation, property taxes, and carrying costs on pipe replacement costs incurred between rate cases has not been justified and should be denied.

C. Company's Deferral Proposal for Installation of Southwest Facilities to Replace COYL

Q. What is a COYL?

A. A COYL typically begins from the point of delivery connection at Southwest's meter at the property line or public right-of-way, and extends underground from the meter to the house, building or gas utilization equipment where gas is consumed. Southwest does not own the COYL, and the customer is responsible for inspecting and maintaining it. As described by Mr. Schmitz on pages 8-9 of his testimony, although Southwest is not responsible for maintaining the line, Southwest is required to notify customers with COYLs at least once about various information, including the customers' responsibility for maintaining the COYL and that the COYL should be periodically inspected. At page 9, Mr. Schmitz indicates that Southwest reminds customers about COYLs once per month through bill notices.

Q. What has the Company proposed for deferral of costs related to COYL?

A. As noted above, at pages 19-21 of his Direct Testimony, Mr. Mashas presents a Company proposal to defer depreciation expense, carrying costs, property taxes and incremental expenses related to the Company's proposed installation of Southwest facilities to replace customer-owned yard lines. Southwest witness Schmitz presents testimony describing Southwest's proposed COYL pilot program. At page 8, he states that Southwest is proposing a "pilot program" to replace up to 5,000 COYLs to help customers manage their

COYLs. At pages 10-11, he states that upon Commission approval for a COYL replacement pilot program, Southwest proposes the following:

1) Establish a two-year pilot program for COYL replacements;
2) Establish a deferral account to allow Southwest Gas to recover, between rate cases, the incremental costs associated with the pilot program. The prepared testimony of Company witness Robert A. Mashas describes in detail the Company's deferred accounting proposal for the pilot program;
3) Visually inspect selected COYLs;
4) Cap the total pilot program costs at either $10,000,000, the total estimated cost associated with completing the COYL replacement and meter relocation for 5,000 customers, or the total incremental cost associated with the pilot program incurred within two years, whichever occurs first.

Mr. Mashas' testimony at page 20 indicates that the Company believes it can assist customers in managing their COYLs by initiating a pilot program to begin replacing the COYL with a Southwest Gas owned and maintained service line extension. The general body of Southwest's ratepayers would be charged with the COYL replacement costs in future rates.

Q. How are customers with COYLs currently managing them?

A. As described on page 10 of Mr. Schmitz' testimony, when leaks are found on a COYL, the customers have the option of replacing the COYL with a Southwest-owned facility and relocating the meter, calling a licensed plumber to replace or repair the COYL, or discontinuing gas service.

Q. What have affected customers typically chosen in that situation?

A. Mr. Schmitz' testimony at page 10 indicates that, based on 2009 data, only 15 percent of customers who experienced leaks on COYLs elected to replace their COYL with a Southwest-owned facility and relocate the meter. Less than 1 percent discontinued service. Approximately, 70 percent, a significant majority, contacted a licensed plumber who repaired the leak, leaving the meter and COYL intact.

Q. What does this suggest?

A. It suggests that, when faced with the cost of replacing a COYL, a significant majority of customers have chosen to instead, have it repaired by a licensed plumber.

Q. How many COYLs does Southwest estimate are on its Arizona gas distribution system?

A. Southwest witness Schmitz states at page 9, lines 12-15 states that: "Southwest Gas sent a first class bulletin/letter during 2009 and 2010 to approximately 108,000 customers in Arizona who are responsible for the operation and maintenance of their COYLs." This suggests that there are approximately 108,000 COYLs. Staff discovery was issued to Southwest to identify the number and locations of the COYLs. Southwest's response to data request STF-16-7 indicates that the Company's current estimate of the number of COYLs on its system in Arizona is 102,574 and provides the estimated number by district as follows:

Eastern District:	1,944
Mountain District:	2,840
Southeast District:	2,489
Tucson District:	70,406
Valley District:	9,345
Yuma District:	846
Phoenix District:	12,919
Wickenburg District	348
Bullhead District:	1,437
	========
Total:	102,574

Q. What cost does Southwest estimate per COYL replacement?

A. As stated on page 10 of Mr. Schmitz' testimony, Southwest estimates $2,000 per location, where the yard line can be replaced and the meter relocated without the need for major construction activity.

Q. How does that estimate compare with Southwest's actual cost for COYL replacements?

A. It is more than double the Company's actual average cost of COYL replacements for the five-year period through 2010. In response to data request STF-16-8, the Company provided information for 2006 through 2010 on the number of COYL replacements and the annual cost. That information is summarized below:

Number and Cost of COYLs Replaced by Year

Year	No. of COYLs Replaced	Cost	Average Cost per Replaced COYL
2006	498	$ 454,536	$ 912.72
2007	432	$ 412,406	$ 954.64
2008	306	$ 293,778	$ 960.06
2009	322	$ 331,278	$ 1,028.81
2010	272	$ 282,304	$ 1,037.88
Average	366	$ 354,860	$ 969.56

Source: STF-16-8

As shown, the average cost per COYL replacement is about $970. The average cost for the most recent year, 2010, is about $1,038 per COYL replacement.

Q. Has Southwest claimed its proposed COYL replacement program is cost-justified?

A. No. Southwest's testimony does not offer overall cost savings to Arizona ratepayers as justification for this program.

Q. Would this proposed program cause rates to be higher in future rate cases?

A. Presumably Southwest would request recovery of the COYL replacement costs. Thus, the $10 million pilot program cost, or eventually the cost of replacing all approximately 108,000 COYLs (which at an average of $2,000 per replacement, could accumulate to $216,000,000) could find its way into customer rates. That estimate used Southwest's previously identified COYL count of 108,000. Southwest's response to data request STF-16-7(d) states that:

> Southwest Gas estimates that it can replace COYLs at an average cost of $2,000 per service, excluding those residences where there are significant physical obstacles. At 102,574 COYLs, Southwest Gas' best estimate of the total cost to replace COYLs on its system in Arizona is $205 million at current costs.

Replacement of all COYLs could therefore cost more than $205 million, not an insignificant amount to be added to Arizona jurisdictional rate base.

Q. Has Southwest projected that some customers will continue to have the Company replace their COYLs in the absence of its proposed $10 million Pilot Program?

A. Yes. The Company's response to data request STF-16-6 indicates that under its current tariff Southwest performs COYL replacements at the expense of the customer. Per that response, customer contributions for the installation of Southwest Gas facilities to replace

COYLs actually experienced after the test year, and as projected by the Company are as follows:

> Consistent with Arizona Tariff Rule No. 6, section E(6)(b), Southwest Gas performs the replacement of customer owned yard lines (COYL) at the expense of the customer. Customer contributions for the installation of Southwest Gas facilities to replace COYLs are as follows:
>
> June 30, 2010 through December 31, 2010: $159,730
>
> December 31, 2010 through March 31, 2011: $173,966
>
> Projected/budgeted for March 31, 2011 through December 31, 2011: $276,034
>
> Total amount Projected/budgeted for Calendar 2011: $450,000

Q. Has Southwest explained why it selected 5,000 COYLs?

A. Not really. Presumably, a full replacement at a total cost potentially in excess of $205 million was too massive an undertaking, without some type of pilot. However, why 5,000 versus some other level has not been explained by Southwest.

Q. At the rate of replacing 5,000 COYLs every two years, how long would it take to replace all of the COYLs?

A. Southwest's response to data request STF-16-7(e) estimates that it would take approximately 41 years to replace all of the COYLs:

> Given Southwest Gas' estimate of 102,574 COYLs, and assuming that all customers would want their COYL facilities replaced by utility-owned and operated facilities, at a rate of 5,000 replacements every two years as posed in this question, it would take approximately 41 years to replace all COYLs.

Q. Has Southwest explained why it selected a two-year program?

A. Not really.

Q. Could a two-year program term result in a termination of the program between rate cases?

A. It could. In response to data request STF-7-13 Southwest has stated that it has a four-year plan for filing Arizona rate cases. The selection of a two-year program for COYLs may thus not cover the full period between rate cases.

Q. Has Southwest demonstrated a compelling need to replace COYLs?

A. No. There is a concern that some customers may not be inspecting or maintaining their COYLs. However, in situations where leaks have been detected on COYLs, as noted above, the vast majority of the affected customers have chosen to use a licensed plumber to repair the leak, and not to have Southwest replace their COYL and relocate their meter.

Q. Please summarize your recommendation regarding Southwest's request for accounting deferrals up to $10 million for a two-year COYL pilot program.

A. For the reasons stated above, this request by Southwest Gas for an exceptional regulatory treatment of deferring depreciation, property taxes, and incremental costs on a COYL replacement program has not been justified and should be rejected.

VI. NEED FOR AN UPDATED DEPRECIATION RATE STUDY

Q. What is depreciation?

A. The NARUC manual, Public Utility Depreciation Practices[15] defines depreciation as follows:

[15] National Association of Regulatory Utility Commissioners, August 1996.

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.

Q. When was Southwest's last depreciation rate study?

A. The Company's response to data request STF-1-5 states that:

> For corporate (i.e. system allocable) plant, a portion of which is allocated to Arizona, the last approved depreciation study was filed in Nevada during 2007 using a period ended date of December 31, 2006. The system allocable rates approved in Nevada are used in all of Southwest's ratemaking jurisdictions so the appropriate amounts of corporate plant are recovered in rates from Southwest's Arizona, Nevada, and California customers.
>
> At the time of the last depreciation study in Arizona, Arizona had two separate rate jurisdictions: Southern Arizona and Central Arizona. In 1996, the two Arizona rate jurisdictions were combined into one rate jurisdiction and the depreciation rate for the combined jurisdiction was a blended average of the existing rates for the Southern Arizona and Central Arizona jurisdictions. This combined rate is the currently approved rate used in the Arizona rate jurisdiction.

The most recent depreciation rate studies that Southwest provided in response to data request STF-1-5 include:

1) A book depreciation study as of December 31, 1988 of the Central Arizona property;
2) A book depreciation study as of December 31, 1988 of the Southern Arizona property; and

3) A depreciation rate study for System Allocable plant at December 31, 2006, that Southwest indicated it filed in Nevada.

Q. Do you have any concerns related to these depreciation rate studies as they apply to Southwest's Arizona plant?

A. Yes. The depreciation studies being relied upon by Southwest for recording depreciation expense for its Arizona plant are outdated, and would not reflect changes in factors that have affected depreciation rates for such plant occurring over the past 23 years, including changes in pipe installation practices and replacements. Ideally, utility depreciation rates are updated periodically to assure that such depreciation rates are accurate and incorporate the impacts of changing conditions. Because the depreciation rate studies for Southwest's Arizona plant are so outdated, the depreciation rates being used by Southwest with respect to its Arizona plant should be reviewed in detail in Southwest's next Arizona rate case. To facilitate this review, Southwest should be ordered to file a new fully-updated depreciation rate study in the Company's next Arizona rate case.

Q. Do you have any concerns related to these depreciation rate studies as they apply to Southwest's system allocable plant?

A. Yes. It appears from the Company's response to data request STF 1-5 that Southwest may have implemented new depreciation rates, based on a 2007 study, for system allocable plant, without having those new depreciation rates reviewed or approved by the Arizona Corporation Commission. While Southwest's system allocable plant may be primarily located in Nevada, where Southwest has its corporate headquarters, it should also be recognized that Southwest's Arizona jurisdictional operations represent the majority (over 56 percent) of Southwest's total gas utility operations. Accordingly, Southwest should not implement any further changes to depreciation rates on its system allocable plant without

having those rates first reviewed and approved by the jurisdiction in which those rates have the greatest impact, i.e., by the Arizona Corporation Commission.

Q. Does Staff have any recommendations related to these depreciation rate studies?

A. Yes, Staff has the following recommendations:

- None of Southwest's proposals that request deferral of depreciation should be approved. The depreciation rate studies Southwest is using for its Arizona plant both date back to December 31, 1988, and thus should not be the basis for any depreciation expense deferrals until after they are updated.

- Utility depreciation rates should be updated periodically, ideally every three to five years, as conditions change. Because Southwest's Arizona plant depreciation studies are so outdated (the studies of December 31, 1988 Arizona plant are now approximately 23 years old), Southwest should be ordered to file updated depreciation rate studies in its next Arizona rate case.

- Southwest should also file an updated depreciation study for System Allocable plant in its next Arizona rate case.

- Southwest's Arizona jurisdictional operations represent the majority (over 56 percent) of Southwest's total gas utility operations, and consequently changes to depreciation rates on Southwest's system allocable plant would have the greatest impact on Arizona. Because Arizona jurisdictional operations represents over 56 percent of Southwest's total gas utility operations, any changes to System Allocable plant depreciation rates should not be instituted for book purposes until

such depreciation rates have been authorized by the Arizona Corporation Commission.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)

Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0085	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-0872-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Phase I (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, Inc. (Arizona CC)
E-01773A-09-0496	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208,	

R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)

Southwest Gas Corporation
Docket No. G-01551A-10-0458
Attachment RCS-2
Staff Accounting Schedules
Accompanying the Direct Testimony of Ralph C. Smith

Schedule	Description	Pages
	Revenue Requirement Summary Schedules	
A	Calculation of Revenue Deficiency (Sufficiency)	1
A-1	Gross Revenue Conversion Factor	1
B	Adjusted Rate Base	1
B.1	Summary of Rate Base Adjustments	2
C	Adjusted Net Operating Income	1
C.1	Summary of Net Operating Income Adjustments	3
D	Capital Structure and Cost Rates	1
	Rate Base Adjustments	
B-1	Corrections to Completed Construction Not Classified	1
B-2	Yuma Manors Pipe Replacement	1
B-3	Cash Working Capital	1
B-4	Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC	1
B-5	Remove Corporate Aircraft Costs	1
B-6	Remove One-Half of Prepaid D&O Insurance	1
	Net Operating Income Adjustments	
C-1	CCNC Correction Depreciation and Property Tax Expense	2
C-2	Yuma Manors Depreciation and Property Tax Expense	2
C-3	Management Incentive Program	1
C-4	Restricted Stock/Unit Plan	1
C-5	Supplemental Executive Retirement Expense	1
C-6	American Gas Association Dues	3
C-7	Loss on Sale of Employee Homes for Relocation Expense	2
C-8	Test Year Rent Charged to Affiliate IntelliChoice Energy LLC	1
C-9	Gas Heat Pump Development Expenses	1
C-10	Interest Synchronization	1
C-11	Directors' and Officers' Liability Insurance	1
C-12	Self-Insurance Retention Expense	2
C-13	Leased Aircraft Operating Costs	1
C-14	COYL Leak Detection Survey	1
	Total Pages	37

Southwest Gas Corporation
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule A

Line No.	Description	Reference	SWG Proposed Original Cost (A)	SWG Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value (Alt. 1) (D1)	Staff Proposed Fair Value (Alt. 2) (D2)	Difference Fair Value (E) = D2 - B
1	Adjusted Rate Base	Sch. B	$ 1,073,700,633	$ 1,456,517,468	$ 1,070,115,558	$ 1,452,932,391	$ 1,452,932,391	$ (3,585,077)
2	Rate of Return	Sch. D	9.73%	7.50%	9.08%	6.69%	7.02%	
3	Operating Income Required		$ 104,483,741	$ 109,211,529	$ 97,138,991	$ 97,138,991	$ 101,924,201	$ (7,287,328)
4	Net Operating Income Available	Sch. C	$ 65,065,829	$ 65,065,829	$ 68,793,670	$ 68,793,670	$ 68,793,670	$ 3,727,841
5	Operating Income Excess/Deficiency		$ 39,417,912	$ 44,145,700	$ 28,345,321	$ 28,345,321	$ 33,130,531	$ (11,015,169)
6	Gross Revenue Conversion Factor	Sch. A-1	1.6579	1.6579	1.6579	1.6579	1.6579	1.6579
7	Overall Revenue Requirement		$ 65,350,956	$ 73,189,155	$ 46,993,708	$ 46,993,708	$ 54,927,107	$ (18,262,048)
8	Additional revenue requirement on Fair Value	Line 7		$ 7,838,200 (B - A)		$ - (D1 - C)	$ 7,933,399 (D2 - C)	

Notes and Source

Cols. A & B taken from SWG filing, Schedule A-1

SWG Schedule A-1 does not carry the Company's Original Cost calculations in its Schedule A-1, column c, through to a revenue requirement amount.

Southwest Gas Corporation
Computation of Gross Revenue Conversion Factor

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule A-1

Line No.	Description	Rate (A)	Company Proposed (B)	Staff Proposed (C)
1	Gross Revenue		1.0000000	1.0000000
2	Less: Uncollectible Revenue	0.2543%	0.0025428	0.0025428
3	State Taxable Income		0.9974572	0.9974572
4	Less: State Income Taxes	6.9680%	0.0695030	0.0695030
5	Federal Taxable Income		0.9279542	0.9279542
6	Federal Income Tax	35.0000%	0.3247840	0.3247840
7	Change in Net Operating Income		0.6031702	0.6031702
8	Gross Revenue Conversion Factor		1.6579	1.6579

Notes and Source

Cols.A&B: SWG Filing, Schedule C-3

Components of Revenue Requirement Increase

		Amount	Percent
9	Net Income	$ 28,345,195	60.31700%
10	Federal and State Income Taxes	$ 18,529,008	39.42870%
11	Uncollectibles	$ 119,505	0.25430%
12	Total Revenue Increase	$ 46,993,708	100.00000%
13	Computation of State and Federal Income Tax Rate	L.10 / L.3	39.5292%
14	Per SWG Schedule C-3, page 3 of 3		39.5292%

Southwest Gas Corporation
Original Cost and RCND Adjusted Rate Base

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B

Line No.	Description	Original Cost As Adjusted by SWG (A)	Original Cost Staff Adjustments (B)	Original Cost As Adjusted by Staff (C)	RCND As Adjusted by SWG (D)	RCND Staff Adjustments (E)	RCND As Adjusted by Staff (F)
	Gas Plant in Service						
1	Direct	$ 2,255,372,875	$ (335,852)	$ 2,255,037,023	$ 3,734,684,180	$ (335,852)	$ 3,734,348,328
2	System Allocable	$ 104,539,455	$ (1,512,324)	$ 103,027,131	$ 113,079,915	$ (1,512,324)	$ 111,567,591
3	Total Gross Plant	$ 2,359,912,330	$ (1,848,176)	$ 2,358,064,154	$ 3,847,764,095	$ (1,848,176)	$ 3,845,915,919
	Accumulated Depreciation and Amortization						
4	Direct	$ (886,327,699)	$ -	$ (886,327,699)	$ (1,483,912,048)	$ -	$ (1,483,912,048)
5	System Allocable	$ (68,873,041)	$ 197,292	$ (68,675,749)	$ (72,423,689)	$ 197,292	$ (72,226,397)
6	Total Accumulated Depreciation and Amortization	$ (955,200,740)	$ 197,292	$ (955,003,448)	$ (1,556,335,737)	$ 197,292	$ (1,556,138,445)
7	Net Gas Plant in Service	$ 1,404,711,591	$ (1,650,884)	$ 1,403,060,707	$ 2,291,428,358	$ (1,650,884)	$ 2,289,777,474
	Other Rate Base Items						
	Working Capital						
8	Cash Working Capital	$ (4,472,151)	$ (468,000)	$ (4,940,151)	$ (4,472,151)	$ (468,000)	$ (4,940,151)
9	Materials and Supplies	$ 9,920,409	$ -	$ 9,920,409	$ 9,920,409	$ -	$ 9,920,409
10	Prepayments	$ 4,744,133	$ (185,097)	$ 4,559,036	$ 4,744,133	$ (185,097)	$ 4,559,036
11	Customer Advances for Construction	$ (62,033,165)	$ -	$ (62,033,165)	$ (62,033,165)	$ -	$ (62,033,165)
12	Customer Deposits	$ (48,475,278)	$ -	$ (48,475,278)	$ (48,475,278)	$ -	$ (48,475,278)
13	Deferred Income Taxes	$ (230,694,907)	$ (1,281,095)	$ (231,976,002)	$ (351,778,007)	$ (1,281,095)	$ (353,059,102)
14	Other		$ -			$ -	
15	Total Other Rate Base Items	$ (331,010,958)	$ (1,934,192)	$ (332,945,149)	$ (452,094,058)	$ (1,934,192)	$ (454,028,249)
16	Total Rate Base	$ 1,073,700,633	$ (3,585,076)	$ 1,070,115,558	$ 1,839,334,300	$ (3,585,076)	$ 1,835,749,225

Notes and Source

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

	Fair Value Calculation (Per Company)		
17	Original Cost	$ 1,073,700,633	
18	RCND	$ 1,839,334,300	
19	Total	$ 2,913,034,934	
20	Average (Fair Value)	$ 1,456,517,468	See Sch. A
	Fair Value Calculation (Per Staff)		
21	Original Cost	$ 1,070,115,558	
22	RCND	$ 1,835,749,225	
23	Total	$ 2,905,864,783	
24	Average (Fair Value)	$ 1,452,932,391	See Sch. A

Southwest Gas Corporation
Summary of Rate Base Adjustments
Original Cost
Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B.1 (OCRB)

Line No.	Description	Staff Adjustments	Corrections to Completed Construction Not Classified	Yuma Manors Pipe Replacement	Cash Working Capital	Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC	Remove Corporate Aircraft Costs	Remove One-Half of Prepaid D&O Insurance
			B-1	B-2	B-3	B-4	B-5	B-6
	Gas Plant in Service							
1	Direct	$ (335,852)	$ (110,407)	$ (225,445)				
2	System Allocable	$ (1,512,324)	$ (956,250)				$ (556,074)	
3	Total Gross Plant	$ (1,848,176)	$ (1,066,657)	$ (225,445)	$ -	$ -	$ (556,074)	$ -
	Accumulated Depreciation and Amortization							
4	Direct	$ -						
5	System Allocable	$ 197,292					$ 197,292	
6	Total Accumulated Depreciation and Amortization	$ 197,292	$ -	$ -	$ -	$ -	$ 197,292	$ -
7	Net Gas Plant in Service	$ (1,650,884)	$ (1,066,657)	$ (225,445)	$ -	$ -	$ (358,782)	$ -
	Other Rate Base Items							
	Working Capital							
8	Cash Working Capital	$ (468,000)			$ (468,000)			
9	Materials and Supplies	$ -						
10	Prepayments	$ (185,097)						$ (185,097)
11	Customer Advances for Construction	$ -						
12	Customer Deposits	$ -						
13	Deferred Income Taxes	$ (1,281,095)				$ (1,286,985)	$ 5,890	
14	Other	$ -						
15	Total Other Rate Base Items	$ (1,934,192)	$ -	$ -	$ (468,000)	$ (1,286,985)	$ 5,890	$ (185,097)
16	Total Rate Base	$ (3,585,076)	$ (1,066,657)	$ (225,445)	$ (468,000)	$ (1,286,985)	$ (352,892)	$ (185,097)

Southwest Gas Corporation
Summary of Rate Base Adjustments
Reconstruction Cost New Depreciated
Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B.1 (RCND)

Line No.	Description	Staff Adjustments	Corrections to Completed Construction Not Classified	Yuma Manors Pipe Replacement	Cash Working Capital	Accumulated Deferred Income Taxes - Bonus Tax	Remove Corporate Aircraft Costs	Remove One-Half of Prepaid D&O Insurance
			B-1	B-2	B-3	B-4	B-5	B-6
	Gas Plant in Service							
1	Direct	$ (335,852)	$ (110,407)	$ (225,445)				
2	System Allocable	$ (1,512,324)	$ (956,250)				$ (556,074)	
3	Total Gross Plant	$ (1,848,176)	$ (1,066,657)	$ (225,445)	$ -	$ -	$ (556,074)	$ -
	Accumulated Depreciation and Amortization							
4	Direct	$ -						
5	System Allocable	$ 197,292					$ 197,292	
6	Total Accumulated Depreciation and Amortization	$ 197,292	$ -	$ -	$ -	$ -	$ 197,292	$ -
7	Net Gas Plant in Service	$ (1,650,884)	$ (1,066,657)	$ (225,445)	$ -	$ -	$ (358,782)	$ -
	Other Rate Base Items							
	Working Capital							
8	Cash Working Capital	$ (468,000)			$ (468,000)			
9	Materials and Supplies	$ -						
10	Prepayments	$ (185,097)						$ (185,097)
11	Customer Advances for Construction	$ -						
12	Customer Deposits	$ -						
13	Deferred Income Taxes	$ (1,281,095)				$ (1,286,985)	$ 5,890	
14	Other	$ -						
15	Total Other Rate Base Items	$ (1,934,192)	$ -	$ -	$ (468,000)	$ (1,286,985)	$ 5,890	$ (185,097)
16	Total Rate Base	$ (3,585,076)	$ (1,066,657)	$ (225,445)	$ (468,000)	$ (1,286,985)	$ (352,892)	$ (185,097)

Southwest Gas Corporation
Adjusted Net Operating Income

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C

Line No.	Description	As Adjusted by Company (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Revenues	$ 410,912,098	$ -	$ 410,912,098
2	Gas Cost		$ -	$ -
3	Total Margin	$ 410,912,098	$ -	$ 410,912,098
	Operating Expenses			
4	Other Gas Supply	$ 1,138,145	$ -	$ 1,138,145
5	Distribution	$ 100,579,868	$ 625,094	$ 101,204,963
6	Customer Accounts	$ 33,881,272	$ -	$ 33,881,272
7	Customer Information	$ 1,205,135	$ -	$ 1,205,135
8	Sales	$ -	$ -	$ -
	Administrative and General			
9	Direct	$ 6,339,402	$ (4,160,309)	$ 2,179,093
10	System Allocable	$ 58,786,097	$ (2,451,994)	$ 56,334,103
	Depreciation and Amortization			
11	Direct	$ 93,057,028	$ (17,099)	$ 93,039,929
12	System Allocable	$ 6,244,982	$ (115,257)	$ 6,129,725
13	Regulatory Amortizations	$ 284,581	$ -	$ 284,581
14	Other Taxes	$ 27,203,877	$ (138,360)	$ 27,065,517
15	Interest on Customer Deposits	$ 2,908,517	$ -	$ 2,908,517
16	Income Taxes	$ 14,217,365	$ 2,530,084	$ 16,747,449
17	Total Operating Expenses	$ 345,846,269	$ (3,727,841)	$ 342,118,428
18	Net Operating Income	$ 65,065,829	$ 3,727,841	$ 68,793,670

Notes and Source

Col. A: SWG filing, Schedule C-1, page 1 of 18, colume e
Col. B: Staff Schedule C.1

Southwest Gas Corporation
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2010

Line No.	Description	Staff Adjustments	CCNC Correction Depreciation and Property Tax Expense	Yuma Manors Depreciation and Property Tax Expense	Management Incentive Program	Restricted Stock/Unit Plan	Supplemental Executive Retirement Expense	American Gas Association Dues	Loss on Sale of Employee Homes for Relocation Expense
			C-1	C-2	C-3	C-4	C-5	C-6	C-7
	Operating Revenues								
1	Revenues	$ -							
2	Gas Cost	$ -							
3	Total Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses								
4	Other Gas Supply	$ -							
5	Distribution	$ 625,094							$ (374,906)
6	Customer Accounts	$ -							
7	Customer Information	$ -							
8	Sales	$ -							
	Administrative and General								
9	Direct	$ (4,160,309)			$ (1,768,249)	$ (1,033,723)	$ (1,225,220)		
10	System Allocable	$ (2,451,994)					$ (500,619)	$ (90,898)	$ (128,714)
	Depreciation and Amortization								
11	Direct	$ (17,099)	$ (4,218)	$ (12,881)					
12	System Allocable	$ (115,257)	$ (95,625)						
13	Regulatory Amortizations	$ -							
14	Other Taxes	$ (138,360)	$ (2,236)	$ (4,566)	$ (131,558)				
15	Interest on Customer Deposits	$ -							
16	EXPENSES BEFORE INCOME TAXES	$ (6,257,925)	$ (102,079)	$ (17,447)	$ (1,899,807)	$ (1,033,723)	$ (1,725,839)	$ (90,898)	$ (503,620)
17	PRE-TAX OPERATING INCOME	$ 6,257,925	$ 102,079	$ 17,447	$ 1,899,807	$ 1,033,723	$ 1,725,839	$ 90,898	$ 503,620
18	Income Taxes	$ 2,530,084	$ 40,351	$ 6,897	$ 750,979	$ 408,622	$ 682,210	$ 35,931	$ 199,077
19	TOTAL OPERATING EXPENSES	$ (3,727,841)	$ (61,728)	$ (10,550)	$ (1,148,828)	$ (625,101)	$ (1,043,629)	$ (54,967)	$ (304,543)
20	OPERATING INCOME	$ 3,727,841	$ 61,728	$ 10,550	$ 1,148,828	$ 625,101	$ 1,043,629	$ 54,967	$ 304,543

Notes and Source

Combined Effective Tax Rate 39.5292%
Per SWG Schedule C-3, page 2

Southwest Gas Corporation
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2010

Line No.	Description	Test Year Rent Charged to Affiliate IntelliChoice Energy LLC	Gas Heat Pump Development Expenses	Interest Synchronization	Directors' and Officers' Liability Insurance	Self-Insurance Retention Expense	Leased Aircraft Operating Costs	COYL Leak Detection Survey
		C-8	C-9	C-10	C-11	C-12	C-13	C-14
	Operating Revenues							
1	Revenues							
2	Gas Cost							
3	Total Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses							
4	Other Gas Supply							
5	Distribution							$ 1,000,000
6	Customer Accounts							
7	Customer Information							
8	Sales							
	Administrative and General							
9	Direct	$ (13,156)				$ (119,961)		
10	System Allocable		$ (711,287)		$ (386,402)	$ (459,813)	$ (174,261)	
	Depreciation and Amortization							
11	Direct							
12	System Allocable						$ (19,632)	
13	Regulatory Amortizations							
14	Other Taxes							
15	Interest on Customer Deposits							
16	EXPENSES BEFORE INCOME TAXES	$ (13,156)	$ (711,287)	$ -	$ (386,402)	$ (579,774)	$ (193,893)	$ 1,000,000
17	PRE-TAX OPERATING INCOME	$ 13,156	$ 711,287	$ -	$ 386,402	$ 579,774	$ 193,893	$ (1,000,000)
18	Income Taxes	$ 5,200	$ 281,166	$ 56,377	$ 152,742	$ 229,180	$ 76,644	$ (395,292)
19	TOTAL OPERATING EXPENSES	$ (7,956)	$ (430,121)	$ 56,377	$ (233,660)	$ (350,594)	$ (117,249)	$ 604,708
20	OPERATING INCOME	$ 7,956	$ 430,121	$ (56,377)	$ 233,660	$ 350,594	$ 117,249	$ (604,708)

Notes and Source

Combined Effective Tax Rate 39.5292%
Per SWG Schedule C-3, page 2

Southwest Gas Corporation
Capital Structure & Cost Rates
Cost of Service Methodology

Docket No. G-01551A-10-0458
Schedule D

Test Year Ended June 30, 2010

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	I. SWG Proposed				
	A. Weighted Average Cost of Capital for Original Cost Rate Base				
1	Long-Term Debt		47.70%	8.34%	3.98%
2	Common Equity		52.30%	11.00%	5.75%
3	Total		100.00%		9.73%
	B. Fair Value Rate of Return for Fair Value Rate Base				
4	Long-Term Debt		35.16%	8.34%	2.93%
5	Common Equity		38.55%	11.00%	4.24%
6	Appreciation Above OCRB		26.28%	1.24%	0.32%
7	Total		100.00%		7.50%
	II. Staff Proposed				
	A. Weighted Average Cost of Capital for Original Cost Rate Base [b]				
8	Long-Term Debt		47.70%	8.34%	3.98%
9	Common Equity		52.30%	9.75%	5.10%
10	Total		100.00%		9.08%
	B. Fair Value Rate of Return for Fair Value Rate Base - Alternative 1 [a]				
11	Long-Term Debt		35.13%	8.34%	2.93%
12	Common Equity		38.52%	9.75%	3.76%
13	Appreciation Above OCRB		26.35%	0.00% [a]	0.00%
14	Total		100.00%		6.69%
	B. Fair Value Rate of Return for Fair Value Rate Base - Alternative 2 [b]				
15	Long-Term Debt		35.13%	8.34%	2.93%
16	Common Equity		38.52%	9.75%	3.76%
17	Appreciation Above OCRB		26.35%	1.25% [b]	0.33%
18	Total		100.00%		7.02%

Notes and Source

Lines 1-7: SWG Schedule D-1

Lines 11-14, Col.A:

		Amount		Percent
19	Fair Value Rate Base	###########	Schedule A	
20	Original Cost Rate Base	###########	Schedule A	73.65%
21	Difference	$ 382,816,834		26.35%
				100.00%

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

22	Long-Term Debt	35.13%
23	Common Equity	38.52%
24	Appreciation Above OCRB	26.35%
25	Total	100.00%

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost, per Staff witness Parcell.

[b] Per Staff witness David Parcell

Southwest Gas Corporation
Corrections to Completed Construction Not Classified

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B-1

Line No.	Description	Account	Amount (A)	Reference
	I. Southwest Gas Arizona Direct			
1	Company proposed adjustment		$ 2,806,169	SWG Filing, Adjustment 17
2	Amount corrected for plant in service at 6/30/2010		$ 2,695,762	Response to STF-6-7
3	Adjustment (decrease) to Company's requested rate base	376	$ (110,407)	
4	Percentage reduction		-3.93%	Line 3 / Line 1
5	Percentage relationship of corrected amount to Company's original amount		96.07%	Line 2 / Line 1
	II. Remove SCADA Project from System Allocable Account 303			
6	Adjustment (decrease) to Company's requested rate base		$ (1,700,000)	Response to STF-6-7(d)
7	Four-factor Allocation to Arizona Jurisdictional		56.25%	
8	Adjustment (decrease) to Company's requested rate base	303	$ (956,250)	
	III. Total Adjustment to ADIT for Tax Depreciation on CCNC			
9	Arizona Direct	376	$ (110,407)	Line 3
10	Corporate System Allocable	303	$ (956,250)	Line 8
11	Total Adjustment		$ (1,066,657)	

Notes and Source

	System Allocable CCNC:		
12	Per Southwest's Filing	$ 5,839,131	SWG Filing, Adjustment 17
13	As corrected to remove SCADA Project	$ 4,139,131	Response to STF-6-7(d)
14	Adjustment	$ (1,700,000)	Response to STF-6-7(d)

Southwest Gas Corporation
Yuma Manors Pipe Replacment

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B-2

Line No.	Description	Account	Account 376 Mains Amount (A)	Account 380 Services Amount (B)	Total Amount (C)	Reference
	I. Staff Adjustment in SWG's Last Rate Case Adopted by the Commission					
	Staff Adjustment					
1	Adjustment to Test Year Plant in Service		$ (737,377)	$ (494,385)	$ (1,231,762)	Note A
2	Adjustment to Test Year Accumulated Depreciation		$ 116,703	$ 22,611	$ 139,314	Note A
3	Adjustment to Test Year Net Plant		$ (620,674)	$ (471,774)	$ (1,092,448)	
4	Adjustment adopted in Decision No. 70665 (50%)		$ (310,337)	$ (235,887)	$ (546,224)	Note B
5	Amount written off by Southwest Gas				$ 320,779	Note C
6	Amount remaining in SWG's rate base				$ 225,445	Note C; - (L4&L5)
	II. Remove Disallowance Amount from Last Rate Case that SWG Included in Current Case Rate Base					
7	Remove amount SWG included in rate base				$ (225,445)	Note C; - Line 6

Notes and Source

A Testimony of Staff Witness Ralph Smith in Docket No. G-01551A-07-0504, Attachment RCS-2, Schedule B-1
B Decision No. 70665 at page 8
C SWG witness Robert Mashas direct testimony, page 21

Allocation of remaining amount between mains and services for calculation of Depreciation Expense adjustment:

From Docket No. G-01551A-07-0504:	Amount (D)	Percent (E)	Allocation (F)	
Account 376, Mains	$ (310,337)	56.8150%	$ (128,087)	Note D
Account 380, Services	$ (235,887)	43.1850%	$ (97,358)	Note D
Total	$ (546,224)	100.0000%	$ (225,445)	Note D

D Also see SWG's response to data request STF-16-1, line 19

Southwest Gas Corporation

Cash Working Capital
Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B-3

Line No.	Description	Per Company Cost (A)	Staff Adjustments (B)	Staff Adjusted (C)	Lag Days (D)	Dollar Days (E)
1	Cost of Gas	$ 379,159,715	$ -	$ 379,159,715	42.43	$ 16,087,746,707
2	Labor Cost	$ 130,360,854	$ (5,254,018)	$ 125,106,836	10.90	$ 1,363,664,509
3	Provision for Uncollected Accounts	$ 2,008,980	$ -	$ 2,008,980	120.00	$ 241,077,600
4	Other O & M Expenses	$ 68,719,020	$ (1,459,398)	$ 67,259,622	2.03	$ 136,537,033
5	Total O & M Expenses	$ 580,248,569	$ (6,713,416)	$ 573,535,153	30.73	$ 17,829,025,849
6	Interest	$ 42,713,744	$ (142,621)	$ 42,571,123	91.00	$ 3,873,972,193
7	Taxes Other Than Income Taxes	$ 27,203,877	$ (138,360)	$ 27,065,517	174.28	$ 4,716,978,303
8	Income Taxes-Current	$ 26,047,797	$ 2,530,084	$ 28,577,881	37.00	$ 1,057,381,597
9	Total Operating Expenses	$ 676,213,987	$ 2,391,724	$ 671,749,674	40.90	$ 27,477,357,942
10	Number of Days in Test Period	365		365		
11	Average Daily Operating Expense	$ 1,852,641		$ 1,840,410		
12	Lag in Receipt of Payment of Cash Expenses	40.64			40.90	
13	Lag in Receipt of Revenue	38.22			38.22	
14	Net Difference Revenue-Expense Lag	(2.41)		(2.68)		
	Cash Working Capital:					
14	Per Staff			$ (4,939,960)		
15	Per Company	$ (4,472,151)		$ (4,472,151)		
16	Staff Adjustment			$ (467,809)		
17	Staff Adjustment (rounded to thousands)			$ (468,000)		

Notes and Source

Col.A: SWG Sch B-5, page 2 of 4
Col.B: Staff Schedule B-3 workpaper
Col.C: Col. A + Col.B
L.6: Schedule C-10, L.3, Synchronized interest
Col.D: SWG Sch B-5, page 2 of 4
Col.E: Col. C x Col.D

Southwest Gas Corporation
Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC

Test Year Ended June 30, 2010

Line No.	Description	Account	Amount (A)	Reference
	I. Southwest Gas Arizona Direct			
1	Correction to Southwest's filing for ADIT on CCNC		$ (704,030)	Response to STF-6-7(d)
2	Relationship of CCNC corrected and original claimed CCNC		96.07%	Schedule B-1
3	Adjustment (decrease) to Company's requested rate base	282	$ (676,330)	
	II. Southwest Gas Corporate System Allocable			
4	Correction to Southwest's filing for ADIT on CCNC		$ (1,085,609)	Response to STF-6-7(d)
5	Relationship of CCNC corrected and original claimed CCNC		100%	Note A
6	Adjustment (decrease) to Company's requested rate base		$ (1,085,609)	
7	Four-factor Allocation to Arizona Jurisdictional		56.25%	Note B
8	Adjustment (decrease) to Company's requested rate base	282	$ (610,655)	
	III. Total Adjustment to ADIT for Tax Depreciation on CCNC			
9	Arizona Direct		$ (676,330)	Line 3
10	Corporate System Allocable		$ (610,655)	Line 8
11	Total Adjustment	282	$ (1,286,985)	

Notes and Source

A Per Southwest's response to STF-6-7(d):
"The Company is removing the $1,700,000 cost of the SCADA system originally included in Adjustment 17 in System Allocable Account 303. There was no deferred tax associated with this project included in this application, therefore, no adjustment to deferred taxes related to the removal of this project is required."

B SWG Schedule B-6, Sheet 3 of 3

Details of System Allocable Federal ADIT:

12	Account 282 - Federal ADIT Liability	$ 15,583,217	SWG Schedule B-6, Sheet 3
13	Correction to reflect ADIT on CCNC	$ 1,085,609	Response to STF-6-7(d)
14	Account 282 - Federal ADIT Liability, as corrected	$ 16,668,826	Response to STF-6-7(d)

Southwest Gas Corporation
Remove Corporate Aircraft Costs

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B-5

Line No.	Description	Airplane Hanger (A)	Airplane Equipment (B)	Total Arizona Allocation (C)	Staff Adjustment (D)
1	Original Cost	$ 509,388	$ 46,686	$ 556,074	$ (556,074)
2	Accumulated Depreciation	$ (160,803)	$ (36,489)	$ (197,292)	$ 197,292
3	Accumulated Deferred Income Taxes	$ (2,321)	$ (3,569)	$ (5,890)	$ 5,890
4	Net Arizona Rate Base	$ 346,264	$ 6,628	$ 352,892	$ (352,892)

Notes and Source

SWG's response to data request STF-7-9

Southwest Gas Corporation
Remove One-Half of Prepaid D&O Insurance

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B-6

Line No.	Description	Account	Prepaid D&O Insurance In AZ Jurisdictonal Rate Base (A)	Staff Allowance (One-Half) (B)	Staff Adjustment (C)
1	Prepayments	165	$ 370,193	$ 185,097	$ (185,097)

Notes and Source

SWG's response to data request STF-6-9

Southwest Gas Corporation
CCNC Correction Depreciation and Property Tax Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-1

Line No.	Description	Account	Plant Amount (A)	Depreciation Rate (B)	Adjustment to Depreciation Expense (C)
1	Arizona Direct	376	$ (110,407)	3.82%	$ (4,218) [a]
2	Corporate System Allocable	303	$ (956,250)	10.00%	$ (95,625) [b]
3	Adjustment to Annualized Depreciation Expense		$ (1,066,657)		$ (99,843)

Notes and Source

Col.A: Schedule B-1
Col.B: SWG Depreciation and Annualization Expense Excel file workpaper
SWG wp 303, 10-year amortization applied for $1.7 million SCADA post test year adjustment
Col.C: Col. A x Col. B
[a] Also see, SWG's response to STF-16-3
[b] Also see, SWG's response to STF-16-2

FERC 403

Southwest Gas Corporation
CCNC Correction Depreciation and Property Tax Expense

Docket No. G-01551A-10-0458
Schedule C-1

Test Year Ended June 30, 2010

Line No.	Description	Amount	Reference
	Adjustment to Property Tax Expense		
1	Adjustment to Net Plant in Service	$ (110,407)	Note A
2	Statutory Assessment Ratio	20.0%	Note C
3	Taxable Value	$ (22,081)	Note C
4	Property Tax Rate	10.13%	Notes C and B
5	Property Tax Expense Adjustment	$ (2,236)	Note C

Notes and Source

A Schedule B-1, line 3
B Also see Company's Schedule C-2, Adj. No. 14
C Also see, Company's response to STF 16-2 and STF 16-3

FERC 408.1

Southwest Gas Corporation
Yuma Manors Depreciation and Property Tax Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-2

Line No.	Description	Plant Amount (A)	Depreciation Rate (B)	Adjustment to Depreciation Expense (C)
1	Account 376, Mains	$ (186,438)	3.82%	$ (7,122)
2	Account 380, Services	$ (108,664)	5.30%	$ (5,759)
3	Adjustment to Plant and Annualized Depreciation Expense	$ (295,102)		$ (12,881) [a]
4	Decision No. 70665, Adjustment to Accumulated Depreciation	$ 69,657		
5	Decision No. 70665, Adjustment to Net Plant	$ (225,445)		

Notes and Source

Col.A: Schedule B-2 and SWG's response to STF-16-1
Col.B: SWG Depreciation and Annualization Expense Excel file workpaper
Col.C: Col. A x Col. B
[a] Also see Company's response to STF-16-1

FERC 403

Southwest Gas Corporation
Yuma Manors Depreciation and Property Tax Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-2

Line No.	Description	Amount	Reference
	Adjustment to Property Tax Expense		
1	Adjustment to Net Plant in Service	$ (225,445)	Note A
2	Statutory Assessment Ratio	20.0%	Note C
3	Taxable Value	$ (45,089)	Note C
4	Property Tax Rate	10.13%	Notes C and B
5	Property Tax Expense Adjustment	$ (4,566)	Note C

Notes and Source

A Schedule B-2
B Also see Company's Schedule C-2, Adj. No. 14
C Also see Company's response to STF-16-1
FERC 408.1

Southwest Gas Corporation
Management Incentive Program

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-3

Line No.	Description	Amount	Reference
1	Adjustment to Management Incentive Program Expense	$ (1,768,249)	A
2	Related Adjustment to Payroll Tax Expense	$ (131,558)	B
3	Total reduction to test year operating expenses	$ (1,899,807)	L1 and L2

Notes and Source

A	Adjustment to Management Incentive Program Expense		
	Amount below from SWG's responses to STF-1-83 and STF 17-2		
4	Test Year amount of Management Incentive Program Expense (Corporate)	$ 6,537,494	STF 17-2(a)
5	Allocation to Paiute (MMF)	$ (250,386)	3.83%
6	Net of Allocation to Paiute	$ 6,287,108	
7	Arizona Four Factor allocation rate per SWG Schedule C-1, sheet 17	56.25%	
8	Test Year amount of Management Incentive Program Expense (Arizona)	$ 3,536,498	
9	Shareholder allocation percentage	50%	
10	50% Allocation of MIP Expense to Shareholders	$ 1,768,249	FERC 920
B	Adjustment to Payroll Tax Expense		
11	Adjustment to Test Year MIP Expense	$ 1,768,249	Line 10
12	Payroll Tax Expense Rate	7.440%	C
13	Adjustment to Payroll Tax Expense	$ 131,558	

C Estimated based on SWG's annualized payroll tax expense per
SWG Workpaper Supporting Adjustment No. 3, Annualized Fica And Medicare

Southwest Gas Corporation
Stock Based Compensation (Other Than MIP)

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-4

Line No.	Description	Amount	Reference
1	Adjustment to remove expense for Stock Based Compenation (other than MIP)	$ (1,033,723)	A

Notes and Source

A	Response to STF-6-5, amount is after allocation to Arizona	
	Compare, RSUP from SWG's response to STF-17-2	$ (1,033,831)

Account 920

Southwest Gas Corporation
Supplemental Executive Retirement Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-5

Line No.	Description	Total Amount (A)	Arizona Amount (B)
1	Test Year Supplemental Executive Retirement Expense (Arizona)	$ (1,419,193)	$ (1,154,655)
2	Test Year Supplemental Executive Retirement Expense (Corporate Direct Arizona)	$ (70,565)	$ (70,565)
3	System Allocable Amount of SERP	$ (962,289)	$ (500,619)
4	Total	$ (2,452,046)	$ (1,725,839) [a]

Notes and Source

Col.A: SWG Workpaper Supporting Adjustment No. 3, Annualized Employee Benefits, Line 12, SERP
Col.B: SWG's response to STF 17-1
[a] Represents estimated amount of SERP expense in SWG's filing
SERP is recorded by SWG in FERC 926 and then allocated to other expense accounts via SWG's labor loading.

Southwest Gas Corporation
American Gas Association Dues

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-6

Line No.	Description	Staff Adjustment (A)	Company Adjustment (B)	Net Staff Adjustment (C)	Reference
1	2009 AGA Dues per Filing	$ 495,541	$ 495,541		A
2	Recommended disallowance percentage	40%	6.09%		B
3	Recommended disallowance	$ (198,216)	$ (30,178)		L1 x L2
4	Less: Paiute & SGTC Allocation at 3.83%	$ 7,592	$ 1,156		C
5	Adjustment to AGA Dues Before Four-Factor	$ (190,624)	$ (29,022)		
6	Arizona Four-Factor Allocation	56.25%	56.25%		D
7	Adjustment to Arizona Related AGA Dues	$ (107,222)	$ (16,324)	$ (90,898)	

Notes and Source

A: SWG Filing, Schedule C-2, Adjustment No. 10, line 1
B: See testimony of Staff witness Ralph C. Smith and page 2 of this schedule
C: SWG Filing, Schedule C-2, Adjustment No. 10, line 4
D: SWG Filing, Schedule C-1, Sheet 17, Line 10(b)

FERC Account 930.2

Southwest Gas Corporation
American Gas Association
Schedule of Expenses by NARUC Category

Line No.	NARUC Operating Expense Category	March 2005 NARUC Audit Report for Year Ended 12/31/02		AGA 2007 Budget			AGA 2008 Budget		
		% of Dues	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Public Affairs	24.13%	24.13%	23.29%	28.67%	28.67%	24.44%	30.63%	30.63%
2	Advertising			1.39%	1.71%	1.71%	1.18%	1.48%	1.48%
3	Communications	15.53%							
4	Corporate Affairs and International	10.54%	10.54%	8.44%	10.39%	10.39%	9.14%	11.46%	11.46%
5	General Counsel & Corp Secretary	5.20%	2.60%	4.09%	5.04%	2.52%	4.17%	5.23%	2.62%
6	Regulatory Affairs	15.51%							
7	Policy Planning & Regulatory Affairs			14.76%	18.17%		15.78%	19.78%	
8	Marketing Department	2.37%	2.37%						
9	Operating & Engineering Services	15.85%		24.11%	29.68%		21.71%	27.21%	
10	Policy & Analysis	12.94%							
11	Industry Finance & Admin. Programs	4.75%		5.16%	6.35%		3.36%	4.21%	
12	General & Administrative			18.77%			20.22%		
13	Total Expenses	106.82%	39.64%	100.01%	100.01%	43.29%	100.00%	100.00%	46.19%
14	Lobbying per IRC Section 162			2%			4%		

Notes and Source

Col.A: March 2005 Annual Audit Report on the Expenditures of the American Gas Association for the 12 month period ended December 31, 2002
Col.C: Southwest's Response to Staff data request STF-6-52 from SWG's last rate case, Docket No. G-01551A-07-0504
Col.F: Southwest's Response to Staff data request STF-6-50(b) from SWG's last rate case, Docket No. G-01551A-07-0504

Southwest Gas Corporation
American Gas Association
Schedule of Expenses by NARUC Category

Docket No. G-01551A-10-0458
Schedule C-6

Line No.	AGA Categories of Expenses	2001	2002	2003	2004	2005	2006	2007	2008	2009	Forecast 2010
	I. AGA Expenditures from STF-6-21										
1	Public Affairs	$ 5,703,920	$ 5,939,486	$ 6,336,326	$ 7,015,121	$ 5,726,187	$ 5,878,345	$ 5,563,947	$ 7,036,204	$ 6,087,552	$ 6,143,000
2	Policy, Planning & Regulatory Affairs	3,382,900	3,261,692	3,212,553	3,031,053	3,120,112	3,325,727	3,925,034	4,041,413	4,277,647	4,427,000
3	Market Development	1,196,791	349,589	-	-	-	-	-	-	-	-
4	Corporate Affairs	2,123,818	2,014,503	2,304,775	1,993,049	2,072,208	2,398,515	2,271,158	2,754,868	2,880,397	2,354,000
5	Operations & Engineering Management	3,664,863	3,729,829	4,302,428	4,262,228	5,154,993	5,116,637	5,693,934	5,119,289	5,474,235	5,085,000
6	Industry Finance & Administrative Programs	934,852	1,230,238	1,157,023	1,286,859	1,363,591	1,252,846	1,516,308	996,593	1,027,748	1,129,000
7	General Counsel	641,984	768,219	757,481	746,667	808,157	877,030	945,643	1,043,295	1,172,072	1,067,000
8	General and Administrative	4,273,134	3,894,457	4,124,675	5,034,491	4,322,358	4,676,721	4,932,418	5,275,571	5,569,647	5,535,000
9	**Total Expense Actuals**	$ 21,922,262	$ 21,188,013	$ 22,195,261	$ 23,369,468	$ 22,567,606	$ 23,525,821	$ 24,848,442	$ 26,267,233	$ 26,489,298	$ 25,740,000
	II. Percentage of Annual Totals by Category										
10	Public Affairs	26.02%	28.03%	28.55%	30.02%	25.37%	24.99%	22.39%	26.79%	22.98%	23.87%
11	Policy, Planning & Regulatory Affairs	15.43%	15.39%	14.47%	12.97%	13.83%	14.14%	15.80%	15.39%	16.15%	17.20%
12	Market Development	5.46%	1.65%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	Corporate Affairs	9.69%	9.51%	10.38%	8.53%	9.18%	10.20%	9.14%	10.49%	10.87%	9.15%
14	Operations & Engineering Management	16.72%	17.60%	19.38%	18.24%	22.84%	21.75%	22.91%	19.49%	20.67%	19.76%
15	Industry Finance & Administrative Programs	4.26%	5.81%	5.21%	5.51%	6.04%	5.33%	6.10%	3.79%	3.88%	4.39%
16	General Counsel	2.93%	3.63%	3.41%	3.20%	3.58%	3.73%	3.81%	3.97%	4.42%	4.15%
17	General and Administrative	19.49%	18.38%	18.58%	21.54%	19.15%	19.88%	19.85%	20.08%	21.03%	21.50%
18	Totals	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
19	Totals excluding General & Administrative	80.51%	81.62%	81.42%	78.46%	80.85%	80.12%	80.15%	79.92%	78.97%	78.50%
	III. Percentage of Totals With G&A Allocated										
20	Public Affairs	32.32%	34.35%	35.06%	38.26%	31.38%	31.19%	27.94%	33.52%	29.10%	30.40%
21	Policy, Planning & Regulatory Affairs	19.17%	18.86%	17.78%	16.53%	17.10%	17.64%	19.71%	19.25%	20.45%	21.91%
22	Market Development	6.78%	2.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
23	Corporate Affairs	12.03%	11.65%	12.75%	10.87%	11.36%	12.72%	11.40%	13.12%	13.77%	11.65%
24	Operations & Engineering Management	20.77%	21.57%	23.81%	23.25%	28.25%	27.15%	28.59%	24.39%	26.17%	25.17%
25	Industry Finance & Administrative Programs	5.30%	7.11%	6.40%	7.02%	7.47%	6.65%	7.61%	4.75%	4.91%	5.59%
26	General Counsel	3.64%	4.44%	4.19%	4.07%	4.43%	4.65%	4.75%	4.97%	5.60%	5.28%
27	General and Administrative										
28	Totals	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	IV. Calculated Disallowance Percentages										
29	Public Affairs	32.32%	34.35%	35.06%	38.26%	31.38%	31.19%	27.94%	33.52%	29.10%	30.40%
30	Policy, Planning & Regulatory Affairs										
31	Market Development										
32	Corporate Affairs	12.03%	11.65%	12.75%	10.87%	11.36%	12.72%	11.40%	13.12%	13.77%	11.65%
33	Operations & Engineering Management										
34	Industry Finance & Administrative Programs										
35	General Counsel	1.82%	2.22%	2.10%	2.04%	2.21%	2.33%	2.37%	2.49%	2.80%	2.64%
36	General and Administrative										
37	Totals	46.17%	48.22%	49.91%	51.17%	44.96%	46.24%	41.71%	49.13%	45.67%	44.69%

Notes and Source

Lines 1-9: *Southwest Gas'* response to data request STF-6-21

Southwest Gas Corporation
Loss on Sale of Employee Homes for Relocation Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-7

Line No.	Description	Account	Company Recorded (A)	Staff Adjusted (B)	Staff Adjustment (C)
	I. Adjust to Normalized Level				
	Employee Relocation Expense And Losses Associated With Sales Of Employee Homes				
1	Arizona	88000001	$ 374,906	$ 199,331	$ (175,574)
2	Corporate Allocated	92100001	$ 237,939	$ 111,574	
3	Paiute & SGTC MMF		3.83%	3.83%	
4	Less: Paiute & SGTC Allocation		$ 9,113	$ 4,273	
5	Relocation Expenses Before 4-Factor		$ 228,826	$ 107,301	
6	Arizona 4-Factor Allocation		56.25%	56.25%	
7	Adjustment Allocated to Arizona	92100001	$ 128,714	$ 60,357	$ (68,357)
8	Total Arizona Relocation Costs		$ 503,620	$ 259,688	$ (243,931)
	II. Remove Remaining Expense from Test Year				
9	Arizona Direct				$ (199,331)
10	Corporate Allocated				$ (60,357)
11	Total				$ (259,688)
	II. Total Staff Adjustment to Remove Expense from Test Year				
12	Arizona Direct				$ (374,906)
13	Corporate Allocated				$ (128,714)
14	Total				$ (503,620)

Notes and Source

Col.A SWG's response to data request STF-6-29; also see page 2 of this schedule
Col.B Normalized Using a Five-Year Average. See page 2 of this schedule

Line No.	Description	2006 Loss	2006 Commission	2007 Loss	2007 Commission	2008 Loss	2008 Commission	2009 Loss	2009 Commission	2010 Loss	2010 Commission	Test Year July 2009 - June 2010 Loss	Test Year July 2009 - June 2010 Commission
	I. Annual Information Provided by Company												
1	Arizona - Account 88000001	$ -	$ -	$ 170,312	$ 33,144	$ 681,746	$ 62,220	$ 74,007	$ 14,400	$ 70,592	$ 34,338	$ 374,906	$ 62,520
2	Corporate - Account 92100001	$ 55,444	$ 23,940	$ 35,366	$ 16,440	$ 247,851	$ 49,830	$ 219,210	$ 20,700	$ -	$ -	$ 237,939	$ 50,100
3	Paiute & SGTC MMF	4.12%	4.12%	3.91%	3.91%	3.90%	3.90%	3.89%	3.89%	3.84%	3.84%	3.83%	3.83%
4	Less: Paiute & SGTC Allocation	$ 2,284	$ 986	$ 1,383	$ 643	$ 9,666	$ 1,943	$ 8,527	$ 805	$ -	$ -	$ 9,113	$ 1,919
5	Relocation Expenses Before 4-Factor	$ 53,160	$ 22,954	$ 33,983	$ 15,797	$ 238,184	$ 47,887	$ 210,683	$ 19,895	$ -	$ -	$ 228,826	$ 48,181
6	Arizona 4-Factor Allocation	56.81%	56.81%	56.81%	56.81%	56.54%	56.54%	56.42%	56.42%	56.05%	56.05%	56.25%	56.25%
7	Adjustment Allocated to Arizona	$ 30,200	$ 13,040	$ 19,306	$ 8,974	$ 134,669	$ 27,075	$ 118,867	$ 11,225	$ -	$ -	$ 128,715	$ 27,102
8	Total Arizona Relocation Costs	$ 30,200	$ 13,040	$ 189,617	$ 42,118	$ 816,416	$ 89,295	$ 192,874	$ 25,625	$ 70,592	$ 34,338	$ 503,620	$ 89,622

Notes and Source

SWG response to data request STF 6.29 (a), (b), (c) and (f)

Please note, for illustrative purposes, commissions were shown separately; however commissions are included in the loss amounts.

II. Summary of Loss on Sale of Employee Homes

	Year	Total AZ	AZ Direct Acct 921	Corporate Before Allocation Acct 880
9	2006	$ 30,200	$ -	$ 55,444
10	2007	$ 189,617	$ 170,312	$ 35,366
11	2008	$ 816,416	$ 681,746	$ 247,851
12	2009	$ 192,874	$ 74,007	$ 219,210
13	2010	$ 70,592	$ 70,592	$ -
14	**Average**	**$ 259,940**	**$ 199,331**	**$ 111,574**
15	**Test Year**	**$ 503,620**	**$ 374,906**	**$ 237,939**
16	TY Vs Avg $	$ 243,680	$ 175,574	$ 126,365
17	TY Vs Avg %	194%	188%	213%
	TY compared with:			
18	2009 $	$ 310,746	$ 300,899	$ 18,729
19	%	261.1%	506.6%	108.5%
20	2010 $	$ 433,028	$ 304,313	$ 237,939
21	%	713.4%	531.1%	N/A

Southwest Gas Corporation
Test Year Rent Charged to Affiliate IntelliChoice Energy LLC

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-8

Line No.	Description	FERC Account	Amount	Reference
	Test Year Rent that should have been reimbursed by affiliate ICE			
1		908	$ (1,760)	SWG Response to STF-11-1(n)
2		931	$ (11,396)	SWG Response to STF-11-1(n)
3	Total		$ (13,156)	

Notes and Source

Per SWG's response to data requeset STF-11-1(n), due to a billing error, ICE was not billed for its portion of rent and utilities during the test year. SWG identified the amount of rent that was not reimbursed in that response. Those amounts are removed from test year expense.

Southwest Gas Corporation
Gas Heat Pump Development Expenses

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-9

Line No.	Description	Account	Total EETD Amount (A)	Total GHP Development Amount (B)	Arizona EETD Amount (C)	Arizona as Percent of Total EETD (D)
	Remove Gas Heat Pump Development Expenses					
1		908	$ 1,679,741	$ (1,091,832)	$ 906,220	53.95%
2		920	$ 13,611	$ (8,847)	$ 13,853	101.78%
3		921	$ 8,477	$ (5,510)	$ 4,585	54.09%
4		930.2	$ 250,000	$ (162,500)		
5		931	$ 64,015	$ (41,609)	$ 34,629	54.10%
6	Total O&M Expense		$ 2,015,843	$ (1,310,298)	$ 959,287	
7	Account 930.2		$ 250,000		$ 135,000	54.00%
8	Total Arizona EETD				$ 1,094,287	
9	Portion of EETD related to GHP development				65%	
10	Adjustment to Test Year O&M Expense				$ (711,287)	

Notes and Source

Col.A: SWG response to STF-11-1(b) and STF-11-21; see page 2 of this Schedule
Col.B: 65% of EETD expenses are for Gas Heat Pump development per SWG's response to STF-11-1
Col A x 65%
Col.C: SWG response to STF-11-21 provided Arizona amounts for Accounts 908, 920, 921 and 931
Line 7: Arizona allocation estimated at 54 percent
Col.D: Col.C / Col.A

Southwest Gas Corporation
Gas Heat Pump Development Expenses

Test Year Ended June 30, 2010

Line No.	Account/Description	2008	2009	2010	TME 6/30/2010	
	(a)	(b)	(c)	(d)	(e)	
1	182.3	$ -	$ 731,681	$ 550,532	$ 336,626	
2	426.5	56,384	83,696	38,491	27,307	
3	908	1,799,610	1,817,865	1,974,948	1,679,741	[a]
4	920	44,246	92,303	-	13,611	[a]
5	921	2,805	13,321	427	8,477	[a]
6	930.2	-	250,000	250,000	250,000	[a]
7	931	66,799	63,603	69,028	64,015	[a]
8	Total EETD	$ 1,969,844	$ 3,052,469	$ 2,883,426	$ 2,379,775	
9	Est. GHP%	85%	65%	65%	65%	[a]
10	Alloc to GHP	$ 1,674,368	$ 1,984,105	$ 1,874,227	$ 1,546,854	
11	Cumulative GHP Cost	**1,674,368**	**3,658,472**	**5,532,699**		
12	Estimated Arizona allocation	**54%**	**54%**	**54%**		
13	Estimated Cumulative AZ GHP Cost	**$ 904,159**	**$ 1,975,575**	**$ 2,987,657**		

Source

Lines 1-10: SWG response to data request STF-11-1(b)

Line 12: See page 1 of this Schedule and SWG response to STF-11-21

[a] See page 1 of this Schedule for operating expense adjustment to remove GHP development costs

Southwest Gas Corporation
Interest Synchronization

Test Year Ended June 30, 2010

Line No.	Description		Amount	Reference
1	Adjusted rate base	$	1,070,115,558	Schedule B
2	Weighted cost of debt		3.98%	Schedule D
3	Synchronized interest deduction	$	42,571,123	Line 1 x Line 2
4	Synchronized interest deduction per Company	$	42,713,744	Note A
5	Difference (decreased) increased interest deduction	$	(142,621)	Line 3 - Line 4
6	Combined federal and state income tax rates		39.529%	Schedule A-1
7	Increase (decrease) to income tax expense	$	56,377	

Notes and Source

A SWG Schedule C-3, Sheet 2 of 3

Southwest Gas Corporation
Directors' and Officers' Liability Insurance

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-11

Line No.	Description		Arizona Direct	System Allocable Before FERC Allocation	FERC Allocation 3.83%	System Allocable	System Allocable To Arizona 56.25%	Total
			(A)	(B)	(C)	(D)	(E)	(F)
	I. Company Test Year Recorded							
1	Reserve for Self Insurance	Note A	$ -	$ 1,428,590	$ (54,715)	$ 1,373,875	$ 772,805 c	$ 772,805
	II. Staff Recommended (50/50 Shareholder/Ratepayer Sharing)							
2	Staff Recommended	Note B		$ 714,295	$ (27,357)	$ 686,938	$ 386,403	$ 386,403
3	Staff Adjustment to SWG Request	L2 - L1		$ (714,295)			$ (386,402)	$ (386,402)

Notes and Source

A SWG's response to data request STF-1-72

B Allowance reflects 50/50 Shareholder/Ratepayer sharing of the D&O Liability Insurance Expense

Southwest Gas Corporation
Reserve for Self Insurance

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-12

Line No.	Description		Arizona Direct (A)	System Allocable Before FERC Allocation (B)	FERC Allocation 3.83% (C)	System Allocable (D)	System Allocable To Arizona 56.25% (E)	Total (F)
	I. Company Test Year Recorded							
1	Reserve for Self Insurance	Note A	$ 537,500	$ 275,000	$ (10,533)	$ 264,467	$ 148,763 c	$ 686,263
	II. Company Requested							
2	Reserve for Self Insurance	Note A	$ 834,961	$ 1,000,000	$ (38,300)	$ 961,700	$ 540,956	$ 1,375,917
3	Company proposed adjustment	Note A	$ 297,461	$ 725,000				$ 689,654
4	Percent increase over test year recorded amount	Note B	55.3%	263.6%				100.5%
	III. Staff Recommended							
5	Staff Recommended	Note C	$ 715,000	$ 150,000	$ (5,745)	$ 144,255	$ 81,143	$ 796,143
6	**Staff Adjustment to SWG Request**	Note D	**$ (119,961)**				**$ (459,813)**	**$ (579,774)**
6a	Staff Adjustment to SWG Request			$ (850,000)				
	IV. Staff Recommended Compared with Test Year Recorded							
7	Staff Recommended versus Test Year Recorded	Note E and F	33.0% E	-45.5% E				16.0% E
8	Staff Recommended increase from Test Year Recorded							$ 109,880

Notes and Source

A	Derived from SWG filing, Schedule C-2, Company Adjustment No. 9			
B	Line 3 / Line 1			
C	See page 2 of this schedule for details of Staff recommended normalized amount for self-insured expense.			
D	Line 5 - Line 2			
E	(Line 5 / Line 1) - 1			
F	Staff recommended compared with ten-year average excluding May 2005 extreme event			
9	Ten Year Average	Page 2	$ 713,828	$ 57,450
10	(Line 5 / Line 9) - 1		0.16% F	161.10% F

Southwest Gas Corporation
Injuries and Damages, Account 925
Reserve for Self-Insurance Expense Normalization
Test Year Ended June 30, 2010

Line No.	Description	Year	Total Expense Recorded Arizona (A)	Total Expense Recorded Common (B)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Arizona (C)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Common (D)	Staff Proposed Arizona (E)	Staff Proposed Common (F)
	Reserve for Self-Insurance Expense							
1		2001	$ 426,955	$ 100,000	$ 426,955	$ 100,000		
2		2002	$ 350,000	$ 200,000	$ 350,000	$ 200,000		
3		2003	$ 1,941,509	$ (300,000)	$ 1,941,509	$ (300,000)		
4		2004	$ 2,154,000	$ 275,000	$ 2,154,000	$ 275,000		
5		2005	$ 1,360,224	$ 10,367,500 a	$ 1,360,224			
6		2006	$ (975,540)	$ 200,000	$ (975,540)	$ 200,000		
7		2007	$ 713,629	$ (25,500)	$ 713,629	$ (25,500)		
8		2008	$ 230,000	$ (300,000)	$ 230,000	$ (300,000)		
9		2009	$ 400,000	$ 275,000	$ 400,000	$ 275,000		
10		2010	$ 537,500	$ 150,000	$ 537,500	$ 150,000		
11	Total, 2001 through TYE 6/30/2010		$ 7,138,277	$ 10,942,000	$ 7,138,277	$ 574,500		
12	Ten Year Average		$ 713,828	$ 1,094,200	$ 713,828	$ 57,450	$ 715,000 b	$ 150,000 c
13	Pauite allocation	3.83%		$ (41,960)		$ (2,203)		$ (5,752)
14	Common before AZ allocation			$ 1,052,240		$ 55,247		$ 144,248
15	AZ allocation	56.25%		$ 591,885		$ 31,076		$ 81,140
16	AZ allocated and direct		$ 713,828	$ 591,885	$ 713,828	$ 31,076	$ 715,000	$ 81,140
	Adjustment to Southwest Proposed as Filed							
17	Southwest Gas proposed:							
	Page 1, line 2, Cols.A and E, respectively		$ 834,961	$ 540,956	$ 834,961	$ 540,956	$ 834,961	$ 540,956
18	Adjustment to SWG Proposed As Filed, Based on Ten-Year Average		$ (121,133)	$ 50,929	$ (121,133)	$ (509,880)	$ (119,961)	$ (459,816)
19	Net adjustment to Arizona expense			$ (70,204)		$ (631,013)		$ (579,777)
				L.21, Col.A&B		L.21, Col.C&D		L.21, Col.E&F

Notes and Source

L 1-9: SWG's response to STF-6-12

L1-6: Also see, Staff Attachment RCS-2, Schedule C-12, from SWG's last rate case, Docket No. G-01551A-07-0504

L7-9: Also see, Company's response to STF-1-71, Reserve for Self Insurance, Account 92500001

Ten-Year Average is from the Company's' workpapers for Schedule C-2, Adjustment No. 10, Sheets 72 to 75 and response to data requests STF-6.12

a The 2005 common expense is abnormally high because of the impact of a May 2005 leaking gas line fire. The eventual settlement of that incident exceeded the Company's self-retention in effect at the time of the occurrence, per the response to data requests, such as STF-10-11(B) and (F) from Docket No. G-01551A-07-0504

b Ten-Year Average, rounded up to nearest $5,000

c Calendar 2010 accrual used as reasonably representative; note this amount exceeds the 10-year average, excluding the impact of the abnormal and extreme payout relating to the May 2005 leaking gas line fire.

Southwest Gas Corporation
Leased Aircraft Operating Costs

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-13

Line No.	Description	Amount (A)	Reference
	Normalize Leased Aircraft Expense Allocated to Arizona		
1	Normalized expense	$ 298,000	See line 16, below
2	Test year expense	$ 472,261	Note A
3	Adjustment to test year expense	$ (174,261)	Line 2 - Line 1
4	Remove Depreciation Expense on Corporate Aircraft	$ (19,632)	Response to STF 7.9
5	Total Adjustment to Operating Expenses	$ (193,893)	

Notes and Source

A Prior year amounts are from SWG's response to STF-10-26 in Docket No. G-0551A-07-0504.

	Account	2004 (B)	2005 (C)	2006 (D)	2007 (E)	Average (F)	Test Year [Note A] (G)	Percent Increase (H)
4	908				$ 1,800	$ 450	$ 3,545	688%
5	920	$ 208,306	$ 220,273	$ 259,841	$ 231,208	$ 229,907	$ 300,159	31%
6	921	$ 181,231	$ 225,338	$ 216,448	$ 193,086	$ 204,026	$ 232,453	14%
7	925						$ 22,713	n/a
8	930.2	$ 28,500	$ 42,210	$ 53,300	$ 35,950	$ 39,990	$ 43,005	8%
9	931	$ 24,101	$ 27,026	$ 24,049	$ 25,134	$ 25,078	$ 271,180	981%
10	935	$ 679	$ 924	$ 4,297		$ 1,475		n/a
11	Totals	$ 442,817	$ 515,771	$ 557,935	$ 487,178	$ 500,926	$ 873,055	74%
12	Allocation to Paiute Pipeline				3.83%	$ (19,210)	$ (33,480)	
13	Aircraft Expense Net of PP/SGTC					$ 481,716	$ 839,575	74%
14	Arizona allocation factor and normalized leased aircraft expense				56.25%	$ 270,965	$ 472,261	74%
15	Limit increase to 10 percent					1.10		
16	Recommended normalized allowance, rounded to nearest $1,000					$ 298,000	$ 472,261	58%

A	Response to STF 7.9			
B	Compare: Normalized amount allowed from Docket No. G-0551A-07-0504 Testimony of Staff witness Ralph Smith, Attachment RCS-2, Schedule C-13	$ 272,533	$ 472,261	73%

Southwest Gas Corporation
COYL Leak Detection Survey

Test Year Ended June 30, 2010

Line No.	Description	Cost for COYL Leak Detection Survey	Reference
1	Estimate for COYL leak detection survey	$ 3,000,000	Note A
2	Period, in years	3	Interval between SWG Arizona rate cases
3	Annual allowance for COYL leak detection survey	$ 1,000,000	

Notes and Source

[A] See testimony of Staff witness Frye for the recommendation concerning the COYL leak detection survey
Estimate is from Southwest's response to data request STF-20-3

Southwest Gas Corporation
Docket No. G-01551A-10-0458
Attachment RCS-3
Copies of SWG's Responses to Data Requests
and Workpapers Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
ACC-STF-6-7	Completed Construction Not Classified - removal of SCADA system not placed into service (without Attachment b)	No	4	2 - 5
ACC-STF-1-26	ADIT - 50% Bonus Depreciation	No	2	6 - 7
ACC-STF-6-9	Removal of 50% of Directors and Officers' Liability Insurance	No	2	8 - 9
ACC-STF-6-1	Changes made to MIP	No	3	10 - 12
ACC-STF-11-10 (a)	Calculation of MIP for 2009-2001 (only Attachment A is included)	No	2	13 - 14
ACC-STF-1-50	Employee Benefits - Retirement and Incentive Programs	No	16	15 - 30
ACC-STF-1-92	Deviations from prior Commission Orders	No	1	31
ACC-STF-1-56	Pro Forma deviations from prior Commission orders	No	1	32
ACC-STF-1-57	Company affirmation of including MIP and SERP in filing contrary to Commission orders	No	1	33
ACC-STF-17-2	MIP and other incentive compensation - 2008-2010 jurisdictional amounts	No	2	34 - 35
ACC-STF-6-4	SERP expense and actuarial study	No	14	36 - 49
ACC-STF-6-2	Changes have not been made to SERP since last rate case	No	1	50
ACC-STF-6-21	AGA Dues - budget and financial information for 2008-2011	No	8	51 - 58
	Excerpts from NARUC-sponsered Audits of the Expenditures of the American Gas Association	No	10	59 - 68
	Excerpt from Florida PSC City Gas Company rate case, Docket No. 030569-GU on AGA Dues	No	3	69 - 71
ACC-STF-6-29	Relocation expense for losses associated with sale of employee homes	No	3	72 - 74
ACC-STF-11-21	Southwest Gas Energy Efficient Technology - Removal of GHP development cost from test year operating expenses	No	5	75 - 79
ACC-STF-1-98	Research and Development projects	No	28	80 - 107
ACC-STF-7-17	ICE charges and how they are treated for ratemaking purposes	No	3	108 - 110
ACC-STF-6-12	Computation of Injuries and Damages allowance	No	3	111 - 113
ACC-STF-20-3	Estimate of annual cost to conduct a leak survey of all COYLs	No	1	114
ACC-STF-16-7	COYL Replacement expense	No	2	115 - 116
ACC-STF-16-8	COYL Replacement - cost for years 2006-2010	No	1	117
ACC-STF-16-6 Corrected	COYL - SWG cost related to replacement of COYL for periods between June 30, 2010 and December 31, 2011	No	1	118
ACC-STF-7-13	Rate case filing cycle plans (without confidential attachment)	No	1	119
ACC-STF-1-5	SWG's last complete depreciation study (without voluminous attachments)	No	1	120
ACC-STF-16-1	Yuma Manors - calculation of plant, accumulated depreciation, property tax, and depreciation expense	No	2	121 - 122
ACC-STF-16-3	Completed Construction Not Classified correction to property tax and depreciation expense	No	1	123
ACC-STF-16-2	SCADA - removal affect on property tax and depreciation and amortization expense	No	1	124
ACC-STF-1-83	Service Planning Quality Award and Key Account Management Incentive Plan documents; 2008-2010 expenses for all Incentive programs.	No	17	125 - 141
ACC-STF-17-1	Calculation of SERP allocation to Arizona	No	2	142 - 143
	SWG's response to STF-6-52 from Southwest Gas Docket No. G-01551A-07-0504 regarding AGA Dues	No	2	144 - 145
	SWG's response to STF-6-50(b) from Southwest Gas Docket No. G-01551A-07-0504 regarding AGA Dues	No	2	146 - 147
ACC-STF-1-72	Itemization of Insurance expense included in test year	No	2	148 - 149
ACC-STF-1-71	Injuries and Damages expense for 2007-2010	No	2	150 - 151
	SWG's response to STF-10-26 from Southwest Gas Docket No. G-01551A-07-0504 regarding Leased Aircraft	No	2	152 - 153
ACC-STF-7-9	Leased aircraft and aviation equipment expense	No	3	154 - 156
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499-007

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-7:

Refer to Adjustment 17, Completed Construction Not Classified ("CCNC").

a. Was the entire $2,806,169 in service as of June 30, 2010? If not, explain fully why not and identify all components and the related dollar amounts that were not in service as of that date.

b. Provide an itemization of the specific assets included in each of the following accounts:

   1) Computer Equipment, account 391.1

   2) Tools, Shop and Garage Equipment, account 394.0

c. Has all of the $2,806,169 been closed to Plant in Service by 12/31/2010? If not, explain fully why not and identify all components that have not been closed to plant in service by that date.

d. For purposes of computing 2009 bonus income tax depreciation, show in detail how the $2,806,169 CCNC was treated and reflected in SWG's rate filing. Include supporting workpapers.

Respondent: Revenue Requirements

"

"

"

"

Response:

A. The Company considers the facilities constructed through the work orders that make up Adjustment No. 17, reduced to $2,695,762 (please refer to response to Item C below), to be in-service and serving customers at the end of the test year June 2010. $2,525,939 (Workpaper B-2, Adj. 17, Sheet 1, Lines 4-9), or 90% of the adjustment relates to either pipe replacement or pressure reinforcement. The dollars recorded at June 2010 represents the cost of pipe that was delivering gas to customers at the end of the test year. Many of the work orders included in the CCNC adjustment were designed to accumulate the cost of replacing additional pipe which takes place after the test year. The attached schedule shows that the 38 work orders that the Company is now including in its CCNC adjustment were designed to receive $8,663,971 of charges. As of June 2010 these work orders were charged $2,695,762. The Company did not include these additional costs in Adjustment No. 17. The $160,124 of general plant included in Adjustment No. 17 represents plant that was acquired and serving the customer at the end of the test year, but were not closed on a timely basis. Please also refer to the response to item B.

B. Attached is the detail of the assets acquired as result of the two work orders included in Adjustment No. 17 Account 391.1 and the two workorders in Account 394.0. All assets were acquired as of June 2010.

C. Attached is a schedule that lists the in-service date of the work orders included in the CCNC adjustment. There are two work orders that have not closed and should be removed from the Company's original adjustment. The original $2,806,169 should be $2,695,762.

D. The Company's response to Staff Data Request No. ACC-STF-1-26 calculates the bonus depreciation January to August 2010 (50%) and September to December 2010 (100%) related to the $2,771,114. The deferred tax resulting from these plant additions was $704,030. In preparing this application, it was believed that the $704,030 was included in the $5,362,740 direct Arizona deferred tax adjustment to the Account 282, Accumulated Deferred Income Taxes. Schedule B-6, Sheet 3 of 3, Line 4, Col. (c) shows a balance of $210,794,189 which consists of the balance recorded at June 2010 of $205,431,448 and the $5,362,740 adjustment. In preparing the response to this data request, it came to the Company's attention that the $704,030 was not included. The Company's Schedule B-6, Sheet 3 of 3, Line 4, Col. (c) should be increased by $704,030 to $211,498,218. This correction is needed only if the Commission accepts the Company's adjusted proposed $2,771,114 CCNC Adjustment No. 17.

Schedule B-6, Sheet 3 of 3, Line 7 col. (c) shows $15,583,217 which is comprised of the balance per books of $14,936,004 and the $647,213 bonus depreciation adjustment shown in the attachments to Staff Data Request No. ACC-STF-1-26. This adjustment reflected the impact of bonus depreciation related to plant additions from January through June 2010. Not reflected was the impact of bonus depreciation on the Corporate CCNC reflected in Adjustment No. 17. Schedule B-6, Sheet 3 of 3, Line 7, Col. (c) should be increased by $1,085,609 to $16,668,826 which is an amount before allocation to Arizona. Again, this adjustment is only appropriate if the $4,139,131 adjusted CCNC Adjustment No. 17, is accepted by the Commission.

The Company is removing the $1,700,000 cost of the SCADA system originally included in Adjustment 17 in System Allocable Account 303. There was no deferred tax associated with this project included in this application, therefore, no adjustment to deferred taxes related to the removal of this project is required.

This response supplements the response to Staff Data Request No. ACC-STF-1-26, and a notice of correction of errors contemplated in Staff Data Request No. ACC-STF-1-54.

SOUTHWEST GAS CORPORATION
ARIZONA
COMPLETED CONSTRUCTION NOT CLASSIFIED TO PLANT IN-SERVICE
CWIP BALANCE AT JUNE 30, 2010
RESPONSE TO STAFF DATA REQUEST NO 6-7(A)

Line No.	Work Order Number [1]	FERC Account	BI No.	Work Order Description	Filed - Includes all Projects	Revised - Removed Two Projects	Original Estimate on Project	Transfer Date	In-Service Date at 3-31-2011
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	0036-C8526424	376	9604	FN: TWIN PEAKS JOINT TRENCH IN	$ 62,917	$ 62,917	$ 36,841	07/2010	7/16/2010
2	0036-C8527535	376	9604	FN: TWIN PEAKS & SANTA CRUZ RI	48,576	48,576	182,431	07/2010	7/15/2010
3	0036-W1166792	376	9604	FN:WRIGHTSTOWN AND HARRISON CU	81,631	81,631	66,204	07/2010	7/14/2010
4	0036-W1162974	376	9604	FN: MAGEE ROAD - ORACLE ROAD T	43,933	43,933	74,369	08/2010	9/17/2010
5	0042-W1027502	376	9604	FRE SCOT PIMA RD IMPROVEMENTS	60,023	60,023	123,975	07/2010	7/13/2010
6	0046-W0943131	376	9604	FRAN JESSE HAYES MAIN REPLACEM	78,677	78,677	79,224	07/2010	4/15/2010
7	**TOTAL BUDGET ITEM - 9604: Mains - Franchise Requirements**				**$ 375,756**	**$ 375,756**	**$ 563,043**		
8	0036-W1013692	376	9605	HDRP (2010) - ATLAS 0378 PHI	$ 66,611	$ 66,611	$ 452,900	10/2010	9/20/2010
9	0036-W1015125	376	9605	HDRP (2010) ATLAS 0316	181,067	181,067	685,305	01/2011	10/8/2010
10	0036-W1015362	376	9605	HDRP (2010) - ATLAS 0546	55,917	55,917	95,519	07/2010	6/30/2010
11	0036-W1015367	376	9605	HDRP (2010) - ATLAS 0324	43,027	43,027	698,068	01/2011	11/15/2010
12	0036-W1015372	376	9605	HDRP (2010) - ATLAS 0091	74,132	74,132	125,873	10/2010	5/11/2010
13	0036-W1033500	376	9605	HDRP (2010) - ATLAS 0314	24,132	24,132	220,863	10/2010	8/16/2010
14	0036-W1033502	376	9605	HDRP (2010) - ATLAS 0078	30,714	30,714	73,252	10/2010	7/22/2010
15	0036-W1036507	376	9605	SI - EL MORAGA MAIN REPLACEMEN	25,939	25,939	20,338	01/2011	1/14/2011
16	0036-W1084375	376	9605	HDRP (2010) - ATLAS 0378 PHII	26,378	26,378	676,989	10/2010	9/20/2010
17	0036-W1089739	376	9605	HDRP (RSRP) - ATLAS 0339	66,587	66,587	63,967	07/2010	7/19/2010
18	0036-W1122904	376	9605	IARP-ISOLATION AREA 123, 306,	35,055	-	-	-	-
19	0036-W1140931	376	9605	SI-MARYVALE MANOR STEEL REPLAC	37,720	37,720	264,108	07/2010	6/28/2010
20	0036-W1141832	376	9605	RPLC (2010) - ATLAS 0347 PHASE	101,783	101,783	98,700	07/2010	7/26/2010
21	0036-W1151150	376	9605	HDRP (RSRP) - ATLAS 0575 S&P E	25,584	25,584	30,182	07/2010	7/19/2010
22	0036-W1151915	376	9605	SI-GREEN VALLEY ABS REPLACEMEN	47,351	47,351	165,282	10/2010	10/11/2010
23	0036-W1169927	376	9605	HDRP (2010) - ATLAS 0113 PHII	67,397	67,397	442,774	10/2010	8/25/2010
24	0042-W1000572	376	9605	CITY SCAPE	63,337	63,337	53,761	07/2010	6/24/2010
25	0042-C7527275	376	9605	SPE-2010 PVC MAIN REPLACEMENT	162,788	162,788	1,059,478	12/2010	11/3/2010
26	0046-W1036763	376	9605	SI BOSTON ST. & HIGHLAND DR. S	58,056	58,056	94,591	07/2010	7/8/2010
27	**TOTAL BUDGET ITEM - 9605: Main Replacements**				**$ 1,193,575**	**$ 1,158,520**	**$ 5,321,950**		
28	0036-C8526474	376	9606	SI: I-10 CROSSING & TIFFANY LO	$ 87,498	$ 87,498	$ 98,767	07/2010	7/15/2010
29	0036-C8527415	376	9606	SI: LINDA VISTA & CMO DE MANAN	44,924	44,924	107,733	08/2010	8/5/2010
30	0042-C7524036	376	9606	PRASADA HIGH PRESSURE REINF	482,641	482,641	1,967,056	10/2010	9/16/2010
31	0042-W1067233	376	9606	SPE-HUNT HWY & ATTAWAY RD 6" M	108,591	108,591	84,575	07/2010	6/30/2010
32	**TOTAL BUDGET ITEM - 9606: Main - Pressure Reinforcement**				**$ 723,653**	**$ 723,653**	**$ 2,258,130**		
33	0042-C8524811	378	9607	PRASADA REGULATOR STATION	$ 36,874	$ 36,874	$ 69,775	10/2010	9/16/2010
34	0042-W1131431	378	9607	SPE-DR #424360 REPLACEMENT	31,796	31,796	116,504	10/2010	9/18/2010
35	**TOTAL BUDGET ITEM - 9607: Measuring and Regulating Station Equipment**				**$ 68,669**	**$ 68,669**	**$ 186,279**		
36	0048-W1150609	380	9609	RENEWAL OF CITY OF YUMA FRANCH	$ 51,437	$ 51,437	$ 51,437	07/2010	7/20/2010
37	**TOTAL BUDGET ITEM - 9609: Service Replacements**				**$ 51,437**	**$ 51,437**	**$ 51,437**		
38	0042-W1138058	376	9611	INSTALL RECTIFIER / SAE GROUND	$ 63,438	$ 63,438	$ 69,021	07/2010	5/7/2010
39	0042-W1155395	376	9611	REPLACE GROUNDBED - DEPLETED	60,889	60,889	43,180	07/2010	4/22/2010
40	0042-W1167888	376	9611	REPLACEGROUNDBED - DEPLETED RE	33,276	33,276	42,154	07/2010	5/21/2010
41	**TOTAL BUDGET ITEM - 9611: Mains - Cathodic Protection**				**$ 157,602**	**$ 157,602**	**$ 154,355**		
42	0042-W1001926	376	9635	SPW - TRANSMISSION MAIN VALVE	$ 75,353	$ -	$ -	-	-
43	**TOTAL BUDGET ITEM - 9635: High Pressure Distribution Mains**				**$ 75,353**	**$ -**	**$ -**		
44	0042-W1155080	394	9709	43RD OPS ABOVE GROUND HOIST	$ 50,199	$ 50,199	$ 50,199	07/2010	7/15/2010
45	0042-W1137625	394	9709	PURCHASE REGENT HYDRAULIC STEE	36,748	36,748	22,650	08/2010	8/16/2010
46	**TOTAL BUDGET ITEM - 9709: Tools, Shop and Garage Equipment**				**$ 86,947**	**$ 86,947**	**$ 72,849**		
47	0042-W0000306	391.1	9715	Line Matrix Printer Replc	$ 40,563	$ 40,563	$ 16,300	07/2010	7/26/2010
48	0042-W0000407	391.1	9715	Server Replacements - 6	32,614	32,614	39,627	08/2010	8/16/2010
49	**TOTAL BUDGET ITEM - 9715: Computer Equipment**				**$ 73,177**	**$ 73,177**	**$ 55,927**		
50	TOTAL ARIZONA DOLLARS				$ 2,806,169	$ 2,695,762	$ 8,663,971		
51	TOTAL ARIZONA WORK ORDERS				40	38	38		

491-026

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-26:

Accumulated Deferred Income Taxes. Please show in detail how the Company reflected 50 percent bonus depreciation on all qualifying assets placed in to service from January 1 through June 30, 2010. If this was not reflected in the Company's filing, explain fully why not and provide calculations quantifying the adjustment necessary to reflect it.

Respondent: Corporate Tax

Response:

This adjustment is reflected in the Company's filing. Please refer to the attached spreadsheet for the detail of how the Company reflected the 50 percent bonus depreciation adjustment on all qualifying assets placed into service from January 1 through June 30, 2010 for both Arizona and Common.

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS TO SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458
RESPONSE TO STF 1.26

Arizona

Federal Tax Depreciation - 1/1/10-6/30/10		46,978,160
Accum Book Depreciation - 6/30/10	886,327,699	
Accum Book Depreciation - 12/31/09	851,193,683	
Book Reserve - 1/1/10-6/30/10		35,134,016
Book/Tax Difference - 1/1/10-6/30/10		11,844,144
Tax Rate		35%
2820 2105 Activity 1/1/10- 6/30/10 - Before So Ga		(4,145,450)
South Georgia Adjustment		(145,057)
2820 2105 Activity 1/1/10- 6/30/10		(4,290,507)
2820 2105 Balance at 12/31/09 - Per G/L		(206,503,681)
Adjusted 2820 2105 Balance at 6/30/10		(210,794,188)
2820 2105 Balance at 6/30/10 - Per G/L		(205,431,448)
2820 2105 Bonus Depreciation Adjustment at 6/30/10		(5,362,740)

Note 1: Schedule B-6, Sheet 3 of 3, Line 4 Col. (b)

Common

Federal Tax Depreciation - 1/1/10-6/30/10		3,754,017
Accum Book Depreciation - 6/30/10	122,445,201	
Accum Book Depreciation - 12/31/09	118,788,495	
Book Reserve - 1/1/10-6/30/10		3,656,706
Book/Tax Difference - 1/1/10-6/30/10		97,311
Tax Rate		35%
2820 2105 Activity 1/1/10- 6/30/10 - Before So Ga		(34,059)
South Georgia Adjustment		-
2820 2105 Activity 1/1/10- 6/30/10		(34,059)
2820 2105 Balance at 12/31/09 - Per G/L		(15,549,158)
Adjusted 2820 2105 Balance at 6/30/10		(15,583,217)
2820 2105 Balance at 6/30/10 - Per G/L		(14,936,004)
2820 2105 Bonus Depreciation Adjustment at 6/30/10		(647,213)

Note 1: Schedule B-6, Sheet 3 of 3, Line 7 Col. (b)

499-009

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-9:

Directors and Officers' Liability Insurance expense.

a. Has Southwest included any prepaid Directors and Officers' Liability Insurance expense in its proposed operating expenses? If so, please identify the amount, by account.

b. Was 50% of Southwest's Directors and Officers' Liability Insurance expense disallowed in Southwest's most recent Nevada rate case, Docket No. 09-04003? If so, please explain fully Southwest's understanding of why that disallowance was made.

c. Has Southwest included any prepaid Directors and Officers' Liability Insurance cost in its proposed rate base? If so, please identify the amount, by account.

d. Was 50% of Southwest's Directors and Officers' Liability Insurance prepaid expense disallowed from rate base in Southwest's most recent Nevada rate case, Docket No. 09-04003? If so, please explain fully Southwest's understanding of why that disallowance was made.

Respondent: Revenue Requirements

Response:

a. Prepaid D&O expense is not included in operating expenses; it is included in prepayments and the 13-month average of the prepayment balance is a component of rate base. Prepaid D&O is charged to Account 165 when the insurance premiums are paid, and the prepaid balance is amortized monthly to Account 925. Please also refer to response to ACC-STF-1-72 for the amount of D&O expense included in Account 925 for the test year.

b. Yes, the Public Utilities Commission of Nevada (PUCN) allowed Southwest Gas to recover 50 percent of D&O insurance expenses. The D&O issue was addressed in the Order in Docket No. 09-04003, provided in response to ACC-STF-2-14, on pages 46-48. Southwest's understanding of the PUCN's rationale is limited to the wording contained in the Order.

c. Yes, prepaid D&O expenses are a component of rate base in Account 165. The amount included in the test year prior to allocation to Arizona is $658,144, and after 4-Factor the amount allocated to Arizona is $370,193.

d. Yes, the rate base related to the 13-month average of the D&O prepayment balance received the same ratemaking treatment from the PUCN as D&O expense.

499-001

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-1:

Identify and fully explain all changes Southwest Gas has made to its Management Incentive Program (MIP) incentive compensation program since the test year utilized in SWG's last rate case, Docket No. G-01551A-07-0504.

Respondent: Human Resources

Response:

Please refer to the attached document.

ARIZONA GENERAL RATE CASE
DATA REQUEST NO. STF 6.1
MANAGEMENT INCENTIVE PLAN CHANGES

Southwest Gas Corporation (SWG) has made two modifications to the Management Incentive Plan (MIP) since the end of the test year (April 30, 2007) in the Company's last rate case affecting the performance measures and participant eligibility.

1. PERFORMANCE MEASURE CHANGES

The performance measures of the variable at-risk MIP were evaluated and modified in 2008, replacing five performance measures with four.

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 on 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 averaged 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.

2. TIER STRUCTURE CHANGES

The second modification to the MIP became effective in 2009 following approval by both SWG's Compensation Committee and Board of Directors. This change included increasing the eligibility threshold for the Non-Officer (30 percent) tier and creating a level for Technical Managers (10 percent tier).

The table below compares the previous and current MIP participant tier structure.

Position	Previous	Current [1]
CEO	115%	115%
President	100%	100%
Executive Officers	90%	90%
Sr Officers	75%	75%
Officers	50%	50%
Non-Officers [2]	30%	30%
Technical Managers [3]		10%

[1] Effective beginning in the 2009 plan year
[2] Eligibility threshold increased to positions with 775 Hay Points versus 700 Hay Points
[3] New tier added for Technical Managers, encompassing positions between 677 and 774 Hay Points

504-010

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 to ACC-STF-11-23)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 8, 2011

Request No. ACC-STF-11-10:

Refer to the 11/15/2010 Compensation Committee meeting minutes, Exhibit A.

a. Please show in detail how each of the MIP figures for 2009, 2010 and 2011 listed there were derived. Include supporting calculations.

b. Are the 2009 and 2010 MIP criteria figures shown there based on actual results? If not, please provide MIP 2009 and 2010 actual results for each MIP performance measure and show in detail how such actual results were derived.

Respondent: Human Resources

Response:

a. Annually, the Compensation Committee* (Committee) of the Board of Directors reviews historical and forecasted data relevant to the four MIP performance measures (Return on Equity, Customer Satisfaction, Customer-to-Employee ratio and Operating Costs) and is responsible for setting the targets for each measure.

   As discussed in the Proxy Statements issued annually, 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.

   Please also refer to ACC-STF-11-10 Attachment A for supporting calculations.

b. Please refer to ACC-STF-11-10 Attachment B for supporting calculations of actual results for 2009 and 2010.

*The Board members who served on the Compensation Committee during 2009 and 2010 have never been an officer or employee of the Company or any of its subsidiaries. No member of the Compensation Committee had any relationship requiring disclosure under any paragraph of Item 404 of Regulation S-K of the Exchange Act.

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF 11.10 (a)
MIP PERFORMANCE TARGET CALCULATIONS

Line No.	Description	2011	2010	2009	Line No.
		(a)	(b)	(c)	
	Return-on-Equity (ROE)				
1	Companywide Authorized Weighted Average ROE	10.18%	10.33%	10.30%	1
2	*Threshold (70% of Target)*	*5.70%*	*5.78%*	*5.77%*	2
3	*Target (80% of Line 1, Cols (a), (b), (c), respectively)*	*8.14%*	*8.26%*	*8.24%*	3
4	*Maximum (140% of Target)*	*11.40%*	*11.56%*	*11.54%*	4
	Customer Satsifcation				
	According to the American Customer Satisfaction Index, the industry benchmark is 74%				
5	*Threshold*	*75%*	*75%*	*75%*	5
6	*Target*	*85%*	*85%*	*85%*	6
7	*Maximum*	*95%*	*95%*	*95%*	7
	Operating Costs				
	Blue Chip Economic Indicators *(estimated 2011, actual 2010 and 2009)*				
8	Minimum	2.1%	2.6%	3.4%	8
9	Average	1.5%	1.9%	2.5%	9
10	Maximum	1.0%	1.3%	1.7%	10
11	Growth *(actual 2010, 2009)*		1.35%	1.5%	11
12	High	1.2%			12
13	Average	0.8%			13
14	Low	0.4%			14
15	*Threshold*	*3.30%* [1]	*3.95%* [4]	*4.90%* [7]	15
16	*Target*	*2.30%* [2]	*3.25%* [5]	*4.00%* [8]	16
17	*Maximum*	*1.40%* [3]	*2.65%* [6]	*3.20%* [9]	17
	Customer-to-Employee Ratio				
18	*Threshold*	*782* [14]	*743* [13]	*743* [10]	18
19	*Target*	*790* [15]	*754* [13]	*754* [11]	19
20	*Maximum*	*802* [16]	*762* [13]	*762* [12]	20

[1] Line 8 Col (a) + Line 12 Col (a)
[2] Line 9 Col (a) + Line 13 Col (a)
[3] Line 10 Col (a) + Line 14 Col (a)
[4] Line 8 Col (b) + Line 11 Col (b)
[5] Line 9 Col (b) + Line 11 Col (b)
[6] Line 10 Col (b) + Line 11 Col (b)
[7] Line 8 Col (c) + Line 11 Col (c)
[8] Line 9 Col (c) + Line 11 Col (c)
[9] Line 10 Col (c) + Line 11 Col (c)
[10] Actual 2008 ratio of 743 customers per employee
[11] 1.5% improvement over the actual 2008 ratio of 743 customers per employee
[12] 2.5% increase over the actual 2008 ratio of 743 customers per employee
[13] Unchanged from 2009 due to the slow growth environment
[14] Actual 2010 ratio of 782 customers per employee
[15] 1.0% improvement over the actual 2010 ratio of 782 customers per employee
[16] 2.5% increase over the actual 2010 ratio of 782 customers per employee

491-050

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-50:

Employee Benefits.

a. List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to SWG.

b. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

c. State the cost by program, of each retirement program directly charged or allocated.

d. Provide the incentive compensation program financial performance goals for 2008, 2009 and 2010.

e. For each incentive compensation program goal, for each year, show the actual results and how it compared with the target.

f. Provide the incentive compensation program in effect in each year, 2008, 2009 and 2010.

g. Show in detail how any special recognition awards recorded in the test year were determined.

Respondent: Human Resources

Response:

a. List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to SWG.

Note: Affiliate officers and employees are not eligible for the programs described below.

Pension and Supplemental Retirement Plan

Southwest Gas' non-contributory, Defined Benefit Retirement Plan ("DBRP"), is available to all employees of the Company. 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 Internal Revenue Service ("IRS") does place a limit on the amount of annual compensation that can be considered in determining benefits under the DBRP. For 2010, the maximum annual compensation amount was $245,000. In future years, the maximum annual compensation will be adjusted to reflect changes in the cost of living as established by the IRS.

Executives also participate in the Company's Supplemental Executive Retirement Plan ("SERP"). Benefits from the plan, when added to the benefits received under the basic retirement plan, will equal 60 percent of annual compensation for senior executives, and 50 percent of annual compensation for all other officers. Annual compensation is defined as the 12-month average of the highest 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 creditors of the Company). SERP benefits are common in the utility industry and are a current practice among the majority of the Company's peer group.

Executive Deferral Plan

Under the Executive Deferral Plan ("EDP"), executives at the vice president level and above may defer 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 401(k) plan, which is available to all employees, equal to one-half the deferred amount up to 7 percent of their annual salary. 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 Moodys Seasoned Corporate Bond Rate.

The EDP is an unqualified plan and, as such, participant balances are not guaranteed (i.e., participants are general creditors of the Company and their contributions to this account are at risk). A deferred compensation plan is common in the utility industry and is a current practice among the majority of the Company's peer group.

Employees Investment Plan/401(k)

The Southwest Gas Corporation Employees' 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 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. Officers of the Company may invest in the EIP, but they are not eligible to receive a Company match under this plan.

Variable At-Risk Pay

Management Incentive Plan

The Management Incentive Plan ("MIP") provides variable at-risk compensation to executives and upper-level management based on specific goals and performance objectives vital to the Company's short and long-term success. 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. Forty percent of the total award earned under the MIP is paid in cash immediately following the financial close of the most recent calendar year. The remaining 60 percent is issued as performance shares and vest three years in the future. The longer-term performance shares act as a retention tool while aligning the interests of customers, Company management, and shareholders for continued financial and customer-oriented performance.

The MIP is measured as a percentage of base salary and varies by title, as follows:

Position	
CEO	115%
President	100%
Executive VP	90%
Senior VP	75%
VP	50%
Non-Officers	
Director/Senior Manager	30%
Key Management Employees	10%

Each measurement has a threshold, a target and a maximum, and, at target, contributes 25 percent toward the total award for the year. An award under a specific criterion may be given within a range from 70 percent, at threshold, to 140 percent, at maximum. Performance below the threshold results in no award under a specific criterion. There is no incremental value for performance over the maximum for any of the four criteria. In summary, an award can range from 0 percent to 140 percent of the stated MIP opportunity. In any year where the corporate dividend is reduced, there is no MIP distribution.

Restricted Stock/Unit Plan

The second component of variable at-risk pay is the Restricted Stock/Unit Plan ("RSUP"), which in May 2007 replaced the Company's Stock Incentive Plan. The RSUP is designed for the purpose of enhancing the competitive position of the total direct compensation and to further align customer, management, and shareholder interests, while sustaining a strong commitment to the long-term financial success of the Company and further encouraging management with ownership of Company stock.

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
VP	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 of the award 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.

Aspire

The Aspire program ("Aspire") provides management with a tool with which to reward and recognize exempt (salaried) employees whose accomplishments demonstrate improved productivity, significant cost savings, or enhanced business processes. Only exempt employees who do not qualify for the MIP are eligible.

To qualify, an employee must be recommended in writing by an officer of the Company. The nomination must both quantify and qualify the contributions made to Southwest Gas during the calendar year. All nominations are approved by senior management and the Company's Board of Directors. Awards range from $2,500 to $7,500 and are granted to individuals who go significantly above and beyond their job responsibilities with substantial contributions toward the overall betterment of Southwest Gas, as well as demonstrate dedication to the goals and philosophy of the Company.

Going the Extra Mile

In 2009, the Company's perfect attendance program, Constant Flame, was replaced with the Going the Extra Mile ("GEM") program. GEM is a performance-based recognition program designed to recognize non-exempt employees for high-quality, sustained performance that provides a significant contribution to the Company. Employees nominated are evaluated on five measures: productivity, customer service, innovation, leadership, and character. The nomination must both quantify and qualify the contributions made to Southwest Gas during the calendar year. All nominations are approved by senior management and the Company's Board of Directors. All non-exempt employees who have completed twelve months of service, without disciplinary actions, preventable personal injuries or vehicle accidents are eligible each year. The number of employees who may be recognized each year is limited to one hundred non-exempt employees Companywide. The number of awards allocated to each jurisdiction is determined by the number of non-exempt employees in that jurisdiction as a percent of the total non-exempt employee population companywide.

b. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

The amount of SERP requested for recovery in this proceeding allocated to Arizona is approximately $1.65 million.

c. State the cost by program, of each retirement program directly charged or allocated.

The amounts requested for recovery in this proceeding allocated to Arizona for the following retirement programs are approximately:

DBRP (Pension): $15.1 million

EDP: $1.55 million

401K: $2.08 million

d. Provide the incentive compensation program financial performance goals for 2008, 2009 and 2010.

Please refer to the attached Excel spreadsheet.

e. For each incentive compensation program goal, for each year, show the actual results and how it compared with the target.

Please refer to the attached Excel spreadsheet.

f. Provide the incentive compensation program in effect in each year, 2008, 2009 and 2010.

A copy of the MIP brochure has been provided in response to this item.

g. Show in detail how any special recognition awards recorded in the test year were determined.

Please refer to the paragraphs in item (a) above describing the Aspire and GEM programs.

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF 1.50 (d) (e)
MANAGEMENT INCENTIVE PLAN ("MIP")
PERFORMANCE GOALS AND ACTUAL RESULTS

Measurement	Plan Year 2008	2009	2010
Return on Equity			
Actual	0.0%	7.64%	8.23%
Target	8.06%	8.24%	8.26%
Earned	0.0%	92.7%	99.6%
x 25% weight	0.0%	23.18%	24.91%
Customer-to-Employee Ratio			
Actual	743	753	782
Target	735	754	754
Earned	121.32%	97.28%	140.0%
x 25% weight	30.33%	24.32%	35.0%
Customer Satisfaction			
Actual	96.0%	94.0%	92.5%
Target	85.0%	85.0%	85.0%
Earned	140.0%	136.0%	130.0%
x 25% weight	35.0%	34.0%	32.5%
Operating Cost Containment			
Actual	3.6%	2.09%	2.02%
Target	4.78%	4.00%	3.25%
Earned	140.0%	140.0%	140.0%
x 25% weight	35.0%	35.0%	35.0%
Total Percent of Target	100%	116%	127%

SOUTHWEST GAS

Management Incentive Plan

GENERAL REMARKS

This document has been created to explain the concepts of the Southwest Gas Corporation (SWG), Management Incentive Plan (MIP), adopted by the Board of Directors in 1993 and revised in 2009. It is intended for use by employees included in the MIP.

Every attempt has been made to ensure that the MIP conforms to the latest rules and regulations of the Securities and Exchange Commission (SEC) and Internal Revenue Service (IRS). This booklet, however, should not be considered an official legal document. The official plan document is available in Corporate Human Resources and may be consulted for further information.

MIP participants should periodically check with their personal tax, accounting, or legal counsel about changes in regulations governing incentive programs, created through legislative actions, new or amended SEC regulations, and IRS and Tax Code interpretations. For information about tax savings, or the ramifications of participation in the plan, you should consult your tax professional.

This document reflects current federal income tax treatment (which may be subject to change in the future) and does not include state or local ramifications.

PURPOSE OF THE PROGRAM

The Company's MIP provides variable incentive-based compensation to executives for the achievement of specific goals and benchmarks important to both the short-term and long-term success of the Company. The MIP strives to achieve the following:

- To focus SWG management on the achievement of specific performance objectives important to the Company's short-term and long-term success
- To ensure that there is a strong link between Company performance and financial rewards for management.
- To foster a common interest between SWG management, customers and shareholders.
- To encourage management ownership of SWG stock.

ELEMENTS OF THE PROGRAM

Annual Incentive Award: The dollar amount awarded to a plan participant on the basis of SWG performance during the annual performance period. A portion of the award is payable in cash as soon as practicable following the end of the performance period. The remaining portion is converted into performance shares and subject to a restriction period.

Performance Shares: A contingent right to receive shares of common stock in SWG which are not to be distributed to the participant until and unless certain restrictions have lapsed.

Dividend Credits: Additional dollar amounts convertible into Performance Shares (during the restriction period) as determined by the cumulative quarterly dividends declared on Company common stock during the restriction period.

Note: Normally, annual incentive awards will be calculated and paid during the first quarter following the end of the plan year.

ELIGIBILITY AND SELECTION

Positions qualifying for participation in the MIP will be determined by SWG senior management and approved by the Compensation Committee of SWG's Board of Directors, hereafter referred to as the "Committee."

Generally speaking, award potential and/or guidelines will be determined separately for each eligible tier of SWG management. The tiers, their composition, and the guideline awards for each tier are subject to change from time to time.

Selection for participation in one year does not guarantee selection in succeeding years.

INCENTIVE AWARD OPPORTUNITIES

Individuals selected for participation in the MIP will be assigned incentive award opportunities, which are expressed as a percentage of their base salaries.

The incentive award opportunities include a targeted incentive award and a range around the target that corresponds to various levels of performance measured on a number of dimensions. Meeting the individual measurement goal at the expected target pays 100 percent of that measurement. The range for each individual measurement equals 70 percent at threshold and increases to 140 percent at maximum. Performance below threshold results in zero payout for the specific measure.

Target, threshold, or maximum incentive award opportunities for any tier are subject to change at the discretion of the Committee. The following table depicts the current targeted incentive award opportunity as a percentage of base salary, by tier of participant:

INCENTIVE AWARD OPPORTUNITY					
TIER	POSITION	MINIMUM	THRESHOLD	TARGET	MAXIMUM
1	CEO	0%	81%	115%	161%
2	President	0%	70%	100%	140%
3	Executive Officers	0%	63%	90%	126%
4	Senior Officers	0%	53%	75%	105%
5	Officers	0%	35%	50%	70%
6	Non-Officers	0%	21%	30%	42%
7	Other Key Employees	0%	7%	10%	14%

FREQUENCY

Incentive awards will be granted on an annual basis consistent with SWG's compensation philosophy and strategy, and taking into account the Company's overall competitive posture on all aspects of direct compensation.

ANNUAL INCENTIVE AWARD

Annual incentive awards will be provided to eligible participants in the plan each year if Company performance measures are achieved.

ANNUAL PERFORMANCE MEASURES

Each measurement has a threshold, target and maximum, and, at target, contributes 25 percent toward the total award for the year. An award under a specific criterion may be given within a range from 70 percent, at threshold, to 140 percent, at maximum. Performance below the threshold results in no award under the specific criteria. There is no incremental value for

performance over the maximum for any of the four criteria. An award can range from zero percent to 140 percent of the stated MIP opportunity. In any year where the corporate dividend is reduced, there is no MIP award given. For the purposes of determining the actual awards under the MIP, performance will be evaluated on several dimensions.

The annual performance measures, which are equally weighted, are as follows:

- Return on equity (ROE)
- Customer-to-employee ratio
- Customer service satisfaction (independently determined)
- Operating cost increases

Note: Individual performance will be measured annually. If a participant fails to meet established goals or performance expectations, an adjustment may be made to the individual award.

AWARD CALCULATIONS SCHEDULES

Targets – The measurement target will be established annually. Current measurements, which are weighted equally, are reflected in the following tables.

PERFORMANCE MEASURES AND WEIGHTS					
MEASURE	THRESHOLD	TARGET	MAXIMUM	WEIGHTING	SOURCE FOR MEASUREMENT
ROE	5.77%	8.24%	11.54%	25%	Company-wide authorized weighted average ROE
Customer-to-Employee Ratio	743	754	762	25%	Target = prior year actual ratio adjusted upward by 1.5%
Customer Service Satisfaction	75%	85%	95%	25%	Monthly surveys
Operating Cost Increases	4.9%	4.0%	3.2%	25%	Inflation (1.7% to 3.4%) plus customer growth of 1.5%
POTENTIAL	**70%**	**100%**	**140%**	**100%**	**TOTAL**

Note: No annual incentive awards will be payable unless the Company's dividends equal or exceed the prior year's dividends.

Award Payout – Following the calculation and Committee approval of the annual incentive award, it is divided into short- and long-term components. The short-term component, which is 40 percent of the total award, is paid in cash to the participant. The long-term component, which is the remaining 60 percent of the award, is converted into performance shares that will be subject to a three-year restriction period.

Award Form – The short-term component of the annual award each year will be paid in cash. The long-term component award is paid in Company stock following successful completion of the three-year restriction period.

Withholding Taxes – The Company will deduct all applicable federal, state, and local taxes of any kind required by law to be withheld upon the payment of the annual incentive award.

PERFORMANCE SHARES

The long-term component of the MIP is reflected through the use of the performance shares, which are paid in shares of Company common stock following successful completion of the restriction period.

Award Term – Awards of performance shares will be made each year (contingent on a payout from the annual incentive plan), and will be subject to a three-year restriction period.

Number of Shares Granted – The number of performance shares granted to an individual is determined by two factors: the amount of the award earned under the long-term component of the annual incentive plan, and the price of SWG common stock at the date of the conversion into performance shares.

The amount of the annual incentive award to be converted into performance shares is divided by the average of the fair market value of SWG stock on the first five trading days of January to determine the number of performance shares that a participant receives.

Restriction Period – All performance shares will be restricted for a period of three years, during which time the plan participants will not have ownership of, or be able to sell, the stock, or rights to the stock which underlie the award. During the restriction period, SWG will maintain performance share accounts for each participant, which may increase in size as dividends are declared on SWG common stock and are reinvested. At the end of the restriction period (or earlier if circumstances warrant), each participant's performance share account will be closed by calculating a final number of shares and paying the participant in whole shares of SWG common stock, either before or after taxes are withheld.

DIVIDENDS

The dividend rate paid on SWG common stock during the restriction period will be used to determine the amount credited to the participant's performance share account.

Dividends will be credited to the participant's performance share account in an equivalent number of performance shares on a quarterly basis.

ANNUAL INCENTIVE AWARD – ROE COMPONENT

The target is set at 80% of the authorized weighted-average ROE. The minimum is set at 70% of the target, with the maximum set at 140% of the target. The range of performance and possible payouts are as follows:

	Minimum	Target	Authorized ROE	Maximum
Performance	5.77%	8.24%	10.30%	11.54%
Payout	70%	100%	125%	140%
Weighting	17.50%	25%	31.25%	35%

ANNUAL INCENTIVE AWARD – C/E RATIO COMPONENT

The target is set at a 1.5% improvement over the actual prior year customer to employee ratio. The minimum is set at zero percent improvement, with the maximum set at a 2.5% improvement over the previous year. The range of performance and possible payouts are as follows:

	Minimum	Target	Maximum
Performance	743	754	762
Payout	70%	100%	140%
Weighting	17.50%	25%	35%

ANNUAL INCENTIVE AWARD – CUSTOMER SATISFACTION COMPONENT

The target is set at an 85% customer satisfaction rating. The minimum is set at 75%, with the maximum set at a 95% customer satisfaction rating. The range of performance and possible payouts are as follows:

	Minimum	Target	Maximum
Performance	75%	85%	95%
Payout	70%	100%	140%
Weighting	17.50%	25%	35%

ANNUAL INCENTIVE AWARD – OPERATING COST COMPONENT

The threshold, target, and maximum are comprised of inflation (ranges from 1.7% to 3.4%) plus customer growth factor of 1.5%. The target is set at 4.0%, based on inflation of 2.5% and a 1.5% customer growth factor. The minimum is set at 4.9%, which is calculated using an inflationary factor of 3.4% and a 1.5% customer growth factor. The maximum is set at 3.2%, which is calculated using an inflationary factor of 1.7% with 1.5% customer growth factor. The range of performance and possible payouts are as follows:

	Minimum	Target	Maximum
Performance	4.9%	4.0%	3.2%
Payout	70%	100%	140%
Weighting	17.50%	25%	35%

SAMPLE AWARD PAYOUT

The following is a sample of a payout for an officer (with a 50% of salary award opportunity), based on 2009 targets and ***hypothetical actual results*** for 2009:

MEASUREMENT	2009
ROE	5.60%
target	8.24%
% target award earned	0
x 25% weight	0
Customer/Employee Ratio	762
target	754
% target award earned	140.0%
x 25% weight	35
Customer/Service Satisfaction	95.0%
target	85.0%
% target award earned	140.0%
x 25% weight	35
Operating Costs	4.0%
target	4.0%
% target award earned	100.0%
x 25% weight	25
TOTAL EARNED (as percentage of target)	95

Based upon the above, the payout, expressed as a percent of your salary, would be as follows:

Total Incentive Award	47.5%
Short-term (40%)	19.0%
Long-term (60%)	28.5%

491-092

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-92:

Precedent. Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

Respondent: Revenue Requirements

Response:

Please refer to the response of Southwest Gas to ACC-STF-1-56 and ACC-STF-1-57.

491-056

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-56:

Filing Information. Do any of the Company's proposed pro forma adjustments represent a conscious deviation from the treatment of similar items in the Commission's order in the Company's last rate case? If so, please identify, quantify and explain each such item for which the Company has not followed the same treatment applied in the Commission's order in its last rate case.

Respondent: Revenue Requirements

Response:

No. Southwest Gas calculated each proposed proforma adjustment based on a reasonable analysis of the facts and circumstances in this rate case.

491-057

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-57:

Filing Information. Has the Company knowingly failed to reflect in its filing any adjustments that were ordered of similar items in the Commission's order in the Company's last rate case? If so, please identify, quantify and explain each such item for which the Company has not followed the same treatment applied in the Commission's order in its last rate case.

Respondent: Revenue Requirements

Response:

Yes. Southwest Gas is requesting full recovery of its Management Incentive Plan and Supplemental Executive Retirement Plan. Please also refer to the prefiled direct testimony by Sandra Gaffin for further explanation of the Company's justification for inclusion of these costs in rates; and the supporting documents included with the Company's filing for information supporting the amount requested.

513-002

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
*** * ***

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-17
(ACC-STF-17-1 to ACC-STF-17-2)

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 21, 2011

Request No. ACC-STF-17-2:

MIP and other incentive comp. Refer to the response to STF-1-83, which lists various incentive compensation amounts for 2008, 2009 and 2010 before allocation to Arizona.

a. Provide the Arizona jurisdictional amount for the MIP amount requested by Southwest, and show in detail how that was derived. Include supporting calculations.

b. Provide the Arizona jurisdictional amount for the MIP amount for each of the annual MIP amounts listed in response to STF 1-83. For each year, show in detail how the Arizona jurisdictional amount was derived. Include supporting calculations.

c. For each non-MIP item of incentive comp, listed in the response to STF 1-83, for each year, show the corresponding Arizona jurisdictional amount and show in detail how the Arizona jurisdictional amount was derived. Include supporting calculations.

d. For each non-MIP item of incentive comp, listed in the response to STF 1-83, for the test year, show the corresponding Arizona jurisdictional test year amount and show in detail how the Arizona jurisdictional test year amount was derived. Include supporting calculations.

Respondent: Revenue Requirements

Response:

Please refer to the attached spreadsheet.

SOUTHWEST GAS CORPORATION
MIP and OTHER INCENTIVE COMPENSATION EXPENSES
TEST YEAR JULY 2009 to JUNE 2010
RESPONSE TO DATA REQUEST NO. STF-17-2 (a) and (d)

	MIP 920	Aspire Award 920	GEM 920	RSUP 920	SP Quality Award 903	KAM Incentive Plan 903
Test Year July 2009 to June 2010						
Corporate Costs	$ 6,537,494	$ 73,500	$ 196,000	$ 1,911,117	$ -	$ -
Paiute & SGTC MMF	3.83%	3.83%	3.83%	3.83%		
Less: Paiute & SGTC Allocation	$ 250,386	$ 2,815	$ 7,507	$ 73,196	$ -	$ -
Incentive Compensation Expenses Before 4-Factor	6,287,108	70,685	188,493	1,837,921	-	-
Arizona 4-Factor Allocation	56.25%	56.25%	56.25%	56.25%		
Incentive Compensation Allocated to Arizona	$ 3,536,498	$ 39,760	$ 106,027	$ 1,033,831	$ -	$ -
Arizona Direct Costs	$ -	$ -	$ -	$ -	$ 231,974	$ 69,184
Total Arizona Incentive Compensation Costs	$ 3,536,498	$ 39,760	$ 106,027	$ 1,033,831	$ 231,974	$ 69,184

499-004

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-4:

Provide a breakout of the amount of test year SERP expense by participant. Include supporting calculations.

Respondent: Revenue Requirements

Response:

Test year SERP expense is based on the most recent actuarial study, which is attached. SERP expense is a total company amount that is allocated to each ratemaking jurisdiction, based on charged labor, using the labor loading process. Test year SERP expense by participant is not information that is used by the Company, and is not readily available to the Company.

Hewitt

Actuarial Report

Southwest Gas Corporation
Supplemental Retirement Plan
2010 Pension Cost and 2009 Year-end Disclosure

To protect the confidential and proprietary information included in this material, it may not be disclosed or provided to any third parties without the approval of Hewitt Associates LLC.

Preparation of this Actuarial Valuation

Supplemental Retirement Plan for Southwest Gas Corporation

This report has been prepared as of December 31, 2009 for the Supplemental Retirement Plan. The primary purpose of this report is to present to management the accounting and reporting requirements for the 2009 and 2010 fiscal years for pension benefits as set forth in Accounting Standards Codification (ASC) section 715 (FASB Statement of Financial Accounting Standard No. 87 as amended ("SFAS No. 87") and No. 88 as amended ("SFAS No. 88")—including the provisions of SFAS No. 132(R) and SFAS No. 158. Determinations for purposes other than financial accounting requirements may be significantly different from the results reported herein. Thus, the use of this report for purposes other than those expressed here may not be appropriate.

In conducting the valuation, we have relied on personnel, plan design, and asset information supplied by the plan sponsor. While we cannot verify the accuracy of all this information, the supplied information was reviewed for consistency and reasonability. As a result of this review, we have no reason to doubt the substantial accuracy of the information and believe that it has produced appropriate results. This information, along with any adjustments or modifications, is summarized in various sections of this report.

This valuation has been conducted in accordance with generally accepted actuarial principles and practices, including the applicable Actuarial Standards of Practice as issued by the Actuarial Standards Board. In addition, the valuation results are based on our understanding of the requirements of SFAS No. 87 and SFAS No. 88. The information in this report is not intended to supersede or supplant the advice and interpretations of the Company's auditors.

The actuarial assumptions and methods used in this valuation are described in the Actuarial Assumptions section of this report. The plan sponsor selected the economic assumptions and prescribed them for use for purposes of compliance with SFAS No. 87 and SFAS No. 88. While the demographic assumptions were also prescribed by the plan sponsor, Hewitt Associates provided guidance with respect to these assumptions and it is our belief that they represent reasonable expectations of anticipated plan experience.

The undersigned is familiar with the near-term and long-term aspects of pension valuations and meets the Qualification Standards of the American Academy of Actuaries necessary to render the actuarial opinions herein. All of the sections of this report are considered an integral part of the actuarial opinions.

Preparation of this Actuarial Valuation (continued)

To our knowledge, no associate of Hewitt Associates providing services to Southwest Gas Corporation has any direct financial interest or indirect material interest in Southwest Gas Corporation. Thus, we believe there is no relationship existing that might affect our capacity to prepare and certify this actuarial report for Southwest Gas Corporation.

Hewitt Associates LLC

Steven R. Camferdam
Fellow of the Society of Actuaries
Enrolled Actuary

John S. Nelson
Associate of the Society of Actuaries

February 2010

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Determination of Net Periodic Pension Cost

Net Periodic Pension Cost

	2009	2010
Current service cost	$ 194,718	$ 371,829
Interest cost	2,064,530	2,045,330
Expected asset return	0	0
Amortization of:		
Unrecognized transition obligation/(asset)	0	0
Unrecognized prior service cost	0	0
Unrecognized net loss/(gain)	909,451	1,154,628
Net periodic pension cost	$ 3,168,699	$ 3,571,787
Expected benefit payments	$ 2,400,000	$ 2,500,000
Expected contributions	$ 2,400,000	$ 2,500,000
Key assumptions:		
Discount rate	6.75%	6.00%
Expected rate of return on plan assets	8.00%	8.00%
Amortization period for unrecognized net gain/(loss)	6.89	7.61

Year-end Disclosure

	2008	2009
Change in Projected Benefit Obligation (PBO)		
Benefit obligation at beginning of year	$ 32,605,426	$ 31,785,623
Service cost	97,167	194,718
Interest cost	2,041,353	2,064,530
Plan amendments	0	0
Special termination benefits	0	0
Curtailment gain	0	0
Actuarial (gain)/loss	(594,843)	3,785,371
Benefits paid	(2,363,480)	(2,491,402)
Benefit obligation at end of year	$ 31,785,623	$ 35,338,840
Accumulated Benefit Obligation, End of Year	$ 28,426,550	$ 31,517,460
Change in Plan Assets		
Fair value of plan assets at beginning of year	$ 0	$ 0
Actual return on plan assets	0	0
Company contributions	2,363,480	2,491,402
Benefits paid	(2,363,480)	(2,491,402)
Fair value of plan assets at end of year	$ 0	$ 0
Funded Status	$ (31,785,623)	$ (35,338,840)
Amounts Recognized in the Statement of Financial Position		
Noncurrent assets	$ 0	$ 0
Current liabilities	(2,500,000)	(2,500,000)
Noncurrent liabilities	(29,285,623)	(32,838,840)
Net pension asset/(liability) at year-end	$ (31,785,623)	$ (35,338,840)
Amounts Recognized in Accumulated Other Comprehensive Income (OCI)		
Net actuarial loss/(gain)	$ 9,444,680	$ 12,320,600
Prior service cost/(credit)	0	0
Net transition obligation/(asset)	0	0
	$ 9,444,680	$ 12,320,600
Weighted-Average Assumptions as of December 31		
Discount rate	6.75%	6.00%
Rate of compensation increase	3.75%	3.25%

Year-end Disclosure (continued)

	2008	2009
Components of Net Periodic Pension Cost		
Service cost	$ 97,167	$ 194,718
Interest cost	2,041,353	2,064,530
Expected return on plan assets	0	0
Amortization of:		
Unrecognized net (gain)/loss	996,909	909,451
Unrecognized prior service cost	0	0
Unrecognized net (asset)/obligation	0	0
Net periodic pension cost	$ 3,135,429	$ 3,168,699
Special termination benefits	0	0
Curtailment (gain)/charge	0	0
Total net periodic pension cost	$ 3,135,429	$ 3,168,699
Other Changes in Plan Assets and PBO Recognized in OCI		
Net actuarial loss/(gain)	$ (594,843)	$ 3,785,371
Amortization of net actuarial (loss)/gain	(996,909)	(909,451)
Prior service cost/(credit)	0	0
Amortization of prior service cost	0	0
Amortization of net transition obligation	0	0
Total recognized in OCI	$ (1,591,752)	$ 2,875,920
Total recognized in net periodic pension cost and OCI	$ 1,543,677	$ 6,044,619

The estimated net loss, prior service cost and transition obligation that will be amortized from accumulated other comprehensive income into net periodic benefit cost during fiscal 2010 are $1.1 million, $0 and $0, respectively.

Weighted-Average Assumptions Used to Determine Net Periodic Pension Cost for Year Ended December 31		
Discount rate (pension cost)	6.50%	6.75%
Expected rate of return on plan assets	8.00%	8.00%
Rate of compensation increase	4.00%	3.75%

Estimated Future Benefit Payments	Pension Benefits
2010	$ 2,500,000
2011	$ 2,500,000
2012	$ 2,500,000
2013	$ 2,500,000
2014	$ 2,500,000
Years 2015-2019	$ 12,100,000

Personnel Information

This section begins with summary information concerning the various types of participants included in this actuarial valuation—active participants, retired participants, beneficiaries, and terminated participants with deferred vested benefits.

The January 1, 2010 actuarial valuation was based on personnel information from Company records as of August 1, 2009. The following table shows the number of participants by category.

Personnel Summary

	August 1, 2008	August 1, 2009
Actives	17	20
Terminated vesteds	1	1
Retirees and beneficiaries	29	31
Total participants	47	52

Personnel Information (continued)

Following are the characteristics of the participants included in the valuation.

	August 1, 2008	August 1, 2009
Active Participants		
Number	17	20
Average present age	54.3	53.5
Average years of service	24.2	23.0
Average compensation[1]	$ 240,802	$ 255,494
Retirees and Beneficiaries		
Number	29	31
Average age	72.2	72.4
Average annual benefit	$ 80,180	$ 74,215
Term Vested Participants		
Number	1	1
Average present age	61.0	62.0
Average annual benefit	$ 1,012	$ 1,012

[1] Includes EDP deferrals.

Plan Provisions

Effective Date	Restated effective March 2, 1993.
Plan Participation	Officers and participants in the Executive Deferral Plan participate in the SERP.
Retirement Benefits	
Eligibility	Eligibility for benefit amount described in (a) below: All participants are eligible at age 55 and 20 years of service; senior executives are also eligible at age 65 and 10 years of service. (Senior officers who became participants prior to March 5, 1991 are eligible at age 55 and 10 years of service.) Eligibility for benefit amount described in (b) below: Participants who do not meet the above eligibility requirements but who are vested in their basic plan benefit.
Benefit Amount	Benefit amounts are described below: (a) 50% (60% for senior officers) times average earnings less benefits under the basic plan. The benefit is reduced in the same manner as the basic plan for retirement before age 60. (b) Basic plan benefit without IRS limits calculated as if EDP deferrals were included in pensionable earnings less the actual basic plan benefit.
Preretirement Death Benefits	
Eligibility	Eligibility for retirement benefits with an eligible spouse.
Benefit Amount	50% of the benefit amount determined as if the participant had retired and begun receiving a benefit on the first of the month before the date of death.
Postretirement Death Benefit	
Eligibility	Receiving retirement benefits with an eligible spouse.
Benefit Amount	50% of the benefit the participant was receiving. The benefit at retirement is not reduced for this coverage.

Plan Provisions (continued)

Disability Benefits	
Eligibility	Total disability before age 65.
Benefit Amount	50% (60% for senior officer) times Average Earnings less any salary continuance, long-term disability or Basic Plan benefits. The benefit begins at disability and continues for life or until recovery.
Average Earnings	Average earnings for the highest consecutive 36-month period with the Company (highest 12 months for participants prior to March 5, 1991).
Earnings	Includes Effective Earnings as defined in the Basic Plan plus any EDP deferrals, but generally excludes amounts received or deferred from any company incentive or bonus plan.
Basic Plan	The defined benefit plans of Southwest Gas.
Senior Officer	Officers with the title "Senior Vice President" or above.
Eligible Spouse	The spouse to whom the participant has been legally married at least one year at the time of death or time of benefit commencement, if earlier.

Actuarial Assumptions

Measurement Date

December 31, 2009.

Actuarial Method

Projected unit credit.

Market Related Value of Assets

The plan is considered unfunded for SFAS 87 purposes.

Discount Rate

6.00% at December 31, 2009.

Salary Increases

2.75% base pay increases plus merit increases. Sample merit increases are shown below:

Age	Rate
30	4.0%
40	2.0%
50	0.5%
60	0.0%

Mortality Rates

RP2000 Combined Healthy Mortality Table projected to 2010.

Termination Rates

None assumed.

Disability Rates

None assumed.

Retirement Age

Rates of retirement as shown below:

	Rate by Service			Rate by Service	
Age	Under 20	20+	Age	Under 20	20+
55	3%	15%	62	20%	20%
56	3%	10%	63	25%	25%
57	3%	10%	64	40%	40%
58	3%	10%	65	67%	67%
59	10%	15%	66	67%	67%
60	12%	12%	67	100%	100%
61	16%	16%			

Marital Status

100% assumed to be married with wives two years younger than husbands.

Maximum Qualified Plan Benefit

As described in IRC Section 415 ($195,000 for 2009) projected 3.25% per year.

Actuarial Assumptions (continued)

Maximum Qualified Plan Pensionable Pay	$245,000 in 2009 with 3.25% per year increases.
EDP Deferrals	Future deferrals assumed to continue at current rates.

499-002

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
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ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-2:

Identify and fully explain all changes Southwest Gas has made to its Supplemental Executive Retirement Program (SERP) since the test year utilized in SWG's last rate case, Docket No. G-01551A-07-0504.

Respondent: Human Resources

Response:

No changes have been made to the Supplemental Executive Retirement Plan since SWG's last rate case, Docket No. G-01551A-07-0504.

499-021

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-21:

AGA dues. Request No. ACC-STF-1-41(b) asked Southwest to Provide all budget and financial information the Company possess for the AGA for years 2008, 2009 and 2010 and/or budgeted for 2011.

a. Why did Southwest's response to ACC-STF-1-41 not include any of the information requested in ACC-STF-1-41(b)?

b. Provide all information in Southwest's possession that is responsive to ACC-STF-1-41(b).

c. Has Southwest requested any budget or financial information from the AGA for any of the years, 2008, 2009 and 2010 and/or budgeted for 2011? If not, explain fully why not. If so, provide a copy of Southwest's request and identify and provide a copy of the documents received.

Respondent: Revenue Requirements

Response:

The response to ACC-STF-1-41(b) was inadvertently omitted. Southwest Gas requested 2009 and 2010 information from AGA for the preparation of this rate case since those are the two years that covered the test year. The attached documents include a copy of the information request made by Southwest Gas to AGA for purposes of preparing its proforma adjustment to AGA dues, along with information provided by the AGA that is responsive to part (b) of this request.

Randi Aldridge - RE: AGA Financial Information

From: "Allen, Doug" <DAllen@aga.org>
To: "Randi Aldridge" <Randi.Aldridge@swgas.com>, "Martin, Joe" <JMartin@aga.org>
Date: 8/19/2010 11:19 AM
Subject: RE: AGA Financial Information
Attachments: Lobbying Percentages 2003_2009.pdf; 2009 Actuals v2.pdf

Hello, Randi. I believe the attached files contain all the information you requested. Please let me know if you need anything else.

Thanks.

Doug Allen

From: Randi Aldridge [mailto:Randi.Aldridge@swgas.com]
Sent: Tuesday, August 17, 2010 8:05 PM
To: Martin, Joe
Cc: Allen, Doug
Subject: RE: AGA Financial Information

Thanks Joe. If I could get the information from you or Doug by the 25th that would be great, if not please let me know. Thanks for your help, Randi

Randi

Randi L. Aldridge, CMA
Manager/Revenue Requirements | Southwest Gas Corporation
p.702.876.7184 f.702.222.1475

PLEASE CONSIDER THE ENVIRONMENT BEFORE PRINTING THIS EMAIL.

>>> "Martin, Joe" <JMartin@aga.org> 8/17/2010 5:03 PM >>>

Hi Randi,

Sorry I didn't get back to you sooner. I'm out of town until Thursday. I've copied Doug Allen on this message who can get you the information you need.

Joe

From: Randi Aldridge [mailto:Randi.Aldridge@swgas.com]
Sent: Monday, August 16, 2010 8:28 PM
To: Martin, Joe
Subject: RE: AGA Financial Information

Hi Joe, Southwest Gas is beginning preparations for an Arizona rate case. I was wondering if you could provide the below numbers for 2009, and if you have any budgeted amounts for 2010. If you have .pdf documents to support the amounts that would be suitable to use as exhibits or workpapers in our filing, that would be helpful.

Thank you! Randi

Randi

Randi L. Aldridge, CMA
Manager/Revenue Requirements | Southwest Gas Corporation
p.702.876.7184 f.702.222.1475

PLEASE CONSIDER THE ENVIRONMENT BEFORE PRINTING THIS EMAIL.

>>> "Martin, Joe" <JMartin@aga.org> 8/18/2009 4:17 AM >>>

Randi,

Here are the 2008 actual final numbers for the Association. I'm not sure where the $300,000 for advertising comes from. We do advertising but it's all advocacy and is included in the lobbying numbers. Many years ago we use to do advertising that was more marketing in nature that many state commissions would disallow. That program was terminated about 10 years ago.

Public affairs	7,036,204
Policy, Planning and Regulatory Affairs	4,041,413
Corporate affairs and International	2,754,868
Operating and engineering	5,119,289
Industry Finance and Admin. Programs	996,593
General counsel	1,043,295
Political Action Committee	190,595
General & Administration	5,275,571

Lobbying percentages:

2003	2.10%
2004	1.55%
2005	2.35%
2006	2.30%
2007	2.13%
2008	4.38%

Joe

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AMERICAN GAS ASSOCIATION
2003 - 2009 LOBBYING PERCENTAGES

Listed below are the percentages of AGA dues related to lobbying activities for the years 2003 through 2009. AGA uses lobbying expenses as defined under IRC Section 162.

Year	Lobbying %
2003	2.10%
2004	1.55%
2005	2.35%
2006	2.30%
2007	2.13%
2008	4.38%
2009	6.09%

08/19/2010

AMERICAN GAS ASSOCIATION
2008 BUDGET

	$ 2008 ALLOCATION	% 2008 ALLOCATION
Advertising	$300,000	1.18%
Corporate Affairs	$2,317,000	9.14%
General & Administrative	$5,127,000	20.22%
General Counsel	$1,056,000	4.17%
Industry Finance & Administrative Programs	$852,000	3.36%
Operations & Engineering Management	$5,505,000	21.71%
Policy, Planning & Regulatory Affairs	$4,000,000	15.78%
Public Affairs	$6,195,000	24.44%
Total Budget	$25,352,000	100.00%

Note
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 4% of member dues in 2008.

AMERICAN GAS ASSOCIATION
2009 BUDGET

	$ 2009 ALLOCATION	% 2009 ALLOCATION
Advertising	$250,000	0.90%
Corporate Affairs	$2,979,000	10.77%
General & Administrative	$5,267,000	19.05%
General Counsel	$1,148,000	4.15%
Industry Finance & Administrative Programs	$1,204,000	4.35%
Operations & Engineering Management	$5,929,000	21.44%
Policy, Planning & Regulatory Affairs	$4,329,000	15.65%
Public Affairs	$6,547,000	23.68%
Total Budget	$27,653,000	100.00%

Note
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 5% of member dues in 2009.

AMERICAN GAS ASSOCIATION
2009 Non Dues Revenue Actuals

AGA Program Categories	2009
Public Affairs	$623,783
Policy, Planning & Regulatory Affairs	$148,436
Market Development	$0
Corporate Affairs	$617,396
Operations & Engineering Management	$2,227,420
Industry Finance & Administrative Programs	$760,640
General Counsel	$195,570
General and Administrative	$223,995
Total Non Dues Revenue Actuals	$4,797,240

AGA Categories of Expenses	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010 (forecast)
Public Affairs	$ 5,703,920	$ 5,939,486	$ 6,336,326	$ 7,015,121	$ 5,726,187	$ 5,878,345	$ 5,563,947	$ 7,036,204	$ 6,087,552	$ 6,143,000
Policy, Planning & Regulatory Affairs	3,382,900	3,261,692	3,212,553	3,031,053	3,120,112	3,325,727	3,925,034	4,041,413	4,277,647	4,427,000
Market Development	1,196,791	349,589	-	-	-	-	-	-	-	-
Corporate Affairs	2,123,818	2,014,503	2,304,775	1,993,049	2,072,208	2,398,515	2,271,158	2,754,868	2,880,397	2,354,000
Operations & Engineering Management	3,664,863	3,729,829	4,302,428	4,262,228	5,154,993	5,116,637	5,693,934	5,119,289	5,474,235	5,085,000
Industry Finance & Administrative Programs	934,852	1,230,238	1,157,023	1,286,859	1,363,591	1,252,846	1,516,308	996,593	1,027,748	1,129,000
General Counsel	641,984	768,219	757,481	746,667	808,157	877,030	945,643	1,043,295	1,172,072	1,067,000
General and Administrative	4,273,134	3,894,457	4,124,675	5,034,491	4,322,358	4,676,721	4,932,418	5,275,571	5,569,647	5,535,000
Total Expense Actuals	$ 21,922,262	$ 21,188,013	$ 22,195,261	$ 23,369,468	$ 22,567,606	$ 23,525,821	$ 24,848,442	$ 26,267,233	$ 26,489,298	$ 25,740,000

Provided By: American Gas Association
October 2010

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31,1999)

JUNE 2001

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005

Telephone No. (202) 1898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER **31,1999**

EXPENSE CATEGORY	PERCENTAGE
Public Affairs	15.43%
Communications	11.64%
Media Communications:	
Commercial Equipment	4.47%
Environmental	0.74 %
Promotional	0.74%
Residential Equipment	2.96%
Corporate Affairs & International	11.30%
General Counsel & Corporate Secretary	4.02%
Regulatory Affairs	11.20%
Marketing Services	15.02%
Operating & Engineering Services	14.70%
Policy & Analysis	12.07%
Industry Finance & Admin. Programs	2.94 %
General & Administrative Expense	0.00%
TOTAL	107.23% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1999

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (5)	Adjusted Net Expense	% of Dues
03	Public Affairs	4,147,682	3, 4	(1,690,669)	455,752	2,912,765	15.43%
03	Communications		4	1,698,695	498,479	2,197,174	11.64%
08	Media Communications						
	Commercial Equipment	759,932	1,2	61,868	21,400	843,200	4.47%
	Environmental	126,708	1,2	10,316	3,568	140,592	0.74%
	Promotional	126,708	1,2	10,316	3,568	140,592	0.74%
	Residential Equipment	503,934	1,2	41,027	14,191	559,152	2.96%
06. 16	Corporate Affairs and International	1,483,688	3	(5,217)	655,144	2,133,615	11.30%
05	General Counsel & Corp. Secretary	588,436	3		170,907	759,343	4.02%
09	Regulatory Affairs	1,492,676	3	194,393	427,268	2,114,337	11.20%
08	Marketing Services	4,654,503	1, 2	(2,302,920)	484,237	2,835,820	15.02%
14	Operating & Engineering Services	1,949,534			826,051	2,775.585	14.70%
07	Policy & Analysis	1,374,743	1	277.704	626,659	2,279,106	12.07%
12	Industry Finance & Admin. Programs	498,349			56,969	555,318	2.94%
01.10.11	General & Administrative Expense	4,247,002	3	(2,809)	(4,244,193)		0.00%
	Grand Total	21,953,895		$ (1,707,296)	$ -	$ 20,246,599	107.23%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 Breakout of communications portion of division expenses
5 G&A allocated on basis of equivalent full-time employees during 1999.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1999

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity. Public affairs provides members with information on legislative developments: prepares testimony, comments, and filings regarding legislative activities; lobbies on behalf of the industry.
08	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media. Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas. Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels. Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applicationsof specific equipment. Institutional - to enhance the image of the natural gas industry as a business entity. Power Generation Natural Gas Equipment - explains cost-savings. energy-savings and other benefits provided by specific equipment for generating power. Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas. Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
12	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.

05 General Counsel & Corporate Secretaw provides legal counsel to the Association

06 Corporate Affairs provides opportun'ities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

09 Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

08 Market Development assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Donnelson

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 1998)

JANUARY 2000

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue, N.W., Suite 200
Washington, D.C. 20005

Telephone No. (202) 898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 1998

EXPENSE CATEGORY	PERCENTAGE
Communications	10.27%
MEDIA COMMUNICATIONS:	
Commercial Equipment	5.96%
Environmental	3.37%
Industrial Equipment	1.36%
Promotional	1.46%
Residential Equipment	8.40%
Finance & Administration Services	12.17%
General Counsel & Corporate Secretary	5.54%
Government Relations	23.86%
Marketing Services	16.20%
Meeting Services	-0.18%
Operating & Engineering Services	4.90%
Planning & Analysis	9.51%
General & Administrative Expense	0.00%
TOTAL	102.82% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1998

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (4)	Adjusted Net Expense	% of Dues
03	Communications	1,561,612	2	(2,679)	430,782	1,989,715	10.27%
13	Media Communications						
	Commercial Equipment	1,105,739	1,2	31,943	17,848	1,155,530	5.96%
	Environmental	625,598	1,2	18,072	10,098	653,768	3.37%
	Industrial Equipment	252,954	1,2	7,307	4,083	264,344	1.36%
	Promotional	270,820	1,2	7,823	4,372	283,015	1.46%
	Residential Equipment	1,557,378	1,2	44,990	25,139	1,627,507	8.40%
06	Finance & Administration Services	1,797,937	3	(13,893)	574,377	2,358,420	12.17%
05	General Counsel & Corp. Secretary	938,797	3	(8,566)	143,594	1,073,825	5.54%
09	Government Relations	3,802,555	3	22,459	800,025	4,625,039	23.86%
08	Marketing Services	2,693,462	1	(107,456)	553,863	3,139,869	16.20%
04	Meeting Services	(34,155)		-	-	(34,155)	-0.18%
14	Operating & Engineering Services	661,825		-	287,188	949,013	4.90%
07	Policy & Analysis	1,392,718		-	451,296	1,844,014	9.51%
01,10,11	General & Administrative Expense	3,302,665		-	(3,302,665)	0	0.00%
				-			
	Grand Total	19,929,905		$ 0	$ 0	$ 19,929,905	102.84%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 G&A allocated on basis of equivalent full-time employees during 1997.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1998

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
13	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
	Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
	Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applications of specific equipment.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
06/ 16	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.
05	General Counsel & Corporate Secretary provides legal counsel to the Association.
09	Government Relations provides members with information on legislative and regulatory developments; prepares testimony, comments, and filings regarding legislative and regulatory activities; lobbies on behalf of the industry.
08	Marketing assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

04 Meeting Services and Membership Services provides support services for committee meetings and conferences. In addition, coordinates services provided to members.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: DECEMBER 23, 2003

TO: DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

FROM: DIVISION OF ECONOMIC REGULATION (BRINKLEY, BAXTER, DRAPER, GARDNER, HEWITT, KAPROTH, KENNY, LESTER, LINGO, C. ROMIG, SPRINGER, STALLCUP, WHEELER, WINTERS)
DIVISION OF COMPETITIVE SERVICES (MAKIN)
OFFICE OF THE GENERAL COUNSEL (JAEGER)

RE: DOCKET NO. 030569-GU - APPLICATION FOR RATE INCREASE BY CITY GAS COMPANY OF FLORIDA.

AGENDA: 01/06/04 - REGULAR AGENDA - PROPOSED AGENCY ACTION - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES: 5-MONTH EFFECTIVE DATE: JANUARY 15, 2004 (PAA RATE CASE)

SPECIAL INSTRUCTIONS: NONE

FILE NAME AND LOCATION: S:\PSC\ECR\WP\City Gas 030569-GU\
Final.RCM
Final Attachments 1-5.123
Final Attachments 6A-7P.123
Final Attachment 8.xls

ISSUE 39: Is City Gas's $(2,847) adjustment to Account 921, Office Supplies and Expenses, for American Gas Association membership dues appropriate?

RECOMMENDATION: No. Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for American Gas Association membership dues related to charitable contributions and advertising that is not informational or educational in nature. (C. ROMIG)

STAFF ANALYSIS: On MFR Schedule G-2, Page 17 of 34, the Company included $1,966,495 in its Account 921, Office Supplies and Expense for the 2003 interim year. Included in this amount is $39,277 related to American Gas Association (AGA) membership dues. This was inflated for customer growth and general inflation of 1.0232 to $40,188. On MFR G-2, Page 2 of 34, it removed $2,847 that was labeled as "attributable to lobbying." This represents an adjustment of 7.08%.

In City Gas's last rate case, In re: Request for rate increase by City Gas Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. In re: Application for a rate increase by City Gas Company of Florida, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent

NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

499-029

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-29:

Relocation expense and losses associated with sales of employee homes.

a. Please identify, by account, all expense in the test year related to gains or losses associated with sales of employee homes.

b. Please identify, by account, all expense in the test year related to sales commissions on the purchase or sale of employee homes.

c. Please provide comparative information for each calendar year, 2006 through 2010.

d. Please identify, by account, all rate base amounts in the test year related to Company ownership of employee homes.

e. As of June 30, 2010, identify, by account, the Company's equity in employee homes.

f. For all amounts identified in response to parts a through e, above, please also provide the Arizona jurisdictional amount.

Respondent: Revenue Requirements

Response:

Please refer to the attached spreadsheets for answers to ACC-STF-6-29 (a), (b), (c), (e) and (f). Please note, for illustrative purposes, commissions were shown separately from the loss amounts; however, commissions are included in the loss amounts.

With regard to ACC-STF-6-29 (d), no amounts related to Company ownership of employee homes were included in rate base.

SOUTHWEST GAS CORPORATION
2010 ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
EMPLOYEE RELOCATION EXPENSE AND LOSSES ASSOCIATED WITH SALES OF EMPLOYEE HOMES
DATA REQUEST STF 6.29 (a), (b), (c) and (f)

	2006		2007		2008		2009		2010		Test Year July 2009 - June 2010	
	Loss	Commission	Loss	Commission	Loss	Commission	Loss	Commission	Loss	Commission	Loss	Commission
Arizona - Account 88000001	$ -	$ -	$ 170,312	$ 33,144	$ 681,746	$ 62,220	$ 74,007	$ 14,400	$ 70,592	$ 34,338	$ 374,906	$ 62,520
Corporate - Account 92100001	$ 55,444	$ 23,940	$ 35,366	$ 16,440	$ 247,851	$ 49,830	$ 219,210	$ 20,700	$ -	$ -	$ 237,939	$ 50,100
Paiute & SGTC MMF	4.12%	4.12%	3.91%	3.91%	3.90%	3.90%	3.89%	3.89%	3.84%	3.84%	3.83%	3.83%
Less: Paiute & SGTC Allocation	$ 2,284	$ 986	$ 1,383	$ 643	$ 9,666	$ 1,943	$ 8,527	$ 805	$ -	$ -	$ 9,113	$ 1,919
Relocation Expenses Before 4-Factor	$ 53,160	$ 22,954	$ 33,983	$ 15,797	$ 238,184	$ 47,887	$ 210,683	$ 19,895	$ -	$ -	$ 228,826	$ 48,181
Arizona 4-Factor Allocation	56.81%	56.81%	56.81%	56.81%	56.54%	56.54%	56.42%	56.42%	56.05%	56.05%	56.25%	56.25%
Adjustment Allocated to Arizona	$ 30,200	$ 13,040	$ 19,306	$ 8,974	$ 134,669	$ 27,075	$ 118,867	$ 11,225	$ -	$ -	$ 128,715	$ 27,102
Total Arizona Relocation Costs	$ 30,200	$ 13,040	$ 189,617	$ 42,118	$ 816,416	$ 89,295	$ 192,874	$ 25,625	$ 70,592	$ 34,338	$ 503,620	$ 89,622

Please note, for illustrative purposes, commissions were shown separately; however commissions are included in the loss amounts.

SOUTHWEST GAS CORPORATION
2010 ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
EQUITY IN EMPLOYEE HOMES AS OF JUNE 30, 2010
DATA REQUEST STF 6.29 (e) and (f)

		Balance as of June 30, 2010
Total Company - Account 17401150	$	1,634,654.55
Arizona 4-Factor Allocation		56.25%
Arizona Portion of Equity in Employee Homes	$	919,493

504-021

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 to ACC-STF-11-23)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 8, 2011

Request No. ACC-STF-11-21:

Southwest Gas Energy Efficient Technology (EET).

a. Please identify all costs included in the test year related to the Southwest Gas Energy Efficient Technology department or unit.

b. Please provide a breakout for the test year, and, for comparison purposes, for calendar years 2009 and 2010, of the EET time and costs related to (1) gas heat pump research and development and (2) other energy efficiency projects.

c. Please identify and explain each other energy efficiency project in 2009 and 2010 in which EET was engaged, other than the gas heat pump research and development.

d. Are there any other departments in the Westwood facility other than EET and Intellichoice Energy LLC? If not, explain why not. If so, please identify the other Southwest departments at that location.

e. What was the total cost of the Westwood facility for the test year and for calendar 2009 and 2010? Show in total and also show the Arizona jurisdictional amounts for each period.

Respondent: Revenue Requirements / Energy Efficient Technology Department

Response:

a. Total costs included in Arizona for EETD during the test year are $336,626 charged to Account 182.3 and recovered through the Arizona R&D surcharge; $1,679,741 to Account 908 of which $906,220 was allocated to Arizona; $25,609 to Account 920 of which $13,853 was allocated to Arizona; $8,477 to Account 921 of

which $4,585 was allocated to Arizona; and $64,014 to Account 931 of which $34,629 was allocated to Arizona.

b. Please refer to the attached spreadsheet of test year EETD charges requested in base rates in Arizona compared to calendar years 2009 and 2010. Amounts shown are after allocation to Arizona. While costs are not tracked by project, the EETD estimates that 65 percent of its time was related to gas heat pump research, and the remaining 35 percent is related to other energy efficiency projects.

c. Please refer to the attached document.

d. No. The Westwood facility does not have suitable available space for other Southwest departments to utilize.

e. The total costs of the Westwood facility, before and after allocation to Arizona, are included in the attached spreadsheet.

SOUTHWEST GAS CORPORATION
ARIZONA
ENERGY EFFICIENT TECHNOLOGY DEPARTMENT
COSTS REQUESTED FOR RECOVERY IN BASE RATES
CALENDAR YEARS 2009 AND 2010, AND TWELVE MONTHS ENDED JUNE 30, 2010

Line No.	Description	Test Year	2009	2010	Line No.
	(a)	(b)	(c)	(d)	
1	Account 908	$ 906,220	$ 980,738	$ 1,065,485	1
2	Account 920	13,853	49,932	-	2
3	Account 921	4,585	7,206	231	3
4	Account 931	34,629	34,406	37,341	4
5	Total	$ 959,287	$ 1,072,282	$ 1,103,057	5

SOUTHWEST GAS CORPORATION
ARIZONA
ENERGY EFFICIENT TECHNOLOGY DEPARTMENT
WESTWOOD FACILITY COSTS
CALENDAR YEARS 2009 AND 2010, AND TWELVE MONTHS ENDED JUNE 30, 2010

Line No.	Description	Test Year	2009	2010	Line No.
	(a)	(b)	(c)	(d)	
1	Rent	$ 64,015	$ 63,603	$ 69,028	1
2	Gas	12,942	12,689	7,905	2
3	Electric	17,268	19,950	15,581	3
4	Water	290	230	303	4
5	Sewer	595	549	438	5
6	Trash	4,648	7,513	3,040	6
7	Janitorial, Alarm Monitoring, Pest Control	6,828	6,828	6,828	7
8	Total	$ 106,585	$ 111,362	$ 103,122	8
9	4-Factor Allocation	56.25%	56.25%	56.25%	9
10	Amount Allocated to Arizona	$ 59,954	$ 62,641	$ 58,006	10

2009-2010 Energy Efficiency Projects

1. Arizona Corporation Commission - Solar Thermal / Demonstration (Tempe, AZ)
   - System Installation/Operations
   - Data Monitoring Installation / Review
   - ACC Final reports / presentation
2. Arizona Corporation Commission - Solar Thermal / Water & Space Heating Demonstration (Tucson, AZ) Pepper Viner Home
   - System Installation/Operations
   - Data Monitoring Installation / Review
   - ACC Final reports / presentation
3. Arizona Corporation Commission - Gas Engine Driven Water Heating (GEDWH), Phase II and III
   - Final report (Phase II)
   - Scope of Work (Phase III)
   - Design & Fabrication (Phase III)
4. Operations Technology Development (OTD) Board Involvement
   - OTD Administration and Individual Project Oversight
   - NYSEARCH Administration and Individual Project Oversight
5. Utilization Technology Development (UTD)Program
   - Nevada Filing for Rate Recovery of Dues
   - UTD Administration and Individual Project Oversight
   - UTD Board Involvement
6. Energy Solutions Center (ESC)
   - ESC Administration and Project Oversight
   - Quarterly Technology and Marketing Assessment Forum (TMAF) meetings
7. Natural Gas Vehicles (NGV) Initiative
   - Co-Lead of NGV Workgroup
   - American Gas Association (AGA)/ America's Natural Gas Alliance (ANGA) – Participate in review of marketing analysis
   - Clean American Transportation Alliance (CATA)
8. SWG Biogas Task Group
9. Desert Research Institute (DRI)
   - DRI Engine Testing
   - DRI Maintain Relationship
10. Codes, Standards, Guidelines Support
    - American Gas Association (AGA) Building Energy Codes Standards (BECS) Committee
    - American Society of Heating, Ventilation, Air-conditioning and Refrigeration Engineers (ASHRAE) Standards – 90.1, 189.1
    - United States Green Building Council (USGBC) – Leadership in Energy and Environmental Design (LEED) Guidelines
    - National Association of Home Builders (NAHB) – Green Homes
    - Energy Star
    - Nevada Solar Thermal Regulations
    - Consortium for Energy Efficiency

491-098

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-98:

Research and Development.

a. Does the Company undertake R&D projects for only those studies which will most beneficially impact its operations?

b. How does the Company determine which R&D studies will be most cost beneficial to it?

c. List each research and development project for which the Company is incurring cost, or for which costs are being allocated to the Company, during the test year. For each, show the accounts and amounts in which such cost is being recorded.

d. Provide a copy of any and all cost/benefit analyses for each research and development project for which the Company is incurring cost, or for which costs are being allocated to the Company, during the test year.

e. Provide the amount of R&D expense recorded in each year, 2005 through calendar year 2010 and identify the accounts charged.

Respondent: Revenue Requirements / Energy Efficient Technology Department

Response:

a. The Company does undertake projects that are anticipated to benefit its operations, but also undertakes projects that will benefit customers, the community and the natural gas distribution industry. In Decision No. 68487 (D.68487), pp. 60-61, the Commission directed Southwest Gas to fund R&D projects, subject to oversight by the Commission. The funds for such projects are collected from customers through a surcharge, and held and disbursed through a balancing account.

b. While some R&D projects have potential cost benefits, most natural gas R&D pursued by the Company is difficult to analyze from a traditional cost-benefit analysis perspective. Rather the Company considers potential benefits such as enhanced pipeline safety or integrity, streamlined operation and maintenance activities, improved end-use energy efficiency, and improved processes to address environmental challenges.

   The Company has established an internal research committee comprised of representatives from engineering, operations, construction, environmental, and energy efficiency groups. This committee reviews research proposals taking into consideration the potential benefits discussed above, and recommends projects to fund. An internal steering committee has also been established, which reviews and approves recommendations brought forward by the research committee.

   In addition to the Company committees, the projects are reviewed by the ACC Staff every year as ordered in D.68487. The Company is required to file a list of projects to be funded every year. Before the official filing, the Company hosts a conference call with the ACC Staff to discuss the projects. Once Southwest makes its official filing, typically around April, the Commission has 30 days to provide the Company input on the projects funded for the given year.

c. Please refer to the attached worksheet for the list of R&D projects undertaken by Southwest Gas in accordance with D.68487. In addition, Southwest Gas has pursued energy efficient technology projects, specifically a gas engine driven air conditioner or what is termed the "GEDAC" project. This has been a part of Southwest Gas' efforts to utilize energy efficient technologies to help reduce electric peak demand, assist in the transition to a more environmentally-friendly and carbon neutral society, and more efficiently and effectively use natural gas in desert climates. This project was undertaken with the knowledge and encouragement of the Commission Staff and Commissioners. This project was also sponsored and co-funded by the U.S. Department of Energy. Amounts allocated to Arizona for this project during the test year in Account 908 totaled $337,959.

d. The Company does not conduct a traditional cost-benefit analysis for each R&D project. The Company does, however, evaluate potential benefits for every project and these benefits are noted in each project description in the attached worksheet.

e. Please refer to the table below and attached worksheet.

Year	Amount	Account	General Description
2005	$55,000	92100001	Gen. Studies (AGF), Pipeline Integrity and Keyhole (GTI), Yield Strength (ASME)
2006	$20,000	92100001	Keyhole (GTI)
2006-2010	See attached worksheet	18236403	See attached worksheet

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	*Project Description*	***Potential*** Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
	Operations Technology Development (OTD) Program								
	Dues (Project Allocation and Administrative Costs)				***$430,000***	***$430,000***	***$430,000***	***$430,000***	***$216,108***
	Carry over from previous year					$268,500	$91,360	$115,082	$233,892
	Refunds/Royalties								$3,084
	Total Available for Allocation					***$698,500***	***$521,360***	***$545,082***	***$453,084***
OTD-0	OTD Administrative Costs	GTI			$21,500	$21,500	$22,399	$32,250	$33,750
OTD-1	**(1.6.h) Complete** Project Development and Field Testing of the Digital Leak Detector	GTI	The objective of this project is to develop and commercialize a leak detection and pinpointing digital leak detector (DLD) that is proven in multi-utility applications. The DLD detects the acoustic signal created by the gas or fluid escaping the pressurized pipe.	Improved accuracy in pinpointing hard to find leaks. In addition, reduced costs in pinpointing leaks.	$40,000	$18,120	$7,550		
OTD-2	**(1.7.a) Complete -** Universal Utility Locator	GTI	The objective of this project is to develop a prototype locating system that is able to locate plastic and other non-metallic pipes in a variety of soil conditions. The prototype will also be able to provide information about depth, diameter and material composition of the pipe.	Reduced costs in locating non-metallic pipe.		$20,000	($11,365)		
OTD-3	**(1.7.b) CANCELED** Low-Cost, Nano-Methane Sensor	GTI				$0			
OTD-4	(1.8.g) Acoustic Sewer Lateral Locator	GTI	Trenchless pipe installation techniques greatly reduce natural gas pipe installation costs and minimize impact to the environment and general public. Unfortunately, there have been occasions where a gas plastic pipe has been unintentionally installed through a sewer lateral and the operator is unaware of this situation. The intent of this project is to develop acoustic tools/processes. The key challenges to address include:1) operations in all types of soil under various operating conditions, 2) cost effectiveness of the device, and 3) ease of operation by field crews.	Enhanced safety through a more accurate method of locating sewer laterals. In addition, reduced costs in locating sewer laterals.			$15,000	$14,368	

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	***Potential*** Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
OTD-5	(1.h) Hand-held Acoustic Pipe Detector (Phase II & III)	GTI	The objective of this project is to design, build and test a commercial-grade (Phase III), handheld pulse-echo sonic detector capable of detecting and locating small diameter metallic and nonmetalic pipe in all soil types.	Reduced costs in locating non-metallic pipe.	$15,000	$11,893		$10,902	$3,624
	(1.10.a) Ethane Only Detector	GTI	Natural gas typically contains 1-5% ethane. When situations require the identification of natural gas is crtitical (ex., distinguishing between sewer gas or pipeline natural gas), detection of ethane can help verify natural gas is present. This project will develop a handheld instrument which can be utilized rapidly and easily in the field to resolve the absence or presence of ethane as a fingerprint for natural gas whenever the origin of a methane signal is questionable. Optical technology will be utilized.	Reduced costs in distinguishing natural gas vs. other sources of methane.					$5,000
OTD-6	(2.7.b) Qualification of Saddle and Electrofusion Joint Designs and Test Methods to Validate Safe Long Term Performance	GTI	The objective of this project is to develop a novel approach to ensure the safe and long-term performance of various types of lateral connections including: saddle heat fusion joints, electrofusion joints, and mechanical joining.	Improved joining procedures and/or joint evaluation, to ensure long term joint integrity.		$25,000	$12,500	$15,000	$15,000
OTD-7	(2.7.d) Cold Adhesive Repair (CAR) and Joining of Polyethylene Pipes with Minimal Surface Preparation	GTI	The primary objective of this project is to develop and commercialize an economical, reliable, and safe technology to quickly and effectively repair damaged and leaky PE gas pipes using modern structural cold adhesives, optimized for low-surface-energy-materials such as PE, that: require little surface preparation, cure at typical field temperatures, cure within short periods not exceeding 90 minutes, and do not require any tools, heating, pressure or significant training.	Reduced costs in repairing damages to plastic pipe.		$10,000	$9,268		

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OTD-8	(2.7.e) External Repair Tool for PE Pipe	GTI	The overall objective of this project is to continue the research that Timberline has already conducted to: optimize the design of the repair patch and repair patch material, optimize the design of the mechanical tool to apply the repair patch, and perform appropriate testing and address regulatory codes for the repair patch to be accepted as a repair method for PE pipe.	Reduced costs in repairing damages to plastic pipe. Enhanced safety by allowing the repair of damaged plastic pipe from above ground (i.e not in the ditch)		$45,000	$32,936		$10,000
OTD-9	(2.7.g) Composite Pipeline Repair Systems - Analysis of Adhesive Degradation - Permanence of Repair	GTI	This project will include the evaluation of the adhesives used in commercially available composite repair techniques to establish if their performance dictates a "permanent" or "temporary" repair classification for the overall repair system. Composite system repairs depend heavily on the adhesives used to transfer the load from the repaired pipe to the repair system. In order to fully assess the suitability of such repairs (as *permanent or temporary solutions*), the possibility of degradation of the adhesive over time must be investigated.	Enhanced integrity and possible reduced costs in repairing steel pipe.		$25,000	$15,018	$12,922	
OTD-10	**(2.7.h) Complete -** Investigate a Mitigation Strategy for Elemental Sulfur Deposits in Gas Pipelines (SWG Initiated Project)	GTI	A review and evaluation of the cause of elemental sulfur powder deposit in gas pipeline equipment.	Enhanced safety and reliability by better understanding root cause of sulfur deposits. In addition, possible reduced costs in addressing/resolving deposits.		$44,000	($15,719)		

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OTD-11	(2.8.c) Electrofusion Coupling Guidelines	GTI	Extensive work has been done to develop the electrofusion (EF) joining process and to investigate both the short and long term performance of coupling joint. However, a great deal of dimensional variation can exist with the fit of the coupling onto the pipe due to differences in EF coupling tolerances, tooling, and installer practices. Current industry standards for EF couplings place no limitations on the coupling I.D. tolerances, scrapping limits, or the annular gap. The objective of this project is to develop guidelines to address these issues.	Improved joining procedures and/or joint evaluation, to ensure long term joint integrity.			$5,000	$0	
OTD-12	(2.9.e) HP stopping equipment	GTI	To develop "high pressure" inflatable stoppers as an alternative to currently employed stopping equipment for routine and emergency stopping operations on pipe materials such as steel, cast iron, PE, and PVC. New line stopping equipment can address challenging by-pass or pipe shut-off situations. In addition, inflatable stoppers could save significant time and money during day to day operations.	Reduced costs in emergency stopping operations.				$15,000	$10,128
OTD-13	**(4.5.d) Complete -** Monitor Internal Corrosion Using Fluidized Sensors	GTI	The objective of this project is to develop sensors and delivery package that can be introduced into the gas stream and identify likely locations of internal corrosion as they flow through the pipeline. This type of information would reduce the total number of required excavations for internal corrosion assessment or eliminate the need to excavate the pipe altogether.	Reduced costs in detecting internal corrosion areas.	$25,000	$4,997		($1,903)	
OTD-14	(4.6.a) Repair Techniques for Low Stress Pipelines	GTI	*Testing and assessment* of various repair techniques will be conducted to help provide justification for their use as long term repair methods on low stress pipelines allowed by CFR 49 Part 192. Results may help reduce the cost of repairing the steel pipelines by minimizing the need to cut full sections of pipe to make repairs.	Enhanced integrity and possible reduced costs in repairing steel pipe.	$25,000	$10,714	$22,551	$0	

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OTD-15	**(4.6.b) Complete** - Risk-Based DIMP Procedure for Plastic Gas Pipelines	GTI	The primary objective of this project is to develop a risk-based distribution integrity management procedure and software for companies to manage their plastic distribution pipelines.	Improved process for assessing plastic pipe risks.	$25,000	$13,500	$12,790		
OTD-16	**(4.7.a) Complete.** In-Field Corrosion Rate Measurement for IMP	GTI	The purpose of this project is to provide a systematic and simple method to measure the general corrosion rate of steel or cast iron materials in the field and to collect and measure key soil and environmental parameters responsible for pitting/localized corrosion for a pipeline region/system. These sets of data (with select pre-assessment data) will be entered into a simple computer program/spreadsheet that combines the measured and collected data with historical/statistical data and provides a realistic corrosion growth rate to calculate reassessment intervals.	More efficient method for determining corrosion rates.		$30,000	$36,923		
OTD-17	(4.7.f) Internal inspection sensor and platform for Explorer II (robot for 6"/8") (NYSEARCH)	NYSEARCH	See description under 4.3 below. This is the same effort but was funded under a separate OTD line item. Efforts under this funding is complete.	Application of a new technology to help meet PHMSA's integrity management regulations. In addition, possible reduced assessment costs for steel transmission pipe.		$25,000			
OTD-18	(4.7.g) Yield Strength Determination using pipe coupons	GTI	Federal safety regulations establish a minimum yield strength of steel pipe at 25,000 psi if the specifications of the steel pipe are unknown. Current methods to determine actual yield strength are cumbersome in that a pipe section is removed, which typically requires the pipeline to be taken out of service. This project is evaluating the determination of yield strength from small pipe coupons that do not require the pipeline to be taken out of service. If successful, the process developed will provide SWG a more economic option to determine yield strength which would allow SWG to more appropriately address the risks posed by the pipeline.	Reduced costs in determining actual yield strength of in-service pipe.		$17,000	$15,941	$10,000	$8,458

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OTD-19	(4.8.a) Guided Wave Validation as Hydro Equivalent	GTI	Guided wave technology is being used to assess steel transmission pipe in casings as a result of federal transmission pipeline integrity regulations. Federal regulators however, are uncertain of the effectiveness and limitations of the technology. The purpose of this project is to compare the defects identified by guided wave technology to those identified in a pressure test (typically conducted as a hydro/water test). Pressure testing is currently accepted by federal regulators as an assessment technology.	Enhanced safety and integrity of transmission facilities covered under PHMSA's integrity management regulation through the appropriate use of guided wave technology. In addition, possible reduced costs to meeting regulations.			$25,000	$19,036	
OTD-20	(4.8.g) GTI/NYSEARCH North American Casing Program (GTI Project)	GTI	All steel pipe in casings that fall within the scope of federal transmission pipeline integrity management regulations, have to be assessed by December 2012. Pipelines in casing are challenging to assess because they are often un-piggable, can not be taken out of service to conduct a pressure test, and have limited external corrosion direct assessment tools that are applicable. The intent of this program is to identify and conduct research projects through the collaboration of all stakeholders that include pipeline operators, federal and state regulators, research organizations, and manufacturers and service providers.	Enhanced safety and integrity of transmission facilities covered under PHMSA's integrity management regulation through the appropriate use of casing assessment methodologies. In addition, possible reduced costs to meeting regulations.			$15,000		
OTD-21	(4.8.i) Extended Reassessment Interval Validation Through Dielectric Wax Casing Fill	GTI/Profile	To develop in-situ corrosion monitoring techniques and validation testing associated with the use of dielectric wax used to fill a casing. Monitoring techniques will be used for determining corrosion growth rate and for ensuring the quality and long-term performance of the wax fill. The results of the monitoring techniques could be used to help justify an extend re-assessment intervals for confirmatory direct assessment under integrity management regulations.	Improved understanding of affects of wax fills on corrosion rates. Possible reduced costs to meeting PHMSA integrity management regulations.			$10,000	$9,333	$7,033

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OTD-22	(4.9.a) Increase Trmn. Boundary 20 -> 30% SMYS	GTI	This project attempts to verify that a lower boundary of 20% SMYS for transmission classification is overly conservative. The work in this project will involve an international incident review and mathematical modeling (if necessary) to demonstrate that a lower boundary of 30% SMYS is more representative of actual leak vs rupture failures. The overall objective of the project will be to provide regulators and operators with information based on sound engineering principles that allows the selection of the most appropriate integrity management process.	Better understanding of risks and consequences of failures on lower stressed transmission pipelines. Results could provide a basis to reduce PHMSA integrity management requirements, thus reducing costs, without sacrificing safety.				$19,000	$13,963
OTD-23	(4.9.b) 2" Camera for Live Gas Internal Inspection	TBD	To identify, develop, and/or demonstrate the use of a camera for the internal inspection of 2-inch gas mains without having to shut off the flow of gas and segment the pipe. This will be done by identifying a capable camera and then, working with the manufacturer, making modifications (if necessary) for live gas use. Fittings will also be reviewed and developed if necessary. The device and fittings will be capable of inspecting 2-inch and larger PE, PVC, steel, or cast iron mains.	Reduced costs for inspecting 2" gas mains.				$15,000	$29,219
OTD-24	(4.10.a) 4" MFL Tethered Inspection Tool for Unpiggable Pipe	GTI	A tethered 4" MFL tool capable of entering transmission pipe in live conditions has been developed but not fully demonstrated. In addition, no efforts have been pursued for a similar tool for larger pipe sizes (6" - 12"). If this technology is effective, then it could help utilities inspect transmission pipe in casings that fall under the PHMSA integrity management rules. This particular effort includes the demonstration of the 4" tool.	Application of a new technology to help meet PHMSA's integrity management regulations. In addition, possible reduced assessment costs for steel transmission pipe.					$25,183

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OTD-25	(4.e) Inspection Platforms for Unpiggable Pipelines (NYSEARCH)	NYSEARCH	This is a NYSEARCH effort that is being funded with OTD funds. There are 2 NYSEARCH robotics inspection tools for un-piggable pipe, included in these efforts. One is the development of an Explorer II robot that utilizes an Remote Field Eddy Current (RFEC) sensor for 6" - 8" pipe. The other is for the TIGRE robot that is for 22" - 24" pipe and utilizes MFL technology. Both efforts were initiated due to transmission integrity management regulations promulgated by PHMSA. Distributions companies like SWG operate transmission pipelines that can not accommodate traditional in-line inspection tools (i.e. smart pigs).	Application of a new technology to help meet PHMSA's integrity management regulations. In addition, possible reduced assessment costs for steel transmission pipe.		$105,000		$11,484	$86,923
OTD-26	**(5.6.c) Complete -** Field Collection of Mapping and GIS Information Using GPS Coordinates: Phase 2	GTI	The objective of this project is to develop a system that automatically collects digital mapping and GIS data during routine operations (locates, leak survey, corrosion monitoring, meter reading). This will be accomplished by implementing methodologies and software to attach GPS coordinates to field data. The field data will be collected using an "electronic work ticket" that geo-codes the data with no additional operator effort.	Evaluation of processes that may help reduce costs in updating mapping systems.		$1,000			
OTD-27	**(5.6.e) Complete.** Portable Propane Air Residential Temporary Gas Supply	GTI	The purpose of this project is to research, design, prototype, test, and commercialize a portable Propane-Air system for use as a temporary gas supply on residential applications.	New device that can keep customers in-service during maintenance to gas facilities.	$10,000	$8,404			
OTD-28	(5.7.a) Re-Coating with Minimal or No Surface Preparation for Vaults and Other High Moisture Environments (SWG Initiated Project)	GTI	The project will research/develop a coating system that can be applied over gas piping with little or no surface preparation that will prevent atmospheric corrosion.	Reduced costs by reducing the amount of work required to re-coat pipe.		$45,000	$40,645		

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OTD-29	**Complete - (5.7.c)** Guidelines for Use of Copper Clad Steel Tracer Wire	GTI	The objective of this project is to test and evaluate Copper Clad Steel (CCS) tracer wire under laboratory and field conditions, examine the properties of the wire to develop installation methods, develop an installed wire comparison to copper wire, and to provide guidelines for the use of copper clad steel tracer.	Reduced costs by utilizing an alternative material to copper.		$25,000	$18,421		
OTD-30	(5.7.f) Automated Meter Shut-Off Device (AMS)	GTI	This project will develop an automated meter shut-off (AMS) device that would fit over the current meter shut-off valve (existing meter inlet valve) without the need to interrupt gas supply to the customer. Upon remote actuation of the battery powered device releasing the rotary actuator (via Itron type device or drive by vehicle), the AMS will close the gas meter inlet valve, stopping the flow of gas through the meter.	Reduced costs in installing a remote shut off device.		$5,000	$4,519		
OTD-31	**(5.7.l) Complete -** Integrating Radio Frequency Identification (RFID) into Daily Gas Operations	GTI	The overall project objective is to demonstrate that the use of direct burial RFID can save considerable time and effort in daily utility operations for a very modest cost.	Reduced costs in data collection processes.		$5,000			
OTD-32	**(5.6.q) Complete -** EFV testing	GTI	Starting in June of 2008, all natural gas service lines to certain types of services will be required to have an excess flow valve (EFV) installed. This is a result of a new federal pipeline safety regulation issued in 2007. The purpose of this project is to conduct independent testing and analysis of various EFVs to help operators determine the most appropriate EFVs to utilize in their distribution systems.	Enhanced safety through the selection of appropriate EFV types.		$30,000	$26,933		

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OTD-33	(5.7.p) GPS Consortium (GTI Project)	GTI	The objective of the GPS Consortium Program is to facilitate technology transfer regarding the use of GPS technology for utility operations. The program activities include demonstrations, *identification of* research needs, workshops, pilot projects, best practices/standards development and general information sharing. A key focus is to establish standards or best practices for GPS data collection and GIS integration processes.	Reduced costs in implementing new GPS and GIS systems or devices.		$15,000		$15,000	
OTD-34	**(5.8.b) Complete** - Study of Anode Life Effectiveness (SWG Initiated Project)	GTI	The intent of this project is to identify the various factors affecting the life of one pound anodes utilized in isolated steel services in AZ.	Enhanced safety through the appropriate specification and application of anodes.			$30,000		
OTD-35	(5.8.e) Development of Standardized Algorithms and Identifiers for Enhanced Material Tracking and Traceability	GTI	The purpose of this project is to develop a series of protocols that can be used effectively by gas distribution companies to more accurately track their underground facilities. The protocols will be developed from standardized algorithms and identifiers to characterize the various components within the gas distribution network (pipe, fittings, and appurtenances). These are then to be integrated within a utility's procurement, design, build, and construction process. Material traceability is important, particularly in the event that products are identified with defects that may affect the integrity of the system.	Standardized traceability among major gas carrying component manufacturers. This could help reduce costs associated with establishing internal tracking processes.			$15,000	$10,798	$8,333
OTD-36	**(5.8.n) Complete** - Quality Assurance Remote Management (QARM) - GPS Cameras for Joint Inspection	GTI	The objective of this program is to identify and develop procedures and tools to allow inspectors and management to monitor the quality of field operations remotely. This program will identify key elements to consider if implementing the use of cameras to photograph plastic joining operations as a means of recording visual inspections.	Enhanced inspection reporting.			$10,000		

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OTD-37	(5.9.c) Mitigating Electrical Interference on CP Systems	GTI	To identify or develop practices that mitigate the effects of electrical interference on cathodic protection (CP) and telemetry systems. In addition to steady state AC interference, transient conditions such as power line faults and lightning strikes will be examined. The evidence for corrosion or damage that is caused by AC interference will also be examined. This project will focus on particular areas evident to LDCs, such as those related to light-rail systems or underground high voltage electric lines.	Enhanced safety by mitigating interference on CP systems. Also, possible reduced costs in mitigating interference.				$20,000	$19,980
OTD-38	(5.9.j) Gas Distribution Model (GTI Project)	GTI	The objective of this program is to develop an industry data model and standards for natural gas distribution operators to reduce the cost of software implementation, increase interoperability, and improve data collection efforts. The Gas Distribution Model (GDM) and standards will specify the data structure for operations, assets, field data collection, and regulatory compliance without requiring operators to restructure their existing data model.	Standardized approach in creating distribution risk models. This could help reduce costs in establishing or implementing various types of risk models.				$5,000	$5,000
OTD-39	(5.10.g) Indoor Air Quality and Safety Issues	GTI	This effort is to gather historical information and research on indoor air quality and safety issue. This will provide a readily available resource for natural gas operators to help address codes, standards, and guidelines that attempt to dis-allow or discourage gas appliances.	Will help ensure natural gas appliances are treated fairly in codes, standards, and guidelines.					$20,000
OTD-40	(6.6.a) Keyhole Project	GTI	Keyhole technology provides access to buried pipelines through a hole approximately 18" in diameter. This small size has many advantages including, lower excavation costs and required resources and minimal impact and restoration to pavement. This program evaluates and demonstrates new applications for keyhole technology.	Reduced excavation and restoration costs.		$20,000		$20,000	$0

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OTD-41	(6.8.a) GTI Carbon Management Initiative (GTI Project)	GTI	The CMIC is intended to serve as a clearinghouse for relevant carbon management information and to develop, where necessary, credible information products and functional tools to meet the needs of investors and their customers. Some deliverable for 2008 include a public-access and members-only website containing technical reports and information on products and a database of energy use profiles of gas, oil and electric end-use technologies for residential and commercial markets	Better understanding of the role natural gas end-use equipment has in reducing overall energy use and in reducing green house gas emissions (i.e. CO2).			$25,000	$25,000	$30,000
OTD-41	**(6.8.c) Complete** - Study on Direct Use of Nat. Gas to Reduce CO2 (GTI Project)	GTI	The goal of the program is to provide credible, defensible technical information on the benefits and costs of direct use of natural gas in residential, commercial, and industrial markets to reduce greenhouse gas emissions. The approach to achieve that goal in this program is to perform scenario analyses using the National Energy Modeling System (NEMS), the economy-wide, integrated energy model used by the Energy Information Administration to provide energy market and infrastructure projections to 2030.	Better understanding of the role natural gas end-use equipment has in reducing overall energy use and in reducing green house gas emissions (i.e. CO2).			$5,000		
OTD-42	**(7.7.b) Complete** - Evaluating Distribution Greenhouse Gas Sources, including Field Measurement Program	Other	This project to be completed by Innovative Environmental Solutions, Inc. (IES), will improve high priority greenhouse gas (GHG) emissions factors (EFs) for estimation of GHGs from measurement and regulation facilities. The emission factors investigated will be determined based on input from project investors and the results of an AGA collaborative project with INGAA and API that prioritized GHG emission factors for natural gas systems.	Enhanced standardized GHG emissions reporting. Also, possible reduction in costs associated with tabulating GHG emissions from distribution systems.		$15,000	$14,448		

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OTD-43	**(7.7.d) Complete** Biogas: Guidance for Dairy Waste (GTI Project)	GTI	Biogas from dairy cow waste can be processed and utilized as a renewable energy. The objective of this project is to help develop a basis for a national standard on the quality of biogas for acceptance into natural gas pipeline systems. This project will assess and document available domestic and international information to develop a broader knowledge base related to biogas production, gas treatment, gas quality standards, and gas quality test protocols. In addition, it will develop and execute a laboratory-testing program to evaluate raw (before cleanup) and post-cleanup biogas in order to assess quality, safety, and compatibility with existing supplies, pipeline delivery infrastructure, and customer end use equipment.	Reduction in overall green house gas emissions through the use of renewable gas. Also, local supply of gas may help reduce gas costs to customers.		$20,000		$3,000	
OTD-42	(7.8.a) (GTI) Biogas: Guidance for Landfill and Water Treatment Facilities	GTI	This project is primarily being funded by the U.S. Department of Transportation's Pipeline and Hazardous Material Safety Administration (DOT/PHMSA). This project attempts to develop guidance on requirements on accepting biogas from landfills and waste water treatment facilities into natural gas pipelines. This project will include a sample collection and data analysis program to include up to a total of 90 samples (40 raw/20 clean landfill gas, 10 raw/10 clean wastewater treatment biogas and 10 natural gas samples).	Reduction in overall green house gas emissions through the use of renewable gas. Also, local supply of gas may help reduce gas costs to customers.				$15,000	
OTD-43	(7.9.c) Biogas: Siloxane Concentrations, Phase I (GTI Project)	GTI	The objective of this project is to initiate the assessment and documentation to help prepare guidance material on acceptable levels of siloxane in biogas, mainly from landfills and wastewater treatment plants. This project is aimed at developing a detailed test program for determining acceptable siloxane levels.	Reduction in overall green house gas emissions through the use of renewable gas. Also, local supply of gas may help reduce gas costs to customers.				$0	$10,000

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OTD-44	(7.9.d) Improving Methane Emission Estimates for LDCs - Phase I	GTI/Heath	This is in relation to OTD project 7.7.b which addressed pipeline measurement and regulation equipment. This 7.9.d project address emissions from pipelines. Current estimation methodologies for quantifying fugitive and vented methane emissions are broad based and may over or under estimate actual emissions based on an operators pipeline system characteristics. The resulting emission methodologies should ultimately be integrated with existing gas distribution software and system tools to allow for convenient implementation and reasonable methane emissions management practices.	Enhanced standardized GHG emissions reporting. Also, possible reduction in costs associated with tabulating GHG emissions from distribution systems.				$15,000	$2,292
OTD-47	(7.9.e) Biogas: Portable Package for On-site Analysis	GTI	The objective of this project is to develop a cost-effective portable (skid-mounted or smaller) analytical package (instrumentation or surrogate analytical techniques) for biomethane.					$0	
OTD-45	(7.10.a) Trace Constituents Phase I (GTI Project)	GTI	The purpose of the overall study (Phase I and Phase II) is to more fully understand the trace constituent profile in natural gas, so that more accurate comparison of renewable natural gas with existing natural gas supplies may be facilitated. The natural gas industry will benefit from this study because an updated analytical profile of trace constituents will be amassed, through a sampling and analysis program of natural gas samples collected throughout various regions in the US.	Reduction in overall green house gas emissions through the use of renewable gas. Also, local supply of gas may help reduce gas costs to customers.					$5,000
OTD-46	(7.10.b) Odor Fade Guidelines (GTI Project)	GTI	The goal of the project will be to provide a "Practical Pipeline Operator Guide" to manage odor fade issues associated with typical gas system operating conditions and materials of construction.. This will include a tested methodology to validate additional combinations of Gas, System, and Material scenarios.	Enhanced safety through the appropriate specification and procedures for ensuring sufficient odorant in distribution systems.					$12,940

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OTD-47	(7.10.c) Improving Methane Emissions Estimate for LDCs Phase II	GTI	This is a continuation of 7.9.d and will entail field testing using the procedure developed from Phase 1. Field measurements will be compared to previous estimates.	Enhanced standardized GHG emissions reporting. Also, possible reduction in costs associated with tabulating GHG emissions from distribution systems.					$20,000
OTD-48	Other - UTD MIT Study Support on Direct Use of Gas	GTI	The MIT study is being conducted on behalf of DOE. Initially, this study did not consider direct use of natural gas as means of reducing overall energy consumption and a reduction in green house gases. This funding will help MIT expand the scope of their work to address direct use of natural gas.						$5,000
					$161,500	*$616,128*	*$420,758*	*$311,190*	*$386,826*
				Credits		***$8,988***	***$14,480***		
				OTD Balance	*$268,500*	***$91,360***	***$115,082***	***$233,892***	***$66,258***

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Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
	NYSEARCH								
	NYSEARCH Membership Dues				***$37,500***	***$12,400***	***$67,150***	***$40,000***	***$40,000***
NYS-1	**Complete** - Effect of Gas Quality Changes on Pipeline Components	GTI	Natural gas received as LNG import gas, has different gas quality characteristics as compared to the natural gas historically received from North American supplies (US and Canada). Import LNG is typically "drier" and hotter than domestic supplies. This dry gas has been identified as a potential cause of leaks in mechanical fittings due to the drying of the elastomers. This study will evaluate various compositions of "dry" natural gas to elastomers used in various types of mechanical fittings.	Enhanced safety through the use of appropriate interchangeability standards/guidelines for new sources of natural gas.	$41,560				
NYS-2	**Complete** - Demonstration of Long Range Ultrasonic tool at NYSEARCH test bed	NYSEARCH	The purpose of this effort is to test and evaluate a specific guided wave ultrasonic tool utilized by SWG. At the time of this evaluation, PHMSA did not establish rigorous guidelines for the use of such tools.	Enhanced safety and integrity of transmission facilities covered under PHMSA's integrity management regulation through the appropriate use of guided wave technology. In addition, possible reduced costs to meeting regulations.	$27,600				
NYS-3	Rock Impingement resistance of PE pipe	Hessel Labs	The objective of this project is to determine resistance of polyethylene pipe to rock impingement. New grades of plastic pipe have appeared to more resistant to rock impingement but no thorough evaluations have been conducted.	Enhanced safety and integrity of PE pipe through improved pipe installation procedures (if required)	*$12,140*				

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
NYS-4	Butt Fusion Joint Integrity Program	GTI	This work is being done in conjunction with project OTD-6 (2.7.b) related to lateral joint integrity. A controlled butt heat fusion process will be developed on the basis of comprehensive testing and evaluation using novel test methodologies in order to validate the safe long term performance of PE butt fusion joints over their intended design life. The process will take into account actual in-service stress states through comprehensive computer modeling and empirical testing. Criteria will then be developed to identify suspect joint via short and long term testing. Finally, key criteria for existing and future NDE technologies will be identified.	Improved joining procedures and/or joint evaluation, to ensure long term joint integrity.	$13,450			$26,485	
NYS-5	**Complete** - Casing assessment technologies		To develop & share information about the performance of inspection technologies on cased pipe in live field applications. Five service providers using 2 types of guided wave technologies will evaluate similar pipe segments.	Enhanced safety and integrity of transmission facilities covered under PHMSA's integrity management regulation through the appropriate use of casing assessment methodologies. In addition, possible reduced costs to meeting regulations.		$33,955			
NYS-6	Gas Quality Impact on Residential Appliances	Environ/GTI	Natural gas received as LNG import gas, has different gas quality characteristics as compared to the natural gas historically received from North American supplies (US and Canada). Import LNG is typically "drier" and hotter than domestic supplies. The impact of the changes in gas quality to residential appliances has been known to cause some safety issues because gas burners are adjusted for a certain range of gas quality specifications. The intent of this project is to help identify the effects of varying gas quality in residential appliances.	Enhanced safety through the use of appropriate interchangeability standards/guidelines for new sources of natural gas.			$35,425		

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	***Potential*** Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
NYS-7	**Complete** - 3rd Party Detection and Damage	Magal	This effort will evaluate technologies that can be applied to third party monitoring that were developed by Magal Senstar Inc. The applications are: 1) PipeGuard – consist of sensing units that consist of geophones buried 3 feet below grade to sense third party intrusions, 2) Dreambox – a video analytics platform that uses cameras to detect and alarm when it recognizes images of excavating equipment. The intent is to determine if these technologies are effective and practical to apply to pipeline monitoring to help prevent 3rd party damage.	Enhanced safety through the identification of 3rd party threats to pipelines.		$9,360			
NYS-8	Casing risk assessment methodology (M2001-003-B, Phase III)	Malbauer	Integrity management regulations require that transmission pipeline in casings in high consequence areas be assessed. The challenge with casings for distribution companies, is that ECDA and ILI tools are not feasible to utilize. The objectives of the proposed project are to: 1) develop a simple tool for making data validated decisions on assessment or monitoring of cased pipes in HCAs, and, 2) *allow a streamlined and formal* approach for prioritizing casings inspection activities that can be integrated with other benchmarking and technology developments for this purpose.	Standardized approach to assessing risk of casings. Possible reduced costs in conducting risk analysis of casings.				$4,440	$17,000
NYS-9	Explorer Demonstration in AZ (robotics demo)	Invondane	The objective of this effort is to field demonstrate the Explorer II in-line inspection robot in a SWG 8" transmission pipeline facility in Phoenix. This is one of the tools we are funding under OTD-17 and OTD-25 above. The approximate length of the demonstration would include about 3,000 feet of pipe. The sensor technology is a Remote Field Eddy Current (RFEC) which is not commercially used in the industry (i.e. *standard is MFL*).	Application of a new technology to help meet PHMSA's integrity management regulations. In addition, possible reduced assessment costs.				$0	*$60,000*

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
NYS-10	NDE inspection technology for PE fusions joints	TWI	The key objective of this effort are to determine the detection capabilities of TWI's existing NDE equipment for 4" and 8" PE butt fusions. In addition, this effort intends to determine critical flaw sizes that impact long term integrity of butt fusion joints. Finally, this effort will include the manufacturing of a new prototype system(s) that will be demonstrated at various utilities.	Enhanced safety and integrity through detection of defective fusion joints.					*$0*
					$132,250	***$55,715***	***$102,575***	***$70,925***	***$117,000***

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
	American Gas Foundation (AGF)								
AGF-1	**Complete** - Study on Research and Development in Natural Gas Transmission and Distribution	GOIA	This effort will consist of a comprehensive review of past and current RD&D funding and programs for the natural gas transmission and distribution pipelines.	Better understanding of RD&D organizations and efforts which will help SWG in managing AZ customer RD&D dollars.	$15,000	$0			
AGF-2	Bldg. Energy Codes and Stds. Research	Misc.	Natural gas safety standards and guidelines that apply to facilities downstream of the meter, are critical in helping ensure that natural gas is used safely in buildings and residences. This effort helps provide technical research to support changes to codes and standards.	Enhanced safety in the utilization and application of natural gas equipment.	$25,000	$0			
					$40,000	***$0***	***$0***	***$0***	***$0***
	Managed by EETD								
EETD-1	Gas Engine Driven Heat Pump Water Heater		A natural gas engine driven heat pump can be utilized for hot water heating which would increase the total energy efficiency as compared to current natural gas or electric water heaters. This development would be a multiple year project including phases for research, bread boards, prototyping site verification and installation.	Such a product would provide an opportunity to replace existing inefficient water heaters and provide a better energy alternative for new construction buildings.	$46,737	$100,000		$1,242	
EETD-2	Solar Air Conditioning with Natural Gas back-up		This solar demonstration project will illustrate the value of utilizing solar energy to cool homes, supermarkets, office buildings, factories, etc. Solar will be the primary energy source with natural gas as the back-up. Solar energy would be utilized during daylight hours and natural gas at night or on cloudy days. The purpose of this solar air conditioning demonstration is to show the significant environmental benefits and consumer energy savings potential of the technology.	A possible more efficient, effective and environmentally friendly way to air condition buildings.	*$28,017*	$85,000		$126,187	$3,000

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
EETD-3	CO_2 sensor for industrial natural gas boilers		A small number of larger boilers with output >10 million BTUs, use oxygen and carbon monoxide (CO) sensors to calculate hydrocarbon and CO2 levels, to optimize combustion. The recent advent of a novel gas sensor technology platform capable of producing low cost sensors that can measure directly flue hydrocarbon and CO2 levels, offers an alternate and better method for maximizing combustion efficiency for gas burners. The purpose of this project would be to determine the applicability and feasibility of utilizing this new sensor for existing boilers, to improve the overall efficiency.			$0			
EETD-4	Solar Thermal Domestic Water Heating and Hydronic Space Heating with Natural Gas Backup		The solar thermal domestic water heating and hydronic space heating project will demonstrate the efficient use of solar energy and natural gas to meet the day to day hot water and space heating demands of single family homes. The solar thermal energy will be used as the primary energy source and natural gas will be used as the backup or secondary energy source.	Demonstrates the potential natural gas savings from the use of solar thermal systems.				$4,228	$3,000
EETD-5	Gas Engine Driven Heat Pump - Generator Addition for Plug-in Hybrid		Natural gas engine drive heat pumps are currently being commercialized in AZ. The engine utilized in these heat pumps can be utilized to drive an electric generator, which could then be utilized to help charge a plug-in hybrid. Some effort has already been initiated in this regard, and this funding would help further evaluate appropriate generators and plug-in vehicle charging requirements.	Demonstrates the potential for further development of commercial gas heat pumps providing plug-in vehicle charging. This would help SWG AZ customers with plug-in vehicles reduce their overall electric grid requirements to charge their vehicles.				$0	

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	***Potential*** Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
EETD-6	GHP Prototype w/Stirling Engine combined with EHP (Deluge and 10-ton EHP 13 SEER)		The objective of this project is to evaluate whether additional efficiencies can be gained from overall GHP performance utilizing a stirling engine. A prototype unit will be developed using a sterling engine and an off the shelf 13 SEER electric heat pump. The sterling engine will utilize natural gas as a fuel source.	While this is a proof of concept effort, if proven feasible, such a product would provide additional efficiencies for gas cooling applications.				$35,700	$50,000
EETD-7	Solar Thermal System Equipment Demo		An additional system will be installed for a commercial or residential application to further evaluate actual operations and energy usage from solar thermal systems. While manufacturers have published data on potential energy savings of solar thermal systems, actual savings varies significantly depending on application and use by customers. Evaluation of more systems are required to provide SWG customers a better estimate of potential savings. The location of the installation is yet to be determined.	Demonstrates the potential natural gas savings from the use of solar thermal systems.				$8,256	$15,000
EETD-8	GHP Demonstration Project in AZ		The objective of this effort is to further demonstrate the energy savings of GHP applications. This project would include the purchase and installation of GHPs at a SWG customer facility. Data monitoring equipment would be added.	Demonstrates potential overall building energy savings by the use of gas heat pumps.					$200,000
					$74,754	***$185,000***	***$149,830***	***$175,613***	***$271,000***

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
	ASME Pipeline Research								
ASME-1	**Complete.** Application Guide for Determining Yield Strength of In-Service Pipe Using Hardness Testing (Previously paid $10K under O&M)		Federal safety regulations establish a minimum yield strength of steel pipe at 25,000 psi if the specifications of the steel pipe are unknown. Current methods to *determine actual* yield strength are cumbersome in that a pipe section is removed, which typically requires the pipeline to be taken out of service. This project evaluates the use of hardness testing which does not require a cut out of pipe sections, to correlate to the pipes yield strength. A significant portion of this effort will be to develop a field guide on how to use hardness testing to correlate to yield strength.	Reduced costs in determining actual yield strength of in-service pipe.	$10,000	$0			
	Other								
OTH-1	Research consultant - help manage projects, develop proposals	Campbell	SWG will utilize this outside consultant to help manage and/or stay abreast of projects funded. Consultant will also help SWG prepare research proposals, specific to SWG's needs, to present to various research organizations.	Helps provide input on projects funded by SWG to help ensure they are to the benefit of AZ customers.	$1,000	$18,000	*$11,116*	$4,691	$10,000
OTH-2	Safety Vest Evaluation/Testing	SWG	The objective of this project is to help identify appropriate safety vests for field use during natural gas emergencies. Safety vests require reflective coatings, however vests utilized by SWG have experienced color degradation as well as static charges. GTI will evaluate phenomenon behind issues and tests various vests on the market.	Enhanced safety through the application of appropriate safety vests.					$25,000
OTH-3	SWG Application of ASME Hardness Testing Procedure	SWG	This project will design and familiarize Southwest Gas technical staff and field inspectors with the capabilities and limitations of the methodology described in ASME CRTD-91 "Applications Guide for Determining the Yield Strength of In-Service Pipe by Hardness Evaluation".	Reduced costs in determining actual yield strength of in-service pipe.					*$15,000*
					$1,000	*$18,000*	*$11,116*	*$4,691*	*$50,000*

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding

Allocation Summary

Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
$688,004	$688,715	$693,521	$681,229	$654,108
$688,712	$688,712	$688,712	$683,903	$688,712
$708	***-$3***	***-$4,809***	***$2,674***	***$34,604***

General Notes:

1	**Total authorized collection in Final Order is $688,712 per year. Funding is collected in a deferred balancing account (18236403)**
2	**Proposed projects reflected in current or proposed funding year may change. Some projects may terminate pending progress or proposed projects may not materialize due to lack of support. In addition, research organizations meet and discuss new and existing projects at**
3	**Actual allocation amount may change due to changes in projects described in 2 above or due to number of companies that ultimately**

	April 2009 - March 2010	April 2010 - March 2011
Total Available	$688,712.00	$688,712.00
EETD Allocation		
Operations Allocation		$256,108.00
EETD Balance	$62,607.44	
Operations Balance	$70,129.83	
Total Balance	***$132,737.27***	***$432,604.00***

500-017

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-7
(ACC-STF-7-1 to ACC-STF-7-23)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 31, 2011

Request No. ACC-STF-7-17:

Intellichoice Energy LLC.

a. Identify and explain all charges from Intellichoice Energy LLC to Southwest Gas during the test year, by account.

b. For each charge from Intellichoice Energy LLC to Southwest Gas identified in response to part a, describe how Southwest Gas has treated the charge for ratemaking purposes in the current rate case.

c. Identify and explain all services and products that are being purchased by Southwest Gas from Intellichoice Energy LLC.

d. Identify which of the services and products identified in response to part c were the subject of competitive bid or request for proposal (RFP) process.

Respondent: Revenue Requirements / Energy Efficient Technology Department

Response:

Per Staff Data Request ACC-STF-11-1(a), this response is being supplemented with information for the pre-Intellichoice Energy (ICE) period, including costs from all entities associated with Tommis Young that were involved in GHP technology, which include Team Consulting, All Air Systems, Blue Mountain Energy, Summit Energy Efficiency Resources, Sundance Energy Holdings, Governet, and Precision Sheet Metal. Blue Mountain Energy and Governet are owned by Paula Young.

a. Please refer to the attached file for the requested information. There were no test year charges for Summit Energy Efficiency Resources, Sundance Energy Holdings, Governet, or Precision Sheet Metal.

b. The ratemaking treatment of the charges included in the attached file are as follows. Charges to Account 107 are included in rate base in the Southern Nevada ratemaking jurisdiction and do not impact Arizona rates. Charges to Account 182.3 are recovered through the Arizona R&D Surcharge, and not in base rates. Charges to Accounts 886 are charged to Arizona operating expenses, and charges to Account 893 are charged to Southern Nevada operating expenses. Charges to Account 426.5 are considered "below-the-line" and are not recovered in rates in any ratemaking jurisdiction. Charges to Account 143 were related to the formation of ICE and not recovered in rates in any ratemaking jurisdiction. Charges to Account 908 are allocated to each state ratemaking jurisdiction based on the 4-Factor.

c. Description of products and/or services purchased by Southwest: ICE: consulting, engineering and testing services and reimbursement for materials. Blue Mountain Energy: project management and administrative services and reimbursement for materials. All Air Systems Inc: maintenance of AISIN units located in Bullhead City district office. Team Consulting: consulting, engineering, and testing services, and reimbursement for materials.

d. These vendors were considered sole source providers during the test year. None of the services and/or products identified in part c to this response were subject to a competitive bid or RFP process.

SOUTHWEST GAS CORPORATION
CHARGES FROM ICE AND OTHER TOMMIS YOUNG-RELATED ENTITIES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2010
IN RESPONSE TO DATA REQUEST NO. STF-7-17

Line No.	Description (a)	Ratemaking Treatment (b)	Amount (c)	Line No.
	Intellichoice Energy, LLC (ICE)			
1	182.3	AZ R&D Surcharge	$ 62,210	1
2	426.5	Below-the-line, not recovered in rates	53,865	2
3	908	4-Factor Allocation	235,441	3
4	Total		$ 351,516	4
	Team Consulting			
5	143	Not recovered in rates	$ 408,570	5
6	182.3	AZ R&D Surcharge	71,345	6
7	908	4-Factor Allocation	365,956	7
8	Total		$ 845,871	8
	All Air Systems			
9	107	Southern Nevada Rate Base	$ 86,714	9
10	886	Arizona Operating Expenses	3,696	10
11	893	Southern NV Operating Expenses	57,546	11
12	Total		$ 147,956	12
	Blue Mountain Energy			
13	182.3	AZ R&D Surcharge	$ 641	13
14	908	4-Factor Allocation	131,001	14
15	Total		$ 131,642	15

499-012

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-12:

Injuries and Damages. Refer to Decision No. 70665, at pages 13-15. Please provide all information needed to compute the allowance for Injuries and Damages in the current SWG rate case to be computed similarly to how that allowance was determined in SWG's last Arizona rate case, Docket No. G-01551A-07-0504.

Respondent: Revenue Requirements

Response:

Please refer to the attached schedule that calculates the self-insured component of injuries and damages expense in a manner consistent with Staff's and ultimately the Commission's adoption of Staff's calculation in the last rate case proceeding. Simply put, the Staff in the last rate case calculated the ten-year average of Arizona direct self-insured amounts up to and including $1 million for each claim. The Staff in the last rate case removed the only claim that was for an amount greater than $1 million up to $5 million, otherwise referred to by the Company as the self-insured aggregate. The Staff also included the four-factor allocation of liability insurance which covers the cost of claims above the $5 million aggregate self-insurance amount. Finally, the Staff also included the cost of Arizona direct self-insured workers compensation expense along wtih miscellaneous legal expense associated with injuries and damages. The Company's proposal in this proceeding mirrors Staff's calculation in the last rate case except for one item. The Company's proposal includes a normalized cost for the category of self-insurance not included in the Staff calculation. The Company uses the ten-year average of the two Arizona claims that exceed the $1 million self-insured retention, but limited each incident to the current $5 million maximum. The aggregate for the two incidents totaled $10 million, which when divided by ten years averages out to $1 million per year. The Company then four-factors this amount to Arizona. The self-insured aggregate has the effect of reducing system allocable liability insurance premiums, therefore, allocating these costs to all jurisdictions appears reasonable.

SOUTHWEST GAS CORPORATION
INJURIES AND DAMAGES, ACCOUNT 925
IN RESPONSE TO STF 6.12
RESERVE FOR SELF-INSURANCE EXPENSE NORMALIZATION
TEST YEAR ENDED JUNE 30, 2010

Line No.	Description		Company Test Year As Recorded (a)	Company Requested As Filed (b)	Staff Proposed (c)	Staff Adjustment (d) Col (c)-(b)
	Arizona Direct					
1	Legal and Other Costs		$ 718,799	$ 718,799	$ 718,799	$ -
2	Reserve for Self Insurance		$ 537,500	$ 834,961	$ 720,000 b	$ (114,961)
3	Workmen's Comp Expense		$ 308,201	$ 308,201	$ 308,201	$ -
4	Self-Insured Workmen's Self-insured		$ -	$ -	$ -	$ -
5	Total Arizona Direct		$ 1,564,500	$ 1,861,961	$ 1,747,000	$ (114,961)
	Common Before Allocation to Arizona					
6	Legal and Other Costs		$ 269,748	$ 269,748	$ 269,748	$ -
7	Reserve for Self Insurance		$ 275,000	$ 1,000,000	$ 275,000 b	$ (725,000)
8	Self-Insured Workmen's Comp		$ -	$ -	$ -	$ -
9	Insurance		$ 9,927,437	$ 9,927,437	$ 9,927,437	$ -
10	Subtotal before Paiute Allocation		$ 10,472,185	$ 11,197,185	$ 10,472,185	$ (725,000)
11	Paiute Allocation	3.83%	$ (401,591) a	$ (429,393) a	$ (401,591) a	$ 27,803
12	Subtotal after Paiute Allocation		$ 10,070,594	$ 10,767,792	$ 10,070,594	$ (697,197)
	Arizona Allocation of Common					
13	Legal and Other Costs	56.25%	$ 151,728	$ 151,728	$ 151,728	$ 0
14	Reserve for Self Insurance	56.25%	$ 154,682	$ 562,481	$ 154,682	$ (407,799)
15	Self-Insured Workmen's Comp	56.25%	$ -	$ -	$ -	$ -
16	Insurance	56.25%	$ 5,583,990	$ 5,583,990	$ 5,583,990	$ 0
17	Paiute Allocation	56.25%	$ (225,887)	$ (241,525)	$ (225,887)	$ 15,638
18	Total Common Allocated to Arizona		$ 5,664,513	$ 6,056,673	$ 5,664,513	$ (392,160)
19	Total Arizona Direct and Allocated		$ 7,229,013	$ 7,918,634	$ 7,411,513	$ (507,121)
20	Company's proposed adjustments to Account 925 in its filing			$ 689,621	$ (507,121)	
				Col.B - Col.A		
	Components of Company's proposed adjustments to Account 925, I&J Expense:					
21						
22	SWG Adjustment 9, Self Insured Retention Normalization			$ 661,818 b	$ (479,319)	
23	SWG Adjustment 10, A&G Expenses, Annualized Paiute Allocation			$ 27,803	$ (27,803)	
24	Total Company-proposed adjustments to Account 925 expense			$ 689,621	$ (507,121)	
25	Percentage increase over test year recorded amount			10%	-7%	
26	Staff proposed adjustment to SWG as-filed pro forma expense for Account 925					$ (507,121)

Notes and Source

a Line 10 multiplied by Paiute Allocation
b See page 2 of this schedule for replica of Staff Analysis of ten years of recorded expense

SOUTHWEST GAS CORPORATION
INJURIES AND DAMAGES, ACCOUNT 925
IN RESPONSE TO STF 6.12
RESERVE FOR SELF-INSURANCE EXPENSE NORMALIZATION
TEST YEAR ENDED JUNE 30, 2010

Line No.	Description	Year	Total Expense Recorded Arizona (A)	Total Expense Recorded Common (B)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Arizona (C)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Common (D)	Staff Proposed Arizona (E)	Staff Proposed Common (F)
	Reserve for Self-Insurance Expense							
1		2001	$ 426,955	$ 100,000	$ 426,955	$ 100,000		
2		2002	$ 350,000	$ 200,000	$ 350,000	$ 200,000		
3		2003	$ 1,941,509	$ (300,000)	$ 1,941,509	$ (300,000)		
4		2004	$ 2,154,000	$ 275,000	$ 2,154,000	$ 275,000		
5		2005	$ 1,360,224	$ 10,367,500 a	$ 1,360,224	$ 367,500 a		
6		2006	$ (975,540)	$ 200,000	$ (975,540)	$ 200,000		
7		2007	$ 713,629	$ (25,500)	$ 713,629	$ (25,500)		
8		2008	$ 230,000	$ (300,000)	$ 230,000	$ (300,000)		
9		2009	$ 400,000	$ 275,000	$ 400,000	$ 275,000		
10		2010	$ 537,500	$ 150,000	$ 537,500	$ 150,000		
11	Total		$ 7,138,277	$ 10,942,000	$ 7,138,277	$ 942,000		
12	Ten Year Average		$ 713,828	$ 1,094,200	$ 713,828	$ 94,200	$ 720,000 b	$ 275,000 c
13	Pauite allocation	3.83%		$ (41,961)		$ (3,612)		$ (10,546)
14	Common before AZ allocation			$ 1,052,239		$ 90,588		$ 264,454
15	AZ allocation	56.7%		$ 596,620		$ 51,363		$ 149,946
16	AZ allocated and direct		$ 713,828	$ 596,620	$ 713,828	$ 51,363	$ 720,000	$ 149,946
	Adjustment to Southwest Proposed as Filed							
17	Page 1, Col.B, Lines 2 and 13, respectively		$ (558,765)	$ 2,341,855	$ (558,765)	$ 2,341,855	$ (558,765)	$ 2,341,855
18	Adjustment to SWG Proposed As Filed, Based on Ten-Year Average	L.16 - L.17	$ 1,272,593	$ (1,745,235)	$ 1,272,593	$ (2,290,492)	$ 1,278,765	$ (2,191,909)
19	Net adjustment to Arizona expense		$ (472,642)		$ (1,017,899)		$ (913,144)	
			L.18, Col.A&B		L.18, Col.C&D		L.18, Col.E&F	
	Adjustment to Southwest Proposed as Corrected							
20	Page 1, Col.C, Lines 2 and 13, respectively		$ (858,765)	$ 2,852,024	$ (858,765)	$ 2,852,024	$ (858,765)	$ 2,852,024
21	Adjustment to SWG Proposed As Filed, Based on Ten-Year Average	L.16 - L.20	$ 1,572,593	$ (2,255,404)	$ 1,572,593	$ (2,800,661)	$ 1,578,765	$ (2,702,078)
22	Net adjustment to Arizona expense		$ (682,811)		$ (1,228,068)		$ (1,123,313)	
			L.21, Col.A&B		L.21, Col.C&D		L.21, Col.E&F	

Notes and Source

a May 2005 leaking gas line fire excluded.
b Ten-Year Average, rounded upward to nearest $10,000
c Whole year before test period.

518-003

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-20
(ACC-STF-20-1 to ACC-STF-20-3)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 29, 2011

Request No. ACC-STF-20-3:

Regarding the customer-owned yard lines (COYLs), what would be the cost, timeline, and feasibility of doing a leak survey of all COYLs? Could this survey be completed in two years or in three years? Please provide a detailed cost estimate.

Respondent: Engineering

Response:

Southwest Gas is not responsible nor has any obligation for the maintenance (including the leak survey) of COYLs; thus the cost, timeline, and feasibility of such an activity is difficult to estimate due the lack of historical knowledge of and experience with the COYLs themselves. The COYLs are not mapped nor is information on their location usually available from the homeowners. The location of the underground COYLs, from the custody transfer point located at the outlet of Southwest Gas' meter to a customer's house, building or gas utilization equipment may not be obvious. The COYLs could also have one or more branch connections with extensions that do not surface above ground. The actual location of each underground COYL would be difficult and in many cases impossible to know with certainty unless the COYL was completely exposed. Additionally, the homeowners must grant Southwest Gas permission to access private property. Denial of such access would prevent Southwest Gas from performing the leak survey. Southwest Gas therefore does not believe it would be feasible to leak survey all COYLs.

Because Southwest Gas is not responsible for maintaining and servicing COYLs, it can only provide an estimate of the cost and timeline based upon experience and knowledge of leak surveying Company owned and mapped services. To leak survey a total of 102,570 services, which is the approximate number of COYLs in Southwest Gas' Arizona system, would cost an estimated $3,000,000 over a minimum three year timeframe. Additional costs and time would be realized when leaks are found on COYLs to properly secure the situation and turn off the service. When necessary, these actions also include evacuating the premises and ~~to~~ aerating any residual natural gas. Customers would also be notified of their financial responsibility to repair or replace the COYL prior to Southwest Gas reactivating their service.

512-007

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-7:

COYL.

a. Please provide the Company's estimates total number of COYLs on Southwest's system if different from the 108,000 mentioned at page 9 of Mr. Schmitz's direct testimony.

b. Provide the actual (or if actual is not available, estimated) numbers of COYLs on Southwest's Arizona system for Central Arizona and Southern Arizona and, also, if available the numbers of COYLs located in each city, town, or district.

c. Please provide estimates of the COYL locations (city, town or district) that Southwest would propose to replace for $10 million in its pilot program.

d. Please provide Southwest's best estimate of the total cost of replacing all COYLs on its Arizona system.

e. Please provide Southwest's best estimate of the time frame it would take to replace all COYLs on its Arizona system assuming replacements were to occur at a rate of 5,000 every two years.

Respondent: Division Operations/Revenue Requirements

Response:

a. Southwest Gas' estimate of COYLs in Arizona has been further refined, based on feedback received as a result of customer mailings. Southwest Gas' current estimate of COYLs on its system in Arizona is 102,574.

b. The estimated number of COYLs on Southwest's Arizona system by district is as follows:

Eastern District:	1,944
Mountain District:	2,840
Southeast District:	2,489
Tucson District:	70,406
Valley District:	9,345
Yuma District:	846
Phoenix District:	12,919
Wickenburg District	348
Bullhead District:	1,437
	========
Total:	102,574

c. To maximize the available dollars for the pilot, a sampling strategy would be utilized to perform the replacements based on a representative sample of the population in Southwest Gas' Arizona service territory. Because the majority of COYLs are located in the Tucson district, it is expected that a representatively large portion of the pilot project would be conducted in that district.

d. Southwest Gas estimates that it can replace COYLs at an average cost of $2,000 per service, excluding those residences where there are significant physical obstacles. At 102,574 COYLs, Southwest Gas' best estimate of the total cost to replace COYLs on its system in Arizona is $205 million at current costs.

e. Given Southwest Gas' estimate of 102,574 COYLs, and assuming that all customers would want their COYL facilities replaced by utility-owned and operated facilities, at a rate of 5,000 replacements every two years as posed in this question, it would take approximately 41 years to replace all COYLs. Southwest Gas proposed the instant pilot program to gain experience with actual replacement costs and customer receptiveness to the program, and, pending Commission approval, would review its experience with the pilot program prior to proposing any further expansion of the COYL replacements to the Commission.

512-008

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-8:

COYL. Please identify the number of COYLs that Southwest Gas has replaced in Arizona in each year, 2006 through 2010, and what the total cost was for each year.

Respondent: Division Operations/Revenue Requirements

Response:

The replacement of COYL is predominantly performed in Southwest Gas' Tucson district. The number and cost of COYLs replaced by year is as follows:

2006	498	$454,536
2007	432	412,406
2008	306	293,778
2009	322	331,278
2010	272	282,304

512-006

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
*** * ***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)
*** * ***
DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-6:

COYL. Please identify all costs related to Southwest's installation of Southwest Gas facilities to replace customer owned yard lines for each of the following periods:

1. June 30, 2010 through December 31, 2010.
2. December 31, 2010 through March 31, 2011.
3. Projected/budgeted for March 31, 2011 through December 31, 2011.
4. Projected/budgeted for Calendar 2011.

Respondent: Revenue Requirements/Engineering

Response:

Consistent with Arizona Tariff Rule No. 6, section E(6)(b), Southwest Gas performs the replacement of customer owned yard lines (COYL) at the expense of the customer. Customer contributions for the installation of Southwest Gas facilities to replace COYLs are as follows:

June 30, 2010 through December 31, 2010: $159,730
December 31, 2010 through March 31, 2011: $173,966
Projected/budgeted for March 31, 2011 through December 31, 2011: $276,034
Total amount Projected/budgeted for Calendar 2011: $450,000

500-013

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-7
(ACC-STF-7-1 to ACC-STF-7-23)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 31, 2011

Request No. ACC-STF-7-13:

Rate case.

a. Please identify and provide Southwest's rate case filing plans.

b. Please describe how the plans identified in response to part a have affected the period selected by Southwest for the normalization of rate case cost for its current Arizona rate case.

Respondent: Revenue Requirements

Response:

a. Attached is Southwest Gas' most recent anticipated rate case preparation and processing work schedule, which covers 2011-2013.

b. Southwest Gas anticipates a four year rate case cycle in Arizona. Therefore, Southwest Gas proposed to amortize rate case expense over four years.

491-005

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-5:

Please provide a complete copy (both in electronic and paper) of SWG's last complete depreciation study.

Respondent: Revenue Requirements

Response:

For corporate (i.e. system allocable) plant, a portion of which is allocated to Arizona, the last approved depreciation study was filed in Nevada during 2007 using a period ended date of December 31, 2006. The system allocable rates approved in Nevada are used in all of Southwest's ratemaking jurisdictions so the appropriate amounts of corporate plant are recovered in rates from Southwest's Arizona, Nevada, and California customers.

At the time of the last depreciation study in Arizona, Arizona had two separate rate jurisdictions: Southern Arizona and Central Arizona. In 1996, the two Arizona rate jurisdictions were combined into one rate jurisdiction and the depreciation rate for the combined jurisdiction was a blended average of the existing rates for the Southern Arizona and Central Arizona jurisdictions. This combined rate is the currently approved rate used in the Arizona rate jurisdiction.

The complete studies are attached in electronic format only since the studies are voluminous.

512-001

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
*** * ***

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)
*** * ***

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-1:

Yuma Manors.

a. Provide a breakout of the $225,445 rate base amount mentioned on page 21 of Mr. Mashas' testimony between (1) Plant and (2) Accumulated Depreciation.

b. Identify the property tax expense included in jurisdictional operating expenses by Southwest related to the $225,445 rate base amount for Yuma Manors. Include supporting calculations.

c. Identify the Depreciation expense included in jurisdictional operating expenses by Southwest related to the $225,445 rate base amount for Yuma Manors. Include supporting calculations.

Respondent: Revenue Requirements

Response:

Please refer to the attached calculations.

SOUTHWEST GAS CORPORATION
2010 ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
YUMA MANORS PIPE REPLACEMENT
DATA REQUEST STF 16.1

Line No.	Description	Account	Account 376 Mains Amount (A)	Account 380 Services Amount (B)	Total Amount (C)	Line No.
	I. Costs Recorded by Company Through End of Test Year Ended April 30, 2007					
	A. For New Plant Replacing the Original Plant					
1	Costs incurred prior to and during the test year	101	$ 368,689	$ 247,193	$ 615,881	1
2	Accumulated Depreciation	108	(550)	(603)	(1,153)	2
3	Net Plant in Service - replacement plant		$ 368,139	$ 246,590	$ 614,729	3
	B. For the Original Cost of Plant Installed 1954-1958					
	1. Plant in Service					
4	Gas Plant in Service	101	$ 75,770	$ 13,731	$ 89,501	4
5	Gas Plant Retired	101	(75,770)	(13,731)	(89,501)	5
6	Gas Plant in Service After Retirement	101	$ -	$ -	$ -	6
	2. Accumulated Depreciation					
7	Accumulated Depreciation recorded at April 2007	108	$ (135,640)	$ (28,599)	$ (164,239)	7
8	Gas Plant Retired	108	75,770	13,731	89,501	8
9	Removal costs incurred prior to and during the test year	108	2,069	4,166	6,234	9
10	Impact on Accumulated Depreciation	108	$ (57,802)	$ (10,703)	$ (68,505)	10
11	Impact on Net Plant		$ 57,802	$ 10,703	$ 68,505	11
	II. Staff Adjustment					
12	Remove impact on test year of replacement plant		$ (368,139)	$ (246,590)	$ (614,729)	12
13	Remove impact on test year of original plant retired		57,802	10,703	68,505	13
14	Adjustment to Test Year Net Plant		$ (310,337)	$ (235,887)	$ (546,224)	14
15	Adjustment to Test Year Plant in Service		$ (368,689)	$ (247,193)	$ (615,881)	15
16	Adjustment to Test Year Accumulated Depreciation		58,352	11,306	69,657	16
17	Adjustment to Test Year Net Plant		$ (310,337)	$ (235,887)	$ (546,224)	17
18	Decision No. 70665 Page 8 Line12		$ (182,250)	$ (138,529)	$ (320,779)	18
19	Decision No. 70665 Page 8 Line13		$ (128,087)	$ (97,358)	$ (225,445)	19
	Property Tax Expense					
20	Adjusted Net Plant In-Service				$ (225,445)	20
21	Assessment Ratio				20%	21
22	Assessed Property				$ (45,089)	22
23	Property Tax Rate				10.1263%	23
24	Property Tax Expense				$ (4,566)	24

	Depreciation Expense	Account 376 Mains Amount	Account 380 Services Amount	Total Amount	
25	Gross Depreciable Plant	$ (368,689)	$ (247,193)	$ (615,881)	25
26	Commission Adjustment	(182,250)	(138,529)	(320,779)	26
27	Adjusted Depreciable Plant	$ (186,438)	$ (108,664)	$ (295,102)	27
28	Depreciation Rate	3.82%	5.30%		28
29	Depreciation Expense	$ (7,122)	$ (5,759)	$ (12,881)	29

512-003

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-3:

Completed Construction Not Classified (CCNC) correction. In response to Staff discovery, including STF-6-7(a) and (c), the Company indicated that two work orders have not closed and should be removed from the Company's original adjustment, which should be reduced to $2,695,762. The reduction is $110,407.

a. Identify the amount of property tax expense included in jurisdictional operating expenses by Southwest related to the $110,407 correction for CCNC. Include supporting calculations.

b. Identify the amount of Depreciation expense included in jurisdictional operating expenses by Southwest related to the $110,407 correction for CCNC. Include supporting calculations.

Respondent: Revenue Requirements

Response:

The effects of removing work order 0036W1122904 for $35,055 and work order 0042W1001926 for $75,353 on property tax expense and depreciation expense are as follows:

Decrease in Net Plant in Service	$ 110,407
2011 Assessment Rate	20%
Subtotal	22,081
Property Tax Rate	10.1263%
Decrease in Property Taxes	$ 2,236

Decrease in Net Plant in Service	$ 110,407
Mains - Account 376 Depreciation Rate	3.82%
Decrease in AZ Direct Depreciation Expense	$ 4,218

512-002

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
*** * ***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-2:

SCADA. The Company's response to data request STF-6-7(d) stated that: The Company is removing the $1,700,000 cost of the SCADA system originally included in Adjustment 17 in System Allocable Account 303. The Company's response to data request STF-6-19(a) states that: The ... SCADA System, has not yet been placed into service; therefore, the Company is no longer requesting that this item be included in rate base or amortization expense in this proceeding, reducing the plant in service increase to $4,139,131.

a. Identify the amount of property tax expense included in jurisdictional operating expenses by Southwest related to $1.7 million SCADA system that is being removed from plant because it was not in service by June 30, 2010. Include supporting calculations.

b. Identify the amount of Depreciation expense included in jurisdictional operating expenses by Southwest related to $1.7 million SCADA system. Include supporting calculations.

Respondent: Revenue Requirements

Response:

a.) Corporate System Allocable Plant located in the state of Nevada, is not subject to Arizona Property Taxes; therefore, the removal of $1,700,000 for the SCADA project had zero effect on property taxes.

b.) The removal of the SCADA project had the following effect on Depreciation and Amortization Expense:

Per Workpapers C-2, Adjustment No. 13, Sheet 8, Ln 40(k), the annual amortization was $170,000, based on a 10-year amortization period. After the 4-Factor percentage of 56.25%, the allocation to Arizona was $95,625.

491-083

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-83:

Payroll, Incentive Programs. Please provide complete copies of any bonus programs or incentive award programs in effect at the Company for the most recent three years. Identify all incentive and bonus program expense incurred in 2008, 2009 and calendar year 2010. Identify the accounts charged. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in 2008, 2009 and calendar year 2010.

Respondent: Human Resources

Response:

The Aspire, Constant Flame, GEM, and Management Incentive Plan ("MIP") programs are discussed in the Company's response to ACC-STF-1-50. Please refer to Attachment A for the current document related to the Service Planning Quality Award and Attachment B for the current document related to the Key Account Management ("KAM") Incentive Plan. Constant Flame (charged to Account 926) was replaced by GEM (charged to Account 920) in 2010.

Expenses incurred in 2008, 2009 and 2010 for each program are reflected on the attached spreadsheet. Please note the amounts shown for each program other than the Service Planning Quality Award are before allocation to Arizona.

There are no incentive or bonus program expenses allocated from affiliates.

SOUTHWEST GAS

SERVICE PLANNING QUALITY INCENTIVE AWARD

2009/2010

Service Planning Quality Award for 2009/2010
Table of Contents

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Administrative Information 1
2009/2010 Service Planning Award Processing Schedule 3
Service Planning Quality Award – 2009/2010 4

1. Administrative Information

A. The effects of the Service Planning Quality Award on employee benefits are summarized below:

1. Salary Continuation Program

   Coverage is provided at no cost to the employee. Payments are based on the hourly rate computed from an individual's September 1 base salary and the previous four quarters total Quality Award compensation.

2. Retirement

   Quality Award compensation is included in the average effective earnings of the five highest calendar years of continuous service during the ten years immediately prior to termination.

3. EIP

   EIP contributions are deducted from Quality Award payments, when paid, at the rate specified by the individual. Contributions are matched $.50 on each $1.00 contributed up to seven percent (7%) of total annual earnings, subject to any IRS limitations.

4. Life Insurance

   a) Basic

      Salary utilized in the computation of life insurance entitlement is comprised of the individual's September 1 base salary and the previous four quarters total Quality Award compensation.

   b) Employee Custom Life Insurance

      Amounts available for purchase are factored off the earnings amount indicated in Basic Life Insurance above (employee paid).

c) Spouse Custom Life

Amounts available for purchase are factored off the earnings amount indicated in Basic Life Insurance above (employee paid).

5. Accidental Death and Dismemberment Insurance

a) Basic

Salary utilized in the computation of life insurance entitlement is comprised of the individual's September 1 base salary and the previous four quarters total Quality Award compensation.

b) Additional

Amounts available for purchase are set for all employees (employee paid).

c) Business Travel Accidental Insurance

Coverage is equal to the individual's September 1 base salary and the previous four quarters total Quality Award compensation. The premium is entirely Company paid.

6. Basic Long-term Disability

Coverage is provided at no cost to the employee. Payout is 66⅔ percent of the individual's September 1 base salary and the monthly average of the previous four quarters total Quality Award compensation.

B. Termination of or adjustments to this Quality Award program could occur at any time at the discretion of the Company, as determined by executive management.

Service Planning Quality Award

PROCESSING SCHEDULE
2009

QUARTER	DUE TO ENERGY SERVICES	DUE TO PAYROLL	PAYDATE
4TH 2008*	01/19/09	01/22/09	01/29/09
1ST 2009	04/15/09	04/20/09	04/24/09
2ND 2009	07/15/09	07/20/09	07/27/09
3RD 2009	10/16/09	10/21/09	10/28/09

Service Planning Quality Award

PROCESSING SCHEDULE
2010

QUARTER	DUE TO ENERGY SERVICES	DUE TO PAYROLL	PAYDATE
4TH 2009*	01/20/10	01/22/10	01/29/10
1ST 2010	04/19/10	04/21/10	04/28/10
2ND 2010	07/20/10	07/22/10	07/29/10
3RD 2010	10/19/10	10/21/10	10/27/10

Service Planning Quality Award 2009/2010

The Service Planning Quality Award was effective as of January 1, 2006.

The Service Planning Quality Award is based on the employee's outstanding achievement and performance for that quarter based on defined production criteria including, but not limited to, customer satisfaction, leadership, innovation and working within the allowable budget. The Quality Award value will be justified based on the defined criteria for the individual employee based on their service territory and submitted to the Division Vice President. Once approved by the Division Vice President, the values will be forwarded to the Energy Services Department for compilation and totaling with all divisions and forwarded to Payroll for processing.

The Service Planning Quality Award value will be up to a maximum of $2500.00 per quarter per Service Planner or Senior Service Planner, up to a maximum of $10,000 annually. A percentage of the award may be earned based on the measured results of the defined criteria.

The Service Planning Quality Award value will be up to a maximum of $3000.00 per quarter per Supervisor, up to a maximum of $12,000 annually. A percentage of the award may be earned based on the measured results of the defined criteria.

The Service Planning Quality Award value will be up to a maximum of $3000.00 per quarter per Manager, up to a maximum of $12,000 annually. A percentage of the award may be earned based on the measured results of the defined criteria. This plan for Service Planning Managers varies from the Service Planner, Senior Service Planner and Service Planning Supervisor in that the award is not included in the retirement calculation. The award, up to $3000 per quarter, is considered a bonus and therefore does not qualify to be included in the retirement calculation.

The Service Planning Quality Award will be paid quarterly.

SOUTHWEST GAS

KEY ACCOUNT MANAGEMENT

2010 PERFORMANCE INITIATIVE AWARD PLAN (PIA)

MANAGER, SUPERVISOR AND INDUSTRIAL GAS ENGINEER

Effective January 1, 2010

Revised: 10/29/09

2010 PIA Schedule - Key Account Management

Quarter	*Due to KAM*	*Due to Payroll*	*Pay date*
1st – 2010	4-12-10	4-21-10	4-28-10
2nd – 2010	7-12-10	7-22-10	7-29-10
3rd – 2010	10-8-10	10-21-10	10-27-10
4th – 2010	1-10-11	1-??-11	??

*These dates may change according to Payroll's schedule for the new year.

KAM PERFORMANCE INITIATIVE AWARD PLAN
IMPACT ON EMPLOYEE BENEFITS
SUPERVISOR AND INDUSTRIAL GAS ENGINEER

SALARY CONTINUATION PROGRAM

Coverage is provided at no cost to the employee. Payments are based on the hourly rate computed from an individual's September 1 base salary and the previous four quarters total PIA compensation.

RETIREMENT

For supervisors and Industrial Gas Engineers, PIA compensation is included in the average effective earnings of the five highest calendar years of continuous service during the ten years immediately prior to termination. This does not apply to managers and above.

EIP

EIP contributions are deducted from PIA payments, when paid, at the rate specified by the individual. Contributions are matched $.50 on each $1.00 contributed up to 7% of total annual earnings, subject to any IRS limitations.

LIFE INSURANCE

Basic

Salary utilized in the computation of Life Insurance entitlement is comprised of the individual's September 1 base salary and the previous four quarters total PIA compensation.

Employee Custom Life Insurance

Amounts available for purchase are factored off the earnings amount indicated in Basic Life Insurance above (employee paid).

Spouse Custom Life Insurance

Amounts available for purchase are factored off the earnings amount indicated in Basic Life Insurance above (employee paid).

Children's Life Insurance

$10,000 per child available (employee paid).

IMPACT ON EMPLOYEE BENEFITS

SUPERVISOR AND INDUSTRIAL GAS ENGINEER

ACCIDENTAL DEATH AND DISMEMBERMENT INSURANCE

Basic

Salary utilized in the computation of Life Insurance entitlement is comprised of the individual September 1 base salary and the previous four quarters total PIA compensation.

Additional

Amounts available for purchase are set for all employees (employee paid).

Business Travel Accident Insurance

Coverage is equal to the individual's September 1 base salary and the previous four quarters total PIA compensation. The premium is entirely Company paid.

LONG TERM DISABILITY

Coverage is provided at no cost to employee. Payout is 66-2/3% of the individual's September 1 base salary and the monthly average of the previous four quarters total PIA compensation.

KAM PERFORMANCE INITIATIVE AWARD PLAN
GUIDELINES AND CALCULATIONS
KAM MANAGER

Program Objective: To incent the KAM Manager to achieve exceptional performance in the areas of customer service, project development/management and contract negotiations related to maintaining or improving the Company's margin. These activities seek to maximize the use of the Company's distribution system which benefits and protects captive customers (residential) by spreading fixed cost recovery over a greater number of customers/volumes.

Program Goals:

- Maintain and increase margin from qualified new and existing KAM customers through installations of new, additional or incrementally larger natural gas equipment.
- Ensure that Southwest Gas facility investments meet required criteria and that security/risk concerns are appropriately addressed.
- Maximize annual margin collection from customers that can demonstrate the ability to use an alternate energy source.

General Guidelines:

- Incentive payment will occur within the following two months of each quarter.
- The Manager will receive 10% of the aggregate amount of incentives earned by the IGE's and Supervisors.
- The Manager may earn a one-time $1,000 incentive payment for each special project successfully negotiated. Special projects are those that require significant negotiating time, investment and involvement of different Corporate departments.
- Termination of or adjustments to this program may occur due to changes in the overall economic condition of the Company.

KAM PERFORMANCE INITIATIVE AWARD PLAN
GUIDELINES AND CALCULATIONS
SUPERVISOR AND INDUSTRIAL GAS ENGINEER

Program Objective: To incent the IGE/Supervisor to achieve exceptional performance in the areas of customer service, project development/management and contract negotiations related to maintaining or improving the Company's margin. These activities seek to maximize the use of the Company's distribution system which benefits and protects captive customers (residential) by spreading fixed cost recovery over a greater number of customers/volumes.

Program Goals:

- Maintain and increase margin from qualified new and existing KAM customers through installations of new, additional or incrementally larger natural gas equipment.
- Ensure that Southwest Gas facility investments meet required criteria and that security/risk concerns are appropriately addressed.
- Maximize annual margin collection from customers that can demonstrate the ability to use an alternate energy source.

General Guidelines:

- At its discretion, management will review the IGE/Supervisor's salary in accordance with the Employee Salary Administration program. The KAM Performance Initiative Award Plan and Employee Salary Administration programs are independent.
- The PIA Plan document will be reviewed annually by KAM management. Continuation of the PIA Plan and incentive programs within the Plan can change at management's discretion from year to year.
- PIA payments generally occur within two months after the end of each quarter. The specific dates are determined by the Payroll Department.
- PIA payments will be based on increasing the company's margin and/or negotiating contracts with KAM qualified accounts (as defined in SP 910.0).
- Termination of, or adjustments to, this program may occur at any time at the discretion of management.
- Under special circumstances compensation under the PIA may be shared by a KAM team where more than one IGE/Supervisor was involved in the project.
- Project costs shall include all facility related costs attributed to serving the customer minus non-refundable Contributions in Aid of Construction (CIAC). Project costs include, but are not limited to the following: Cost of any required taps or tap upgrades, approach mains, onsite mains, reg stations, services and meters.
- All natural gas equipment installed by a Customer and claimed under the PIA must be recorded and verified by the IGE/Supervisor. Each quarter, projects may be audited at

random to verify installation of claimed equipment.

- Compensation under the PIA can only be earned on new or existing KAM qualified accounts. However, at management's discretion, a project that does not qualify as a KAM account on its own may be eligible for a PIA as long as the project is managed by an IGE/Supervisor.
- Caps noted in the Plan apply to an overall project. If the project is broken into phases, an incentive may be requested on each phase if either: 1) the phases could be considered discrete projects so that the cap would be applied to each phase; or 2) it takes multiple phases to reach the incentive cap amount for the project. When a project is organized into phases, the IGE, Supervisor, and KAM manager or designate must determine how the Plan will be applied.
- For purposes of this plan, Alternate Fuel Customers are defined as a class of customer who have historically shown a tendency to switch between energy sources. Examples include irrigation customers and asphalt plants. Also included are any customers who have installed or can easily change to facilities capable of using alternate fuels.
- The use of the Incremental Cost Method (ICM) or multiples of margin to calculate allowable investment in this Plan shall conform to the applicable tariff provisions at the time the award is requested. The multiples noted in the Plan are for illustrative purposes and may change from time to time as the tariff is updated.
- If any provision of this Plan shall be deemed to be prohibited or invalid under applicable law or tariff, such provision shall be ineffective only to the extent of such prohibition or invalidity.

Additional Margin:

Compensation under the PIA can be requested for projects that increase the Company's margin through the installation of new, additional or incrementally larger natural gas equipment or converting existing equipment from an alternate fuel to natural gas. When new equipment is displacing existing gas fired equipment, the net incremental margin will be used as the basis for calculating the award.

Projects for Alternate Fuel Customers without a minimum volume or margin commitment.

A project is eligible for a PIA at the end of the first anniversary date of the equipment being converted and/or the establishment of natural gas service. In addition,

- Project would only be eligible for a PIA if the account has been inactive for at least a one (1) year period.
- IGE/Supervisor must submit an Informational Notification Form describing the project during the quarter the equipment has been installed, is operational and any facility upgrades required by Southwest are complete.
- The customer must remain active for a minimum period of one year.
- A PIA in the amount of 20% of actual margin will be paid at the end of the first

anniversary date, subject to an overall project cap of $2,500.

- A PIA can only be requested once every four years for each account.
- In Arizona, projects must be evaluated using the Incremental Contribution Method (ICM). The project must still meet or exceed the minimum required rate of return with the PIA included. If the return is not acceptable with the PIA included, the award can be reduced accordingly.
- In Nevada, project costs must not exceed four (4) years of calculated annual margin.
- In California, project costs must not exceed 6.2 years of calculated annual margin.

Projects (other than for Alternate Fuel Customers) without a minimum volume or margin commitment.

A project is eligible for a PIA when the equipment has been installed; is operational and any facility upgrades required by Southwest are complete.

- IGE/Supervisor may be compensated up to 20% of the first year's incremental margin subject to a project cap of $2,500.
- In Arizona, projects must be evaluated using the Incremental Contribution Method (ICM). The project must still meet or exceed the minimum required rate of return with the PIA included. If the return is not acceptable with the PIA included, the award can be reduced accordingly.
- In Nevada, project costs must not exceed four (4) years of calculated annual margin.
- In California, project costs must not exceed 6.2 years of calculated annual margin.

Projects (including Alternate Fuel Customers) with a minimum volume or margin commitment.

A project is eligible for a PIA when the Minimum Annual Volume/Margin requirements begin.

- IGE/Supervisor may be compensated up to 20% of the project's incremental margin subject to a project cap of $3,000.
- All projects qualifying for this performance incentive must have a contract containing a minimum volume or minimum margin obligation from the customer.
- The primary term of such contract must be at least two years. Contracts with primary terms less than two years will be treated like projects without a minimum volume or margin obligation.
- The incentive calculation will be based on the lesser of the total contract margin or the margin from the first five years of the contract's primary term.
- In Arizona, project must be evaluated using the Incremental Contribution Method (ICM). The project must still meet or exceed the minimum required rate of return with the PIA included. If the return is not acceptable with the PIA included, the award can be reduced accordingly.
- In Nevada, project costs must not exceed four (4) years of calculated annual margin.

- In California, project costs must not exceed 6.2 years of calculated annual margin.

Contract Negotiation related to Margin Retention:

A performance incentive can be requested for contracts negotiated with Optional Fuel and Bypass capable customers when the contracted margin rate exceeds the required floor margin rate. The successful negotiation is eligible for a PIA when the term of the agreement begins. The following conditions/requirements apply:

- A PIA will be calculated as: 20% x (negotiated margin– floor margin).
- The PIA is subject to a cap of $2,500 per contract.
- A contract must be executed that includes; a minimum annual volume or margin obligation from the customer: financial disincentive to the customer for early contract termination, or; management approved equivalents.
- The floor margin rate will be calculated by the Pricing Department.
- The primary term of the contract must be greater than two years.
- The incentive calculation will be based on the lesser of the total contract margin or the margin from the first five years of the contract's primary term.

Special Incentive:

From time to time, KAM management may offer special incentives related to Company initiatives. These incentives will generally be short-term and will not be a permanent part of the Plan.

SOUTHWEST GAS CORPORATION
INCENTIVE COMPENSATION EXPENSES
CALENDAR YEARS 2008-2010
IN RESPONSE TO DATA REQUEST NO. STF-1-83

	MIP [1]	Aspire Award [1]	Constant Flame/ GEM [1], [2]	RSUP [1]	SP Quality Award	KAM Incentive Plan [1]
2008	$ 5,953,219	$ 133,500	$ 182,500	$ 1,327,123	$ 279,550	$ 123,650
2009	5,953,364	174,500	210,000	2,103,149	244,300	132,436
2010	6,946,420	73,500	196,000	1,835,028	214,025	124,789
Account	920	920	926/920	920	903	903

[1] Amounts are before allocation to Arizona.
[2] The Constant Flame Program (Acct 926) was replaced by the GEM Award (Acct 920) in 2010.

513-001

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
*** * ***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-17
ACC-STF-17-1 to ACC-STF-17-2)

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 21, 2011

Request No. ACC-STF-17-1:

SERP.

a. The response to STF-1-50(b) states that The amount of SERP requested for recovery in this proceeding allocated to Arizona is approximately $1.65 million. Please show in detail how the $1.65 million was derived and reconcile that amount to SWG's workpapers.

b. SWG Workpaper Supporting Adjustment No. 3, Annualized Employee Benefits, Line 12, show the following amounts for SERP:

Test Year Supplemental Executive Retirement Expense (Arizona)	$	(1,419,193)
Test Year Supplemental Executive Retirement Expense (Corporate Direct Arizona)	$	(70,565)
System Allocable Amount of SERP	$	(962,289)
Total	$	(2,452,046)

Please confirm that the test year amount for SERP in SWG's filing is $2,452,046. If not, show in detail what the Arizona jurisdictional amount is and how it was derived.

Respondent: Revenue Requirements

Response:

The amount of SERP requested for the Arizona jurisdiction in the filing is not $2,452,046. The $962,289 system allocable amount of SERP shown on WP C-2Adjustment No. 3, Sheet 5, Ln 12 is prior to allocation to Arizona. The attached schedule shows the approximate amount of SERP included in the filing, and includes references to workpapers supporting the calculations. The precise amount of SERP requested for recovery is impacted by numerous calculations within the cost of service model, including cash working capital and the labor loading allocations. The attached spreadsheet, which does not reproduce every calculation within Southwest Gas' cost of service model, but shows the largest components, shows an impact of approximately $1.73 million. Any changes to the allocation methods, charged labor amounts, or cash working capital components will impact the exact amount of SERP requested for recovery in Arizona.

SOUTHWEST GAS CORPORATION
SUPPLEMENTAL RETIREMENT PLAN
IN RESPONSE TO DATA REQUEST NO. STF-17-1

Line No.	Description	Arizona	Corporate Direct Arizona	System Allocable	Reference	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	SERP	$ 1,419,193	$ 70,565	$ 962,289	WP C-2, Adj. No. 3, Sh 5, Ln 12	1
2	% O&M to Total - Arizona	81.36%			WP C-2, Adj. No. 3, Sh 18, Ln 11	2
3	% O&M to Total - Corporate		100%	96.17%	WP C-2, Adj. No. 3, Sh 20, Ln 9	3
4	% SERP to O&M	$ 1,154,655	$ 70,565	$ 925,433		4
5	Paiute and SGTC MMF Allocation			3.83%	Schedule C-1, Sh 18, Ln 8(h)+(i)	5
6	SERP Net of Paiute and SGTC			$ 889,989		6
7	Arizona 4-Factor Allocation			56.25% [1]	Schedule C-1, Sh 17, Ln 10(b)	7
8	System Allocable SERP to AZ			$ 500,619		8
9	Total SERP (Approximate)			$ 1,725,839	Ln 4(b) + Ln 4(c) + Ln 8(d)	9

[1] The majority of system allocable dollars are allocated to Arizona based on the 4-Factor, as shown on WP C-2, Adj No. 3, Sheets 21-22, Col (i)

254-052

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 THROUGH ACC-STF-6-60)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 28, 2007

Request No. ACC-STF-6-52:

Please refer to Ms. Aldridge's direct testimony, page 24. Please show in detail how the Company identified the portion of AGA costs that relate to marketing and lobbying activities. Include a copy of any and all source documents used to identify those percentages.

Respondent: Revenue Requirements

Response:

The portion of advertising and lobbying costs was provided to Southwest by the AGA in the attached document.

AMERICAN GAS ASSOCIATION
2007 BUDGET

	$ 2007 ALLOCATION	% 2007 ALLOCATION
Advertising	$345,000	1.39%
Corporate Affairs	$2,099,000	8.44%
General & Administrative	$4,665,000	18.77%
General Counsel	$1,016,000	4.09%
Industry Finance & Administrative Programs	$1,283,000	5.16%
Operations & Engineering Management	$5,993,000	24.11%
Policy, Planning & Regulatory Affairs	$3,669,000	14.76%
Public Affairs	$5,790,000	23.29%
Total Budget	$24,860,000	100.00%

Note:
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 2% of member dues in 2007.

254-050

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 THROUGH ACC-STF-6-60)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 28, 2007

Request No. ACC-STF-6-50:

Please refer to Ms. Aldridge's direct testimony, Exhibit RLA-2.

a. Please provide a complete copy of the March 2005 Annual Audit report and show the percentages of AGA cost for each NARUC-designated functional category of AGA activities.

b. Does Southwest Gas or AGA have more current information on the percentage of AGA costs in each NARUC-designated functional category of AGA activities? If so, please provide the most current information.

Respondent: Revenue Requirements

Response:

a. Attached is the copy of the Annual Audit Report on the Expenditures of the American Gas Association (AGA) for the 12 month period ended December 31, 2002, dated March 2005. This report is the most recent audit report submitted to NARUC. According to the AGA, NARUC no longer requests that the AGA provide annual audit reports. The lobbying percentage is found on the page preceding the table of contents. The other percentages are found on page III-2.

b. Attached is the updated budget information for 2008 provided by the AGA to Southwest.

AMERICAN GAS ASSOCIATION
2008 BUDGET

	$ 2008 ALLOCATION	% 2008 ALLOCATION
Advertising	$300,000	1.18%
Corporate Affairs	$2,317,000	9.14%
General & Administrative	$5,127,000	20.22%
General Counsel	$1,056,000	4.17%
Industry Finance & Administrative Programs	$852,000	3.36%
Operations & Engineering Management	$5,505,000	21.71%
Policy, Planning & Regulatory Affairs	$4,000,000	15.78%
Public Affairs	$6,195,000	24.44%
Total Budget	$25,352,000	100.00%

Note
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 4% of member dues in 2008.

491-072

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-72:

Insurance Expense. Itemize each component of insurance expense included in the test year, and provide comparative information for calendar 2007, 2008, 2009 and 2010. Indicate the accounts and amounts in which each item of insurance expense is recorded.

Respondent: Revenue Requirements

Response:

Please see the attached schedule listing the recorded insurance expenses for the test year and calendar years 2007, 2008, 2009, and 2010.

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-1-72
INSURANCE EXPENSE
2007-2009 AND TEST YEAR ENDING JUNE 30, 2010

Line No.	Description	Calendar Year 2007	2008	2009	2010	Test Year TME June 2010	Line No.
	Account 924.0 0001						
1	Property	$ 472,664	$ 475,201	$ 513,300	$ 533,446	$ 555,425	1
	Account 925.0 0001						
2	Aviation Liability	$ 31,000	$ 27,595	$ 23,600	$ 21,350	$ 22,710	2
3	Commercial Crime	12,600	12,600	10,892	8,500	8,842	3
4	Commercial General Liability	7,520,456	7,653,674	7,593,283	7,668,278	7,713,146	4
5	D & O Liability	1,583,246	1,362,984	1,391,214	1,431,467	1,428,590	5
6	Employee Benefits	171,600	172,150	178,198	177,796	178,188	6
7	Workmen's Compensation	149,015	153,506	155,929	162,132	159,454	7

491-071

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-71:

Injuries and Damages. State the amount of injuries and damages expense for each of the last three years, and for the test year, by account.

Respondent: Revenue Requirements

Response:

Attached is a schedule that shows the injuries and damages expense for the twelve month periods ending December 2007 through 2009 and the test year ending June 30, 2010. The expenses are grouped into four categories: 1) legal and other expense; 2) reserve for the self-insurance; 3) self-insured worker's compensation; and 4) insurance.

Also, refer to workpapers to Schedule C-2, Adjustment No. 9, Sheet 1.

SOUTHWEST GAS CORPORATION
ACCOUNT 925 - INJURIES AND DAMAGES
2007-2009 AND TEST YEAR ENDING JUNE 30, 2010

Description	Account Number	Rate Jurisdiction	2007	2008	2009	June 2010
Legal and Other Costs	92500001	Tot. AZ	$ 280,762	$ 322,110	$ 507,803	$ 718,799
Reserve for Self-Insurance	92500001		713,629	230,000	400,000	537,500
Self-Insured Wk Cmp	92501832		293,006	199,472	356,049	308,201
			$ 1,287,397	$ 751,581	$ 1,263,852	$ 1,564,501
Legal and Other Costs	92500001	No. CA	$ 0	$ 2,559	$ 0	$ 0
Reserve for Self-Insurance	92500001		0	0	0	0
Self-Insured Wk Cmp	92501832		3,720	5,157	6,738	7,955
			$ 3,720	$ 7,716	$ 6,738	$ 7,955
Legal and Other Costs	92500001	So. CA	$ 68,011	$ 70,198	$ 46,057	$ 6,469
Reserve for Self-Insurance	92500001		0	400,000	(32,021)	125,000
Self-Insured Wk Cmp	92501832		126,864	182,734	96,440	106,237
			$ 194,876	$ 652,933	$ 110,476	$ 237,706
Legal and Other Costs	92500001	SLT	$	$ 0	$ 0	$ 0
Reserve for Self-Insurance	92500001			175,000	225,000	125,000
Self-Insured Wk Cmp	92501832			0	0	0
			$ 0	$ 175,000	$ 225,000	$ 125,000
Legal and Other Costs	92500001	No. NV	$ 6,813	$ 13,156	$ 72,042	$ 82,506
Reserve for Self-Insurance	92500001		0	0	0	0
Self-Insured Wk Cmp	92501832		126,500	46,084	55,562	16,256
			$ 133,313	$ 59,240	$ 127,603	$ 98,762
Legal and Other Costs	92500001	So. NV	$ 90,121	$ 63,286	$ 53,510	$ 63,000
Reserve for Self-Insurance	92500001		786,405	444,596	9,278	75,000
Self-Insured Wk Cmp	92501832		93,819	88,116	114,439	227,907
			$ 970,345	$ 595,998	$ 177,227	$ 365,907
Legal and Other Costs	92500001	Common	$ 637,558	$ 646,078	$ 243,891	$ 269,748
Reserve for Self-Insurance	92500001		(25,500)	(300,000)	275,000	275,000
Self-Insured Wk Cmp	92501832		11,468	1,908	(63,728)	3,556
Insurance	92501831		9,883,857	9,771,350	9,754,271	9,927,437
Allocation - Paiute	92501900		(430,803)	(391,618)	(394,084)	(403,853)
			$ 10,076,580	$ 9,727,718	$ 9,815,350	$ 10,071,888
Total Account 925			$ 12,666,231	$ 11,795,186	$ 11,501,247	$ 12,346,719

295-026

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-10
(ACC-STF-10-1 THROUGH ACC-STF-10-26)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 29, 2008

Request No. ACC-STF-10-26: ✓

Aircraft and aviation operations. (a) Please identify the investment cost and operating cost of all owned and leased aircraft in the test year, and provide comparable information for calendar 2004, 2005, 2006 and 2007. (b) Please identify all costs and expenses, by account, for all owned and/or leased aircraft and aviation operations for the test year that were charged to Arizona utility operations.

Respondent: Revenue Requirements

Response:

Please find the attached schedule listing the operating costs associated with the leased aircraft used by Southwest for business operations. Southwest does not own any aircraft. The amounts are listed by account, from 2004 through 2007, as well as the test year, and the portion allocated to Arizona is shown. Any amounts that were directly charged to non-Arizona jurisdictions or below-the-line (Account 426.5) were excluded from this schedule.

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
DATA REQUEST NO. STF-10-26
LEASED AIRCRAFT OPERATING COSTS

Line No.	Account	2004	2005	2006	2007	Test Year TME 4/30/2007	Line No.
1	908.0	$ -	$ -	$ -	$ 1,500	$ -	1
2	920.0	208,306	220,273	259,841	231,208	263,810	2
3	921.0	181,231	225,338	216,448	193,086	222,344	3
4	930.2	28,500	42,210	53,300	35,950	50,300	4
5	931.0	24,101	27,026	24,049	25,134	24,049	5
6	935.0	679	924	4,297	-	233	6
7	Total	$ 442,816	$ 515,771	$ 557,935	$ 486,878	$ 560,736	7
	Description						
8	Allocation to Palute Pipeline (PP)/SGTC	4.91%	4.91%	4.11%	4.12%	3.96%	8
9	Aircraft Expense Allocated to PP/SGTC	$ 21,742	$ 25,324	$ 22,931	$ 20,059	$ 22,205	9
10	Aircraft Expense Net of PP/SGTC	$ 421,074	$ 490,447	$ 535,003	$ 466,819	$ 538,531	10
11	AZ Allocation Factor	57.66%	57.10%	56.81%	56.78%	56.70%	11
12	Aircraft Expense Allocated to AZ	$ 242,791	$ 280,045	$ 303,935	$ 265,060	$ 305,347	12

500-009

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-7
(ACC-STF-7-1 to ACC-STF-7-23)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 31, 2011

Request No. ACC-STF-7-9:

Aircraft and aviation. Has Southwest included any amounts in rate base or operating expense related to owned or leased aircraft or aviation equipment? If so, please identity all such amounts by account.

Respondent: Revenue Requirements

Response:

Please refer to the attached spreadsheets. The first illustrates the amount Southwest Gas included for aircraft-related operating expenses during the test year, by account and after allocation to Arizona. The other spreadsheet calculates the rate base associated with the company-operated airplane hangar and collision avoidance equipment after allocation to Arizona.

SOUTHWEST GAS CORPORATION
2010 ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
AIRCRAFT-RELATED EXPENSES
DATA REQUEST STF 7.9

Accounts		Total
90800001	$	3,545
92000001		300,159
92100001		232,453
92501831		22,713
93020001		43,005
93100001		271,180
Total	$	873,055
Paiute and SGTC MMF		3.83%
Less: Paiute and SGTC Allocation	$	33,480
Aircraft Expense Before 4-Factor	$	839,575
Arizona 4-Factor Allocation		56.25%
Arizona Related Operating Expense	$	472,261
Depreciation Expense	$	34,902
Arizona 4-Factor Allocation		56.25%
Arizona Related Depreciation Expense	$	19,632
Total Arizona Aircraft-Related Expenses	$	491,893

SOUTHWEST GAS CORPORATION
2010 ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
AIRCRAFT-RELATED RATE BASE
DATA REQUEST STF 7.9

Line No.	Description	Airplane Hangar	Airplane Equipment	Paiute & SGTC Alloc 3.83%	Net of Paiute & SGTC Alloc	Arizona Allocation 56.25%	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	Original Cost	$ 941,644		$ 36,065	$ 905,579	$ 509,388	1
2	Accumulated Depreciation	(297,257)		(11,385)	(285,872)	(160,803)	2
3	Accumulated Deferred Income Taxes	(4,291)		(164)	(4,127)	(2,321)	3
4	Original Cost		$ 86,303	3,305	82,998	46,686	4
5	Accumulated Depreciation		(67,452)	(2,583)	(64,869)	(36,489)	5
6	Accumulated Deferred Income Taxes		(6,598)	(253)	(6,345)	(3,569)	6
7	Total Rate Base	$ 640,096	$ 12,253	$ 24,985	$ 627,364	$ 352,892	7

Explanation:
To determine the rate base associated with the company operated airplane hangar and collision avoidance equipment.

ATTACHMENT RCS-4
REDACTED

Southwest Gas Corporation
Docket No. G-01551A-10-0458
Attachment RCS-5
Copies of Regulatory Commission Order Excerpts Addressing Sharing of Directors & Officers Liability Insurance Cost Between Shareholders and Ratepayers

Jurisdiction	Docket No.	Order Date	Utility	No. of Pages	Page No.
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Progress Energy Florida, Inc.	DOCKET NO. 090079-EI
In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.	DOCKET NO. 090144-EI
In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc.	DOCKET NO. 090145-EI ORDER NO. PSC-10-0131-FOF-EI ISSUED: March 5, 2010

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

R. ALEXANDER GLENN, JOHN T. BURNETT, ESQUIRES, Progress Energy Service Company, LLC, P.O. Box 14042, St. Petersburg, Florida 33733-4042; JAMES MICHAEL WALLS, DIANNE M. TRIPLETT, and MATTHEW BERNIER, ESQUIRES, Carlton Fields, P.A., Post Office Box 3239, Tampa, Florida 33601-3239; RICHARD D. MELSON, ESQUIRE, 705 Piedmont Drive, Tallahassee, Florida 32312
On behalf of Progress Energy Florida, Inc. (PEF).

CHARLES REHWINKEL, Associate Public Counsel, CHARLIE BECK, Deputy Public Counsel, and PATRICIA A. CHRISTENSEN, Associate Public Counsel, ESQUIRES, Office of the Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

STEPHANIE ALEXANDER, ESQUIRE, 200 West 200 West College Avenue, Suite 216, Tallahassee, Florida 32301
On behalf of the Florida Association for Fairness in Rate Making (AFFIRM).

costs have been removed. Accordingly, we find that PEF has made the appropriate adjustments to remove aviation cost for the test year.

H. Advertising Expenses

PEF removed promotional advertising costs in the amount of $3,388,000, as reflected in MFR Schedule C-2. The jurisdictional amount, net of tax, is $2,081,000. The explanation given by PEF is to exclude the cost of promotional advertising in order to comply with our guidelines.

We note an excerpt from the procedures followed by our auditors for the 2008 base year:

> We reviewed additional samples of utility advertising expenses, industry dues, economic development expenses, outside services, sales expenses, customer service expenses and administrative and general service expenses to ensure that amounts supporting non-utility operations were removed.

The Company's advertising expense is one of the areas specifically examined by our auditors. There were no findings with respect to this issue. Therefore, we find that PEF has made the appropriate adjustments to remove advertising expenses for the test year.

I. Directors and Officers (D&O) Liability Insurance

PEF argued that OPC witness Schultz is incorrect in his assertion that D&O liability insurance does not benefit ratepayers, and thus should be disallowed. PEF cited to the most recent TECO case in which this Commission decided that D&O liability insurance is a necessary and reasonable business expense and is appropriately included in customers' rates.[40] PEF asserted that we have already rejected the argument that Mr. Schultz raises in other cases and there is no valid reason for us to depart from its previous findings in this case.

OPC witness Schultz questioned whether the cost of D&O liability insurance is a necessary and appropriate expense to pass on to ratepayers. He stated that the expense protects shareholders from the decisions they made when they hired the Company's Board of Directors and the Board of Directors in turn hired the officers of the Company. He noted that the Company included $2.2 million in Account 925 for D&O liability insurance, but he believes the correct amount to be $2,750,650 for $300,000,000 in coverage. He disagreed with our recent Peoples Gas case in which the expense was allowed as a legitimate business expense.[41] The witness testified that the pertinent issue is whether the cost is beneficial to ratepayers, not whether it is a legitimate business expense. He stated that we have disallowed the cost in the past.

OPC witness Schultz testified that other jurisdictions have disallowed the expense. He stated, for example, that a Connecticut decision limited recovery by Connecticut Light and

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[40] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.

[41] Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System, p. 37-38.

Power to thirty percent, because ratepayers should not be required to protect shareholders from the decisions they make in electing the Board of Directors. He added that Consolidated Edison was not allowed to recover the full amount in a New York case. He explained that the disallowance was due to excessive coverage in part, and that a portion of the amount found to be reasonable was also disallowed. He stated the reason for the additional disallowance was that D&O Liability insurance provides protection to shareholders from matters in which the customers have no influence.

OPC witness Schultz recommended disallowance of the total cost of D&O liability insurance of $2,750,650 ($2,412,100 jurisdictional) because the purpose of the insurance is to protect shareholders, not ratepayers. He stated that he does not take the position that the Company should not have the insurance, but that it should be paid for by those who benefit from the insurance; that is, the shareholders.

OPC argued that PEF did not offer any testimony in rebuttal to OPC witness Schultz that the D&O liability insurance should be disallowed. OPC stated that, in each of the cases cited by witness Schultz in his testimony, the Company argued that D&O liability insurance is a necessary and prudent cost required to attract and retain competent directors and officers, yet a disallowance was made. OPC challenged the cost for $300,000,000 of coverage as being excessive, and questioned whether the cost for that level of coverage is appropriate to pass on to ratepayers.

OPC noted in particular a Consolidated Edison Company Case. OPC stated that in the final decision, the New York Commission (NYC) ruled that $300,000,000 of coverage was excessive based on the comparisons to similar companies and disallowed the premium associated with $100,000,000 excess, and then disallowed 50 percent of the premium associated with the $200,000,000 that was determined to be reasonable. OPC stated that, in the discussion, the NYC noted that D&O insurance provides substantial protection to shareholders who elect directors and have influence over whether competent directors and officers are in place, while customers have no influence. OPC noted that the NYC further stated at page 91 of its order that:

> We find no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders, especially taking into account the advantage that shareholders have in control over directors and officers. We believe the fairest and most reasonable way to apportion the cost of D&O insurance therefore is to share it equally between ratepayers and shareholders.

FIPUG argued that the amount should be disallowed, because the expense directly benefits only PEF's shareholders.

We agree with OPC witness Schultz that this Commission has disallowed D&O insurance in water and wastewater cases in the past.[42] We do not agree with OPC that the ratepayers do not

[42] See Order Nos. PSC-09-0385-FOF-WS, issued May 29, 2009, in Docket No. 080121-WS, In re: Application for increase in water and wastewater rates in Alachua, Brevard, DeSoto, Highlands, Lake, Lee, Marion, Orange, Palm

benefit from D&O liability insurance. We believe that D&O liability insurance has become a necessary part of conducting business for any company or organization and it would be difficult for companies to attract and retain competent directors and officers with out it. We also believe that ratepayers receive benefits from being part of a large public company, such as easier access to capital which may result in lower rates. As stated in the TECO order:

> We find that [D&O liability] insurance is a part of doing business for a publicly-owned Company. It is necessary to attract and retain competent directors and officers. Corporate surveys indicate that virtually all public entities maintain [D&O liability] insurance, including investor-owned electric utilities. . . . We do not agree with OPC that the ratepayers do not benefit from [D&O liability] insurance. It is not realistic to expect a large public company to operate effectively without [D&O liability] insurance.[43]

We agree with PEF that the amount of the D&O liability insurance provided in discovery responses is $2.2 million, not $2.75 million as adjusted by OPC witness Schultz. However, we note that the amount of the premium for the test year is projected to be higher than the premium for 2008-2009, but lower than the previous three years, even though the amount of coverage was increased from $280 million to $300 million.

In summary, we believe that D&O liability insurance has become a necessary part of conducting business for any publicly owned company and it would be difficult for companies to attract and retain competent directors and officers without it. We also believe that ratepayers receive benefits from being part of a large public company including, among other things, easier access to capital. Because D&O liability insurance benefits both the ratepayer and the shareholder, it should be a shared cost. Thus, we find that O&M expense shall be reduced by $964,913 jurisdictional to reflect the sharing of costs between the ratepayers and the shareholders.

J. Injuries and Damages Expense

PEF stated that FERC Account 925 on MFR Schedule C-4, p. 44 of 48, reflects an expense of $8,882,000 for injuries and expenses. PEF stated that the numbers were audited by our auditors who reconciled the amounts on the MFRs for 2008 expenses to the Company's actual book and records. PEF stated that it based its 2010 budget for injuries and damages expense on the Company's actual historical 2008 expenses. PEF argued that it is, therefore, entitled to recover this expense.

Beach, Pasco, Polk, Putnam, Seminole, Sumter, Volusia, and Washington Counties by Aqua Utilities Florida, Inc., p. 81; PSC-07-0505-SC-WS, issued June 13, 2007, in Docket No. 060253-WS, In re: Application for increase in water and wastewater rates in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p.44; PSC-03-1440-FOF-WS, issued December 22, 2003, in Docket No. 020071-WS, In re: Application for rate increase in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p. 84; and PSC-99-1912-FOF-SU, issued September 27, 1999, in Docket No. 971065-SU, In re: Application for rate increase in Pinellas County by Mid-County Services, Inc., p. 20-22.

[43] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 08-07-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

February 4, 2009

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Anthony J. Palermino

DECISION

TABLE P/R - 5

CORRECTED TABLE

(in $000s)

Compensation Expense	2009	2010
Proposed Base Payroll	$56,627	$59,115
Department Adjustment	($3,880)	($4,565)
Allowed Base Payroll	$52,747	$54,550
Overtime and Premium Pay	$6,754	$7,024
Department Adjustment	($1,672)	($1,942)
Allowed O/T and Premium Pay	$5,082	$5,082
Capitalized Overhead Pay	($4,083)	($4,207)
Department Adjustment	$80	$63
Allowed Cap. O/H	($4,003)	($4,144)
Incentive Compensation	$7,665	$7,791
Department Adjustment	($3,671)	($3,797)
Allowed Incent. Comp.	$3,994	$3,994
Total Compensation Proposed	**$66,963**	**$69,723**
Total Dept. Adjustments	**($9,143)**	**($10,241)**
Total Allowed Compensation	**$57,820**	**$59,482**
Allocated Incentive Comp.	**$1,154**	**$1,146**
Total Department Adjustments	**($553)**	**($559)**
Allowed Alloc. Inc. Comp.	**$601**	**$587**
Total Compensation Adjustments	**($9,696)**	**($10,800)**

To address the public's concern that customers are paying 100% of the compensation paid to the top officers of the Company, the Department offers that, for example, the adjustments made in this Decision reduce the amount of compensation paid to the Company President and Chief Operating Officer, that are actually included in rates and paid by customers, by approximately 33% and 31%, respectively.

2. Directors and Officers Liability Insurance

In its Application UI requested the Department authorize $844 thousand for 2009 and 2010 Directors and Officers Liability Insurance (DOL) ($852 thousand less $8 thousand allocated to non-regulated entities). Schedule WP C-3.31 A&B. The Company's position is that DOL is a business expense of having a public corporation, and the customers pay for all of the ordinary business expenses that a company would incur. Tr. 10/14/08, pp 62 and 63.

The OCC stated that in the past two rate decisions involving UI, the Department has determined that a portion of UI's DOL insurance costs should be funded by ratepayers. Despite this fact, UI is proposing to recover 100% of its DOL insurance

costs in this proceeding. The OCC cited its previous arguments that corporate scandals have increased costs dramatically, that ratepayers do not elect the Board of Directors (BOD) and officers of the Company, and that shareholders, who are protected by the insurance, should not be subsidized by ratepayers for DOL insurance costs that are designed to protect shareholders from their own decisions. The facts and circumstances regarding the DOL insurance have not changed since UI's last rate case. The OCC recommends that the DOL insurance be reduced by 75% with only 25% being passed on to customers, but stated that its absolute preference would be to disallow the cost completely. OCC Brief, pp. 79 and 80.

The AG indicates that the amount requested is roughly six times the amount that the Department approved in the 2006 Decision. In the 2006 Decision, the Department specifically agreed with both the AG and OCC that "DOL insurance protects only shareholders from the actions of management that they selected." Although the Department allowed UI to collect one-quarter of its requested amount in the 2006 Decision, the Company requested the entire amount be funded by ratepayers. The AG stated that this bold act of indifference to the Department's clear precedent and to the financial stresses facing its customers should be firmly rejected. At the very most, the Department should authorize only the levels for DOL insurance that it approved in the 2006 Decision. AG Brief, p. 18.

In the 2006 Decision, the Department noted the OCC's and AG's positions, as well as the position of the Company who stated that if there was no insurance and there was a huge claim, it could put the Company in financial peril, which would potentially impair its ability to serve. Therefore, the Department allocated 75% of DOL costs to the shareholders, with the residual 25% to be funded by ratepayers. 2006 Decision, pp. 46 and 47. The Department rejects the Company's current proposal that ratepayers fund 100% of DOL insurance costs, and reconfirms the precedent afforded by the 2006 Decision. Accordingly, the Department allows $211 thousand of DOL insurance costs to be funded by ratepayers in years 2009 and 2010 ($844 thousand times 25%). This results in DOL insurance expense decreases of $633 thousand in each of years 2009 and 2010.

3. Fringe Benefits

a. Compensation Adjustment to Fringe Benefits

In Section III.1.f., the Department made adjustments to compensation of $12.033 million and $13.655 million in 2009 and 2010, respectively. This also results in an adjustment to fringe benefits that accompany compensation. The Company indicates that its composite fringe benefit rate for 2009 and 2010 is 45%. Responses to Interrogatories EL-30-2; EL-31-2; and EL 33-1.

In its Written Exceptions, the Company argues, against its own filed and sworn record evidence of a 45% fringe benefit expense related to compensation, that the "correct compensation-driven benefits loader from an expense standpoint" is 20.6% and attempts to justify that amount by listing greatly reduced expense amounts for certain "Compensation Driven Employee-Related Benefits Loader." UI Exceptions, pp. 29 and 30. The Department notes that the Company's Response to Interrogatory EL-33 that

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 07-07-01 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND RATE SCHEDULES

January 28, 2008

By the following Commissioners:

Anthony J. Palermino
Anne C. George
John W. Betkoski, III

DECISION

expenses by $2.232 million to remove the non payroll projected costs in excess of the original budget.

2. Insurance Expense

The test year expense for insurance expense was $6.817 million. The Company proposed a rate year increase of $.65 million or a rate year expense of $7.467 million. Application, Schedule C-3.10. CL&P revised the request and reduced the insurance expense by $17,000. The revision was a result of recent premium information. The change is a combination of increases and decreases in different types of insurance. Response to Interrogatory EL-80-SP01.

The Department accepts the Company's revisions except for the Directors and Officers insurance expense and capital allocation as discussed in detail below.

a. Director and Officer Insurance Expense

The test year expense for Director and Officer (D&O) insurance expense was $1.423 million. The Company proposed a rate year increase of $0.164 million or a rate year expense of $1.587 million. Application, WP C-3.10. As indicated above, CL&P revised its rate year insurance expense and decreased the rate year D&O insurance expense amount by $.270 million to $1.317 million. Response to Interrogatory EL-80-SP01 and Late Filed Exhibit No. 112SP-01.

CL&P claims that D&O insurance is a legitimate and customary operating expense and that no director or officer with the necessary knowledge and experience would take the risks associated with serving CL&P without this type of protection. CL&P states that the Sarbanes-Oxley Act requires that certain skill-sets be reflected in the Board of Directors (BOD), and in order to attract and retain individuals that meet these requirements CL&P must offer D&O coverage to its BOD. CL&P indicated that the Department has already confirmed that D&O is a necessary operating expense that is recoverable. CL&P Brief, p. 39.

The AG argues for the removal of the entire $1.587 million. The AG states that it is inappropriate to force customers to fund a plan that benefits only shareholders. D&O insurance protects shareholders from their own decisions and is intended to protect directors and officers from lawsuits brought by shareholders. AG Brief, p. 20.

The OCC states that premiums for insurance excluding D&O insurance decreased from $9.4 million to $8.41 million while D&O insurance is estimated to increase 11.5% from $1.423 million to $1.587 million. Further, the OCC believes that the D&O insurance requested amount is excessive, ignores the Department's prior rulings, and ratepayers should not be required to protect shareholders from the decisions they make in electing the BOD. The OCC argues that Sarbanes-Oxley merely requires officers & directors who have a fiduciary duty to acknowledge responsibility by signing their names. It was not the implementation of Sarbanes-Oxley that caused an increase in premiums, it's the claims filed that caused the increase. The OCC adds that D&O insurance has drastically increased from 5.67% of the aggregate insurance amount in 2002 to 13.15% in 2006 and projected to cost 15.87% in the rate

year. The OCC recommends a D&O insurance reduction of $1.202 million to $0.385 million. The OCC calculated this amount by using the 2002 test year amount increased by inflation. OCC Brief, p. 44.

In Docket No. 03-07-02, CL&P requested a rate year amount of $1.043 million and was allowed the test year amount of $.330 million. 03-07-02 Decision, pp. 48-49. This allowed 33% of the requested amount. In that decision, the Department indicated that it does allow some level of D&O insurance expense in rates to assure some level of ratepayer protection from lawsuits. In the UI Decision, the Department allowed 25% of the D&O insurance expense to be allocated to customers. In the Decision dated February 5, 1999, n Docket No. 98-01-02, DPUC Review of the Connecticut Light and Power Company's Rates and Charges – Phase II, the Department took the OCC approach and calculated the 1999 expense by inflating the 1996 level. This allowed 46.7% of the requested amount. In the Decision dated May 25, 2000, in Docket No. 99-09-03, Application of Connecticut Natural Gas Corporation for a Rate Increase, the Department allowed 20% of the premium amount.

The Department agrees in part with the OCC that ratepayers should not be required to protect shareholders from the decisions they make in electing the BOD. However, the Department historically has allocated a percentage to ratepayers to protect from catastrophic lawsuits. Accordingly, the Department finds it appropriate to allocate 30% to ratepayers and 70% to shareholders. This allocation is fair and consistent with the level allowed in Docket No. 03-07-02. Therefore, the Department allows $.395 million ($1.317 million x 30%) and disallows $.922 million to be collected in rates.

b. Insurance Expense - Capital Allocation

CL&P originally proposed a rate year capitalization factor of 25.3%. Application, Schedule WPC-3.10. The Company revised this amount to 26.6% in order to reflect updates based on recent invoices. Response to EL-80-SP01 and Late Filed Exhibit No. 112. The test year before pro forma adjustment was 35.6%. Application, Schedule WPC-3.10. A majority of the pro forma adjustment was to remove a non-recurring charge for the public liability reserve. This adjustment was based on an independent study performed by Mercer, Inc. The remaining pro forma adjustment included the addition of $284,000 that was for a non-recurring credit or refund received from USICO, a mutual property insurance company. Response to Interrogatory EL-43.

The OCC claims that CL&P has included a significant increase in the percent of costs being charged to expense as opposed to capital. Specifically, the Company's proposed reduction of more than 10% to the capital allocation is significant considering CL&P's focus on system improvements. The OCC argues that the Company did not present any evidence to justify an allocation change. OCC Brief, p. 41. The OCC recommends using the test year capitalization factor of 35.6%. That capitalized amount reduces the aggregate insurance expense to $5.802 million for a total disallowance of $1.665 million. OCC Brief, pp. 43-44.

As indicated below, the Company's insurance capitalization percents have ranged from a low of 25.6% to a high of 40.5% in the years 2002 through 2006.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 05-06-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

January 27, 2006

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Jack R. Goldberg
Anne C. George
Anthony J. Palermino

DECISION

Description	2006	2007	2008	2009
Benchmarking studies	$ 72,000	$ 72,000	$ 73,000	$ 74,000
BPL	$ 98,000	$ 98,000	$ 98,000	$ 98,000
Regulatory consulting	$ 131,000	$ 138,000	$ 145,000	$ 152,000
Client services support	$ 275,000	$ 296,000	$ 311,000	$ 329,000
Total professional services expense disallowed	$ 576,000	$ 604,000	$ 627,000	$ 653,000

8. Outside Services - Audit and Accounting Expense

UI originally projected $533,000, $552,000, $573,000 and $594,000 for audit and accounting expense for rate years 2006 through 2009, respectively. Schedule C-3.16 A–D. UI later increased the projected expenses by $149,000, $164,000, $177,000 and $194,000 for rate years 2006 through 2009, respectively, citing the Company's response to Interrogatory EL-159. Late Filed Exhibit No. 1, Revised.

However, the response to Interrogatory EL-159 only identified a potential increase of $100,000 for 2006. The Company's response to Interrogatory EL-159 and the testimony on 10/14/05 state that the original projection was strictly an estimate and that UI is in negotiations with Pricewaterhouse Coopers for a new contract. UI is seeking to enter into a long term fixed price contract for SEC reporting audit services to mitigate the potential increase. UI testified that the Company is still negotiating and trying to get the price increase down, but, the increase could be greater than the original estimate. Response to Interrogatory EL-159; Tr. 10/14/05, pp. 174 and 175. UI later testified that they negotiated a new contract and the increases in Late Filed Exhibit No. 1 are based on the cost of the new contract. Tr. 11/9/05, p. 2394.

The OCC believes that the response to Interrogatory EL-159 does not support the amount of increase apparently requested by UI in Late Filed Exhibit No. 1 and leaves unanswered questions regarding the certainty of the projected increases. Therefore, the OCC has removed the increases identified in Late Filed Exhibit No. 1. OCC Brief, pp. 63 and 64, Exhibit 5.

The Department takes into account the entire record evidence on a given expense in determining if it is proper for the rate year. Therefore, based on the testimony given during the late filed exhibit hearing, the Department approves the increase to accounting and audit expense as shown in Late Filed Exhibit No. 1, Revised.

9. Directors and Officers Liability Insurance

The Company proposes expenses for Directors and Officers Liability Insurance (DOL) of $533,879 for 2006, and $559,612 for each of the years 2007 through 2009. Response to Interrogatory OCC-104. UI contends that it could not attract a director if it didn't have DOL. It is a cost of doing business. Tr. 10/12/05, p. 868. Further, the Company asserts that, taken to the extreme, "if there was no insurance and there was a huge claim, it could put the company in financial peril, which would potentially impair its ability to serve." Tr. 10/11/05, p. 801.

The OCC indicates that "the numerous corporate scandals since 2001 has caused the cost of the DOL insurance to skyrocket." Schultz and DeRonne PFT, p. 48. Further, "DOL insurance provides shareholders protection from their decision. Ratepayers in general do not elect the Board of Directors and do not appoint officers to run the Company. Shareholders are protected by this insurance against their own decision in the selection of management. Ratepayers should not pay for the cost of insurance designed to protect shareholders from their own decisions." OCC Brief, p. 93; Tr. 10/12/05, pp. 867 and 868. Therefore, the OCC recommends that all of the DOL amounts during the rate period be excluded from rates and be covered completely by shareholders, not ratepayers.

The AG agrees with the OCC's reasoning that DOL insurance protects only shareholders from the actions of management that they selected. Thus, DOL insurance expense should be eliminated from UI's rates entirely. AG Brief, pp. 24 and 25.

The Department partially agrees with the OCC, the AG and the Company. In the 03-07-02 Decision, the Department allowed a portion of that company's proposed expense and stated that "the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits." 03-07-02 Decision, p. 49. The Department also notes that the annual gross DOL premium (before credits and allocations) was $134, 430 in years 2001 and 2002, increasing to $1,029,516 in years 2007 through 2009, lending credence to the OCC's assertion regarding corporate scandals, above. The Department agrees with the OCC that the shareholders should bear the weight of their decisions in appointing directors (who appoint the officers of the Company). Accordingly, the Department allows $140,000 of DOL expense, or approximately ¼ of the total company expense, to be collected in rates as the customers' responsibility.

The Department, therefore, disallows DOL expenses of $393,879 in 2006, and $419,612 in each of 2007, 2008 and 2009.

10. Postage Expense

UI projected postage expense in the amounts of $1,475,000, $1,479,000, $1,485,000, and $1,491,000 for rate years 2006 though 2009, respectively. UI increased the test year expense of $1,361,000 by $74,000 for an anticipated 5.4% increase from the USPS and $31,000 for volume and usage increase. Schedule C-3.20 A – D.

The Governors of the U.S. Postal Service have accepted the recommendation to increase most postal rates and fees by 5.4% effective January 8, 2006, including an increase in the rate for first-class mail from 37 cents to 39 cents. See http://www.usps.com/ratecase/welcome.htm.

UI states that the volume and usage increase is due to items such as increase in collection letters due to higher disconnect for nonpayment activity, new program mailings and increased economic development activity. Response to Interrogatory EL-220.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 03-07-02 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND ITS RATE SCHEDULES

December 17, 2003

By the following Commissioners:

Donald W. Downes
Jack R. Goldberg
John W. Betkoski, III
Linda J. Kelly
Anne C. George

DECISION

The Department, therefore, accepts the Company's revision to computer and other expenses as indicated in the Response to Interrogatory OCC-93. Accordingly, the Department reduces computer expenses by $.348 million ($10.119 million less $9.771 million) and other O&M expenses related to the test year processing and storage balance of $.596 million, for a total O&M adjustment for these items of $.944 million ($.348 million plus $.596 million).

2. Insurance Expense

a. Directors and Officers Liability Insurance

The Company requested Directors & Officers Liability Insurance Expense (D&O Insurance) of $1.043 million in the rate year. This included a test year pro forma adjustment of $.029 million and a rate year adjustment of $.684 million above the test year actual amount of $.330 million based on the actual renewal premiums for the policy period 4/23/03 to 4/23/04. Schedule WP C-3.12; Response to Interrogatory OCC-101.

The OCC argues for the removal of the entire $1.043 million of D&O Insurance expense. The OCC states:

> Ratepayers should not be forced to pay a cost that protects shareholders from the shareholders' own decisions. Shareholders determine who the Board of Directors are and the Board of Directors are responsible for appointing officers of the Company. The officers are highly compensated to provide quality leadership with the utmost integrity. Ratepayers are responsible for paying for the directors and officers services. The shareholders, not ratepayers, determine who the directors and officers are. Therefore, the shareholder should assume the risk associated with their decision regarding the management of the Company. The cost to obtain insurance to protect the shareholders investment from their choice of management should be the responsibility of the shareholders.

OCC Brief, p. 64

The OCC also cites that the escalation in D&O Insurance rates stem from the insurers' need to continue to reserve for litigation and settlement expenses in connection with an influx of claims arising from such entities as Worldcom, Enron, Kmart, etc. Response to Interrogatory OCC-101. The increases in D&O Insurance and the related costs are due to the failures of directors and officers to ensure the Company operated prudently and reasonably. An alternative to total disallowance of cost would be to allow the test year cost of $.330 million. OCC Brief, p. 65.

The Department is sympathetic with OCC's arguments and generally agrees that the increased premiums are, at least in part, caused by Officer/Director mismanagement or misconduct in major corporations. Further, the Department notes that CL&P's recent claims experience includes settlement of eight federal and state shareholder class action lawsuits that stemmed from the Nuclear Regulatory Commission's Watch List of problems at its Millstone Nuclear Plant in 1996 that resulted

in a $20.050 million settlement by its insurer. Further, a $33 million settlement was reached with the non-NU joint owners of Millstone 3 related to the Company's operation of that plant. Late Filed Exhibit 73 and 73-SP01. However, the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits. Therefore, the Department will allow the test year cost of $.330 million and reduce the Company's D&O Insurance expense by $.713 million ($1.043 million less $.330 million).

b. Public Liability Expense

The Company requested Public Liability Expense of $2.591 million in the rate year in Account 925.02. This Account includes the cost of the reserve accrual to protect the utility against injuries and damages claims of employees or others, losses of such character not covered by insurance, and expenses incurred in settlement of injuries and damages claims. It also includes the cost of labor and related supplies and expenses incurred in injuries and damages activities. Uniform System of Accounts prescribed for Electric Utilities, Public Utilities Control Authority State of Connecticut, 1/1/63, p. 177 (USOC). In its calculation of this expense, CL&P removed $1.497 million of test year expense that was capitalized, thus reducing the overall test year expense of $2.591 million to $1.094 million. Schedule WP C-3.12.

In response to an OCC data request, the OCC questioned why CL&P should no longer treat the public liability expense as an overhead cost, subject to capitalization. In the Company's response it indicated "[u]pon further review it was determined that public liability insurance is an appropriate cost to be capitalized under the FERC Electric Plant instructions." CL&P determined that the payroll overhead rate is the best vehicle for capitalizing these costs and changed the overhead rate for the remainder of 2003 to include these costs. Response to Interrogatory OCC-99. Accordingly, the OCC recommends that $1.497 million of public liability expense be capitalized, thereby reducing CL&P's proposed expense.

The Department agrees with the OCC and the Company that a portion of public liability expense, particularly as it relates to construction projects, is properly capitalizable. The USOC provides, for example, that the cost of injuries and damages or reserve accruals capitalized shall be charged to construction directly or by transfer to construction work orders from this account. USOC, p. 177. The Department also notes that it has been CL&P's consistent practice to capitalize a portion of public liability expense. Response to Interrogatory OCC-100. The Company provided a revised schedule that calculated the capitalized portion of Public Liability Expense using a capitalization rate of 38.5% that resulted in a capitalization amount of $.998 million. Schedule WP C-3.12 Revised. The Department notes that the capitalization percentage is consistent with other payroll-related capitalizations. Schedule WP C-3.28a. The Department, therefore, reduces public liability expense by $.998 million to reflect such capitalization.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 98-01-02 DPUC REVIEW OF THE CONNECTICUT LIGHT AND POWER COMPANY'S RATES AND CHARGES - PHASE II

February 5, 1999

By the following Commissioners:

Glenn Arthur
Jack R. Goldberg
Linda Kelly Arnold
Donald W. Downes
John W. Betkoski, III

DECISION

amount. OCC analyzed the storm expense data and found that there is no relationship between total storm expense and inflation. For example, storm expenses were higher in 1992 and 1993 compared to 1994 and expenses in 1995 and 1996 were higher compared to 1997. Therefore, OCC also believes that there is no justification for an escalation factor in the storm budget. PRO Brief, pp. 9 and 10; OCC Brief, pp. IV-52 and 53.

The Department often uses a historical average, excluding the highest and lowest years' costs, to calculate a rate year expense and believes that is the appropriate method for storm expense. The Department agrees with OCC's analysis on the escalation factor. The Department calculates 1999 storm expense to be $8.483 million by averaging storm costs for 1992 - 1997, excluding the lowest and highest costs in 1994 and 1996. Therefore, the Department reduces expenses by $3.169 million ($11.652 million - $8.483 million).

27. Directors' and Officers' Insurance

CL&P has requested $1.391 million in directors' and officers' (D&O) liability insurance premiums for the rate year. Response to Interrogatory OCC-70. D&O insurance expenses for the years 1994 - 1997 were $497,000, $456,000, $630,000 and $1,022,000, respectively. Expenses increased due to claims paid and higher liability limits. CL&P projects 1999 expenses will be higher for the same reasons. Responses to Interrogatories OCC-312 and PRO-6; Late Filed Exhibit No. 5, AR-DPUC-14. The Company indicated that the two reasons were actually one and the same. As claims are paid, the insurance available in the future is reduced by that amount. Because of the claims already paid and potential claims, the Company purchased higher limits to restore its liability coverage to previous amounts. This would give the Company enough coverage for potential future claims. Tr. 10/20/98, pp. 4005 and 4006; Late Filed Exhibit No. 162. A Company witness testified that all of the shareholder lawsuits are well known to CL&P and the Department and any damage claims would be borne by shareholders. Tr. 9/10/98, pp. 430-432.

PRO, AG and OCC argue that D&O costs have increased from 1995 to 1997 as a direct result of management imprudence and the nuclear outages. The claims paid and pending relate to the nuclear outages. OCC and PRO believe the expense should be reduced to the 1996 level. Even though the outages occurred during 1996, PRO believes this would allow for some increase due to inflation. OCC Brief, p. IV-39; PRO Brief, p. 12; AG Brief, p. 15.

Ratepayers should not have to fund higher liability limits for directors and officers when it is those directors and officers who failed to ensure that the Company operated prudently and reasonably. The Department reduces D&O liability insurance premiums to a level that does not reflect the nuclear outages. The Department agrees that the 1999 expense should be based on the 1996 level. However, the Department also believes that this is an expense that is typically influenced by inflation and sets the 1999 allowed expense at $.65 million, which is the 1996 actual expense adjusted for inflation. Therefore, 1999 expenses are reduced by $.741 million ($1.391 million - $.65 million).

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 99-09-03 APPLICATION OF CONNECTICUT NATURAL GAS CORPORATION FOR A RATE INCREASE

May 25, 2000

By the following Commissioners:

Glenn Arthur
Jack R. Goldberg
Linda Kelly Arnold

DECISION

tax rate of 8.3% in the rate year. Tr. 2/16/00, p. 1775. Accordingly, the Department will reduce payroll taxes by an additional $42,746 ($515,017 x 8.3%).

In Version B, CNG made a vacancy adjustment of $160,493. However, the Company failed to make a corresponding adjustment for payroll taxes and the O&M allocation factor of 83.6%. Schedule WPC-3.28. Accordingly, the Department will further reduce this expense by $13,321 ($160,493 x 8.3%). The Department's total reduction to payroll taxes is $255,260 ($199,193 + $42,746 + $13,321).

c. Gross Receipts Tax

Gas distribution companies are subject to the Connecticut gross receipts tax (GRT). GRT rates of 4% and 5% apply to residential customers and commercial/industrial customers, respectively. CNG's initial application projected a pro forma GRT expense of $10,599,786 for pro forma taxes at present rates. Schedule WPC-3.41. The Company's request for a $15,738,284 increase in its revenue requirement added $675,684 for a total pro forma GRT of $11,275,470. Schedule C1/C2. Subsequently, the Company increased its pro forma revenues by $8,010,815. Late Filed Exhibit No. 4, Version B. This increased pro forma GRT by $343,924. Together, the changes increased pro forma GRT by $709,958 to $11,619,394.

The Company calculated a 4.29% blended GRT rate by combining the calculated taxes on residential revenues and commercial revenues. Schedule WPC-3.41. CNG's calculation of its blended GRT rate properly excluded taxes on non-taxable interruptible service revenues. Tr. 1/11/00, p. 137.

In Section II.C, above, the Department adjusted CNG's revenues for firm transportation by $58,700, and for an additional customer by $109,000. The Department will make an adjustment to GRT at the rate of 4.29%. Therefore, the Department will increase CNG's GRT by $7,194 ([$58,700 + $109,000] x 4.29%).

d. Summary of Other Tax Adjustments

The Department's total adjustment for other taxes is $(1,055,804), $(255,260) for payroll tax, $(807,738) for property tax, and $7,194 for gross receipts tax.

9. Insurance

a. Directors and Officers Liability

CNG has included the cost of D&O liability policies in pro forma insurance expense. The D&O insurance provides the Company with coverage for certain types of wrongful acts by directors or officers of the corporation. Its intent is to safeguard the assets of the corporation so that the Company can continue to provide service to its customers and earn a fair return for its shareholders. The Company has two such policies. The first provides regular coverage and has a $84,100 annual premium. The Company included $70,308 of that premium (83.6%) in its pro forma expense. The second policy provides excess coverage and has a $87,900 annual premium. The

Company included $73,397 of that premium in its pro forma expense for a total pro forma D&O insurance cost of $143,705 ($70,308 + $73,397). Schedule WPC-3.32.

OCC recommends that CNG's adjusted expenses be reduced by $81,807 to reflect the allocation of 20% of regular D&O liability insurance and 100% of the excess D&O liability insurance to shareholders. OCC would prefer that the cost be split equally between ratepayers and shareholders. Not withstanding that action, the OCC believes it appropriate to remain consistent with the Previous Rate Decision where 20% of the regulated premium was disallowed. OCC Brief, pp. 11, 37. Based on CNG testimony, PRO recommends a $7,031 reduction to this expense. PRO Brief, p. 11.

In the Previous Rate Decision, the Department found that the Company needed D&O insurance to attract and keep qualified directors and officers. However, because shareholders could also initiate suits against the directors and officers, the Department disallowed 20% of the premium of regular coverage. Additionally, the Department found that the Company had not justified allowance of premiums of excess D&O coverage in rates. Decision, p. 33.

The Company has not presented any evidence in the instant docket to warrant dissimilar treatment. Accordingly, the Department again disallows the cost of the excess coverage policy premium in its entirety and 20% of the regular policy. Accordingly, the Department will reduce this expense by $14,062 (20% x $70,308) to eliminate costs attributable to shareholders. The resultant allowed premium of $56,246 requires an adjustment of $14,062. Adding that to the disallowed excess coverage premium of $73,397 produces a total reduction to D&O insurance expense of $87,459.

b. Weather Stabilization Insurance

CNG seeks to recover $993,063 in premiums for a weather stabilization insurance (WSI) policy covering the 2000/2001 heating season. Schedule C-3.32. This approximates the cost of the policy for the 1999/2000 season but is more than the cost of the policy in the 1998/1999 season. The witness stated that the Company obtained this insurance coverage to mitigate large swings in the Company's earnings in periods of extremely warm weather. CNG also proposed to set up a deferred account to allow true-ups of insurance premium costs in future rate proceedings. Bolduc PFT, pp. 7, 10.

AG proposes that the Department reject CNG's proposal to recover any costs associated with WSI because it is not a cost that ratepayers should bear. Additionally, AG points out that shareholders have already been compensated for weather in the allowed ROE. Furthermore, the Company has failed to show that the WSI provides any real benefits to ratepayers. Brief, p. 6.

OCC opposes the inclusion of WSI premiums above the line. Brief, p. 44. OCC agrees with AG that weather related risks are reflected in a company's ROE, and further states that eliminating that risk would require a fundamental reassessment of the cost of doing business. Cotton PFT, p. 12.

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ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF) ENTERGY ARKANSAS, INC. FOR APPROVAL) OF CHANGES IN RATES FOR RETAIL) ELECTRIC SERVICE)	DOCKET NO. 06-101-U ORDER NO. 10

ORDER

Summary

On August 15, 2006, Entergy Arkansas, Inc. ("EAI") filed in this Docket its Application seeking an increase in the rates it charges its Arkansas retail electric customers. As later amended, EAI seeks a retail revenue requirement increase of $106,534,000 or approximately 11.79% above its current authorized retail revenue requirement. However, based upon the evidence presented in this Docket, the Commission finds that EAI's retail revenue requirement is excessive and should be reduced by approximately $5.67 million effective as of June 15, 2007. Among other adjustments the Commission denied EAI's request for an 11.25% return on equity. Instead, the Commission set EAI's return on equity at 9.9%.

The Commission also denied EAI's request to recover a number of expenses from its ratepayers, including reducing the level of incentive pay and stock options requested by EAI by over $21 million, and by rejecting EAI's request for its ratepayers to pay for entertainment expenses which included tickets to sporting events and concerts, golf balls and golf tournament expenses, and dinners and alcohol to entertain political figures.

Further, the Commission approved EAI's request to recover costs relating to projects and organizations that promote new technologies and research and

Having found no direct or measurable benefit to ratepayers of these types of incentives, the Commission directs that these costs not be included in rates.

As to Mr. Marcus' recommendation to disallow certain perquisites provided EAI's Chief Executive Officer and the five top executives at Entergy Corp. which include club dues, financial counseling, the corporate airplane, and a tax "gross-up", the Commission finds no substantial evidence to support the recovery of such expenditures from EAI's ratepayers. The Commission finds that, as noted by Mr. Marcus, these types of expenditures are unreasonable in light of the salaries paid Entergy's top executives. The Commission therefore disallows these perquisites.

Director and Officer Liability Insurance

EAI's application included $191,580[38] in expenses for Director and Officer Liability ("D&O") Insurance. Staff witness Plunkett recommends a 50% sharing of these costs, pursuant to past Commission practice and based on the benefits that D&O insurance provides for both stockholders and ratepayers. (T. 1472) Ms. Plunkett further testifies that her recommendation does not presuppose that this expenditure is unreasonable nor does it imply it is not useful in shielding officers and directors from shareholder litigation. Rather, she continues, her recommendation recognizes that the protection afforded officers and directors is primarily a benefit to shareholders, with EAI providing little evidence of benefits to ratepayers. (T. 1505)

AG witness Marcus, noting similar Commission findings in other dockets, also recommends that these costs be shared equally between shareholders and ratepayers,

[38]Ms. Plunkett removed $95,790 in D&O Insurance from EAI per book, representing 50% of actual expenses. Actual per book expenses would be twice that amount or $191,580.

testifying that the shareholders are the beneficiaries of such policies when mismanagement is the subject of litigation by shareholders. (T. 702, 767)

Mr. McDonald recommends that the Commission reject the Staff's and the AG's proposed adjustment, arguing that the cost is "a reasonable and legitimate cost...to encourage qualified individuals to serve as a member of the board of directors." Mr. McDonald also testifies that the positions taken by Staff and the AG, on this and other similar recommendations would, if carried to every EAI cost, result in leaving EAI without "its legal right to recover the reasonable costs it incurs to provide electric service to its customers." (T. 155)

The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer.[39]

Civic Dues, Donations, and Club Memberships

Both Staff witness Plunkett and AG witness Marcus recommend disallowance of all costs related to civic club dues, club memberships, donations, and other costs such as "institutional advertising, lobbying, and donations, including support and sponsorship of local community organizations and local events." (T. 695.697, 1471) Ms. Plunkett notes that both FERC, which requires these items be listed as non-utility expenses, and

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ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN APPLICATION FOR A GENERAL CHANGE OR MODIFICATION IN CENTERPOINT ENERGY ARKLA, A DIVISION OF CENTERPOINT ENERGY RESOURCES CORP'S RATES, CHARGES, AND TARIFFS	)	DOCKET NO. 04-121-U ORDER NO. 16

ORDER

On November 24, 2004, CenterPoint Energy Arkla ("Arkla" or the "Company") filed an Application for approval of a general change or modification in its rates and tariffs.[1] Arkla's initial Application reflects that it was seeking a non-gas rate increase of $33,996,382 based on an overall non-gas revenue requirement of $182,525,265. Order No. 4, entered on December 16, 2004, suspended Arkla's proposed rates, charges, and tariffs pending further investigation by the Commission.

The parties to this proceeding are Arkla, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Arkansas Gas Consumers ("AGC"), and the Commercial Energy Users Group ("CEUG").

Arkla filed the written testimonies of Jeffrey A. Bish, Charles J. Harder, F. Jay Cummings, Samuel C. Hadaway, Alan D. Henry, Michael TheBerge, Gerald W. Tucker, Steve Malkey, Michael J. Adams, Walter L. Fitzgerald, Michael Hamilton, and John J. Spanos. The Staff filed the written testimonies of Robert Booth, Alice D. Wright, Alisa Williams[2], Don E. Martin, Gail P. Fritchman, Don Malone, L.A. Richmond, Gayle Frier, Johnny Brown, Robert H. Swaim, and Adrienne R.W. Bradley. The AG filed the written testimony of William B. Marcus.

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[1] Arkla filed additional revisions to its Application on December 27, 2004, January 10, 2005, and January 13, 2005.
[2] On August 3, 2005, the Staff filed Notice that Jeff Hilton, Manager of Staff's Audit Section, was adopting the pre-filed testimony of Staff witness Alisa Williams.

adjustments were calculated by applying the contribution rate to each party's respective payroll adjustments.

The Commission finds that the employee savings plan contribution rate should be applied to the amount determined for regular salaries and wages, overtime, and incentive pay consistent with the Commission's decision on these issues. The Commission accepted Arkla's position on regular salaries and wages, and overtime, and the Staff's position on incentive pay. (Adjustment No. IS-20).

Director's and Officer's Insurance ("D&O")

The purpose of D&O insurance is to protect officers and directors of a corporation from liability in the event of a claim or lawsuit against them asserting wrongdoing in connection with the Company's business. AG witness Marcus has two concerns with Arkla's treatment of this expense: (1) Arkla's revised allocation methodology from an asset-based to an O&M-based allocation has doubled Arkla's costs; and (2) the costs should be split on a 50-50 basis to recognize that shareholders are the major beneficiaries of policy payouts when something goes wrong. (T. 1376-1377) Arkla Witness Harder testified that the use of an O&M allocation factor is appropriate for an expense that bears no relation to the level of plant. He contended that this is a necessary business expense which enables the Company to attract and retain qualified management. (T. 152-153) Mr. Marcus disagreed, stating that the expense is not related to O&M expense either, the allocation shifts the cost to Arkla away from Arkla's electric affiliate, and utility profits are asset-based. Also, since shareholders receive the benefit of insurance payouts, they should bear a portion of the cost of buying the insurance. (T. 1465-1466) Mr.

Harder responded, contending that: (1) the AG cites no evidence to show shareholders are the primary beneficiaries of these insurance proceeds; (2) litigation often involves past stockholders, in which instance they are no different than other individuals filing tort claims; and (3) when current shareholders are involved, payments are made to the corporation in which case customers are the ultimate beneficiaries. (T. 1227-1229)

The Commission finds that Arkla has not justified its change in allocation factors nor has it justified why this expense should not be split equally between stockholders and ratepayers. Arkla did not adequately explain why, at this time, it changed from a asset-based to an O&M expense-based allocation factor. Arkla's explanation that it is an expense to attract qualified management does not establish a justifiable relationship between the cost and the cost expense allocation factor the Company used. Mr. Marcus testified that D&O insurance costs are part of general corporate overhead to protect Company profits which are largely asset-based for a utility. (T. 167-169) Mr. Marcus' testimony that this insurance protects corporate profits also lends support for sharing the insurance costs between shareholders and ratepayers. The news (T. 1040) is replete with stories about companies experiencing lawsuits by shareholders. The Commission agrees with the AG that more often than not it is the current shareholders who sue management and who receive a large portion of the proceeds from the D&O insurance payouts. Accordingly, the Commission finds that Arkla's existing asset-based allocation for D&O insurance should be maintained and that the expense for D&O insurance should be shared on a 50-50 basis between shareholders and ratepayes.

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ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ARKANSAS WESTERN GAS COMPANY FOR APPROVAL OF A GENERAL CHANGE IN RATES AND TARIFFS	))))	**DOCKET NO. 04-176-U** **ORDER NO. 6**

ORDER

PROCEDURAL HISTORY

On December 29, 2004, Arkansas Western Gas Company ("AWG" or the "Company") filed an application for approval of a general change or modification in its rates and tariffs. AWG requested that its rates be increased by $9,739,459 annually. Order No. 2, entered January 10, 2005, suspended AWG's proposed rates, charges, and tariffs pending further investigation by the Commission. Order No. 2 also established a procedural schedule for the purposes of investigating AWG's application.

The parties to this proceeding are AWG, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Northwest Arkansas Gas Consumers ("NWAGC"), and the Commercial Energy Users Group ("CEUG").

On December 29, 2004, AWG filed the Direct Testimony and Exhibits of Alan N. Stewart, Executive Vice-President of AWG, Donna R. Campbell, Manager, Rates and Regulation Department of AWG, Ricky A. Gunter, Vice President of Rates and Regulation for AWG, Glenn M. Morgan, Controller and Treasurer for AWG, and Dr. Roger A. Morin,[1] Principal, Utility Research International, in support of its application.

[1]Professor of Finance, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University, Atlanta, Georgia.

3. **Payroll Taxes**:

Differences between Staff's and the Company's calculation of payroll taxes and that of the AG relate entirely to the differences between the parties regarding the appropriate level of payroll to include in revenue requirement.

In view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for FICA and other payroll taxes is appropriate and should be adopted.

C. Fringe Benefits

As with payroll taxes, any differences among the parties for fringe benefits, including worker's compensation, medical insurance, pension expense, and employee savings plan/life insurance relate to the level of proposed payroll. Therefore, as with payroll taxes, in view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for any fringe benefits should be adopted.

D. Directors and Officers Insurance ("D & O")

The AG and AWG also disagree about inclusion in revenue requirement of 100% of the liability insurance provided by AWG and SWN for its directors and officers. Mr. Marcus argues that the major beneficiaries of this type of insurance will be the stockholders and its issuance provides no assurances of better management or decision making by officers and directors for the benefit of ratepayers. He also testifies that, in AWG's last rate case, Docket No. 02-227-U, the Commission approved a sharing of the cost between ratepayers and stockholders and he recommends that the Commission require equal sharing here. (Tr. at 72-73) Mr. Morgan disputes the AG's view of the benefits provided by this expense, noting that this type of insurance is essential

to the operation of AWG, without which it could not attract the necessary management personnel to operate the Company. (Tr. at 350)

As it has held in previous rate cases, most notably in AWG's last rate case in Docket No. 02-227-U, the Commission finds that D&O insurance benefits both stockholders and ratepayers. Therefore, as recommended by AG witness Marcus this expense should be split 50/50 between stockholders and ratepayers.

E. Uncollectible Accounts Expense

Uncollectible accounts expense has been calculated by the parties, each using a percent of uncollectible accounts to revenues applied to pro forma operating revenues as explained by Staff witness Williams. (Tr. at 1442) As discussed in the following section on the revenue conversion factor, the calculation of that percent remains in dispute. The Commission has found in its discussion of the revenue conversion factor that Staff's calculated factor for uncollectible accounts expense is appropriate. In view of that finding, the Commission, therefore, also approves Staff's calculated level of uncollectible accounts expense.

F. Revenue Conversion Factor

Revenue conversion factor issues still in contention among the parties include: the term over which uncollectible accounts as a percent of revenues are averaged in order to estimate a normal level; a proposal to incorporate late payment charge revenues in the conversion factor as a percent of revenues; and a proposal to calculate and apply separate conversion factors by class to recognize each class's distinctive level of uncollectible accounts.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner
BRENDA BURNS
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 ITS PROPERTIES THROUGHOUT ARIZONA.	)	DOCKET NO. G-01551A-10-0458

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 10, 2010

DAVID C. PARCELL
EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

My Direct Testimony provides my estimate of the cost of capital for Southwest Gas Corporation ("Southwest Gas"). My cost of capital recommendation is as follows:

	Percent	Cost	Return
Long-term Debt	47.70%	8.34%	3.98%
Common Equity	52.30%	9.0-10.5%	5.49%
Total Capital	100.00%		8.69-9.47%
			9.08% Mid-point

The only difference between my 9.08 percent recommendation and the 9.73 percent cost of capital request of Southwest Gas is the cost of common equity – I propose a cost of equity of 9.75 percent and Southwest Gas requests a cost of equity of 11.0 percent.

My 9.75 percent cost of common equity is derived from my application of three cost of equity models:

Discounted Flow	9.0-9.6%
Capital Asset Pricing Model	8.0-8.1%
Comparable Earnings	9.5-10.5%

In addition, my Direct Testimony addresses the Fair Value Rate of Return ("FVROR") which should be applied to the Fair Value Rate Base of Southwest Gas. I recommend two alternative FVROR values for Southwest Gas – a 6.69 percent value using a zero percent return on the Fair Value Increment (differential between Fair Value Rate Base and Original Cost Rate Base) and 7.02 percent value using a 1.25 percent inflation-adjusted risk-free return.

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ATTACHMENT

Resume 1

I. INTRODUCTION

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

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is 9030 Stony Point Parkway, Suite 580, Richmond, Virginia 23235.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In connection with this, I have previously filed testimony and/or testified in approximately 460 utility proceedings before some 50 regulatory agencies in the United States and Canada. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes, I have testified in a number of prior Arizona Corporation Commission ("Commission") proceedings, including the recent gas rate cases involving Southwest Gas Corporation (Docket No. G-01551A-07-0504), UNS Gas, Inc. (Docket Nos. G-04204A-05-0463 and G-04204A-08-0571), as well as electric rate cases involving Tucson Electric Power Co. (Docket No. E-01933A-07-0402 et al.), Arizona Public Service Company (Docket Nos. E-01345A-05-0816 and E-01345A-08-0172), and UNS Electric, Inc. (Docket Nos. E-04204A-06-0783 and E-04204A-09-0206). I have also testified in several water utility proceedings on behalf of the Utilities Division Staff.

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

A. I have been retained by the Utilities Division Staff to evaluate the cost of capital aspects of the current filing of Southwest Gas Corporation ("Southwest Gas" or "Company"). I have performed independent studies and am making recommendations on the current cost of capital for Southwest Gas. My testimony also responds to the Company's cost of capital proposals sponsored by Southwest Gas witness Robert B. Hevert.

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

A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 14. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What are your recommendations in this proceeding?

A. My overall cost of capital recommendations for Southwest Gas are:

	Percent	Cost	Return
Short-Term Debt	0.00%	N/A	N/A
Long-Term Debt	47.70%	8.34%	3.98%
Common Equity	52.30%	9.00-10.50%	4.71-5.49%
Total	100.00%		8.69-9.47%
			9.08% with 9.75% ROE

Southwest Gas' application requests a return on common equity of 11.0 percent and a total cost of capital of 9.73 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 the development of the appropriate capital structure. Southwest Gas' proposed capital structure is the June 20, 2010 "Arizona" capital structure ratios of the Company, which reflects the actual capital structure of the Company and adjusts this for several issues of industrial development revenue bonds issued by localities in California and Nevada.

The second step in a cost of capital calculation is a determination of the embedded cost rate of long-term debt. I have used an 8.34 percent cost for long-term debt which is contained in Southwest Gas' application.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for Southwest Gas. Each of these methodologies is applied to two groups of proxy gas utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.0-9.6%
Capital Asset Pricing Model	7-9-8.0%
Comparable Earnings	9.5-10.5%

Based upon these findings, I conclude that the cost of common equity for the proxy utilities is within a range of 9.0 percent to 10.5 percent (9.75 percent mid-point). This range is determined by the results of two of my cost of equity methodology results (i.e., DCF and CE), since these two sets of results fall within this range. I recommend that

Southwest Gas' cost of equity be the mid-point of my 9.0 percent to 10.5 percent range or 9.75 percent.

Combining the capital structure and individual cost rates, results in a weighted cost of capital for Southwest Gas. My recommended overall cost of capital range is 8.69 percent to 9.47 percent (9.08 percent with 9.75 percent cost of equity). I recommend a 9.08 percent cost of capital for Southwest Gas.

III. 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 allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily 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 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, 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 (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 (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably. 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.

From a legal perspective, while I am not a lawyer, it is my understanding that two United States Supreme Court decisions provide the controlling standards for a fair rate of return. The first decision is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> *What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A **public utility** is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably*

> *sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.* **[Emphasis added.]**

Thus, the Bluefield decision, in my opinion as a non-lawyer, established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> *The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a **balancing** of the **investor** and **consumer interests** . . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the enterprise, so as to **maintain its credit** and to **attract capital**.* **[Emphasis added.]**

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the

fundamental premise on which regulation rests; namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In Simms v. Round Valley Light & Power Company,[1] the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> *"In the Hope case the court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at."*

My testimony does not advocate that the Commission ignore the *Simms* holding in this regard, or the fair value of Southwest Gas' property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the Hope and Bluefield decisions to be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that Southwest Gas witness Hevert also cites the Hope and Bluefield cases as "guidelines" for evaluating the cost of capital for the Company. *See* Hevert Direct at pages 3-5.

[1] 294 P.2d 378 (1956).

Q. How can these parameters be employed to estimate the cost of capital for a utility?

A. Neither the courts nor economic/financial theory have developed exact and 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 cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) 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. Many state regulatory commissions reply upon the DCF and CAPM models to develop the cost of common equity for utilities.

Q. What methods did you use to determine its cost of common equity?

A. I utilized three methodologies to determine Southwest Gas' cost of common equity: the DCF, CAPM, and CE methods. I have not 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.

Q. What methods did the Company use?

A. Mr. Hevert used the DCF, CAPM and RP methods which I discuss later in my testimony.

IV. GENERAL ECONOMIC CONDITIONS

Q. Are economic and financial conditions important in determining the cost 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; and
- expected economic conditions.

My understanding is that this position is consistent with the *Bluefield* decision, in which the Court noted: "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." Bluefield, 262 U.S. at 679.

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

A. I examine 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, including the most recent cycle, allowing for an assessment of changes in long-term trends. This period also approximates the beginning and the 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 timeframe of the four prior business cycles.

A. The four prior complete cycles 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	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
2001-2009	Dec. 2001-Nov. 2007	Dec. 2007-June. 2009

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

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, I do. As I will describe below, 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, over the past four years, the economy has 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, 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." The United States and other governments have been and continue to implement 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 recovery, indicate that the impacts of the recession have been and will be felt for an extended period of time. As an example of this, both the U.S. and Arizona unemployment rates still stand at about 9 percent - near the highest rates in decades.

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

A. Schedule 2 shows several sets of relevant economic data for the cited time period. 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 United States economy ended 2007 as the sixth year of an economic expansion but, as I previously noted, 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 the increase in the unemployment rate.

The rate of inflation is also shown on pages 1 and 2. As is 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. The 0.1 percent rate of inflation in 2008, the 2.7 percent level in 2009, and the 1.5 percent level in 2010 were among the lowest levels of the past 30 years. This is indicative of virtually no inflation, which is reflective of lower capital costs.

Q. What have been the trends in interest rates over the four business cycles (1975-2010)?

A. Pages 3 and 4 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 declined substantially in conjunction with inflation rates during the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their then-lowest levels since the 1960s.

Most recently, the Federal Reserve has lowered the Federal Funds rate (i.e., short-term rate) on several occasions; currently it is 0.25%, an all-time low. In 2008, there was a pronounced decline in short-term rates and long-term U.S. Treasury Securities yields, and an increase in corporate bond yields, reflecting the "flight to safety," wherein there was a reluctance of investors to purchase common stocks and corporate bonds while concomitantly moving their money into very safe government bonds. Since then, as seen

on page 3, bond yields have declined to their lowest levels in the past four business cycles and in more than 35 years, with lending rates remaining at historically low levels.

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

A. Pages 5 and 6 show several series of common stock prices and ratios. These indicate that share 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 current financial crisis saw stock prices decline precipitously. Stock prices in 2008 and early 2009 were down significantly from 2007 levels, reflecting the financial/economic crises. Beginning in the second quarter of 2009, prices have recovered somewhat but still remain well below the levels prevailing prior to the current recession.

Q. What conclusions should the Commission draw from your 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 the increase in corporate bond yields are evidenced in the recent "flight to safety." On the other side of this "flight to safety" is the negative perception of the recent decline, which has 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, including stock returns. Finally, as noted above, interest rates currently are at levels below those prevailing prior to the financial crisis of late 2008-early 2009 and are near the lowest level in the past 35 years. This "flight to safety" does not represent an increase in the cost of capital; rather, it more properly reflects an "availability of capital"

since investors were unwilling to invest in many assets other than U.S. Treasury bonds. Further reflecting a decreased cost of capital, utility bond rates are at their lowest levels in the past four business cycles.

V. SOUTHWEST GAS' OPERATIONS AND RISKS

Q. Please summarize Southwest Gas and its operations.

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. Southwest Gas also owns Paiute Pipeline Co., as well as NPL Construction Company. Until 1996, Southwest Gas owned PriMerit Bank (formerly Nevada Savings and Loan).

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	Baa2
Standard & Poor's	BBB
Fitch	BBB

As this indicates, Southwest Gas' bonds presently carry triple B ratings by the three rating agencies who rate the Company's debt.

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

A. This is also depicted on Schedule 3. As this Schedule indicates, the Company's debt ratings were raised by S&P in 2009 and by Moody's in 2010.

Q. How have the rating agencies recently described Southwest Gas?

A. An example of this is provided in a May 27, 2010 report on Southwest Gas by Moody's, wherein Company's ratings were raised. In this report, Moody's stated:

> *New York, May 27, 2010 -- Moody's Investors Services upgraded the senior unsecured rating of Southwest Gas Corporation (Southwest) to Baa2 from Baa3. The rating outlook is stable.*
>
> *"The upgrade follows improvements in Southwest's cash flow credit metrics which we believe will be sustained for the foreseeable future," said Kevin Rose, Vice President & Senior Analysts. "Even in the face of an economic downturn in Southwest's primary service territories, financial results for 2009 were generally robust", Rose added. The improvement comes primarily as a result of recent rate relief in all of Southwest's regulatory jurisdictions, and the company's continued effort to minimize costs.*
>
> . . .
>
> *The rating upgrade also recognizes signs of improvements in Southwest's regulatory environment where we remain cautiously optimistic about, primarily in Nevada (34% of operating margins) and potentially Arizona (55% of operating margins). In Nevada, the Public Utilities Commission of Nevada approved the company's request for the implementation of decoupling mechanism in its April 2009 general rate case, pursuant to the decoupling legislation approved in 2008. Furthermore, the Arizona Corporation Commission (ACC) has conducted a series of workshops in 2009 and 2010 to evaluate the possibility of implementing a decoupling mechanism in Arizona, and is currently reviewing related proposals submitted by utilities in its jurisdiction, including Southwest. The final ACC decision is expected sometime later this year.*

Q. As noted by Moody's, Southwest Gas is requesting certain regulatory cost-recovery mechanisms in this proceeding. What are the cost of capital implications of the implementation of these?

A. It is my understanding that the Company is requesting approval to implement certain new rate design proposals that, if approved, will be risk-reducing. These proposals include an Energy Efficiency Enabling Provision ("EEP"), which provides for full revenue decoupling for all of Southwest Gas' customers except for its largest general service customers.

Q. How are these proposals risk-reducing to the Company?

A. These rate design proposals, if approved, are risk-reducing to Southwest Gas since the Company's revenues, and income, will be essentially insulated from variations due to weather and usage. The net effect of these proposals is to transfer a significant portion of the Company's risks from its shareholders to its ratepayers.

Q. Is the Staff recommending approval of these new proposals which would transfer significantly more risk to ratepayers?

A. Other Staff witnesses are addressing the Company's new risk-reducing rate design proposals. It is my understanding that the Staff is recommending a different proposal. However, I want to point out that if the Commission should adopt either of them, it would reduce the Company's risk, normally a consideration in the cost of equity estimation.

Q. Are you proposing an adjustment to Southwest Gas' cost of equity if either of the proposed decoupling mechanisms is approved?

A. No, I am not proposing an adjustment if decoupling is approved for Southwest Gas. I have made such recommendations in other rate proceedings based upon the reduction in risk associated with decoupling. However, in this proceeding I am not making such a recommendation. This is the case because the Commission has indicated in its *Final ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, Docket Nos. E-00000J-08-0314 and G-00000C-08-0314* that decoupling should be implemented for an initial three-year period and that more detailed evaluations of its impact, including cost of capital implications, be conducted at the end of the three year period.

VI. 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 Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help 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. 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 first examined the 1995-2010 capital structure ratios of Southwest Gas. Schedule 4 shows the historic capital structure ratios of the Company. The respective common equity ratios over the past five years are as follows:

	Inc'l S-T Debt	Exc'l S-T Debt
2006	38.9%	38.9%
2007	41.0%	41.2%
2008	43.5%	44.5%
2009	46.4%	46.4%
2010	49.3%	50.9%

This indicates a significantly rising common equity ratio over this period. In fact, the most current common equity ratios exceed the levels of five years ago by over 10 percentage points. Also shown on Schedule 4 are the Company's common equity ratios going back to 1995. As this indicates, Southwest Gas maintained a very low equity ratio (i.e., 30 percent to 35 percent) until about 2006. This significant increase in the Company's equity ratio is indicative of a decline in financial risk.

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

A. I have prepared Schedule 5 to make this comparison. Page 1 of this schedule shows the 2006-2010 capital structure ratios of the Value Line group of LDC's, excluding short-term debt. Page 2 of Schedule 5 indicates the 2006-2010 capital structure ratios for this group, including short-term debt. The average ratios are:

	Inc'l S-T Debt	Exc'l S-T Debt
2006	47%	50.5%
2007	46%	52.2%
2008	45%	53.8%
2009	49%	54.7%
2010	49%	57.7%

These common equity ratios (including short-term debt) are similar to those of the most recent Southwest Gas ratios.

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

A. The Company requests use of the following capital structure:

Capital Item	Percent
Long-Term Debt	47.7%
Short-Term debt	0.0%
Common Equity	52.3%

This reflects the Company's actual capital structure as of June 30, 2010, adjusted to remove certain industrial development bonds issued in Nevada and California.

Q. What is the recent history of the Company's capital structure request?

A. In Decision No. 68487 (February 23, 3006), this Commission approved use of a hypothetical capital structure for the Company that contained 55 percent long-term debt, 5 percent preferred stock, and 40 percent common equity. This 40 percent common equity ratio exceeded the actual test period equity ratio and was apparently intended to be an "incentive" for the Company to raise its actual equity ratio. As stated by Mr. Wood in the most recent rate proceeding (Docket No. G-01551A-07-0504), in its Decision in the 2004 proceeding, the Commission directed the Company to submit a "recapitalization plan" explaining how it intended to achieve an actual 40 percent common equity ratio.

In the most recent case (Docket No. G-01551A-07-0504), the Company again requested a hypothetical capital structure, with an even higher common equity ratio, at 45 percent. In that proceeding, Southwest Gas witness Wood described this as a "target" common equity ratio and he indicated (page 9) "it is reasonable to assume that the Company will achieve 45 percent common equity ratio…." In that proceeding, the Commission did not adopt Southwest Gas' proposed hypothetical capital structure (with 45 percent common equity) but rather used the Company's actual capital structure (with 43.44 percent common equity).

Q. Has the Company raised its equity ratio since the last case?

A. Yes, it has. The actual test period capital structure of the Company contains some 52.3 percent common equity. It should be recognized that this reflects a reduction in the financial risk faced by Southwest Gas.

Q. What capital structure have you used in your analyses?

A. I have utilized the adjusted test period capital structure of the Company in my analyses. These are shown on my Schedule 1. I note that I normally include short-term debt in my cost of capital calculations and I understand that this Commission also uses short-term debt. However, in this case, it appears that Southwest Gas did not have any short-term debt at the end of the test period, so I did not include any in the capital structure.

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

A. I have utilized the 8.34 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 rate of debt is 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 which 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.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the cost of common equity for Southwest Gas?

A. Southwest Gas is a publicly-traded company. Consequently, it is possible to directly apply cost of equity models to this entity. However, it is customary to analyze groups of comparison or "proxy" companies as a substitute for Southwest Gas to determine its cost of common equity. I have developed such a proxy group for comparison to Southwest

Gas. I note that Southwest Gas witness Hevert has used a set of proxy companies in his cost of equity analysis.

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 50 percent or greater;
(4) S&P and/or Moody's bond ratings of Triple-B or greater;
(5) Common equity ratio of about 40 percent to 60 percent; and,
(6) Value Line Safety of 1, 2, or 3.

Of the gas distribution companies followed by Value Line, nine companies meet these criteria. However, one of these – Nicor, is being acquired by AGL Resources. As a result, I have not included the former company in my proxy group. This group, which reflects a representative sample of local distribution companies ("LDCs"), is a proper proxy for Southwest Gas.

I have also considered the group of nine natural gas utilities that Southwest Gas witness Hevert utilized in his testimony. These are similar to the group of eight proxy companies I utilize. However, he includes New Jersey Resources and Nicor in his group and does not include Southwest Gas.

I note that, by developing my own group of proxy companies, used in conjunction with the groups of proxy companies utilized by Southwest Gas witness Hevert, I have given consideration to the Company's view as to the appropriate composition of the proxy companies for Southwest Gas.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. What is the theory and methodological basis of the discounted cash flow model?

A. The DCF model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity 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. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework cost of capital is derived by the following formula:

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

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 have combined the current dividend yield for each group of 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 believe the most appropriate dividend yield component is the version listed below:

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

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

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (February - April, 2010). 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 exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2006-2010 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historic growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS") (per Value Line);
3. 2011, 2012, and 2014-2016 projections of earnings retention growth (per Value Line);
4. 2008-2010 to 2014-2016 projections of EPS, DPS, and BVPS (per Value Line); and,

5. 5-year projections of EPS growth as reported in First Call (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 groups 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 should 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 of this schedule show the growth rate for the two groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and high values. These results can be summarized as follows:

	Mean	Median	Mean Low[2]	Mean High[3]	Mean Low[2]	Median High[3]
Proxy Group	8.5%	8.0%	8.2%	9.0%	7.8%	9.0%
Hevert Group	8.4%	8.2%	7.5%	9.3%	7.5%	9.6%

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 groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

[2] Using only the lowest growth rate.
[3] Using only the highest growth rate.

The DCF results in Schedule 7 indicate average (mean and median) DCF cost rates of 8.0 percent to 8.5 percent. The highest DCF rates (i.e., using the highest growth rates only) are 9.0 percent to 9.6 percent.

Q. What do you conclude from your DCF analyses?

A. These analyses reflect a broad DCF range of 8.0 percent to 9.6 percent for the proxy groups. I believe that 9.0 percent to 9.6 percent reflects the proper DCF cost for the proxy groups at this time. I give less weight to the lower end and the mean/median results. I focus on the higher end of the DCF results because it is apparent that current DCF results for gas distribution companies are low by historic stands. Nevertheless, my DCF conclusion is well within the range of results.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Please describe the theory and methodological basis of the capital asset pricing model.

A. The CAPM is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The 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.

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

Rm-R_f = market risk premium

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

Q. What groups of companies have you utilized to perform your CAPM analyses?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

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

A. The first term 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 (February – April, 2010) for 20-year U.S. Treasury bonds. Over this three month period, these bonds had an average yield of 4.32 percent.

Q. What is beta and what betas did 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 of 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 utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. How did 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 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 have 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 return on equity for the S&P 500 group for the period 1978-2009 (all available years reported by S&P). This schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as 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 this version of the risk premium is about 6.2 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2010 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	11.9%	5.9%	6.0%
Geometric	9.9%	5.5%	4.4%

I conclude from this that the expected risk premium is about 5.54 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate because investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 9 shows my CAPM calculations. The results are:

	Mean	Median
Proxy Group	8.0%	7.9%
Hevert Group	8.0%	7.9%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The CAPM results collectively indicate a cost of about 8.0 percent for the two groups of proxy utilities.

X. COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost.

As previously noted, the cost of capital 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, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle underlying regulation.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for examining returns on book 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 consistent with the rate base methodology generally used to set utility rates.

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

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner, it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect 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 cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my analysis uses prospective returns and thus is not confined to historical data.

Q. What time periods have you examined in your CE analysis?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2010 (i.e., past nineteen 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 cost of equity I have focused on two periods: 2002-2010 (the last business cycle) and 1992-2001 (the prior complete business cycle).

Q. Please describe your CE analysis.

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

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

	Proxy Group	Hevert Group
Historic ROE		
Mean	11.0-11.2%	12.3-12.5%
Median	11.4-11.6%	12.2-12.3%
Historic M/B		
Mean	170-172%	185-188%
Median	169-174%	185%
Prospective ROE		
Mean	10.9-11.3%	11.6-11.8%
Median	10.0-10.5%	10.0-11.0%

These results indicate that historic returns of 11.0 percent to 12.5 percent have been adequate to provide market-to-book ratios of 169 percent to 188 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2011, 2012 and 2014-2016 are within a range of 10.0 percent to 11.8 percent for the utility groups. These relate to 2010 market-to-book ratios of 160 percent or greater.

Q. Have you also reviewed earnings of unregulated firms?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, because 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 returns on equity and market-to-book ratios for the S&P 500 group over the past eighteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 12.1 percent to 14.7 percent with market-to-book ratios ranging between 265 percent and 341 percent.

Q. How can the above information be used to estimate the cost of equity for Southwest Gas?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized 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 cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industry with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

Q. What return on equity is indicated by the CE analysis?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 9.5 percent to 10.5 percent (10.0 percent mid-point). Recent returns of 11.0 percent to 12.5 percent have resulted in market-to-book ratios of 170 and greater. Prospective returns of 10.0 percent to 11.8 percent result in anticipated market-to-book ratios of 160 percent or over. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. Accordingly, an earned return of 9.5 percent to 10.5 percent should result in a market-to-book ratio of over 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of 11 percent to 12 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

In applying the CE analysis, it also is important to recognize recent trends. My recommended range of 9.5 percent to 10.5 percent is further supported by the actual newly

authorized returns on common equity from 2002 through 2010, which are as follows for U.S. natural gas utilities as authorized by state regulatory agencies:

Year	ROE
2002	11.16%
2003	11.05%
2004	10.67%
2005	10.50%
2006	10.44%
2007	10.21%
2008	10.36%
2009	10.15%
2010	10.06%

Source: Exhibit No. ___ (RBH-6) of Company Filing.

Please also note that my CE analysis is not based on a mathematic formula approach, as are the DCF and CAPM methodologies. Rather, it is based on recent trends and current conditions in equity markets. Further, it is based on the direct relationship between returns on common stock and market-to-book ratios of common stock. In utility rate setting, a fair rate of return is generally based on the utility's assets (i.e., rate base) and the book value of the utility's capital structure. As stated earlier, maintenance of a financially stable utility's market-to-book ratio at 100%, or a bit higher, is fully adequate to maintain the utility's financial stability. On the other hand, a market price of a utility's common stock that is 150 percent or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected earnings do not directly translate into a utility's reasonable cost of equity. Rather, they must be viewed in relation to the market-to-book ratios of the utility's common stock.

My 9.5 percent to 10.5 percent CE recommendation reflects the fact that historic equity returns of 11.0 percent to 12.5 percent have resulted in market-to-book ratios of 170

percent to 190 percent, which demonstrates that the equity returns exceed the cost of capital. Likewise, projected returns of about 10.0 percent to 11.8 percent relate to 2010 market-to-book ratios of 160 percent and over. My 9.5 percent to 10.5 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for Southwest Gas. Rather, it is based on current market conditions and the proposition that ratepayers should not be required to pay rates based on earnings levels that result in excessive market-to-book ratios.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

Discounted Cash Flow	9.0-9.6%
Capital Asset Pricing Model	7-9-8.0%
Comparable Earnings	9.5-10.5%

My overall conclusion from these results is a reasonable range of 9.0 percent to 10.5 percent, which focuses on the respective model findings for the DCF and CE analyses. The mid-point of this range is 9.75 percent.

Q. What cost of equity do you recommend for Southwest Gas?

A. I recommend a cost of equity of 9.75 percent.

Q. It appears that your CAPM results are somewhat lower than your DCF and CE results. Does this indicate that the CAPM results should not be considered at this time?

A. No, this is not the case. Although my recommended range is above the CAPM results, I have not disregarded the CAPM results. It is apparent that the CAPM results are lower than the DCF results, as well as being lower than CAPM results in recent years. The two reasons for this are the current relatively low yields on U.S. Treasury bonds (i.e., risk-free rate) and a lower risk premium that reflects the decline in stock prices of the past few years. Each of these factors is a result of the recent financial crisis and concurrent recession. As a result, I do not give significant weight to the CAPM results in deriving my return on equity recommendation. On the other hand, the same factors that are creating downward pressure on the CAPM results are also indicative of a decline in capital costs in the economy at this time.

Q. Your 9.75 percent return on equity recommendation is less than the 10.0 percent authorized by the Commission in the last rate proceeding of Southwest Gas. Is a reduction in the Company's authorized return on equity appropriate at this time?

A. Yes, it is. The 10.0 percent cost of equity found appropriate by the Commission in Docket No. G-01551-07-0504 was applicable to a capital structure containing 43.44 percent common equity, which is well below the 52.3 percent common equity contained in the current cost of capital request of the Company. The currently higher equity ratio is reflective of a reduced level of financial risk for the Company, which is also indicative of a reduction in the cost of common equity. I have also noted that authorized common equity cost rates are recently lower than was the case three years ago in Southwest Gas' last rate proceeding. This is also reflective of a decline in the cost of common equity. In this regard, I note that even the Company acknowledges a lower cost of common equity,

as its currently-requested 11.0 percent cost of equity is less than the 11.25 percent cost of equity requested in the prior proceeding.

XII. TOTAL COST OF CAPITAL

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

A. Schedule 1 reflects the total cost of capital for the Company using the actual capital structure and cost of long-term debt, and my common equity cost recommendations. The resulting total cost of capital is a range of 8.69 percent to 9.47 percent (9.08 percent with 9.75 percent cost of equity). I recommend that this 9.08 percent total cost of capital be established for Southwest Gas.

Q. Does your cost of capital recommendation provide the Company with a sufficient level of earnings to maintain its financial integrity?

A. Yes, it does. Schedule 13 shows the pre-tax coverage that would result if Southwest Gas earned my cost of capital recommendation. As the results indicate, my recommended range would produce a coverage level within the benchmark range for a Single A rated utility. In addition, the debt ratio (which reflects the Company's proposed capital structure) is within the benchmark for a Single A rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. Have you reviewed the cost of capital testimony of Southwest Gas witness Robert B. Hevert?

A. Yes, I have.

Q. Please summarize your understanding of Mr. Hevert's cost of equity recommendations.

A. Mr. Hevert proposes an equity return for Southwest Gas of 11.0 percent. This recommendation is based upon the results of several sets of DCF, CAPM, and risk premium models, as is shown in Table 7 on page 46 of his direct testimony, and as summarized below:

	Mean Low	Mean	Mean High
Constant Growth DCF			
30-Day Average	7.43%	8.39%	9.55%
90-Day Average	7.54%	8.50%	9.65%
180-Day Average	7.59%	8.55%	9.71%
Multi-Stage DCF			
30-Day Average	10.08%	10.28%	10.48%
90-Day Average	10.36%	10.48%	10.60%
180-Day Average	10.49%	10.58%	10.66%

Supporting Methodologies

	Near Term 30-Year (3.75%)	Long-Term Projected 30-Year Treasury (4.22%)
CAPM - Current Calculated Beta		
Sharpe Ratio Derived Market Risk Premium	12.40%	12.87%
Market DCF Derived Market Risk Premium	11.94%	12.42%
CAPM - Average Historical Beta		
Sharpe Ratio Derived Market Risk Premium	10.41%	10.88%
Market DCF Derived Market Risk Premium	10.06%	10.53%

Treasury Yield Plus Risk Premium

	Mean Low	Mean	Mean High
Risk Premium	10.23%	10.55%	11.01%

Mr. Hevert maintains that his 11.0 percent recommended return on equity is "based on the various quantitative and qualitative analyses" in his testimony. *See* Hevert Direct at 45, lines 8-9. However, it is apparent that Mr. Hevert's return on equity recommendation is not supported by his analyses.

Q. Do you have any general observations about Mr. Hevert's analyses and conclusions?

A. Yes, I do. It is apparent from Mr. Hevert's Table 7 (as reproduced above) that his 11.0 percent return on equity can only be rationalized by use of the "Current Calculated Beta" CAPM results and the "Mean High" risk premium. Mr. Hevert's "Mean" Constant Growth DCF results indicate 8.39 percent to 8.55 percent results, while even his "Mean High" constant Growth DCF results are 9.71 percent or less. In addition, all of Mr. Hevert's Multi-Stage DCF results indicate a cost of equity of about 10.0 percent to 10.7 percent. I will show below that even these results are over-stated.

I also note that the historic beta CAPM and Risk Premium results using "near-term" U.S. Treasury Bond yields in Mr. Hevert's Table 7 are within a range of about 10.0 percent to 10.5 percent. I will also show that even these results are over-stated.

Q. What are your disagreements with Mr. Hevert's constant growth DCF analyses?

A. Mr. Hevert's Constant Growth DCF analyses are based on 30-day, 90-day and 180-day average stock prices for the periods ending October 8, 2010, annualized dividends per share as of October 8, 2010 and the average of Value Line, First Call, and Zack's EPS projections and projected Retention Growth rates. His DCF analyses are applied to his group of nine natural gas distribution utilities.

Mr. Hevert's Constant Growth DCF analyses are shown on his Exhibit RBH-1. It is apparent from this that his "Low DCF ROE" for each proxy company reflects the dividend yield and the lowest of the four growth rates he considers. His "Mean DCF ROE" considers the average of all four growth rates; and the "High DCF ROE" only considers the highest growth rate for each company. Stated differently, the "Mean High DCF" result considers only the highest of the four growth rates for each company and ignores the other three growth rates. Thus, the "Mean High DCF" result for one proxy company may reflect only the Zacks EPS Growth, while the "Mean High DCF" result for another proxy company may reflect only the BR + SV (Retention Growth) growth result. This implicitly assumes that investors *only* consider the most optimistic growth rate for each individual company in making investment decisions.

It is further apparent that Mr. Hevert's methodology exclusively focuses on three of the four growth rates for at least one proxy company. For example, his "High DCF ROE" for his nine proxy companies relies exclusively on the following growth rates:

AGL Resources	First Call EPS
Atmos Energy	Value Line EPS
Laclede Group	BR + SV
New Jersey Resources	BR + SV
Nicor	BR + SV
Northwest Natural Gas	BR + SV
Piedmont Natural Gas	Zacks EPS
South Jersey Industries	BR + SV
Southwest Gas	BR + SV

Q. Is it appropriate to focus on the highest growth rate, on a company-to-company basis, to determine the cost of equity for a natural gas distribution company such as Southwest Gas?

A. No. It is neither realistic nor proper to focus on a single growth rate in a DCF context, especially when one "cherry picks" the highest growth rate for each company from among the different growth rate indicators that reflect the highest growth rate for each company.

Q. Are there any other problems with Mr. Hevert's constant growth DCF analyses?

A. Yes. Even though Mr. Hevert purports to examine four alternative growth rates in his Constant Growth DCF analyses, in reality each of the four focuses on a single statistic: analysts' forecasts of EPS. Three of the four growth rates directly use EPS forecasts including those by Zacks, Value Line and First Call. The other growth rate, BR + SV, uses EPS forecasts as a component. As a result, all of Mr. Hevert's Constant Growth rates in reality focus on EPS forecasts of security analysts.

Q. Why is it improper to rely on EPS forecasts in a DCF analysis?

A. There are several reasons why it is not proper to rely on analysts' forecasts in a DCF context. First, it is not realistic to believe that investors rely exclusively on a single factor, such as analysts' forecasts, in making their investment decisions. Investors have an abundance of available information to assist them in evaluating stocks and EPS forecasts are only one of many such statistics.

Second, Value Line – one of Mr. Hevert's sources of EPS projections – publishes a large number of individual company data and ratios. Presumably these are published for the consideration of subscribers/investors. It is also apparent that Value Line publishes both

historic and forecast data. Yet, Mr. Hevert considers only *one* factor and only the *forecast* version of this factor.

Third, the vast majority of information available to investors, by both individual companies in the form of annual reports and offering circulars, and by investment publications such as Value Line, is historic data. It is neither realistic nor logical to maintain that investors only consider projected (estimated) data to the exclusion of historic (actual) data.

Fourth, there have been a number of academic studies that indicate that analysts' forecasts have been overly-optimistic in the past. See, for example a 1998 article in *Financial Analysts Journal*, Vol. 54, No. 6, Nov./Dec. 1998, 35-42, titled "Why So Much Error In Analysts' Earnings Forecasts?" by Vijay Kumer Chopra. In this article, the author concluded "Analysts' forecasts of EPS and growth in EPS tend to be overly optimistic." He reasoned that analysts' forecasts of EPS over the past 13 years have been more than twice the actual growth rate. Investors are aware of the propensity of analysts to over-estimate EPS forecasts. In addition, the presumption that investors rely *only* on a single projection, as was made by Mr. Hevert, implies that investors are unsophisticated and unable to make their own decisions. This also is not realistic.

Fifth, the experience over the past three years should be a clear signal to investors that analysts cannot accurately predict EPS levels. Few, if any, analysts predicted the decline in security prices in 2008 and 2009. Thus, relying only on forecasted EPS levels, and not also looking at historic EPS levels, will not produce accurate results.

In summary, investors are now very much aware of recent scandals involving security analysts' conflicts of interest, including the Enron and WorldCom debacles, that have resulted in settlements, fines, and public admonishments, as well as other negative connotations related to the reliability of analysts' forecasts. These problems clearly call into question the reliance of analysts' forecasts as the *only* source of growth in a DCF context. As a result, the landscape has changed in recent years and investors have ample reasons to doubt the reliability of such forecasts at the present time. In any event, it is problematic to rely exclusively on such forecasts in determining the cost of equity for Southwest Gas.

Q. What is your response to Mr. Hevert's "multi-stage" DCF analyses?

A. Mr. Hevert's Multi-Stage DCF results are shown on his Exhibit No. RBH-3. For each of the nine proxy companies he uses, the third growth stage (*i.e.,* Terminal Growth) is an estimate of the long-term growth rate of Gross Domestic Product ("GDP"). Mr. Hevert's estimate of long-term GDP growth (5.83 percent) is determined by combining the "real" GDP growth rate from 1929 through 2009 with projections of inflation by Blue Chip Economic Indicators and the Energy Information Administration ("EIA").

There are three problems associated with Mr. Hevert's long-term GDP component in his DCF analysis. First, Mr. Hevert refuses to even consider historic growth in his Constant Growth DCF analyses and as the short-term growth rates in his Multi-Stage DCF analyses, yet he focuses *exclusively* on historic values of real GDP growth in his Multi-Stage DCF analyses. This is an inconsistency in his testimony. It also is indicative of his practice of only focusing on the highest growth rates in his cost of capital analyses.

Second, the EIA publication cited by Mr. Hevert also contains an estimate of long-term real GDP growth. *See*, Hevert Direct at 24, lines 1-3. Mr. Hevert could have consistently taken the long-term GDP estimate from EIA and combined this with EIA's long-term estimate of CPI. Had he done so, the real GDP growth rate would have been 2.7 percent, rather than the 3.28 percent Mr. Hevert employs. Schedule 14 shows this EIA GDP growth rate.

Third, Mr. Hevert improperly combines the CPI with real GDP growth. Since he is allegedly focusing on the long-term growth rate of the economy, he should have used the "GDP Chain-Type Price Index," which is specifically developed for use with GDP. I note that the EIA projections of this index (1.8 percent), also shown on Schedule 14, are lower than those for CPI (2.4 percent).

Q. What would be the impact of Mr. Hevert using a long-term growth rate as the third stage of his multi-stage DCF analyses?

A. The impact would be to produce lower results than those contained in his Table 7.

Q. You previously noted that Mr. Hevert's CAPM results are his highest. Do you have any response to his CAPM analyses?

A. Mr. Hevert recognizes there are published sources of the beta component of the CAPM equation. *See* Hevert Direct at 28, lines 10-12. However, unlike investors who subscribe to the sources of the published betas *i.e.,* Value Line and Bloomberg, Mr. Hevert substitutes his own "calculated" betas. His "calculated" betas only consider twelve months of stock price data (page 28, lines 23-26) and are higher (average of 0.876) than those published by Value Line and Bloomberg (0.67, as shown on Mr. Hevert's Exhibit RBH-4, Page 8).

Q. Do you agree with Mr. Hevert's risk premium component of the CAPM?

A. No. Mr. Hevert utilizes two risk premium values: 9.42 percent and 9.94 percent. *See,* Hevert Direct at 27 and 28. Both of these greatly exceed the long-term experience (*e.g.,* 1929 to present) of investment return differential between common stocks and government bonds, as described earlier in my testimony.

Q. Do you have any responses to Mr. Hevert's risk premium analyses?

A. Yes. Mr. Hevert's risk premium approach compares the allowed ROEs for natural gas distribution utilities and 30-Year U.S. Government Bond yields over the period 1992 to the third quarter of 2010. He then performs a regression analyses to develop an expected relationship between 30-Year U.S. Government Bond yields and the cost of equity for natural gas distribution companies. He apples this regression result (page 33) to the two projections of 30-Year US Treasury Bonds cited in his CAPM analyses (*i.e.,* 3.75 percent and 4.22 percent) and correspondingly arrives at his 10.23 percent to 11.01 percent conclusion.

It is apparent from Mr. Hevert's Exhibit No. RBH-6 that the actual authorized returns on equity for gas distribution utilities have averages well below the 10.23 percent to 11.01 percent he proposes. In contrast, his exhibit shows recent (*i.e.,* 2007 to present) average quarterly authorized returns on equity between 9.88 percent and 10.57 percent. As shown on Mr. Hevert's own exhibit, over the past six quarters, the average authorized returns on equity have been:

2009 Q2	10.19%
2009 Q3	9.88%
2009 Q4	10.27%
2010 Q1	10.24%
2010 Q2	9.99%
2010 Q3	9.93%
Average	10.08%

Q. Mr. Hevert also "considers" flotation costs in his 11.0 percent conclusion. Do you agree with the inclusion of flotation costs in determining Southwest Gas return on equity?

A. No. It is not proper to include a flotation cost adjustment in determining the cost of equity for Southwest Gas. Even though Mr. Hevert maintains that he does not make an "explicit adjustment" for flotation costs, he does "consider" these impacts in reaching his conclusion. *See* Hevert Direct at 41, lines 8-10. As a result, he is still making an "implicit adjustment" for flotation costs.

XIV. FAIR VALUE RATE BASE COST OF CAPITAL

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

A. It is my understanding that Southwest Gas is requesting that the fair value of its rate base be used in developing its rates. The Company does not appear to be requesting that its weighted cost of capital be applied to the level of its fair value rate base.

Q. What is your understanding of the Commission's procedure for utilizing the fair value of rate base in setting utility rates?

A. My "non-legal understanding" is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree that this implies that the Company's cost of capital must be applied to the fair value of the rate base.

Q. What is your understanding of the use of fair value rate base in Arizona?

A. My "non-legal understanding" is based in part on the 2006 Arizona Court of Appeals in the Chaparral City case that indicates that the Court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base . . . ." The decision goes on to make the following statement: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." It is correspondingly the purpose of this section of my testimony to recommend an "appropriate methodology" for use in conjunction with a FVRB.

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether a cost of capital developed for application to an original cost rate base is consistent with a fair value rate base?

A. Yes, I do. It is my personal experience, based upon nearly 40 years of providing cost of capital testimony, that the concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is 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. In my "non-legal" opinion, both the Commission and Appeals Court have also recognized this lack of compatibility between a customary weighted cost of capital ("WCOC") analysis and FVRB.

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. Based on your experience as a cost of capital witness over the past 40 years, do you have a suggestion as to how to account for the use of a FVRB in setting rates for Southwest Gas?

A. Yes, I do. Since the increment between fair value rate base and original cost rate base 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 made such a proposal in this proceeding?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to Southwest Gas' FVRB.

Item	Percent[4]	Cost	Fair Value Return
Short-term Debt[5]	0.00%	--	--
Long-term Debt	35.13%	8.34%	2.93%
Common Equity	38.52%	9.75%	3.76%
FVRB Increment[6]	26.35%	0.00%	0.00%
Total FVRB Capital	100.00%		6.69%

Applying this 6.69 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and

[4] As shown in Testimony of Utilities Division Staff witness Ralph Smith.
[5] As is the case for my cost of capital calculations, no short-term debt is included since the Company had none at the end of the test period.
[6] FVRB minus OCRB.

economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB. Staff also refers to this as Method 1.

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

A. Yes, I have. 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.

Q. What is the proper cost rate to apply to the Fair Value Increment?

A. As I indicated previously, from a financial perspective, it should not be necessary to provide for <u>any</u> return on the Fair Value Increment since this is not investor-supplied capital. However, the Commission may 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 Fair Value Increment 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 Fair Value Increment, the proper return should be no larger than the real (i.e., after inflation is removed) risk-free rate of return.

Q. What is the risk-free return?

A. The risk-free return is, in financial terms, the return on an investment that carries little or no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with short-term maturities usually being used as the risk-free rate. Over the past several months, various maturities of U.S. Treasury securities have yielded from about 0.2 percent (short-term) to 4.5 percent (long-term) in nominal terms. I also note that 2011 forecasts of long-term U.S. Treasury securities are about 4.0 percent to 5.0 percent. As a result, I use 4.5 percent as the nominal risk-free rate.

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

A. The concept of real rates involves the removal of the rate of inflation from the nominal risk-free rate. In 2010, the rate of inflation, as measured by the Consumer Price Index ("CPI"), was 1.5 percent. Forecasts of the CPI for 2011-2012 are about 2 percent or less. As a result, I propose to use a 2 percent inflation rate for computing the real risk-free rate, which is computed as follows:

Nominal Risk-Free Rate	4.5%
Less: Inflation Rate	2.0%
Equals: Real Risk-Free Rate	2.5%

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 Fair Value Increment 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 FVRB Increment.

Q. What return on the Fair Value Increment do you recommend in your alternative FVROR proposal?

A. My alternative FVROR proposal ("Method 2") incorporates a return on the Fair Value Increment with a maximum value of 2.5 percent, as developed above. However, I wish to emphasize that this 2.5 percent value is the maximum value that could be applied to the FVRB Increment. In reality, any value between zero percent and 2.5 percent could be used as the cost rate on the FVRB Increment. As I stated above, this Fair Value Increment return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, an above-zero cost rate for the fair value increment represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. I would propose the mid-point of this range, or 1.25 percent.

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

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

Capital Item	Percent	Cost	Return
Short-term Debt	0.00%	--	--
Long-term Debt	35.13%	8.34%	2.93%
Common Equity	38.52%	9.75%	3.76%
FVRB Increment	26.35%	1.25%	0.33%
Total	100.00%		7.02%

As shown in the above table, this alternative proposal provides for a non-zero return on the Fair Value Increment of Southwest Gas, and provides for an overall fair value rate of return of 7.02 percent on the FVRB.

Q. Of the two alternative proposals for determining the fair value rate of return that should be applied to the FVRB, which one do you believe is more appropriate and why?

A. From a financial perspective, I believe the first proposal (i.e., zero-cost for FVRB Increment) is most appropriate. This proposal is consistent with financial principles and would fully compensate the Company's investors for their investment. In addition, this proposal utilizes the FVRB of the Company. On the other hand, if the Commission were to determine that a non-zero return on the Fair Value Increment is desirable, the alternative (i.e., a 1.25% cost-rate for the FVRB increment) is not inappropriate. It is my understanding that this second alternative was utilized by the Commission in Southwest Gas' last rate proceeding.

Q. Do these proposals provide for a return on the FVRB of Southwest Gas?

A. Yes, they do.

Q. Will Staff continue to evaluate appropriate methods for determining the fair value rate of return on fair value rate base?

A. It is my understanding that the Commission Staff will continue to consider these issues in the context of future rate cases. Individual rate cases present different issues and varying sets of circumstances. For example, if one were to assign a non-zero cost rate to the fair value increment, it may be appropriate to determine the cost of equity to reflect a reduction in risk. I have not proposed such an adjustment in this case, but these issues may appear as Staff continues to consider appropriate methods for determining and evaluating the concept of fair value rate of return on fair value rate base.

Q. Does this conclude your Direct Testimony?

A. Yes.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATION

Certified Rate of Return Analyst - Founding Member

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of

National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois,

Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified

in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

Exhibit___(DCP-1)
Schedule 1

SOUTHWEST GAS CORPORATION
TOTAL COST OF CAPITAL
AT JUNE 30, 2010

Item	Percent 1/		Cost		Weighted Cost	
Short-Term Debt	0.00% 2/					
Long-Term Debt	47.70%		8.34% 1/		3.98%	
Common Equity	52.30%	9.00%		10.50%	4.71%	5.49%
Total	100.00%				8.69%	9.47%
					Mid-Point 9.08%	

1/ As contained in Company filing, Schedule D-1, Page 1 of 2.

2/ Southwest Gas had no short-term debt outstanding at June 30, 2010, as indicated in the response to ACC-STF-2.5.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
		1975 - 1982 Cycle			
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
		1983 - 1991 Cycle			
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
		1992 - 2001 Cycle			
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	5.9%	4.5%	1.6%	0.0%
1999	4.5%	4.3%	4.2%	2.7%	2.9%
2000	4.1%	4.0%	4.0%	3.4%	3.6%
2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
		2002 - 2009			
2002	1.8%	0.2%	5.8%	2.4%	1.2%
2003	2.5%	1.3%	6.0%	1.9%	4.0%
2004	3.6%	2.3%	5.5%	3.3%	4.2%
2005	3.1%	3.2%	5.1%	3.4%	5.4%
2006	2.7%	2.2%	4.6%	2.5%	1.1%
2007	1.9%	2.7%	4.6%	4.1%	6.2%
2008	0.0%	-3.7%	5.8%	0.1%	-0.9%
2009	-2.6%	-11.2%	9.3%	2.7%	4.3%
		Current Cycle			
2010	2.9%	5.3%	9.6%	1.5%	4.0%

*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	Producer Price Index
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.0%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	2.6%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.4%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.9%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	2.3%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	2.9%	1.7%	4.8%	6.4%	10.8%
2008					
1st Qtr.	-0.7%	-0.1%	4.9%	2.8%	9.6%
2nd Qtr.	0.6%	-0.2%	5.3%	7.6%	14.0%
3rd Qtr.	-4.0%	-1.7%	6.0%	2.8%	-0.4%
4th Qtr.	-6.8%	-6.7%	6.9%	-13.2%	-28.4%
2009					
1st Qtr.	-4.9%	-11.6%	8.1%	2.4%	-1.2%
2nd Qtr.	-0.7%	-12.9%	9.3%	3.6%	0.0%
3rd Qtr.	1.6%	-8.6%	9.6%	2.8%	9.6%
4th Qtr.	5.0%	-3.8%	10.0%	2.4%	-0.8%
					8.8%
2010					
1st Qtr.	3.7%	2.7%	9.7%	1.2%	6.4%
2nd Qtr.	1.7%	6.5%	9.7%	-1.6%	-3.6%
3rd Qtr.	2.6%	6.9%	9.6%	2.8%	4.0%
4th Qtr.	3.1%	6.4%	9.6%	2.8%	8.4%
2011					
1st Qtr.			8.9%		

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

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.44%	5.02%	7.47%	7.59%	7.78%	8.02%
			2002 - 2009 Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.01%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
			Current Cycle				
2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa [1]	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%		6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%		6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%		5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%		6.03%	6.16%	6.51%
2008							
Jan	6.00%	2.86%	3.74%		5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%		6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%		5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%		5.99%	6.29%	6.82%
May	5.00%	1.71%	3.88%		6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%		6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%		6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%		6.09%	6.37%	6.98%
Sept	5.00%	1.46%	3.69%		6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%		6.95%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%		6.83%	7.60%	8.98%
Dec	3.25%	0.04%	2.42%		5.93%	6.54%	8.13%
2009							
Jan	3.25%	0.12%	2.52%		6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%		6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%		6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%		6.20%	6.48%	8.03%
May	3.25%	0.15%	3.29%		6.23%	6.49%	7.76%
June	3.25%	0.17%	3.72%		6.13%	6.20%	7.30%
July	3.25%	0.19%	3.56%		5.63%	5.97%	6.87%
Aug	3.25%	0.18%	3.59%		5.33%	5.71%	6.36%
Sept	3.25%	0.13%	3.40%		5.15%	5.53%	6.12%
Oct	3.25%	0.08%	3.39%		5.23%	5.55%	6.14%
Nov	3.25%	0.05%	3.40%		5.33%	5.64%	6.18%
Dec	3.25%	0.07%	3.59%		5.52%	5.79%	6.26%
2010							
Jan	3.25%	0.06%	3.73%		5.55%	5.77%	6.16%
Feb	3.25%	0.10%	3.69%		5.69%	5.87%	6.25%
Mar	3.25%	0.15%	3.73%		5.64%	5.84%	6.22%
Apr	3.25%	0.15%	3.85%		5.62%	5.81%	6.19%
May	3.25%	0.16%	3.42%		5.29%	5.50%	5.97%
June	3.25%	0.12%	3.20%		5.22%	5.46%	6.18%
July	3.25%	0.16%	3.01%		4.99%	5.26%	5.98%
Aug	3.25%	0.15%	2.70%		4.75%	5.01%	5.55%
Sept	3.25%	0.15%	2.65%		4.74%	5.01%	5.53%
Oct	3.25%	0.13%	2.54%		4.89%	5.10%	5.62%
Nov	3.25%	0.13%	2.76%		5.12%	5.37%	5.85%
Dec	3.25%	0.15%	3.29%		5.32%	5.56%	6.04%
2011							
Jan	3.25%	0.15%	3.39%		5.29%	5.57%	6.06%
Feb	3.25%	0.14%	3.58%		5.42%	5.68%	6.10%
Mar	3.25%	0.11%	3.41%		5.33%	5.56%	5.97%
Apr	3.25%						

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	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	3,783.67	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%

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

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

STOCK PRICE INDICATORS

YEAR	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%	4.01%
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	2,274.82	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%	

[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.

Exhibit___(DCP-1)
Schedule 3

SOUTHWEST GAS CORPORATION
UNSECURED DEBT RATINGS

Date	Moody's	S&P	Fitch
2001	Baa2	BBB-	BBB
2002	Baa2	BBB-	BBB
2003	Baa2	BBB-	BBB
2004	Baa2	BBB-	BBB
2005	Baa2	BBB-	BBB
2006	Baa2	BBB-	BBB
2007	Baa3	BBB-	BBB
2008	Baa3	BBB-	BBB
2009	Baa3	BBB	BBB
2010	Baa2	BBB	BBB
2011	Baa2	BBB	BBB

Source: Response to ACC-STF-2-4.

SOUTHWEST GAS CORPORATION
CAPITAL STRUCTURE RATIOS
1995 - 2010
($000)

YEAR	COMMON EQUITY	PREFERRED STOCK	LONG-TERM DEBT	SHORT-TERM DEBT
1995	$356,050	$60,000	$727,945	$37,000
	30.1%		61.6%	3.1%
	31.1%		63.6%	
1996	$379,616	$60,000	$671,896	$121,000
	30.8%		54.5%	9.8%
	34.2%		60.4%	
1997	$385,979	$60,000	$784,314	$142,000
	28.1%		57.2%	10.3%
	31.4%		63.8%	
1998	$476,400	$60,000	$818,176	$52,000
	33.9%		58.2%	3.7%
	35.2%		60.4%	
1999	$505,425	$60,000	$867,222	$61,000
	33.8%		58.1%	4.1%
	35.3%		60.5%	
2000	$533,467	$60,000	$904,556	$131,000
	32.7%		55.5%	8.0%
	35.6%		60.4%	
2001	$561,200	$60,000	$1,103,992	$93,000
	30.9%		60.7%	5.1%
	32.5%		64.0%	
2002	$596,167	$60,000	$1,100,853	$53,000
	32.9%	3.3%	60.8%	2.9%
	33.9%	3.4%	62.7%	
2003	$630,467	$100,000	$1,127,599	$52,000
	33.0%	5.2%	59.0%	2.7%
	33.9%	5.4%	60.7%	
2004	$705,676	$100,000	$1,192,757	$100,000
	33.6%	4.8%	56.8%	4.8%
	35.3%	5.0%	59.7%	
2005	$751,135	$100,000	$1,308,113	$24,000
	34.4%	4.6%	59.9%	1.1%
	34.8%	4.6%	60.6%	
2006	$901,425	$100,000	$1,313,899	$0
	38.9%	4.3%	56.7%	0.0%
	38.9%	4.3%	56.7%	
2007	$983,673	$100,000	$1,304,146	$9,000
	41.0%	4.2%	54.4%	0.4%
	41.2%	4.2%	54.6%	
2008	$1,037,841	$100,000	$1,193,307	$55,000
	43.5%	4.2%	50.0%	2.3%
	44.5%	4.3%	51.2%	
2009	$1,102,086	$100,000	$1,170,684	$0
	46.4%	4.2%	49.3%	0.0%
	46.4%	4.2%	49.3%	
2010	$1,166,996	$0	$1,124,681	$75,080
	49.3%	0.0%	47.5%	3.2%
	50.9%	0.0%	49.1%	

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

Source: Response to ACC-STF-2-17 and 2010 Annual Report of Southwest Gas.

SOUTHWEST GAS CORPORATION
CAPITAL STRUCTURE RATIOS
1995 - 2010
($000)

YEAR	COMMON EQUITY	PREFERRED STOCK	LONG-TERM DEBT	SHORT-TERM DEBT
1995	$356,050	$60,000	$727,945	$37,000
	30.1%		61.6%	3.1%
	31.1%		63.6%	
1996	$379,616	$60,000	$671,896	$121,000
	30.8%		54.5%	9.8%
	34.2%		60.4%	
1997	$385,979	$60,000	$784,314	$142,000
	28.1%		57.2%	10.3%
	31.4%		63.8%	
1998	$476,400	$60,000	$818,176	$52,000
	33.9%		58.2%	3.7%
	35.2%		60.4%	
1999	$505,425	$60,000	$867,222	$61,000
	33.8%		58.1%	4.1%
	35.3%		60.5%	
2000	$533,467	$60,000	$904,556	$131,000
	32.7%		55.5%	8.0%
	35.6%		60.4%	
2001	$561,200	$60,000	$1,103,992	$93,000
	30.9%		60.7%	5.1%
	32.5%		64.0%	
2002	$596,167	$60,000	$1,100,853	$53,000
	32.9%	3.3%	60.8%	2.9%
	33.9%	3.4%	62.7%	
2003	$630,467	$100,000	$1,127,599	$52,000
	33.0%	5.2%	59.0%	2.7%
	33.9%	5.4%	60.7%	
2004	$705,676	$100,000	$1,192,757	$100,000
	33.6%	4.8%	56.8%	4.8%
	35.3%	5.0%	59.7%	
2005	$751,135	$100,000	$1,308,113	$24,000
	34.4%	4.6%	59.9%	1.1%
	34.8%	4.6%	60.6%	
2006	$901,425	$100,000	$1,313,899	$0
	38.9%	4.3%	56.7%	0.0%
	38.9%	4.3%	56.7%	
2007	$983,673	$100,000	$1,304,146	$9,000
	41.0%	4.2%	54.4%	0.4%
	41.2%	4.2%	54.6%	
2008	$1,037,841	$100,000	$1,193,307	$55,000
	43.5%	4.2%	50.0%	2.3%
	44.5%	4.3%	51.2%	
2009	$1,102,086	$100,000	$1,170,684	$0
	46.4%	4.2%	49.3%	0.0%
	46.4%	4.2%	49.3%	
2010	$1,166,996	$0	$1,124,681	$75,080
	49.3%	0.0%	47.5%	3.2%
	50.9%	0.0%	49.1%	

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

Source: Response to ACC-STF-2-17 and 2010 Annual Report of Southwest Gas.

PROXY GROUP OF GAS DISTRIBUTION COMPANIES
COMMON EQUITY RATIOS

COMPANY	2006	2007	2008	2009	2010	Average
AGL Resources	49.8%	49.8%	49.7%	47.4%	56.0%	50.5%
Atmos Energy	43.0%	48.0%	49.2%	50.1%	55.0%	49.1%
Laclede Group	50.4%	54.6%	55.5%	57.1%	60.0%	55.5%
Northwest Natural Gas	53.7%	53.7%	55.1%	52.3%	54.0%	53.8%
Piedmont Natural Gas	51.7%	51.6%	52.8%	55.9%	55.0%	53.4%
South Jersey Industries	55.3%	57.3%	60.8%	63.5%	65.5%	60.5%
Southwest Gas	39.4%	41.9%	44.7%	46.5%	51.0%	44.7%
WGL Holdings	60.4%	60.3%	62.4%	65.0%	65.0%	62.6%
Average	50.5%	52.2%	53.8%	54.7%	57.7%	51.3%

Source: Value Line Investment Survey.

PROXY GROUP OF GAS DISTRIBUTION COMPANIES
CAPITAL STRUCTURE RATIOS
INCLUDING SHORT-TERM DEBT

Company	2006	2007	2008	2009	2010
AGL Resources	42%	42%	39%	41%	40%
Atmos Energy	45%	47%	46%	51%	49%
Laclede Group	58%	40%	44%	50%	54%
Northwest Natural Gas	48%	47%	45%	47%	45%
Piedmont Natural Gas	47%	45%	43%	48%	49%
South Jersey Industries	44%	50%	47%	50%	45%
Southwest Gas	41%	43%	43%	46%	49%
WGL Holdings	51%	51%	50%	56%	60%
Average	**47%**	**46%**	**45%**	**49%**	**49%**

Source: AUS Utility Reports.

Exhibit___(DCP-1)
Schedule 6

SELECTION OF PROXY COMPANIES

Company	Percent Reg Gas Revenues	S&P Bond Rating	Moody's Bond Rating	Common Equity Ratio	Value Line Safety
Value Line Natural Gas Utility Group					
AGL Resources	63%	A-	A3	40%	2
Atmos Energy	65%	BBB+	Baa2	49%	2
Laclede Group	51%	A	A2	54%	2
New Jersey Resources	**36%**	A+	NR	48%	1
NICOR	81%	AA	Aa3	55%	3
Northwest Natural Gas	94%	A+	A1	45%	1
Piedmont Natural Gas	100%	A	A3	49%	2
South Jersey Industries	51%	A	A2	45%	2
Southwest Gas	83%	BBB	Baa3	49%	3
UGI	**34%**	NR	A3	**39%**	2
WGL Holdings	49%	AA-	A2	60%	1

Note: Figures as of year-end 2010.

Sources: AUS Utility Reports, Value Line.

PROXY COMPANIES
DIVIDEND YIELD

COMPANY	Qtr. DPS	February - April, 2011 DPS	HIGH	LOW	AVERAGE	YIELD
Proxy Group of Natural Gas Distribution Companies						
AGL Resources	$0.450	$1.80	$41.61	$36.82	$39.22	4.6%
Atmos Energy	$0.340	$1.36	$35.25	$32.24	$33.75	4.0%
Laclede Group	$0.405	$1.62	$39.50	$36.30	$37.90	4.3%
Northwest Natural Gas	$0.435	$1.74	$48.72	$44.07	$46.40	3.8%
Piedmont Natural Gas	$0.290	$1.16	$32.00	$27.88	$29.94	3.9%
South Jersey Industries	$0.365	$1.46	$58.03	$52.18	$55.11	2.6%
Southwest Gas	$0.250	$1.00	$39.89	$36.97	$38.43	2.6%
WGL Holdings	$0.388	$1.55	$39.68	$36.09	$37.89	4.1%
Average						**3.7%**
Hevert Proxy Group						
AGL Resources	$0.450	$1.80	$41.61	$36.82	$39.22	4.6%
Atmos Energy	$0.340	$1.36	$35.25	$32.24	$33.75	4.0%
Laclede Group	$0.405	$1.62	$39.50	$36.30	$37.90	4.3%
New Jersey Resources	$0.360	$1.44	$44.10	$40.24	$42.17	3.4%
Nicor	$0.465	$1.86	$55.50	$50.58	$53.04	3.5%
Northwest Natural Gas	$0.435	$1.74	$48.72	$44.07	$46.40	3.8%
Piedmont Natural Gas	$0.290	$1.16	$32.00	$27.88	$29.94	3.9%
South Jersey Industries	$0.365	$1.46	$58.03	$52.18	$55.11	2.6%
WGL Holdings	$0.388	$1.55	$39.68	$36.09	$37.89	4.1%
Average						**3.8%**

Source: Yahoo! Finance.

PROXY COMPANIES
RETENTION GROWTH RATES

COMPANY	2006	2007	2008	2009	2010	Average	2011	2012	2014-'16	Average
Proxy Group of Natural Gas Distribution Companies										
AGL Resources	6.3%	5.3%	5.1%	5.3%	5.6%	5.5%	6.5%	5.5%	6.0%	6.0%
Atmos Energy	3.6%	3.0%	3.1%	2.7%	3.5%	3.2%	3.5%	3.5%	4.0%	3.7%
Laclede Group	5.1%	4.3%	5.2%	5.9%	3.6%	4.8%	4.0%	4.0%	4.5%	4.2%
Northwest Natural Gas	4.5%	6.0%	4.5%	5.0%	4.0%	4.8%	4.0%	4.0%	4.0%	4.0%
Piedmont Natural Gas	2.8%	3.5%	3.9%	4.8%	3.3%	3.7%	3.5%	3.5%	4.0%	3.7%
South Jersey Industries	10.2%	6.7%	6.7%	6.4%	7.1%	7.4%	7.0%	8.5%	9.0%	8.2%
Southwest Gas	5.2%	4.8%	2.1%	4.1%	5.0%	4.2%	5.0%	5.0%	5.5%	5.2%
WGL Holdings	3.2%	3.5%	5.0%	5.0%	3.3%	4.0%	2.5%	3.0%	3.5%	3.0%
Average						**4.7%**				**4.7%**
Hevert Proxy Group										
AGL Resources	6.3%	5.3%	5.1%	5.3%	5.6%	5.5%	6.5%	5.5%	6.0%	6.0%
Atmos Energy	3.6%	3.0%	3.1%	2.7%	3.5%	3.2%	3.5%	3.5%	4.0%	3.7%
Laclede Group	5.1%	4.3%	5.2%	5.9%	3.6%	4.8%	4.0%	4.0%	4.5%	4.2%
New Jersey Resources	6.3%	3.6%	9.5%	7.2%	6.8%	6.7%	6.5%	7.0%	6.5%	6.7%
Nicor	5.2%	5.4%	3.6%	4.9%	3.2%	4.5%	4.0%	4.0%	3.5%	3.8%
Northwest Natural Gas	4.5%	6.0%	4.5%	5.0%	4.0%	4.8%	4.0%	4.0%	4.0%	4.0%
Piedmont Natural Gas	2.8%	3.5%	3.9%	4.8%	3.3%	3.7%	3.5%	3.5%	4.0%	3.7%
South Jersey Industries	10.2%	6.7%	6.7%	6.4%	7.1%	7.4%	7.0%	8.5%	9.0%	8.2%
WGL Holdings	3.2%	3.5%	5.0%	5.0%	3.3%	4.0%	2.5%	3.0%	3.5%	3.0%
Average						**4.9%**				**4.8%**

Source: Value Line Investment Survey.

PROXY COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '08-'10 to '14-'16 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Proxy Group of Natural Gas Distribution Companies								
AGL Resources	4.5%	7.5%	5.5%	5.8%	4.5%	2.0%	5.5%	4.0%
Atmos Energy	4.0%	1.5%	5.0%	3.5%	5.0%	2.0%	4.5%	3.8%
Laclede Group	7.5%	2.5%	7.0%	5.7%	3.0%	2.5%	5.0%	3.5%
Northwest Natural Gas	9.5%	3.5%	4.0%	5.7%	3.0%	4.0%	4.0%	3.7%
Piedmont Natural Gas	5.0%	4.5%	3.5%	4.3%	3.5%	3.5%	3.0%	3.3%
South Jersey Industries	10.0%	7.5%	9.0%	8.8%	9.0%	8.5%	4.5%	7.3%
Southwest Gas	6.0%	2.0%	5.0%	4.3%	7.5%	4.5%	4.5%	5.5%
WGL Holdings	2.5%	2.5%	5.0%	3.3%	1.5%	2.5%	4.0%	2.7%
Average				**5.2%**				**4.2%**
Hevert Proxy Group								
AGL Resources	4.5%	7.5%	5.5%	5.8%	4.5%	2.0%	5.5%	4.0%
Atmos Energy	4.0%	1.5%	5.0%	3.5%	5.0%	2.0%	4.5%	3.8%
Laclede Group	7.5%	2.5%	7.0%	5.7%	3.0%	2.5%	5.0%	3.5%
New Jersey Resources	8.5%	7.5%	10.0%	8.7%	4.0%	4.5%	5.5%	4.7%
Nicor	3.5%	0.0%	5.0%	2.8%	-0.5%	0.0%	4.0%	1.2%
Northwest Natural Gas	9.5%	3.5%	4.0%	5.7%	3.0%	4.0%	4.0%	3.7%
Piedmont Natural Gas	5.0%	4.5%	3.5%	4.3%	3.5%	3.5%	3.0%	3.3%
South Jersey Industries	10.0%	7.5%	9.0%	8.8%	9.0%	8.5%	4.5%	7.3%
WGL Holdings	2.5%	2.5%	5.0%	3.3%	1.5%	2.5%	4.0%	2.7%
Average				**5.4%**				**3.8%**

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
Proxy Group of Natural Gas Distribution Companies								
AGL Resources	4.7%	5.5%	6.0%	5.8%	4.0%	5.6%	5.4%	10.1%
Atmos Energy	4.1%	3.2%	3.7%	3.5%	3.8%	3.6%	3.6%	7.7%
Laclede Group	4.4%	4.8%	4.2%	5.7%	3.5%	3.5%	4.3%	8.7%
Northwest Natural Gas	3.8%	4.8%	4.0%	5.7%	3.7%	3.9%	4.4%	8.2%
Piedmont Natural Gas	3.9%	3.7%	3.7%	4.3%	3.3%	3.6%	3.7%	7.7%
South Jersey Industries	2.8%	7.4%	8.2%	8.8%	7.3%	6.3%	7.6%	10.4%
Southwest Gas	2.7%	4.2%	5.2%	4.3%	5.5%	4.4%	4.7%	7.4%
WGL Holdings	4.2%	4.0%	3.0%	3.3%	2.7%	3.9%	3.4%	7.5%
Mean	3.8%	4.7%	4.7%	5.2%	4.2%	4.4%	4.6%	**8.5%**
Median	4.0%	4.5%	4.1%	5.0%	3.8%	3.9%	4.4%	**8.0%**
Composite - Mean		8.5%	8.5%	**9.0%**	**8.0%**	8.2%	8.5%	
Composite - Median		8.5%	8.1%	**9.0%**	**7.8%**	7.9%	8.4%	
Hevert Proxy Group								
AGL Resources	4.7%	5.5%	6.0%	5.8%	4.0%	5.6%	5.4%	10.1%
Atmos Energy	4.1%	3.2%	3.7%	3.5%	3.8%	3.6%	3.6%	7.7%
Laclede Group	4.4%	4.8%	4.2%	5.7%	3.5%	3.5%	4.3%	8.7%
New Jersey Resources	3.5%	6.7%	6.7%	8.7%	4.7%	2.5%	5.8%	9.3%
Nicor	3.5%	4.5%	3.8%	2.8%	1.2%	-0.2%	2.4%	6.0%
Northwest Natural Gas	3.8%	4.8%	4.0%	5.7%	3.7%	3.9%	4.4%	8.2%
Piedmont Natural Gas	3.9%	3.7%	3.7%	4.3%	3.3%	3.6%	3.7%	7.7%
South Jersey Industries	2.8%	7.4%	8.2%	8.8%	7.3%	6.3%	7.6%	10.4%
WGL Holdings	4.2%	4.0%	3.0%	3.3%	2.7%	3.9%	3.4%	7.5%
Mean	3.9%	4.9%	4.8%	5.4%	3.8%	3.6%	4.5%	**8.4%**
Median	3.9%	4.8%	4.0%	5.7%	3.7%	3.6%	4.3%	**8.2%**
Composite - Mean		8.8%	8.7%	**9.3%**	7.7%	**7.5%**	8.4%	
Composite - Median		8.7%	7.9%	**9.6%**	7.6%	**7.5%**	8.3%	

Sources: Prior pages of this schedule.

PROXY COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Proxy Group of Natural Gas Distribution Companies				
AGL Resources	4.32%	0.75	5.54%	8.5%
Atmos Energy	4.32%	0.65	5.54%	7.9%
Laclede Group	4.32%	0.60	5.54%	7.6%
Northwest Natural Gas	4.32%	0.60	5.54%	7.6%
Piedmont Natural Gas	4.32%	0.65	5.54%	7.9%
South Jersey Industries	4.32%	0.65	5.54%	7.9%
Southwest Gas	4.32%	0.75	5.54%	8.5%
WGL Holdings	4.32%	0.65	5.54%	7.9%
Mean				**8.0%**
Median				**7.9%**
Hevert Proxy Group				
AGL Resources	4.32%	0.75	5.54%	8.5%
Atmos Energy	4.32%	0.65	5.54%	7.9%
Laclede Group	4.32%	0.60	5.54%	7.6%
New Jersey Resources	4.32%	0.65	5.54%	7.9%
Nicor	4.32%	0.75	5.54%	8.5%
Northwest Natural Gas	4.32%	0.60	5.54%	7.6%
Piedmont Natural Gas	4.32%	0.65	5.54%	7.9%
South Jersey Industries	4.32%	0.65	5.54%	7.9%
WGL Holdings	4.32%	0.65	5.54%	7.9%
Mean				**8.0%**
Median				**7.9%**

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

Yields on 20-Year U.S. Treasury Bonds:

Feb., 2011	4.42%
March, 2011	4.27%
April, 2011	4.28%
Average	**4.32%**

PROXY COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1992-2001 Average	2002-2010 Average	2011	2012	2014-16
Proxy Group of Natural Gas Distribution Companies																								
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	12.8%	12.5%	13.0%	12.7%	11.8%	13.5%	12.5%	12.5%	12.5%
Atmos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	9.0%	8.5%	9.1%	11.4%	9.5%	9.0%	8.5%	9.0%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	12.6%	12.9%	10.1%	11.3%	11.4%	10.5%	10.5%	10.0%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.9%	12.4%	11.1%	11.6%	10.9%	10.5%	10.5%	10.5%	10.5%	10.0%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	11.0%	11.8%	12.4%	13.5%	11.8%	13.0%	11.9%	12.0%	12.0%	12.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	13.3%	13.5%	13.4%	14.5%	12.2%	14.0%	15.0%	16.5%	17.5%
Southwest Gas	5.1%	3.9%	7.5%	0.6%	1.7%	5.4%	10.4%	7.5%	7.3%	6.7%	6.6%	6.2%	8.8%	6.5%	9.7%	8.8%	6.0%	8.1%	9.6%	5.6%	7.8%	9.0%	9.0%	9.0%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.0%	11.8%	10.2%	12.4%	11.3%	9.0%	9.5%	10.0%
Average	10.2%	11.5%	10.8%	10.4%	12.0%	11.8%	11.4%	10.0%	10.8%	11.3%	10.0%	11.7%	11.3%	10.9%	12.0%	11.4%	11.1%	11.6%	11.1%	**11.0%**	**11.2%**	**10.9%**	**11.1%**	**11.3%**
Median	11.3%	12.4%	11.6%	11.8%	13.2%	12.5%	11.2%	10.1%	10.7%	11.5%	9.5%	12.0%	11.6%	11.4%	11.0%	11.9%	12.2%	12.4%	10.6%	**11.6%**	**11.4%**	**10.5%**	**10.5%**	**10.0%**
Hevert Proxy Group																								
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	12.8%	12.5%	13.0%	12.7%	11.8%	13.5%	12.5%	12.5%	12.5%
Atmos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	9.0%	8.5%	9.1%	11.4%	9.5%	9.0%	8.5%	9.0%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	12.6%	12.9%	10.1%	11.3%	11.4%	10.5%	10.5%	10.0%
New Jersey Resources	12.2%	11.8%	13.0%	13.3%	13.9%	14.5%	14.7%	15.0%	15.1%	15.2%	15.9%	16.8%	15.8%	16.2%	14.6%	10.2%	16.5%	14.2%	14.4%	13.9%	15.0%	14.5%	15.0%	13.5%
Nicor	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	15.2%	14.9%	12.5%	13.4%	11.8%	16.2%	13.7%	11.0%	11.0%	10.0%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.9%	12.4%	11.1%	11.6%	10.9%	10.5%	10.5%	10.5%	10.5%	10.0%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	11.0%	11.8%	12.4%	13.5%	11.8%	13.0%	11.9%	12.0%	12.0%	12.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	13.3%	13.5%	13.4%	14.5%	12.2%	14.0%	15.0%	16.5%	17.5%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.0%	11.8%	10.2%	12.4%	11.3%	9.0%	9.5%	10.0%
Average	11.6%	12.8%	11.9%	12.3%	13.9%	13.4%	12.2%	11.5%	12.5%	13.1%	11.8%	12.9%	12.2%	12.2%	12.9%	12.0%	12.5%	12.5%	11.7%	**12.5%**	**12.3%**	**11.6%**	**11.8%**	**11.7%**
Median	11.8%	12.7%	12.2%	12.3%	13.9%	13.2%	12.6%	10.3%	11.9%	12.0%	10.8%	12.4%	12.4%	12.1%	13.1%	12.0%	12.5%	13.0%	11.8%	**12.3%**	**12.2%**	**11.0%**	**11.0%**	**10.0%**

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

PROXY COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1992-2001 Average	2002-2010 Average
Proxy Group of Natural Gas																					
Distribution Companies																					
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	188%	146%	138%	158%	179%	172%
Atmos Energy	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	136%	110%	109%	119%	202%	135%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	184%	168%	209%	171%	138%	166%	171%
Northwest Natural Gas	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	208%	201%	173%	182%	155%	173%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	210%	237%	213%	212%	199%	212%
South Jersey Industries	*154%*	*175%*	*141%*	*142%*	*146%*	*178%*	*209%*	*202%*	*196%*	*205%*	*185%*	*170%*	*195%*	*221%*	*209%*	*231%*	*196%*	*204%*	*241%*	*175%*	*206%*
Southwest Gas	81%	100%	103%	103%	121%	129%	139%	147%	120%	127%	123%	118%	127%	135%	161%	149%	117%	97%	127%	117%	128%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	172%	146%	149%	159%	180%	163%
Average	156%	179%	161%	159%	174%	187%	192%	178%	162%	169%	157%	164%	172%	179%	182%	183%	170%	157%	167%	**172%**	**170%**
Median	160%	188%	167%	164%	173%	181%	190%	173%	168%	174%	151%	166%	177%	181%	181%	180%	171%	160%	159%	**174%**	**169%**
Hevert Proxy Group																					
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	188%	146%	138%	158%	179%	172%
Atmos Energy	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	136%	110%	109%	119%	202%	135%
Laclede Group	*158%*	*187%*	*178%*	*163%*	*168%*	*175%*	*174%*	*159%*	*141%*	*155%*	*145%*	*169%*	*179%*	*179%*	*184%*	*168%*	*209%*	*171%*	*138%*	*166%*	*171%*
New Jersey Resources	161%	186%	162%	178%	191%	229%	225%	224%	226%	224%	220%	245%	251%	275%	246%	223%	200%	214%	227%	216%	233%
Nicor	179%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	234%	229%	200%	159%	186%	219%	203%
Northwest Natural Gas	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	208%	201%	173%	182%	155%	173%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	210%	237%	213%	212%	199%	212%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	231%	196%	204%	241%	175%	206%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	172%	146%	149%	159%	180%	163%
Average	167%	192%	171%	170%	187%	204%	209%	192%	181%	187%	173%	181%	190%	200%	197%	196%	183%	170%	180%	**188%**	**185%**
Median	162%	189%	169%	172%	183%	199%	209%	202%	177%	184%	171%	170%	184%	191%	186%	208%	200%	171%	182%	**185%**	**185%**

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

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2009

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
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%	188%
Averages:		
1992-2001	14.7%	341%
2002-2009	12.1%	265%

Source: Standard & Poor's Analyst's Handbook, 2010 edition, page 1.

RISK INDICATORS

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Proxy Group of Natural Gas Distribution Companies						
AGL Resources	2	0.75	B++	3.67	A	4.00
Atmos Energy	2	0.65	B+	3.33	A-	3.67
Laclede Group	2	0.60	B++	3.67	B+	3.33
Northwest Natural Gas	1	0.60	A	4.00	A-	3.67
Piedmont Natural Gas	2	0.65	B++	3.67	A	4.00
South Jersey Industries	2	0.65	B++	3.67	A-	3.67
Southwest Gas	3	0.75	B	3.00	B+	3.33
WGL Holdings	1	0.65	A	4.00	B+	3.33
Average	1.9	0.66	B++	3.63	A-	3.63
Hevert Proxy Group						
AGL Resources	2	0.75	B++	3.67	A	4.00
Atmos Energy	2	0.65	B+	3.33	A-	3.67
Laclede Group	2	0.60	B++	3.67	B+	3.33
New Jersey Resources	1	0.65	A	4.00	A-	3.67
Nicor	3	0.75	A	4.00	B+	3.00
Northwest Natural Gas	1	0.60	A	4.00	A-	3.67
Piedmont Natural Gas	2	0.65	B++	3.67	A	4.00
South Jersey Industries	2	0.65	B++	3.67	A-	3.67
WGL Holdings	1	0.65	A	4.00	B+	3.33
Average	1.8	0.66	B++	3.78	A-	3.59

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	1.9	0.66	B++	A-
Hevert Group	1.8	0.66	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.

SOUTHWEST GAS CORPORATION
RATING AGENCY RATIOS

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Long-Term Debt	47.70%	8.34%	3.98%	3.98%	
Common Equity	52.30%	9.75%	5.10%	8.50%	
Total	100.00%		9.08%	12.48%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage = **3.14** = (12.48% / 3.98%)

Standard & Poor's Utility Benchmark Ratios: Business Profile of "3"	A	BBB
Pre-tax coverage	2.8x - 3.4x	1.8x - 2.8x
Total debt to total capital	50%-55%	55%-65%

EXCERPT FROM ANNUAL ENERGY OUTLOOK, 2011

Table A20. Macroeconomic Indicators
(Billion 2005 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Real Gross Domestic Product	13229	12881	15338	17422	20015	22735	25692	2.7%
Components of Real Gross Domestic Product								
Real Consumption	9265	9154	10444	11669	13277	15049	16978	2.4%
Real Investment	1957	1516	2590	2991	3549	4132	4853	4.6%
Real Government Spending	2503	2543	2555	2665	2796	2935	3069	0.7%
Real Exports	1648	1491	2437	3381	4488	5763	7336	6.3%
Real Imports	2152	1854	2622	3152	3845	4736	5912	4.6%
Energy Intensity (thousand Btu per 2005 dollar of GDP)								
Delivered Energy	5.49	5.33	4.90	4.42	3.94	3.56	3.25	-1.9%
Total Energy	7.57	7.36	6.65	6.02	5.38	4.88	4.45	-1.9%
Price Indices								
GDP Chain-type Price Index (2005=1.000)	1.086	1.096	1.197	1.326	1.452	1.592	1.753	1.8%
Consumer Price Index (1982-4=1.00)								
All-urban	2.15	2.15	2.39	2.69	2.98	3.30	3.66	2.1%
Energy Commodities and Services	2.36	1.93	2.44	2.86	3.26	3.66	4.10	2.9%
Wholesale Price Index (1982=1.00)								
All Commodities	1.90	1.73	2.00	2.20	2.39	2.55	2.74	1.8%
Fuel and Power	2.14	1.59	2.06	2.44	2.86	3.24	3.69	3.3%
Metals and Metal Products	2.13	1.87	2.48	2.68	2.77	2.83	2.87	1.7%
Industrial Commodities excluding Energy	1.81	1.76	2.00	2.14	2.25	2.34	2.43	1.2%
Interest Rates (percent, nominal)								
Federal Funds Rate	1.93	0.16	5.18	4.97	4.88	4.97	5.03	--
10-Year Treasury Note	3.67	3.26	5.77	5.89	5.80	5.78	5.87	--
AA Utility Bond Rate	6.19	5.75	7.43	7.71	7.72	7.76	7.93	--
Value of Shipments (billion 2005 dollars)								
Service Sectors	20737	19555	23157	25591	28640	31694	34669	2.2%
Total Industrial	6720	6017	7478	7956	8397	8829	9298	1.7%
Nonmanufacturing	2039	1821	2200	2317	2388	2443	2537	1.3%
Manufacturing	4680	4197	5278	5639	6010	6386	6761	1.9%
Energy-Intensive	1635	1551	1791	1875	1938	1974	2013	1.0%
Non-energy Intensive	3046	2646	3486	3765	4071	4412	4748	2.3%
Total Shipments	27456	25573	30635	33547	37037	40523	43967	2.1%
Population and Employment (millions)								
Population, with Armed Forces Overseas	305.2	307.8	326.2	342.0	358.1	374.1	390.1	0.9%
Population, aged 16 and over	239.4	241.8	256.5	269.4	282.6	296.2	309.6	1.0%
Population, over age 65	38.9	39.7	47.1	55.1	64.2	72.3	77.7	2.6%
Employment, Nonfarm	136.7	130.9	142.3	148.7	156.1	164.2	170.7	1.0%
Employment, Manufacturing	13.4	11.9	17.4	17.1	15.8	14.3	13.1	0.4%
Key Labor Indicators								
Labor Force (millions)	154.3	154.2	160.7	166.2	170.6	175.8	182.6	0.7%
Nonfarm Labor Productivity (1992=1.00)	1.04	1.07	1.18	1.31	1.47	1.62	1.79	2.0%
Unemployment Rate (percent)	6.82	9.27	6.86	5.47	4.99	4.93	5.20	--
Key Indicators for Energy Demand								
Real Disposable Personal Income	10043	10100	11535	13184	15114	17127	19230	2.5%
Housing Starts (millions)	0.98	0.60	1.84	1.90	1.92	1.83	1.74	4.2%
Commercial Floorspace (billion square feet)	78.8	80.2	85.5	91.5	97.4	103.5	109.8	1.2%
Unit Sales of Light-Duty Vehicles (millions)	13.19	10.40	17.02	16.80	18.23	19.64	20.63	2.7%

GDP = Gross domestic product.
Btu = British thermal unit.
-- = Not applicable.
Sources: 2008 and 2009: IHS Global Insight Industry and Employment models, September 2010. **Projections:** Energy Information Administration, AEO2011 National Energy Modeling System run REF2011.D120810C.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
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 ITS PROPERTIES THROUGHOUT ARIZONA	)	DOCKET NO. G-01551A-10-0458

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 10, 2011

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

My testimony in this proceeding addresses the issues of gas procurement, the purchased gas adjustor, Southwest Gas Corporation's efforts to improve communications with its customers, the Payson Natural Gas Study, and rules and regulations for Southwest.

INTRODUCTION

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

A. My name is Robert G. Gray. I am an Executive Consultant III employed by the Arizona Corporation Commission ("ACC" or "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 III.

A. In my capacity as an Executive Consultant III, I conduct analysis and provide recommendations to the Commission on a variety of electricity, natural gas, and water/wastewater matters. A copy of my resume is attached as Exhibit RGG-1.

Q. What is the scope of this testimony?

A. This testimony will address gas procurement, the purchased gas adjustor, Southwest Gas Corporation's ("Southwest" or "Company") efforts to improve communications with customers, the Payson Natural Gas study, and rules and regulations for Southwest.

GAS PROCUREMENT

Q. Please discuss Southwest's natural gas procurement activities.

A. Southwest purchases large volumes of natural gas in the San Juan supply basin in northwestern New Mexico and the Permian basin in west Texas. The natural gas is then transported to Southwest's distribution system in Arizona via the El Paso Natural Gas Company ("El Paso") and Transwestern Pipeline ("Transwestern") interstate pipeline systems.

Q. Please discuss your review of Southwest's procurement activities.

A. The procurement review in Southwest's previous rate case covered the period of September 2004 through April 2007. Thus, this procurement review will cover the period of May 2007 through the end of the test year, June 2010. The review involves the following topics:

1. An overview of Southwest's system and the purchased gas adjustor;
2. Market conditions during the review period;
3. Southwest's monthly Purchased Gas Adjustor ("PGA") accounting during the review period;
4. Purchases during three months, April 2008, August 2009, and January 2010;
5. Southwest's use of financial instruments;
6. Compressed natural gas purchases by Southwest; and
7. A comparison of Southwest's purchases for core and noncore customers.

Q. Have you prepared a gas procurement review report?

A. Yes. Attached as Exhibit RGG-2 is Staff's review of Southwest's gas procurement activities during the period of May 2007 through June 2010.

Q What findings and recommendations does the Staff review contain?

A. Staff finds that Southwest's procurement activities from May 2007 through June 2010 are prudent. Staff recommends that in all Annual Gas Procurement Plans filed by Southwest, there be a separate section of the report providing a detailed explanation and documentation of the use of financial instruments by Southwest and in particular the swaps used by Southwest. Staff also recommends that Southwest provide an explanation in any future PGA report when it begins to recover compressed natural gas ("CNG") costs

Q. What additional information is Staff proposing that Southwest provide in its monthly PGA reports?

A. Staff is not requesting Southwest to provide any additional data or conduct any additional calculations in the monthly PGA reports. Southwest's reports, and particularly the pages containing the natural gas commodity and interstate pipeline cost information, use a wide variety of terms to describe various costs and other inputs. Over time Southwest changes, adds, and deletes certain terms, and in the past the Company has not noted in the report why terms are added, changed, or deleted or the meaning of new terms. For example, in recent years there have been significant changes in the charges paid by Southwest to El Paso Natural Gas Company for interstate pipeline service, with new line items appearing and disappearing at various times in the interstate pipeline cost section of the report. Staff believes that information would be not be burdensome to Southwest, and would help the Commission more easily understand the information contained in Southwest's monthly PGA report. Therefore, Staff recommends that each time Southwest adds, deletes, or changes specific terms used in its monthly PGA report, it provide an explanation of the change and a definition if the term is new or changed, in the cover letter of that given monthly PGA report. Southwest has indicated in response to a Staff data request that it would not object to providing this information in its monthly PGA reports. To begin this process, Staff further recommends that Southwest file in this docket, within 60 days of the final decision in this case, a document defining each current line item in its monthly PGA report. This would provide a clear starting point for Southwest to then define future changes to terminology used in the monthly PGA report.

PAYSON NATURAL GAS SERVICE EXTENSION STUDY

Q. Did ACC Decision No. 70665 (December 24, 2008) in Southwest's last rate case address the possibility of Southwest extending natural gas service to the Payson, Arizona area?

A. Yes. The order found that "Given the Company's willingness to prepare and submit a study regarding providing service to the Payson area, we find that Southwest Gas shall file such a study or report within 180 days of the effective date of this Decision." (p.56, lines 23-25). The Commission's interest in such a study was the result of several concerns with the current propane service in the Payson, Arizona area by Semstream Arizona Propane, including high prices and billing difficulties.

Q. Did Southwest file a study, pursuant to Decision No. 70665?

A. Yes. On June 15, 2009, Southwest filed a study in the previous rate case docket, which is Docket No. G-01551A-07-0504.

Q. Please discuss the genesis of the Commission's request for Southwest to file this report.

A. There had been several concerns with Semstream Arizona Propane's service in the Payson area, including a significant increase in rates as a result of higher propane prices, as well as billing problems which resulted in longer than normal billing cycles for some customers. Interest in possible natural gas service in Payson was spurred by the lower cost per therm of natural gas in comparison to propane. Amongst other actions, the Commission held a town hall in Payson on March 18, 2008, where public officials and Semstream customers expressed various concerns and questions regarding Semstream. Following the town hall, Staff was directed to prepare a report addressing a number of questions which were raised at the March 18, 2008 town hall as well as in other forums.

Q. Did Staff prepare this report?

A. Yes.

Q. Are you the Robert Gray who prepared the Staff Report dated May 22, 2008, which addressed a number of issues related to propane service in Payson, including the possibility of natural gas service being extended to Payson?

A. Yes. The May 22, 2008 Staff Report addressed eight questions in regard to propane service in Payson, one of which specifically addressed the possibility of extending natural gas service to Payson by either Southwest or UNS Gas. Attached is Exhibit RGG-2, which is Staff's answer to the question of what the possible service alternatives for propane customers in Payson are. Staff's consideration of natural gas service options in this Staff Report represents an initial consideration of the issue, while Southwest's June 15, 2009 study provides a more comprehensive analysis.

Q. Please briefly summarize the Staff and Southwest Gas reports.

A. Both Staff and Southwest found that there were significant barriers to extending natural gas service to Payson. Significant barriers to such an extension include:

1. The long distance from existing natural gas infrastructure, in excess of 50 miles.
2. The rugged terrain and environmental concerns resulting from a pipeline being run through Wilderness and National Forest lands.
3. The high cost of the project, including the initial pipeline and facility changes in the Payson area, by Southwest's estimate $97 million initially and $49 million over the following 9 years. The total customer base in Payson is relatively small to spread this amount of cost over, resulting in Payson residents paying significantly more for natural gas service than they currently pay for propane service.

4. Semstream Arizona Propane currently holds the Certificate of Convenience and Necessity to serve the Payson area, and it is not clear if Semstream would want to sell its Payson Division or what the cost of such a purchase would be if another entity such as Southwest were to extend natural gas service to the area.
5. Service to Semstream Arizona Propane's satellite systems, which currently receive propane service, despite not being connected to the central distribution system in Payson, would somehow have to be addressed.
6. Possible liquid natural gas service to Payson is not feasible due to the very high cost of liquefaction and regasification facilities, as well as other issues.

Q. What are your conclusions regarding Southwest's June 15, 2009 report as well as the possibility of extending natural gas service to Payson?

A. Southwest's study presents a reasonable perspective on the issue and fulfils Southwest's commitment to conduct such a study made in the previous rate case. Staff does not believe extension of natural gas service to Payson is viable for the reasons cited above, absent some major change of circumstances.

CUSTOMER COMMUNICATION IMPROVEMENT EFFORTS

Q. Please discuss the need for improvements in customer communications by Southwest.

A. In February 2011, Southwest experienced significant customer outages in southern Arizona, with approximately 14,000 customers in the Tucson area and 4,500 customers in the Sierra Vista area losing service. There were numerous concerns, during and after the outages, with both the information provided by Southwest regarding the outages and the methods of communication used by Southwest to inform the communities and customers impacted by the outages. On April 6, 2011 and April 7, 2011, the Commission held town hall meetings in southern Arizona to discuss the outages with the public.

Q. Has Southwest provided any information to Staff in this case regarding its efforts to improve communications with its customers?

A. Yes. In response to Staff Data Request STF-12-18 (attached as Exhibit RGG-4), Southwest identified a number of efforts it is undertaking to improve communications with customers. Southwest identifies a number of improvements it is pursuing, including the following items:

1. Creation of Facebook and Twitter accounts,
2. Development of an Outage Mapping System to show areas impacted by outages, number of affected customers, and outage restoration efforts,
3. Utilization of multiple off-site servers to provide server redundancy and thus greater reliability for Southwest's website,
4. Use of reverse 911 calling in coordination with the counties, recognizing its limitations, and
5. Development of predictive dialing to provide customers with contact and other applicable information.

The Company notes that its efforts to improve communications with its customers are on-going.

Q. What is Staff's perspective on Southwest's efforts to improve communications with its customers, as detailed in Exhibit RGG-4?

A. Staff believes that Southwest's efforts to date show promise of improved communications with its customers, but that a number of the improvements are still in development and thus Southwest's overall communications plan for its customers in the future is still at least somewhat unclear. One technology which Southwest did not identify as part of its

efforts to improve communications with its customers is cell phone texting. Therefore, Staff believes that Southwest should investigate the use of texting as a further way the Company can communicate with its customers.

Q. In light of this, does Staff have any recommendations regarding this issue?

A. Yes. Staff recommends that Southwest file a report every six months in this docket, beginning on March 31, 2012, detailing developments in its efforts to improve communications with its customers. This will provide the Commission with on-going information on Southwest's improvements to its content on and systems for communicating with its customers. Staff further recommends that Southwest report to the Commission in its March 31, 2012 report, regarding whether the Company can use texting to communicate with its customers, or if it can't, provide an explanation as to why not.

RULES AND REGULATIONS

Q. Have you reviewed Southwest's proposed Rules and Regulations in this case?

A. Yes.

Q. Please describe Southwest's proposed Rules and Regulations in this case.

A. Southwest's only proposed change to its Rules and Regulations in this case is on page 208, in Rule No. 7, Provision of Service, where additional detail is being added as to who customers should contact in case of an emergency.

Q. Do you have any objection to this proposed change?

A. No.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. My testimony includes the following findings and recommendations:

Gas Procurement

1. Staff recommends that in all Annual Gas Procurement Plans filed by Southwest, there be a separate section of the report providing a detailed explanation and documentation of the use of financial instruments by Southwest, and in particular the swaps used by Southwest.
2. Staff further recommends that Southwest provide an explanation in any future PGA report when it begins to recover CNG costs for serving a given area through the PGA mechanism, indicating the reason(s) for such service, expected length such service will be necessary, and estimated cost and volume of such service.

Purchased Gas Adjustor

3. Staff further recommends that each time Southwest adds, deletes, or changes specific terms used in its monthly PGA report, it provide an explanation of the change and a definition if the term is new or changed, in the cover letter of that given monthly PGA report.
4. Staff further recommends that Southwest file in this docket, within 60 days of the final decision in this case, a document defining each current line item in its monthly PGA report.

Customer Communication Improvement Efforts

5. Staff further recommends that Southwest file a report every six months in this docket, beginning on March 31, 2012, detailing developments in its efforts to improve communications with its customers.

6. Staff further recommends that Southwest report to the Commission in its March 31, 2012 report, regarding whether the Company can use texting to communicate with its customers, or if it can't, provide an explanation as to why not.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Exhibit RGG-1

RESUME

ROBERT G. GRAY

Education

B.A. Geography, University of Minnesota-Duluth (1988)

M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Executive Consultant III (November 2007 – present), Public Utility Analyst V (October 2001 – November 2007), Senior Economist (August 1997 – October 2001), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses on a variety of natural gas issues in Arizona, including gas procurement, rate design, interstate pipeline issues, revenue decoupling, energy conservation, low income issues, natural gas research and development funding, customer services issues, special contracts, various tariff matters, and other natural gas issues. Conduct economic and policy analyses on a variety of electricity issues in Arizona, power plant and transmission line siting cases, energy efficiency, renewable energy standards, rate design, time-of-use service, and low income issues. Prepare recommendations and present written and oral testimony before the Commission and organize workshops and other proceedings on various utility industry issues. Represent the ACC in natural gas proceedings at the Federal Energy Regulatory Commission, at the North American Energy Standards Board, and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas, including serving as a past Vice-Chair and Chair of the NARUC Staff Subcommittee on Gas.

Testimony

Resource Planning for Electric Utilities, (Docket No. 0000-90-088), Arizona Corporation Commission, 1990.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-92-073), Arizona Corporation Commission, 1993.

Resource Planning for Electric Utilities, (Docket No. 0000-93-052), Arizona Corporation Commission, 1993.

Arizona Public Service Company, Rate Settlement (Docket No. E-1345-94-120), Arizona Corporation Commission, 1994.

U S West Communications, Rate Case (Docket No. E-1051-93-183), Arizona Corporation Commission, 1995.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-95-433), Arizona Corporation Commission, 1996.

Resource Planning for Electric Utilities (Docket No. U-000-95-506), Arizona Corporation Commission, 1996.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. U-1551-96-596), Arizona Corporation Commission, 1997.

Black Mountain Gas Company - Northern States Power Company, Merger (Docket Nos. G-03493A-98-0017, G-01970A-98-0017), Arizona Corporation Commission, 1998.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-98-0695, G-03493A-98-0705), Arizona Corporation Commission, 1999.

Graham County Utilities Company Rate Case (Docket No. G-02527A-00-0378), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Cave Creek Division Rate Case (Docket No. G-03703A-00-0283), Arizona Corporation Commission, 2000.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. G-01551A-00-0309), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-01-0263), Arizona Corporation Commission, 2001.

Duncan Rural Services – Natural Gas Rate Case (Docket No. G-02528A-01-0561), Arizona Corporation Commission, 2001.

Toltec Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Y-01-0112), September 2001.

Lap Paz Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000AA-01-0116), December 2001.

Bowie Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000BB-01-0118), December 2001.

Southwest Gas Corporation, Acquisition of Black Mountain Gas Company (Docket No. G-01551A-02-0425), Arizona Corporation Commission, 2002.

Wellton-Mohawk Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Z-01-0114), February 2003.

Arizona Public Service Company, Rate Proceeding (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004.

Graham County Utilities Company Rate Case (Docket No. G-02527A-04-0301), Arizona Corporation Commission, 2004.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-04-0876), Arizona Corporation Commission, 2004.

Southern California Edison, Devers – Palo Verde 2 Transmission Line Application before the Arizona Power Plant and Line Siting Committee, (L-00000A-06-0295-00130), 2006.

Semstream Arizona Propane Acquisition of Energy West (Docket G-02696A-06-0515), Arizona Corporation Commission, 2006.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-06-0463), Arizona Corporation Commission, 2007.

Semstream Arizona Propane Acquisition of Black Mountain Gas Company – Page Division (Docket G-03703A-06-0694), Arizona Corporation Commission, 2007.

Northern Arizona Energy, LLC, Northern Arizona Energy Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000FF-07-0134-00133), 2007.

Arizona Public Service, Palo Verde Hub to North Gila 500 kV Transmission Lint Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000D-07-0566-00135), 2007.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-07-0504), Arizona Corporation Commission, 2008.

Arizona Solar One, LLC, Solana Generating Station and Gen-Tie Application before the Arizona Power Plant and Line Siting Committee, (L-00000GG-08-0407-00139 and L-00000GG-08-0408-00140), 2008.

Coolidge Power Corporation, Coolidge Power Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000HH-08-0422-00141), 2008.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-08-0571), Arizona Corporation Commission, 2009.

El Paso Natural Gas Company, Rate Proceeding (Docket No. RP08-426), Federal Energy Regulatory Commission, 2009.

Arizona Water/Global Water CC&N Extension/Acquisition Proceeding (Docket No. W-01445A-06-0199), Arizona Corporation Commission, 2009.

Graham County Utilities Company Rate Proceeding (Docket No. G-02527A-09-0088), Arizona Corporation Commission, 2009.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A., Vol. 27A, 1993, pp. 1-12.

(with David Berry) Staff Guidelines on Photovoltaics Versus Line Extensions. Arizona Corporation Commission, January 28, 1993.

(with Ray Williamson, Robert Hammond, Frank Mancini, and James Arwood) The Solar Electric Option (Instead of Power Line Extension). A joint publication of the Arizona Corporation Commission and the Arizona Department of Commerce Energy Office, August, 1993.

(with David Berry, Kim Clark, Barbara Keene, Jesse Tsao, Ray Williamson, Randall Sable, Roni Washington, Wilfred Shand, and Prem Bahl) Staff Report on Resource Planning. (Docket No. U-0000-93-052) Arizona Corporation Commission, 1993.

Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

Staff Report on Purchased Gas Adjustor Mechanisms, (Docket No. G-00000C-98-0568) Arizona Corporation Commission, October 19, 1998.

Staff Report on the Rolling Average PGA Mechanism, (Docket No. G-00000C-98-0568),Arizona Corporation Commission, September 6, 2000.

Staff Report on the Use of a Circuit-Breaker in Adjustor Mechanisms, Arizona Corporation Commission, September 3, 2003.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. G-01551A-04-0192), Arizona Corporation Commission, June 2, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. E-01345A-04-0273), Arizona Corporation Commission, August 16, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. E-01345A-05-0895), Arizona Corporation Commission, March 2, 2006.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-01551A-06-0107), Arizona Corporation Commission, May 16, 2006.

Staff Report on UNS Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-04204A-06-0627), Arizona Corporation Commission, January 30, 2007.

Staff Review of UNS Electric 2008 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-07-0593), Arizona Corporation Commission, March 25, 2008.

Staff Report on Semstream Arizona Propane, Payson Division Bankruptcy, Reorganization, and other issues, Arizona Corporation Commission, June 6, 2008.

Staff Review of UNS Electric 2009 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-07-0593), Arizona Corporation Commission, November 26, 2008.

Staff Review of Tucson Electric Power 2009 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-07-0594), Arizona Corporation Commission, November 26, 2008.

Staff Report for Arizona Water Company and Global Water Resources LLC's Consolidated Docket Addressing Numerous Requests for Extensions of Certificates of Convenience and Necessity for Water and Wastewater Service as Well as the Transfer of Assets, (Docket No. W01445A-06-0199, etc.), Arizona Corporation Commission, May 10, 2009.

Staff Review of UNS Electric 2010 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-09-0347), Arizona Corporation Commission, January 5, 2010.

Staff Review of Tucson Electric Power 2010 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-09-0340), Arizona Corporation Commission, January 5, 2010.

Staff Review of UNS Electric 2011 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-10-0265), Arizona Corporation Commission, November 8, 2010.

Staff Review of Tucson Electric Power 2011 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-10-0266), Arizona Corporation Commission, November 9, 2010.

Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition

1997	NARUC 6th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7th Annual Natural Gas Conference
1999 – 2007, 2010	NARUC Summer Committee Meetings
2001	Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2008	NARUC Winter Committee Meetings
2004-2007	NARUC Annual Convention

Memberships

NARUC – Staff Subcommittee on Gas – member, 1998 - present
NARUC – Staff Subcommittee on Gas – Vice-Chair - 2002 - 2004
NARUC – Staff Subcommittee on Gas – Chair - 2005 - 2007
Michigan State Institute for Public Utilities – NARUC Advisory Committee – 2005-2007
NARUC – North American Energy Standards Board Advisory Council – 2006 - present
NARUC – DOE LNG Partnership – 2003 - present

Staff Gas Procurement Review of Southwest Gas Corporation for the May 2007 Through June 2010 Period

Southwest Gas Corporation's ("Southwest" or "Company") previous rate case, in Docket No. G-01551A-07-0504, included a review of Southwest's gas procurement practices for the period of September 2004 through April 2007. The procurement review was conducted by Energy Ventures Analysis, Inc. The gas procurement review in this case will analyze the period from May 2007 through the end of the rate case test year, June 2010.

Purchased Gas Adjustor

Natural gas commodity costs and interstate pipeline transportation costs incurred by Southwest to provide natural gas service to its customers are passed through to customers via the purchased gas adjustor mechanism ("PGA"). Southwest does not earn a profit on costs passed through the PGA. Southwest has had a purchased gas adjustor in place for a very long period of time. The banded 12-month rolling average cost PGA mechanism currently in place for Southwest was initially implemented in June 1999. In creating this new form of the PGA mechanism for Southwest and other Arizona local distribution companies ("LDCs"), the Commission sought to balance various, sometimes conflicting, goals, including sending a price signal as the price of natural gas changes, protecting ratepayers from sudden and dramatic shifts in the cost of gas they pay, and to allow the LDC to collect its natural gas costs in a relatively timely manner. Prior to that time, Southwest's PGA rate only adjusted when Southwest made a filing with the Commission to change the PGA rate. The rolling average PGA mechanism sets Southwest's gas cost per therm for its customers at a rate equal to the average total natural gas cost Southwest has experienced in the most recent previous 12 months. Thus, the monthly PGA rate changes every month, but the changes from month to month tend to be very incremental in nature, barring large price swings or other unforeseen events.

The PGA rate is subject to a band, which limits how much movement the PGA can experience in a 12-month period. Southwest's band was initially $0.07 per therm. In Decision No. 62994 (November 3, 2000), the Commission expanded the PGA bandwidth for Arizona LDCs, including Southwest to $0.10 per therm. Further expansions have taken place in recent times by the Commission to $0.13 per therm in Decision No. 68487 (February 23, 2006), and most recently in Decision No. 70665 (December 24, 2008) to $0.15 per therm.

System Summary

As of December 2010, Southwest serves approximately 977,500 customers in Arizona, including approximately 937,560 residential customers, 39,360 commercial customers, and 220 industrial customers. Southwest's service territory stretches across a wide swath of Arizona, from Cochise County in southeastern Arizona to La Paz County in western Arizona, including all of the Tucson metro area and most of the Phoenix metro area. Southwest also serves a small area around Bullhead City. Southwest's retail sales in Arizona for 2010 were 524,328,720 therms. The total cost, including the natural gas commodity and interstate transportation costs for 2010 was $355,476,672. Due to lower natural gas prices, the total cost in 2010 was

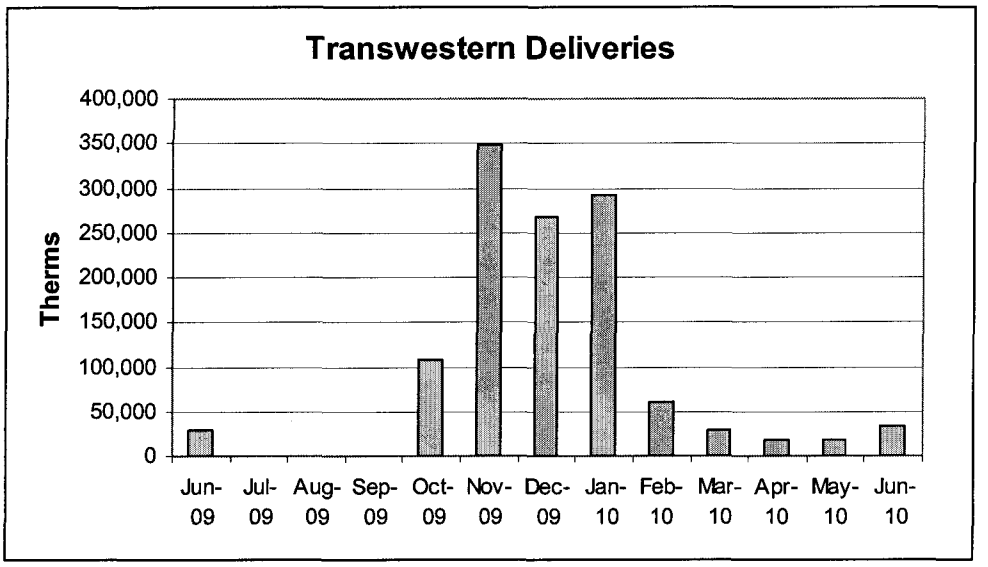
significantly lower than several recent years where Southwest's annual total cost was well in excess of $500,000,000.

Southwest acquires most of the natural gas to serve its customers from the San Juan supply basin in northwestern New Mexico and the Permian supply basin in west Texas. Southwest purchases natural gas supplies from suppliers in the supply basins and contracts with El Paso Natural Gas Company ("El Paso") and Transwestern Pipeline ("Transwestern") for pipeline capacity to deliver its natural gas supplies through their interstate pipeline systems to its service territory in Arizona. Southwest's Arizona distribution system has 208 meters and 123 active small taps on El Paso's system and 5 meters and 1 small tap on the Transwestern system. A meter is generally an interconnection point with service greater than 10,000 therms/day and uses telemetry. A small tap is generally an interconnection point with deliveries less than 10,000 therm/day and where measurement is done monthly. For scheduling on the El Paso system, Southwest is allowed to aggregate certain delivery points together for scheduling purposes, resulting in Southwest having 26 such d-codes in Arizona.

The Commission has had an on-going concern for many years regarding the monopoly on interstate pipeline service that El Paso held in most of Arizona, including central and southern Arizona, reflected in the Commission's involvement in many El Paso dockets at the Federal Energy Regulatory Commission ("FERC") for over a decade. Other shippers on the El Paso system, including large California shippers, have greater supply options and have been able to negotiate significant discounts for their service on the El Paso pipeline system, the costs of which are then borne by other shippers on the system who are unable to negotiate such discounts. This is a growing problem on the El Paso system, with several parties in El Paso's current rate case before FERC (FERC Docket No. RP10-1398) referring to the growing problems of capacity discounting and unsubscribed capacity as leading to a possible "death spiral" on the El Paso system. Both Southwest and the Commission are actively participating in El Paso's current rate proceeding before FERC, as well as other related dockets at FERC.

Transwestern's Phoenix Expansion represents some level of opportunity to diversify service options in central Arizona, although this is the case much more for electric generation facilities than for Southwest. Southwest does hold capacity on the Phoenix Expansion and takes service at a handful of points in the Phoenix area, but the Company is still largely captive to El Paso, given Southwest's many delivery points that are not near the Transwestern pipeline system. Southwest's participation, in the form of purchasing pipeline capacity, in the Phoenix Expansion was pre-approved by the Commission in Decision No. 68753 (June 5, 2006).

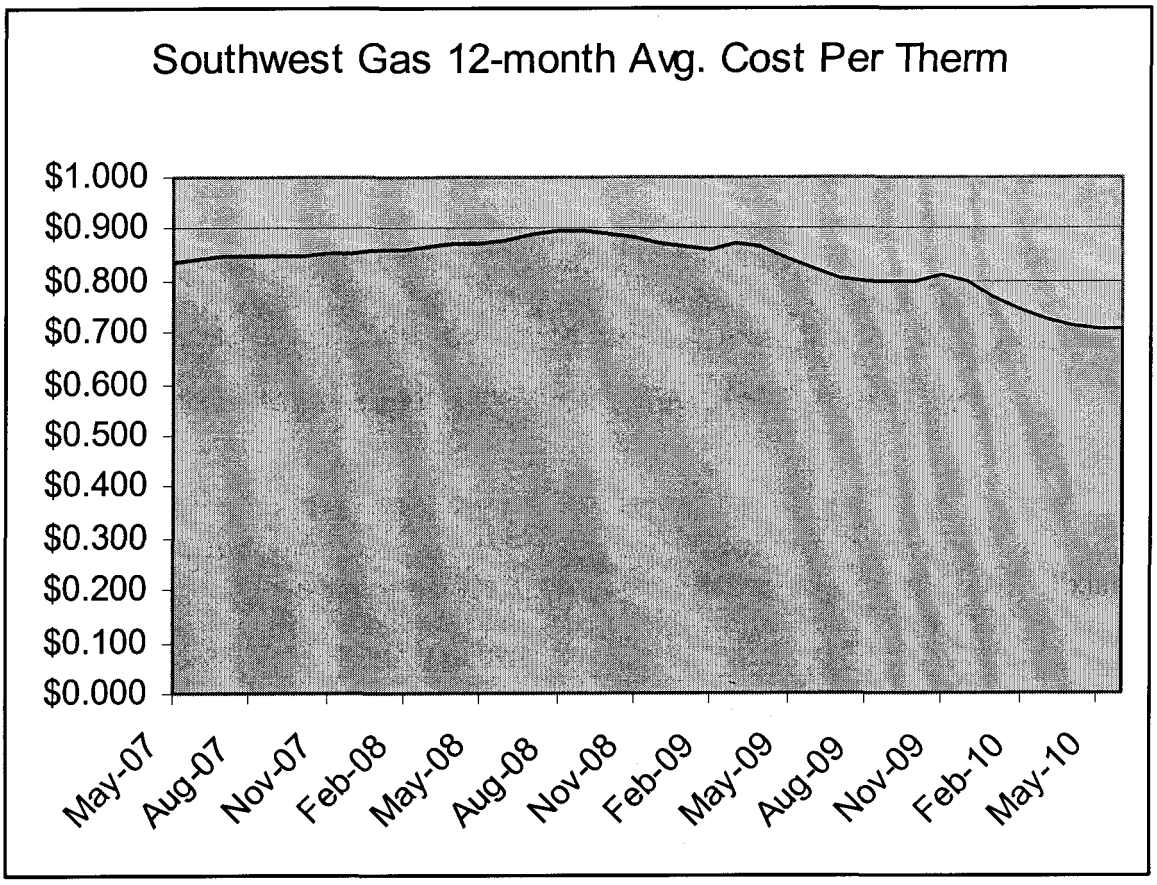
Southwest began receiving volumes in the Phoenix area from Transwestern's Phoenix Expansion beginning in June 2009. The graph below shows the volumes Southwest has received from Transwestern during the review period.



Review period

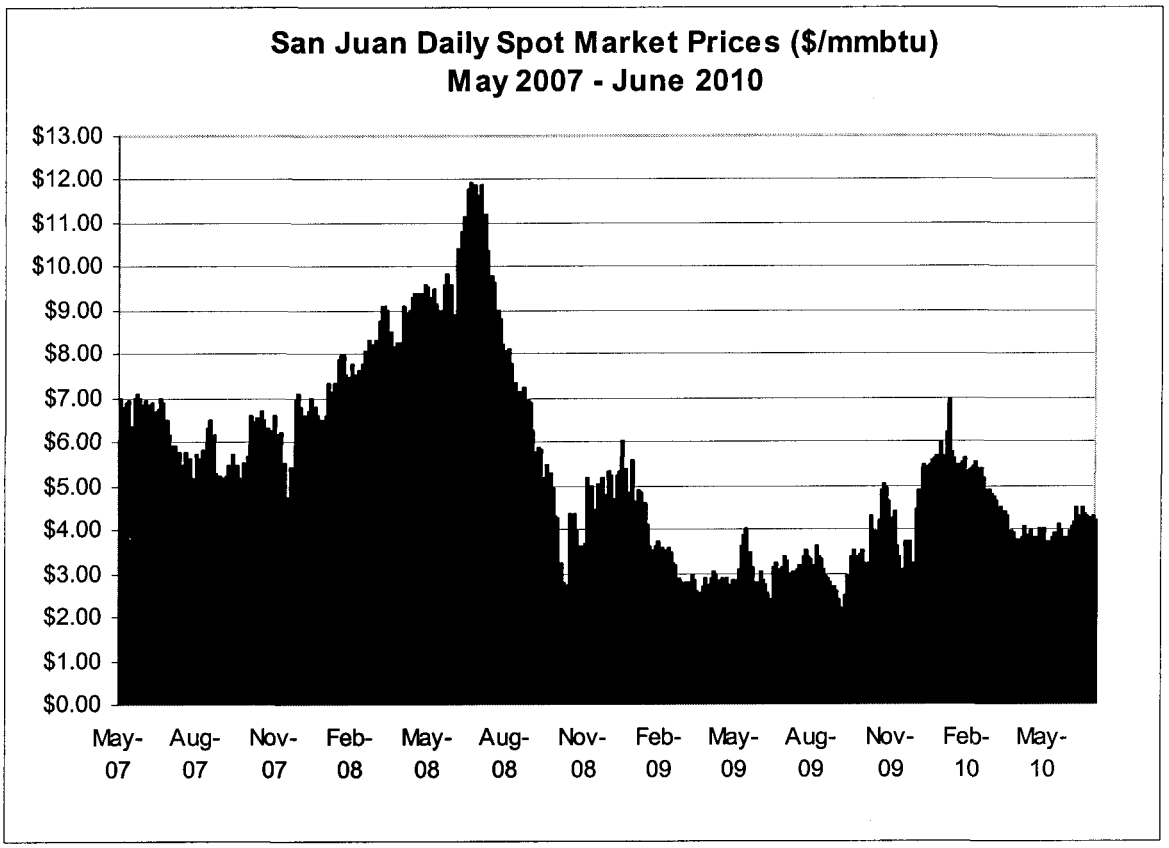
During the review period, Southwest's customer base showed moderate growth. In May 2007, Southwest had 963,101 total customers, compared to June 2010, where the Company had 978,512 customers.

The graph below shows the rolling 12-month average cost of natural gas for Southwest, including both the commodity cost and the interstate pipeline transportation cost. Cost per therm peaked in August and September 2008 at $0.895 per therm, with the lowest level being June 2010 at $0.707 per therm.



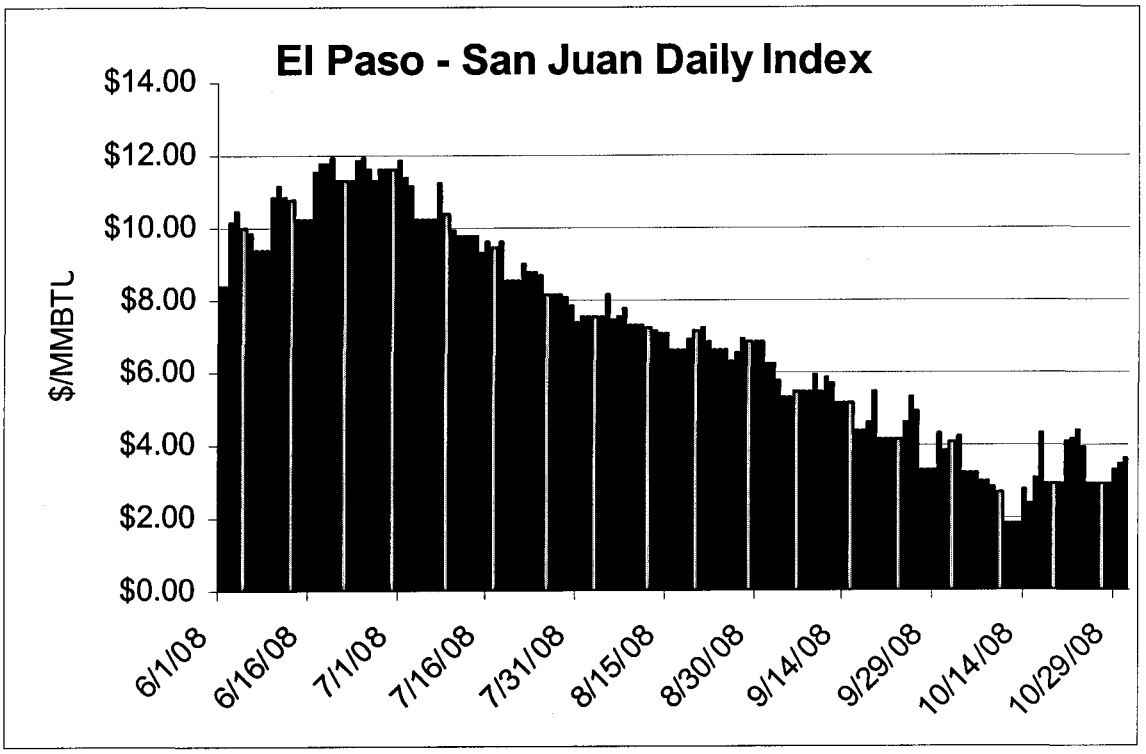
Market Conditions During the Review Period

The review period in broad terms had high and volatile prices early on, followed by much lower prices for the remainder of the review period due predominantly to prolific shale gas production. In contrast to the above graph showing Southwest's 12-month rolling average gas cost, the daily spot market price in the San Juan Basin during the same May 2007 through June 2010 timeframe was much more volatile, as shown in the chart below.



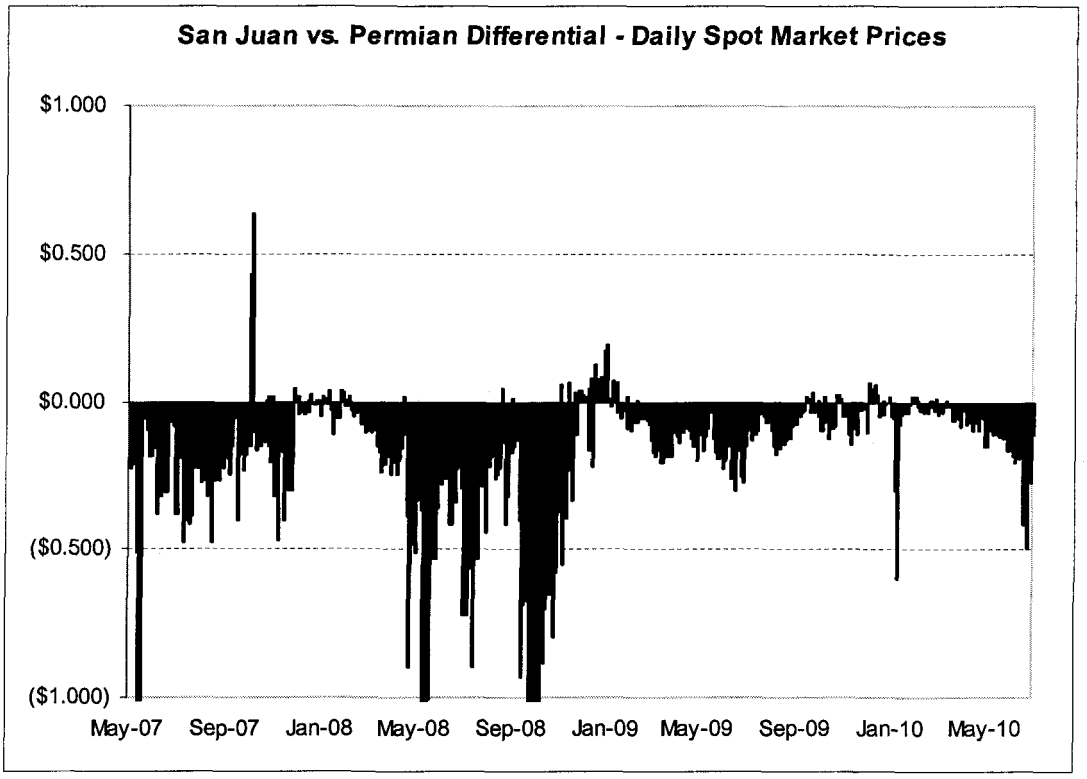
Source: Gas Daily

During the first year of the review period, natural gas prices were high, reaching well above $10.00 per MMBTU during the summer of 2008. During the summer of 2008, natural gas prices tumbled dramatically. The graph below shows the movement of prices during that summer.



Nationally, the explosive growth of shale gas was a primary driver in the lower natural gas prices the United States has experienced since the summer of 2008. The United States Energy Information Administration notes in its 2011 Annual Outlook that from 2006 to 2010, shale gas production increased at an annual average of 48 percent (page 2 of Executive Summary). During the review time period, pricing differentials between various natural gas pricing points declined around the country, due to a number of factors, including shale field development and construction of the Rockies Express pipeline by Kinder Morgan.

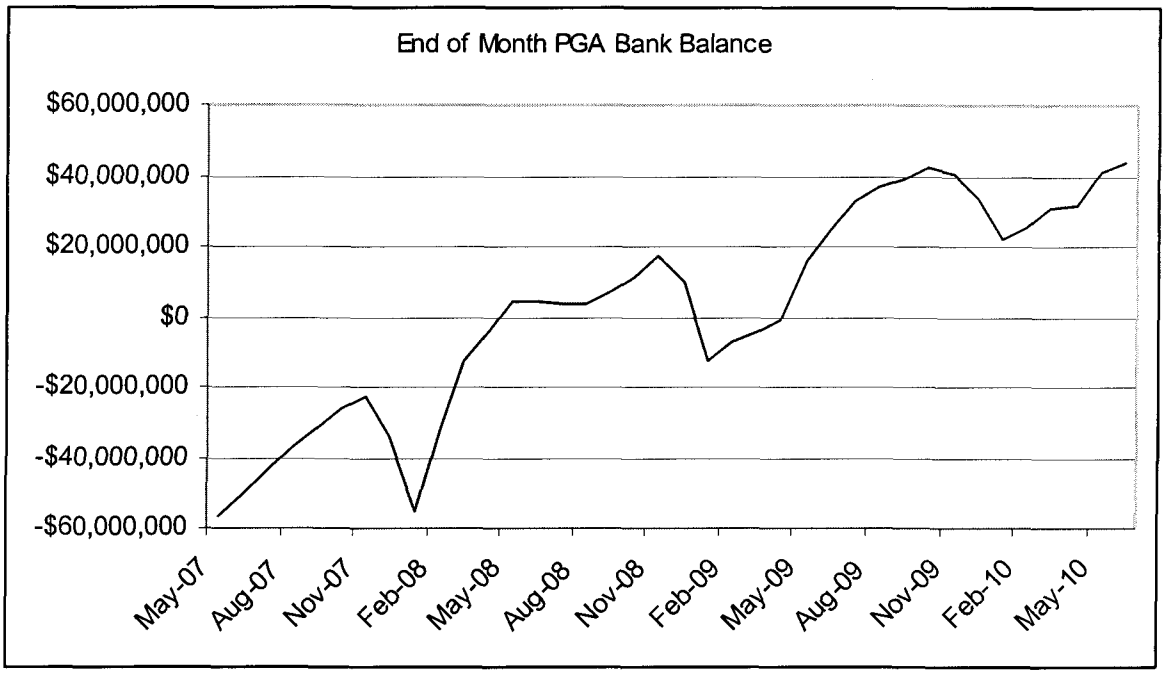
The San Juan and Permian supply basins are the two basins where Southwest gets virtually all of its natural gas supplies for its Arizona customers. Traditionally supplies from San Juan are cheaper than supplies from Permian, although this is not always the case, so Southwest and other Arizona entities typically try to source gas first from the San Juan basin, and secondly from the Permian basin. The graph below shows the differential between San Juan and Permian prices during the review period. A negative number means that the San Juan spot market price is lower than the Permian spot market price. A positive number means the Permian spot market price is lower than the San Juan spot market price.



Source: Gas Daily

The San Juan and Permian basins are not major shale production areas, but the growth in shale gas production had a dampening effect on natural gas prices across the country, including in the San Juan and Permian basins.

The chart below shows the end of month PGA bank balance for Southwest during the review period.



Note: A positive number reflects an over-collected PGA bank balance. A negative number reflects an under-collected PGA bank balance.

Review of Monthly PGA Reporting During Review Period

As part of this procurement review, Southwest's PGA reporting, contained in its monthly PGA report provided to the Commission, was reviewed. The monthly PGA report includes a monthly accounting for the PGA bank balance, consisting of the beginning of month PGA bank balance, inputs that increase and reduce the balance, and the end of month PGA bank balance. Other parts of the monthly PGA report include cost of gas details (commodity and interstate pipeline transportation costs), pipeline penalty charges incurred, calculations used in determining the next month's PGA rate, sales and customer numbers, average usage levels for residential customers, and an affidavit in support of the purchased gas adjustor report. Staff reviews the monthly PGA reports on an on-going basis, and consults with the Company if there are any anomalies or other issues with the report and works with the Company to resolve any outstanding issues. Thus, the review of monthly PGA reporting in this procurement review entails an overview of the on-going review Staff does. Staff does not have any outstanding issues with Southwest's monthly PGA reporting during the review period.

Core Customer Purchase Review

As part of the procurement review, Staff selected three random months to review the purchases made by Southwest as a spot check of their purchasing activities during the review period. Specifically, Staff reviewed Southwest's purchases during April 2008, August 2009, and January 2010. Staff compared the prices paid by Southwest to pricing information available in

the Gas Daily publication, including daily and monthly indices and futures contract prices. Staff also considered market conditions prevalent at the time contracts were entered into and Southwest's efforts to reduce price volatility as one of its supply portfolio goals.

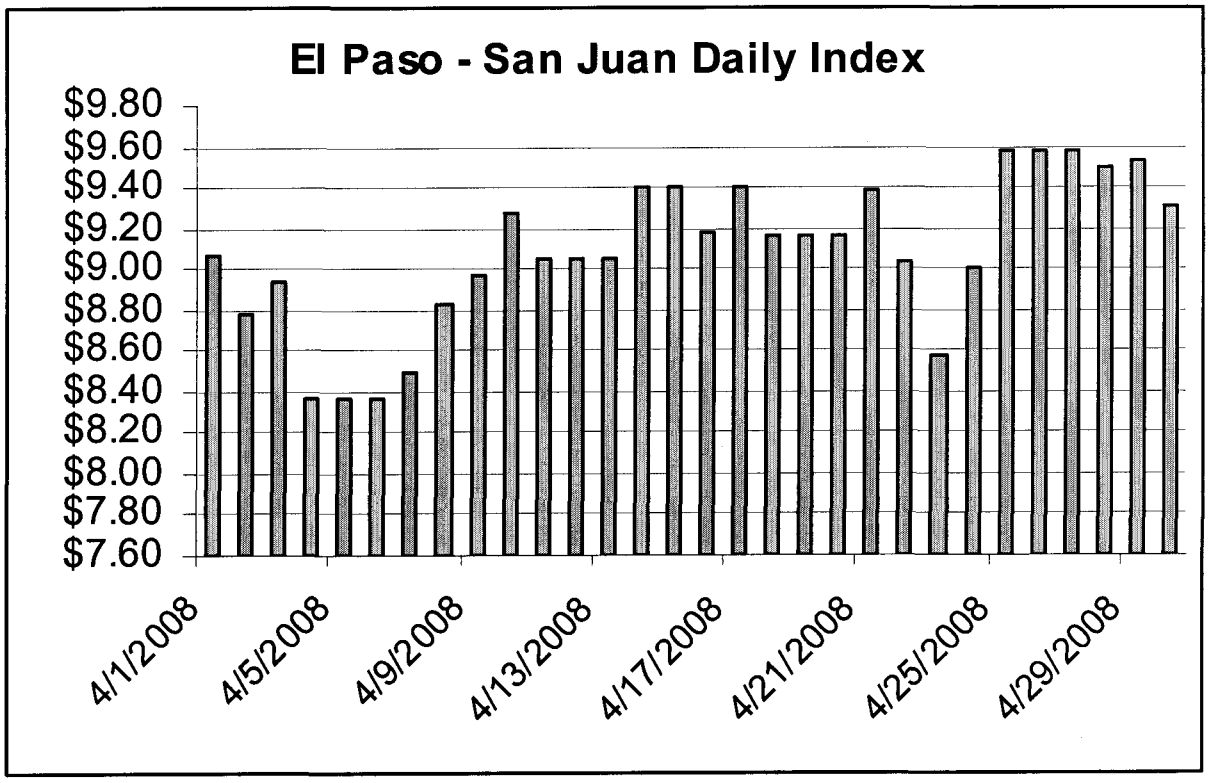
April 2008 Gas Purchases

In April 2008, Southwest had one seven-month fixed price contract in place as well as four one-year contracts in place with a total daily volume of 42,500 decatherms. These contracts were with four different suppliers and they were all sourced at either the Bondad Station or Blanco receipt points in the San Juan supply basin. The term of the seven-month contract was from April 2008 through October 2008. The term of the four one-year contracts was from November 2007 through October 2008. The contracts were entered into between January 1, 2007 and August 9, 2007.

The rest of Southwest's purchases in April 2008 were short term spot purchases, ranging from one to thirty days in length. These short term purchases were from 22 different suppliers. The receipt points involved in these purchases are Bondad Station and Blanco in the San Juan supply basin and Keystone and Waha-El Paso in the Permian supply basin. The vast majority of the short term deals were at a fixed price, with a small minority tied to indices published by the Gas Daily and Inside FERC publications. The table below details the contract lengths and daily volumes involved in the spot short term purchases.

Length of Contract	Number of Contracts	Total Daily Volumes (decatherms)
One Day	114	997,503
Two Days	1	4,200
Three Days	27	258,146
Four Days	2	20,000
Thirty Days	6	16,300

The graph below shows natural gas spot prices during April 2008 at the El Paso – San Juan pricing point, highlighting the high and volatile prices that were occurring during that time period.



Source: Gas Daily

Staff has reviewed the short term and longer term gas supply contracts in place during April 2008 and believes that the prices paid under them are reasonable given prevailing market prices and conditions.

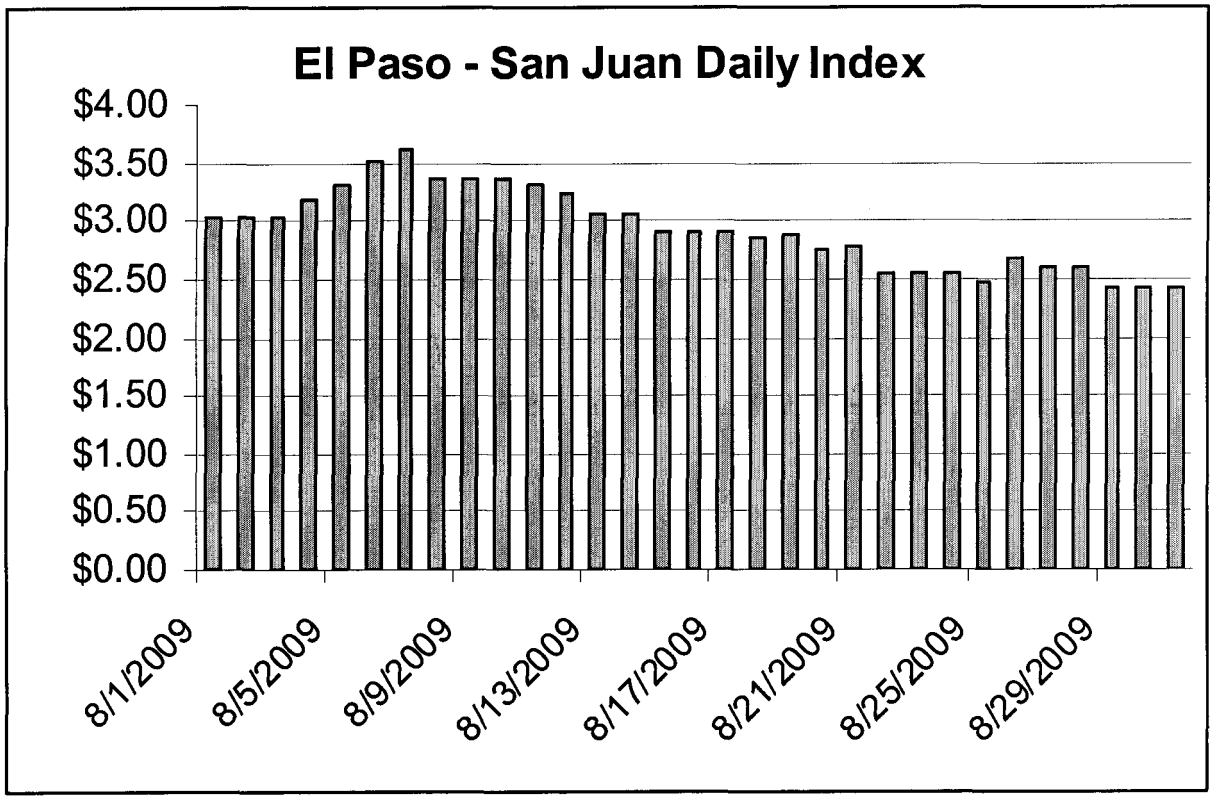
August 2009 Gas Purchases

In August 2009, Southwest had four seven-month fixed price contracts in place with a total daily volume of 35,000 decatherms. These contracts were with two different suppliers and they were all sourced at the Bondad Station in the San Juan supply basin. The term of all four contracts was from April 2009 through October 2009. The contracts were entered into between April 10, 2008 and August 13, 2008.

The rest of Southwest's purchases in August 2009 were short term spot purchases, ranging from one to thirty-one days in length. These short term purchases were from 18 different suppliers. The receipt points involved in these purchases are Bondad Station, Blanco, and TransColorado to Blanco in the San Juan supply basin and Keystone in the Permian supply basin. The vast majority of the short term deals were at an index price published in the Gas Daily and Inside FERC publications, with a minority having a fixed price. The table below details the contract lengths and daily volumes involved in the spot short term purchases.

Length of Contract	Number of Contracts	Total Daily Volumes (decatherms)
One Day	26	130,100
Three Days	15	51,300
Six Days	10	60,000
Seven Days	12	100,000
Thirty-One Days	39	32,900

The graph below shows natural gas spot prices during August 2009 at the El Paso – San Juan pricing point, highlighting the dramatic decline in prices that had taken place since mid 2008.



Source: Gas Daily

Staff has reviewed the short term and longer term gas supply contracts in place during August 2009 and believes that the prices paid under them are reasonable given prevailing market prices and conditions.

January 2010 Gas Purchases

In January 2010, Southwest had forty-five fixed price contracts in place with lengths ranging from one to twelve months. The table below details the contract lengths and volumes for the longer term contracts.

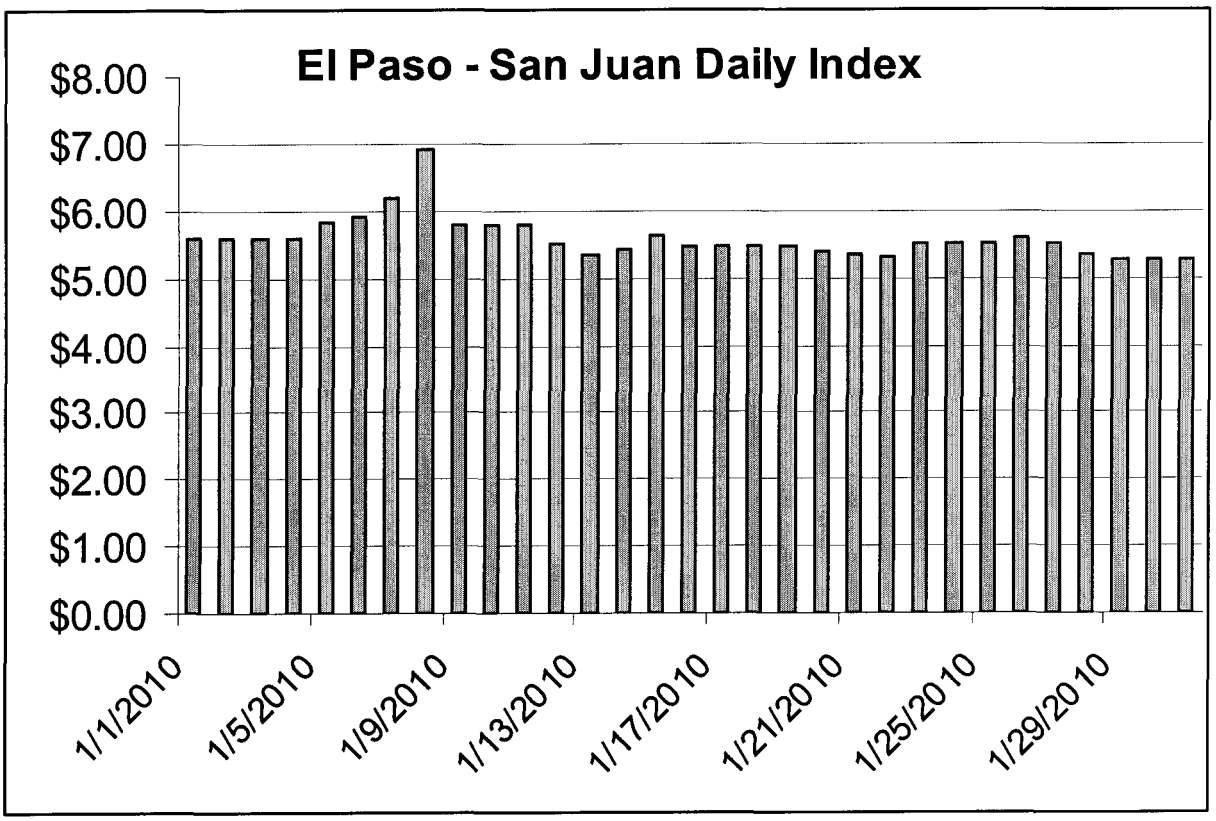
Length of Contract	Number of Contracts	Total Daily Volumes (decatherms)
One Month	4	98,868
Two Months	2	31,690
Three Months	3	55,000
Four Months	3	62,377
Five Months	30	635,871
Twelve Months	3	90,000

These contracts were with eleven different suppliers and they were sourced at the Bondad Station, Blanco, and Transwestern-San Juan receipt points in the San Juan supply basin and the Keystone and Waha-El Paso . The terms of the contracts have starting dates from November 2009 to January 2010 and ending dates from January 2010 to October 2010. The contracts were entered into between December 13, 2007 and October 8, 2009.

The rest of Southwest's purchases in January 2010 were short term spot purchases, ranging from one to thirty-one days in length. These short term purchases were from ten different suppliers. The receipt points involved in these purchases are Blanco, and Transwestern-San Juan in the San Juan supply basin, Keystone in the Permian supply basin, and one purchase from Plains in the Anadarko supply basin. The vast majority of the short term deals were at an index price published in the Gas Daily and Inside FERC publications, with a few having a fixed price. The table below details the contract lengths and daily volumes involved in the spot short term purchases.

Length of Contract	Number of Contracts	Total Daily Volumes (decatherms)
One Day	17	15,893
Three Days	4	22,700
Four Days	4	12,100
Thirty-One Days	4	19,864

The graph below shows natural gas spot prices during January 2010 at the El Paso – San Juan pricing point, highlighting the continued relatively low prices for natural gas during that time period.



Source: Gas Daily

Staff has reviewed the short term and longer term gas supply contracts in place during January 2010 and believes that the prices paid under them are reasonable given prevailing market prices and conditions.

Use of Financial Instruments

During the review period, Southwest utilized one form of financial instrument as part of its natural gas supply portfolio, entering into a number of fixed/float swaps during that time. Southwest has indicated that it continues to review the potential for using other forms of financial instruments, but the Company does not believe that any other form of financial instrument would be beneficial to use within its gas supply portfolio at this time. When Southwest is acquiring its natural gas supply portfolio, fixed/float swaps compete directly with traditional contracts for physical gas delivery.

A fixed/float swap financial instrument is a transaction where Southwest enters into a fixed price financial arrangement with a counterparty for a given volume of natural gas over a period of time. For example, Southwest entered into a fixed/float swap with Key Bank National Association ("Key Bank") on December 17, 2008, for a five month term of November 1, 2009 through March 31, 2010. The fixed price was $6.12 per million british thermal units ("MMBTUs") for a monthly volume ranging from 420,000 to 465,000 MMBTUs per month.

The Index Point referenced in the swap was the El Paso San Juan Gas Daily first of month index. So each month, the fixed price of $6.12 was compared to the first of the month El Paso San Juan index. If the index is higher than the fixed price, the counter party pays Southwest the difference. If the index is lower than the fixed price, Southwest pays the counterparty the difference. For the Key Bank swap, the first of month indices for the five months varied from $4.26 to $5.72 per MMBTU, resulting in Southwest paying Key Bank approximately $2.9 million over the term of the swap. Separately, Southwest actually procures physical supplies to meet its customers' natural gas requirements, given that the swaps are only financial transactions.

During the review period, Southwest entered into float/fixed swap transactions with Key Bank, JP Morgan Ventures Energy Corp, and Credit Suisse Energy. The table below summarizes these transactions.

Counterparty	Trade Date	Swap Term	Volume over Term (MMBTU)	Fixed Price ($/MMBTU)	El Paso – San Juan Index Range ($/MMBTU)	Profit/Loss of Fixed/Float Swap
JP Morgan	4/10/2008	12/08 - 2/09	1,800,000	$9.97	$3.11 to $4.83	-$10,339,200
JP Morgan	2/12/2009	4/10 – 10/10	2,140,000	$5.41	$3.22 to $4.28	-$3,492,600
Key Bank	12/17/2008	11/09 – 3/10	2.265,000	$6.12	$4.26 to $5.72	-$2,902,800
Credit Suisse	4/17/2009	12/09 – 1/10	930,000	$4.84	$4.28 to $5.72	$153,450
Credit Suisse	5/21/2009	12/09 – 3/10	1,210,000	$5.11	$4.28 to $5.72	-$149,050
Credit Suisse	6/11/2009	4/10 – 10/10	1,830,000	$5.48	$3.22 to $4.28	-$3,653,100

In total, Southwest's swaps during the review period involved a total volume of 10,175,000 MMBTUs, a relatively small portion of Southwest's overall gas purchases during that time period. The sum loss or payment to the counterparties during the review period was $20,383,300. This is a significant amount, with by far roughly half of the loss involving the three month swap with JP Morgan in late 2008 and early 2009. However, this loss should be considered within the broader context of Southwest's hedging efforts and the natural gas market conditions that existed during the review period. The fundamental purpose of hedging is not to achieve the lowest price, but rather to reduce volatility in the purchase of natural gas by Southwest, thus reducing the volatility Southwest's customers experience as natural gas costs are passed through by Southwest to its customers. The Commission has recognized the value of hedging natural gas prices over the years, including the decision that created the current PGA mechanism, Decision No. 61225 (October 30, 1998), which stated that "The Commission recognizes price stability as one of the goals of the natural gas procurement process." (page 2, Finding of Fact No. 9)

During the early to mid 2000s, as natural gas prices generally trended upward, Southwest's hedging efforts not only resulted in less volatile prices, but also saved ratepayers many millions of dollars in natural gas costs. In Staff's procurement review in Southwest's 2004-2005 rate case (Docket No. G-01551A-04-0876), Staff noted the following regarding Southwest's fixed price physical purchases at that time:

> "Over time it is to be expected that such fixed price contracts will at times end up being higher priced than actual market prices and at times end up being lower prices that actual spot market prices. In recent years natural gas prices have

generally been increasing. In such an environment, prices which have been locked in for a period of time generally result in lower than market prices over the term of the contract. Therefore Southwest's longer term, fixed price purchases in recent years have generally saved money over a situation where Southwest had bought all of its supplies based upon spot market indices. This has been a beneficial side effect of the longer term, fixed price contracts, but it should be recognized that at points where natural gas market prices may be in decline that such purchases will result in higher than spot market prices, tying back to the recognized goal of such contracts of introducing a measure of price stability." (Gray Direct Testimony, pages 29-30)

In contrast, recent years, including the review period, has been a period of generally declining natural gas prices. In such a market, hedging efforts will likely result in higher overall prices, but such a result is not necessarily a problem. These two time periods demonstrate that over time hedging will at times save money for customers, but will at other times cost more money for customers via changes in the PGA rate over time. Southwest currently has seven approved counterparties which it may enter into swaps with.

Specifically in looking at the swaps during the current review period, the April 2008 JP Morgan swap was entered into at a time when natural gas prices were quite high and trending upward, reaching a peak shortly thereafter on June 20, 2008 of $11.94 per MMBTU for the El Paso – San Juan index. Subsequently natural gas prices dropped precipitously, resulting in the JP Morgan swap appearing to be very expensive and resulting in a significant payment from Southwest to JP Morgan, but if prices had stayed at the June 2008 high or gone even higher, the JP Morgan swap would have saved Southwest and its customers a significant amount. On the day the JP Morgan swap was entered, April 10, 2008, the New York Mercantile Exchange natural gas futures for December 2008, January 2009, and February 2009 were $11.075, $11.30, and $11.265 per MMBTU. The NYMEX futures contract is based upon Henry Hub pricing, which typically trades at a premium to San Juan basin prices. But the premium is typically a dollar or less. Thus, the $9.97 price for the JP Morgan swap seems reasonable given market conditions. Further, it is worth noting that, while the JP Morgan swap resulted in a significant payment from Southwest, the net result is little or no different than if Southwest had directly contracted for natural gas supplies in April 2008 for the December 2008 – February 2009 time period. The loss just would have been built into the high cost of the directly contracted gas, rather than as a payment to the swap counterparty.

From the information available at this time, Staff believes that Southwest's use of swaps is a reasonable way for Southwest to diversify its hedging efforts and that it is reasonable for the direct costs of the swaps to be recovered by Southwest through its PGA mechanism.

Because use of such swaps by Southwest is a relatively recent phenomenon, Southwest's traditional reporting of information to the Commission does not always include detailed information regarding the swaps. Specifically, Southwest's Annual Gas Procurement Plan it files with the Commission does not contain a detailed discussion, explanation, and documentation of Southwest's use of financial instruments, and specifically its use of swaps in

recent years. Therefore, Staff recommends that in all Annual Gas Procurement Plans filed by Southwest, there be a separate section of the report providing a detailed explanation and documentation of the use of financial instruments by Southwest, and specifically at this time the swaps used by Southwest.

CNG Purchases

Between April 2008 and April 2009, Southwest provided compressed natural gas ("CNG") service to the Tartesso Subdivision ("Tartesso") in Buckeye, Arizona. Provision of CNG service is much more expensive than normal natural gas service through Southwest's distribution system. The reason for Southwest's provision of CNG service to Tartesso is that Tartesso was planned to be served off of Transwestern Pipeline's Phoenix Expansion project, a new pipeline that was built to, among other reasons, provide an alternative for interstate pipeline service in central Arizona. Tartesso was not located near Southwest's existing distribution system in the Phoenix area, and delays in construction of the Phoenix Expansion resulted in customers needing natural gas service in Tartesso, but having no way of having natural gas delivered through Southwest's existing distribution system or off of the Phoenix Expansion. The Phoenix Expansion was originally scheduled to go into service in May 2008, but due to siting difficulties and other delays, did not begin operations until March 2009. During that period, Southwest used CNG to serve the customers in Tartesso until such time as gas could be delivered to them off of the Phoenix Expansion. Natural gas was provided to Tartesso during this period by Southwest having natural gas delivered to an existing point on its Phoenix distribution system, and hiring a contractor to compress it and deliver it to Southwest's distribution line in Tartesso. Southwest spent a total of $3,160,638 for compression and transportation services to Rawhide Leasing Company, in addition to Southwest's cost of the natural gas commodity to serve Tartesso. Southwest delivered an estimated 159,520 therms to Tartesso during that period.

The delays in the in-service date for Transwestern's Phoenix Expansion were beyond Southwest's ability to control, and thus Staff believes that Southwest's steps to use CNG for a temporary period, while very expensive in comparison to normal natural gas service, was necessary to provide service to new customers within its certificated service territory in Tartesso. Southwest's only documentation that was provided to the Commission during this period was a line item on the monthly PGA reports that indicated the cost of CNG services each month such costs were incurred. Staff believes that it would be beneficial for Southwest to, in the future, provide an explanation in its monthly PGA reports anytime in the future it uses CNG supplies to provide service within its service territory. Specifically, Staff recommends that Southwest provide an explanation in any future PGA report when it begins to recover CNG costs for serving a given area through the PGA mechanism, indicating the reason(s) for such service, expected length such service will be necessary, and estimated cost and volume of such service.

Comparison of SPA purchases vs. Core Purchases

Southwest purchases natural gas both for its core customers and its special gas procurement agreement ("SPA") customers, who sign separate contracts with Southwest under Schedule G-30, Optional Gas Service. Schedule G-30 is available to customers who can demonstrate one or more of the following criteria:

1. Customers whose average monthly requirements on an annual basis are greater than 11,000 therms per month and who have installed facilities capable of burning alternate fuels or energy.
2. Customers whose average monthly requirements on an annual basis are greater than11,000 therms per month and who can demonstrate to the Utility sufficient evidence of economic hardship under the customer's otherwise applicable sales tariff schedule.
3. Customers whose requirements may be served by other natural gas suppliers at rates lower than the customer's otherwise applicable gas sales tariff schedule. As a condition precedent to qualifying for service under this applicability provision, the customer must qualify for transportation service under Schedule No. T-1 and establish that bypass is economically, operationally and physically feasible and imminent.

Typically in the past the threat of bypass, in the form of taking service directly from a nearby interstate pipeline, has been the main reason why customers have been able to take service under Schedule G-30. Southwest assesses the viability of the threat of bypass, and if it believes the threat is real, it negotiates a SPA with the customer, typically offering a discount off of what the customer would pay under its other applicable tariff(s), but receiving some level of contribution from the customer to help pay for system costs. Southwest then is required to file the SPA with the Commission for approval. Under SPAs, Southwest acquires natural gas supplies for the SPA customer.

In the past the Commission has taken an interest in the prices paid by a utility for natural gas commodity purchases for both core and noncore customers, to ensure that core customer purchases do not suffer as a result of Southwest's efforts to procure the best supplies for its noncore customers. A primary way of comparing a local distribution company's ("LDC") purchases for core and noncore customers is to compare purchases that are similar in nature that were made during the same period of time for core and noncore customers. Staff held a number of discussions with Southwest regarding its purchases for SPA customers and reviewed data provided by Southwest regarding SPA purchases. Information provided by Southwest indicates that during the period of this review, there were periods of time when there were comparable purchases made for both core and noncore customers. Thus, Staff has no reason to believe there are any potential, let alone actual, conflicts of interest between core and noncore purchases.

Summary

In summary, Staff finds that Southwest's procurement activities during the review period of May 2007 through June 2010 are prudent. Staff further makes the following recommendations to update the information provided by Southwest to the Commission regarding its gas procurement and PGA activities:

1. Staff recommends that in all Annual Gas Procurement Plans filed by Southwest, there be a separate section of the report providing a detailed explanation and documentation of the use of financial instruments by Southwest, and specifically at this time the swaps used by Southwest.
2. Staff recommends that Southwest provide an explanation in any future PGA report when it begins to recover CNG costs for serving a given area through the PGA mechanism, indicating the reason(s) for such service, expected length of time such service will be necessary, and estimated cost and volume of such service.

Section of May 22, 2008 Staff Report on Semstream Propane Arizona

7. What other alternatives exist for utility service to Payson? UNS Gas, Southwest Gas, and other options.

Given the very high price of propane and the likelihood that propane will remain an expensive fuel for home heating and other uses, one matter for possible consideration is whether some other utility service option would be possible for Payson. With natural gas prices current roughly half of what propane costs, extension of natural gas service to Payson by one of Arizona's natural gas local distribution companies is one potential option to provide some relief to propane users in Payson.

Semstream indicated that at the time Great Falls Gas Company purchased the Payson Division from Broken Bow, that Great Falls considered the possibility of extending natural gas service to Payson. Semstream indicated that its understanding is that Great Falls found that the volume of sales available in Payson did not justify the cost of building the infrastructure necessary to bring natural gas to Payson. One complication was that the system would have needed to be run at a very high pressure, possibly 800 pounds per square inch ("psi"), due to the significant length of the line that would run to Payson from Camp Verde or another distant location. This pressure level is higher than most end users require, even for power plant operations. To provide this level of pressure would have led to additional costs. Another difficulty that was identified was that the Payson Division has a number of satellite systems serving small groupings of customers that are too distant from the underground system to economically interconnect. These satellite systems can be served with propane service via truck delivery with little difficulty, a delivery mechanism that would not work nearly as well for natural gas. If natural gas service were to reach Payson, it is not clear how customers of these satellite systems would continue to receive service from the Payson Division.

However, extension of natural gas service to Payson faces a number of significant obstacles. Staff has held high level discussions with UNS Gas and Southwest Gas, two natural gas utilities that could potentially extend service to Payson from their existing service territories.

UNS Gas indicated to Staff that its closest facilities to Payson are in Camp Verde. Extension of service to Payson would involve construction of a 54 mile pipeline, with an initial estimate from UNS Gas of a cost of approximately $60 million (roughly $170 to $200 per foot). This amount does not include any additional costs to tie into the local distribution system in the Payson area.

For Southwest Gas, its closest facilities are in Fountain Hills, resulting in a 53 mile pipeline extension if it were to extend service to Payson. Southwest indicated an initial cost estimate would be over $50 million. Southwest believes that if the costs of such an extension were paid specifically by customers in the Payson area, that rates in Payson would be significantly higher than Southwest's general Arizona tariffs. Southwest did indicate that rate

treatment would be a significant issue in determining the economics of the project. If the costs of the extension were given rolled-in treatment, spreading them over all Southwest's customers, Southwest believes that such an increase for all Arizona customers would be a single-digit percentage increase.

If an effort were made to tie directly into the nearest interstate pipeline, this would be El Paso's Maricopa Lateral which roughly tracks the I-17 highway coming down from Flagstaff and is approximately 50 miles west of Payson. Southwest Gas indicated it believed an extension connecting directly to El Paso's system would cost upwards of $50 million.

Beyond the significant cost of extending a pipe to Payson, a number of other issues would need to be addressed. Any line would run through significant amounts of rugged territory such as national forest land and possible national wilderness land, raising possible environmental issues and construction challenges. For UNS, the entire route would traverse national forest land and possibly national wilderness land. There is an Arizona Public Service Company ("APS") transmission line that runs roughly from Camp Verde to Payson, so that route would be one possibility. Another possibility would be to try to have such a line follow the the 260 and 87 Highways at least for portions of the way to Payson. For Southwest Gas, there are several APS transmission lines running from the Cholla generating station through the Payson vicinity and down into the Phoenix area, providing one possible existing right-of-way to explore. Without further investigation, Staff does not know whether any space exists in the APS right-of-way. Another possibility would be for the route to run along Highway 87 from Fountain Hills to Payson. Other possible land issues for Southwest Gas could be the McDowell Mountain Regional Park and the For McDowell Indian Reservation, which skirt Fountain Hills on the north and east. Between the land status and the rugged geology to be crossed, finding a route for a natural gas line extension to Payson would be a challenging endeavor.

Another possible cost issue for a UNS Gas or Southwest Gas expansion would be whether their backbone pipeline systems, which currently deliver gas to Camp Verde and Fountain Hills, have spare capacity to serve the additional load Payson represents. The distribution lines serving Camp Verde and Fountain Hills are at the end of their respective distribution systems and may not have the spare capacity to also be able to handle throughput for potential new demand in Payson. Thus, it seems likely that some amount of additional facilities would need to be added so that the upstream distribution system would be able to handle the additional throughput to which an extension to Payson would lead.

If a way were found to extend a natural gas line to Payson, another issue to be addressed is that Semstream currently holds a Certificate of Convenience and Necessity to serve Payson and surrounding areas and owns the propane distribution system in the Payson area. Semstream paid approximately $15 million to acquire the Payson Division from Energy West in 2006. It is unclear how the extension of a natural gas distribution line by UNS Gas or Southwest Gas for natural gas service in Payson would be made compatible with Semstream's ownership of and investment in the Payson Division. Possibilities would include the acquisition of the Payson Division by UNS Gas or Southwest Gas, or some other arrangement between Semstream and the natural gas LDC.

On a general note, Staff has observed over time that major gas line extensions in Arizona are often the result of the natural gas demand by a large end user, who serves as a sort of "anchor tenant" to give critical mass to demand for the line extension. Staff is not aware of what, if any, large commercial or industrial entities may exist in the Payson area that could serve as an anchor tenant, but if such an end user were identified, it could significantly improve the economics of getting a natural gas pipeline built to Payson.

A historic experience of note is the major buildout program Citizens Utilities ("Citizens"), now UNS Gas, undertook in the 1990s to upgrade the distribution system and extend natural gas service to a number of new communities in northern Arizona. Citizens Utilities' buildout program was ordered as part of Citizens' acquisition of the Arizona natural gas distribution system assets of Southern Union Gas Company and reflect significant concerns at the time regarding the safety and maintenance of the Southern Union system. Citizens Utilities' buildout program has a long and complex history, with the program costing significantly more and taking significantly longer to build than was initially projected. The program provided for customers in communities where natural gas service was extended to, to pay a 50 percent bill adder for a number of years to contribute toward the costs of extending service. Given delays in construction, lower than expected penetration levels, and other factors, these new customers' contributions to the cost of the extensions was less than expected. In combination with higher than expected costs, Citizens' existing customer base ended up paying higher rates to help pay for the buildout program, resulting in some level of cross-subsidization between existing and new customers. Given the likely high cost of extending a natural gas pipeline to Payson, the Commission would need to carefully balance the various interests of both new customers in Payson and existing natural gas utility customers as it considers cost recovery, ratemaking treatment, and other issues.

Another possible option would be to truck liquid natural gas ("LNG) into Payson and the regasify it for distribution via the existing distribution system. As with any option bringing natural gas into Payson, there would likely be some costs to adjust the local distribution system to distribute natural gas rather than propane. However, the larger barrier to bringing LNG to Payson would be the significant investment in liquefaction and regasification facilities. The cost of such LNG would be noticeably higher than natural gas delivered through a normal pipeline system, but if the price differential between propane and natural gas was large enough over a sustained period, such a system could be a possibility.

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-12
(ACC-STF-12-1 to ACC-STF-12-18)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 12, 2011

Request No. ACC-STF-12-18:

The Commission held town halls in southern Arizona on April 6 and 7, 2011 regarding the February 2011 service outages. At the town halls numerous members of the community expressed concern with Southwest's communications during the outages. Please provide a plan in response to this data request, identifying how Southwest will improve both how it communicates with its customers and what information is communicated with its customers regarding any future service outages in Arizona.

Respondent: Conservation and Demand Side Management

Response:

Southwest Gas Corporation (Southwest) has heard its customer's concerns related to the recent outage in Arizona. Customers asked that Southwest provide information that is timely, clear, pertinent, and easily accessible in the event of an emergency situation. Although Southwest's primary objective is to protect people and property, the Company understands the growing demand for enhanced communications and strives to meet the needs of its customers. Southwest has addressed customer concerns with communications during outages by supplying additional means of communication through social media, a map-based application, server redundancy, Reverse 911, and predictive dialing, as further described below. These solutions provide clear, pertinent, and timely information that is readily available and easily accessible.

One of the most frequently used, easily accessible means of communication is the internet. Southwest is incorporating several enhancements to web applications to improve customer communications. Southwest has also created Twitter and Facebook accounts in order to post timely updates in the event of an emergency. The Company's communications experts are developing the internal support needed to keep the information that is posted on these venues current and readily available.

Southwest understands that its customers would like visual representation of the outage and restoration areas. The Company's technology experts have developed an in-house Outage Mapping System (OMS) which is a map-based application used to illustrate the impacted area and the estimated number of affected customers. The application is easily accessed through the Southwest My Accounts web page. OMS provides an additional means of posting information and providing updates on outage restoration efforts. To increase the reliability of Southwest's web applications, Southwest will be utilizing additional servers in separate, off-site locations. Server redundancy will ensure the accessibility of the Company's web applications by utilizing the secondary server as needed.

For those customers who do not access the internet frequently, Southwest is incorporating additional methods of communication via telephone. Reverse 911 can be used to record an emergency message to distribute to the public through the local counties. Southwest understands that Reverse 911 has limitations including message duration, current phone listings, geographical area, and county availability. To better meet the needs of Southwest's customers, the Company is developing in-house predictive dialing which will contain specific contact information for its customers. This will allow customers to choose their preferred contact telephone number whether it be a cell, house, or work phone.

The Company's efforts to improve its communication with customers are on-going, and the Company will continue to provide enhancements with the advancement of technology.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
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 ITS PROPERTIES THROUGHOUT ARIZONA	)	DOCKET NO. G-01551A-10-0458

DIRECT

TESTIMONY

OF

BRYAN FRYE

SENIOR PIPELINE SAFETY INSPECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 10, 2011

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EXECUTIVE SUMMARY
SOUTHWES GAS CORPORATION
DOCKET NO. G-01551A-10-0458

The Direct Testimony of Staff witness Bryan Frye addresses the following issues from the perspective of the Arizona Corporation Commission Office of Pipeline Safety:

1. Southwest Gas Corporation ("SWG") request to include the remaining money for the replacement cost of the Manors subdivision gas distribution system in Yuma, AZ,
2. A deferral account for a proposed two year pilot program to remove 5,000 Customer Owned Yard Lines ("COYL"),
3. A proposed Multiple Rate Customers plan, and
4. A deferral account for the replacement of Early Vintage Plastic Pipe ("EVPP").

Staff makes the following recommendations:

1. The remaining $225,445 from the Manors Subdivision replacement in SWG's most recent rate case should be disallowed from consideration in these proceedings and future rate case proceedings. SWG's original intention was to extend the service life of the pipeline system by installing new cathodic protections ground bed before incorrectly connecting the wires backwards on the rectifier causing the pipeline to corrode at an accelerated rate.
2. A deferral account for the two-year pilot program to replace 5,000 COYL should be disallowed because SWG has failed to provide any documentation regarding how or if this project would benefit the safety of the public.
3. SWG should use configuration number one or three in the attached diagrams in regard to the proposal for multiple rate customers.
4. SWG should continue with the replacement of EVPP and provide documentation of progress and money spent in these proceedings and in future rate cases.

INTRODUCTION

Q. Please state your name and business address?

A. My name is Scott Bryan Frye Jr. My business address is 2200 N. Central 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 Senior Pipeline Safety Inspector; I have been employed by the Arizona Corporation Commission ("Commission") for over 4 years.

Q. Please describe briefly your duties as a Senior 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 and providing testimony on behalf of the Commission.

Q. Please describe your education, training and pertinent work experience.

A. I have over 4 years experience as a Pipeline Safety Inspector with the Commission, where I have been sent to numerous Training and Qualifications classes in Oklahoma City that are conducted by The Department of Transportation Office of Pipeline and Hazardous Materials Safety Administration ("PHMSA"). Attached is a list of those specific classes. Prior to my time with the Commission I have over 10 years experience in the field of utility locating, design, and engineering. (See Attachment No. 1.)

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. The costs associated with the replacing of the distribution pipeline system in the Manors subdivision in Yuma, Arizona,
2. The two-year pilot program Southwest Gas Corporation ("SWG" or "Company") purposes for replacing Customer Owned Yard Lines ("COYL"),
3. The proposed multiple rate customer meter options, and
4. The proposed deferral account requested for the replacement of Early Vintage Plastic Pipe ("EVPP").

MANORS SUBDIVISION YUMA, ARIZONA

Q. Have you reviewed the information and documentation regarding the Manors replacement project in Yuma?

A. Yes, I have reviewed SWG's testimony in this case, the Direct Testimony of Corky Hanson (See Attachment No. 2) in Docket No. G-01551A-07-0504 (2008 rate case) and Decision No. 70665.

Q. Has Staff's position changed since the 2008 rate case with regards to allowing the remaining $225,445 in rate base as part of this case?

A. No, Staff's position has not changed on this matter. As Corky Hanson testified, the circumstances that necessitated the immediate replacement of this system were the direct result of incorrect actions taken by SWG personnel, resulting in the failure of the Manors' system.

Q. Explain the action taken by SWG personnel that caused the failure.

A. During the SWG annual code compliance audit in 2006, conducted by Staff, it was noted on the inspection report that SWG had not taken prompt remedial action to correct deficiencies of the Manors cathodic protection ("CP") identified during the annual CP monitoring done by SWG. The CP deficiency was identified on March 26, 2004. SWG did not complete remedial action until February 28, 2006. Failure to provide adequate and proper CP on a steel pipeline system can lead to deterioration of the pipeline resulting in leaks and ultimately the replacement of the pipeline. The technician responsible for making repairs to the CP rectifier system connected the wiring backwards (positive to negative / negative to positive); i.e., the wiring was improper. This action caused the pipeline to corrode at an accelerated rate resulting in multiple corrosion failures and necessitating the immediate and premature replacement of the steel pipeline system. SWG personnel did not identify this mistake until the system failed and required replacement.

Q. Based on your experience, could the Manors steel pipeline system have lasted for many more years if adequate CP had been properly applied?

A. Yes, based on my CP training and experience as a Pipeline Safety Inspector, this system could have lasted for many more years. Staff members Mr. Marion Garcia (Chemical Engineer) and Mr. Ryan Weight (Mechanical Engineer) were consulted on this issue as well. Both have extensive CP experience, and both agree with Mr. Hanson's and my assessment of this system. Pursuant to State and Federal regulations, SWG had the option to either replace the pipeline with plastic pipe (which does not require CP), or install CP.

Ground bed anodes on impressed current systems are normally designed to last a minimum of 20 years, when properly installed. When SWG made the decision to replace the ground bed anodes, instead of replacing the pipelines at the Manors, it was evident that

the pipeline was in a condition that could be preserved (otherwise why replace the ground bed anodes). Clearly, the intent was to extend the service life of the Manors' system. One of the primary reasons for SWG to expend the cost and effort to replace the CP ground bed anodes to restore CP to the Manors' steel pipe system must have been to extend the service life of this system. Through only 11 months of operation using an incorrectly installed rectifier, the pipeline was corroded to the point of needing to be replaced sooner than otherwise would have been required. It is true that the pipeline had been in service for 50 years. However, as SWG's service life extension efforts demonstrate, there was no need at that time to replace the pipeline. SWG's actions were consistent with Staff's belief that the pipeline had significant remaining life that could have been extended with proper CP.

But for the improper repairs made by SWG personnel, the Company would not be incurring the expense of prematurely replacing the Manors' system. It is Staff's opinion that SWG customers should not have to pay for replacement of the Manors' system when it was the Company's own mistakes and improper repairs that led to the system's failure and need for replacement.

Q. Therefore, should SWG be allowed to recover from ratepayers any portion of the remaining $225,445 requested in this rate case?

A. No.

CUSTOMER OWNED YARD LINES

Q. Have you read the information pertaining to the two year pilot program proposed by SWG for the replacement of 5,000 Customer Owned Yard Lines?

A. Yes.

Q. Does Staff have any concerns with the pilot program?

A. Yes, this pilot program will only eliminate a maximum of 5,000 COYL at a cost of $10,000,000. This is only a small percentage in a small area of the 108,000 COYL estimated by SWG. Using this total, the entire replacement project would cost rate payers approximately $216,000,000. SWG has failed to provide adequate documentation delineating the effect on public safety of replacing or not replacing these lines.

Q. Does Staff have any concerns with COYL not maintained by SWG?

A. Any pipeline not maintained could cause a risk to the public. However, instead of immediately replacing these COYL, Staff recommends that SWG conduct a leak survey of all COYL to determine if there is a need for replacement of all lines or only some lines, and how lines will be selected for replacement. Based on information available, SWG estimates that this leak survey should cost approximately $3,000,000.

Q. Does Staff believe it is feasible to conduct this leak survey?

A. Yes, Staff has researched Remote Methane Leak Detection ("RMLD") technology and feels as though this is a simple and quick way to survey an area of which SWG may not have knowledge of the exact location of installed piping or may not have access to the property.

Q. What is RMLD?

A. RMLD is new technology in leak detection which allows the user to detect leaks remotely from up to 100 feet away. This would allow SWG to scan an entire property quickly without having to enter the private property.

MULTIPLE RATE CUSTOMERS

Q. Have you reviewed the information and drawings provided by SWG relevant to Multiple Rate Customers and SWG possible meter configurations for separate appliance metering submitted to the Commission by SWG on February 9, 2011?

A. Yes I have. In a March 14, 2011 letter to Steve Olea, SWG proposed three different possible customer gas meter configurations to address the issue of end-use specific rate scheduling. (See Attachment No. 3.)

Q. Would you please briefly describe each suggested configuration and state whether or not Staff supports each of the SWG proposals?

A. I will address them in the order they were presented. The first configuration includes a SWG primary meter and SWG-owned sub-meter located downstream on the customer-owned house line just ahead of the appliance it serves. This is an acceptable configuration since SWG would remain responsible for all maintenance and accuracy of the sub-meters.

In the second configuration SWG proposes to provide a primary customer meter but any sub-meters would be customer-owned. In this configuration the customer would be responsible for the cost of the sub-meter and be responsible for the maintenance and accuracy of the sub-meter. Staff does not support this configuration.

The third configuration requires SWG to provide a primary meter to be installed and provide service to individual house lines providing service to different appliances. This is also an acceptable configuration since there are no sub-meters and all metering provided is done prior to the point of transfer from the SWG-owned lines to customer-owned lines.

Q. What are your recommendations for the Multiple Rate Customers?

A. Staff agrees that both configuration numbers one and three would be acceptable and configuration number two would be unacceptable.

Q. In configuration No. 1, SWG would own meters downstream of their original meter. In Staff's opinion, who would be responsible for the maintenance of the line between the SWG original meter and the SWG downstream meter?

A. Staff believes the ownership of the line between the original SWG meter and its downstream meter should remain with the customer, so the customer would retain responsibility for that piece of the line.

EARLY VINTAGE PLASTIC PIPE REPLACEMENT

Q. Are you familiar with the 20-year replacement plan for Early Vintage Plastic Pipe ("EVPP")?

A. Yes, I am. This is a proposal for a deferral account for the replacement of all EVPP in the current SWG system.

Q. Please briefly explain what EVPP SWG is replacing?

A. As per the testimony of Jerome Shmitz with SWG, the Company has four types of EVPP - Acrylonitrile Butadiene Styrene pipe ("ABS"), Aldyl A pipe ("AA"), Aldyl High Density pipe ("AHD") and Polyvinyl Chloride pipe ("PVC").

Q. Please explain the reasons for the need to replace EVPP?

A. ABS and PVC piping is pipe that was installed prior to any code requirements and the AA and AHD piping have shown a history of becoming very brittle and failing over time.

Pipeline and Hazardous Materials Safety Administration Training and Qualifications for Scott Bryan Frye Jr.

5/24/2011 - 5/25/2011

PHMSA-PL1245 Safety Evaluation of Distribution Integrity Management Programs ("DIMP")

Participants will be able to conduct meaningful safety evaluations of distribution integrity management programs/plans. They will have a basic knowledge in specific technical areas regulated by 49 Code of Federal Regulations ("CFR") Part 192, Subpart P and risk analysis processes.

3/28/2011 – 4/1/2011

PHMSA-PL3291 Fundamentals of Supervisory Control and Data Acquisition ("SCADA") System Technology and Operation Course

The course objectives include enabling participants to make field and record inspections to determine whether the design and installation of a SCADA system is adequate, whether the operator has adequate written maintenance and inspection procedures for his/her personnel and whether these procedures have been followed. Participants will be able to determine whether the operator maintains appropriate records for system logs and alarms, as well as the necessary responses, corrections and investigations. As a result of this training, participants will also have a general knowledge of the basic design, installation, operation and maintenance of station equipment and protective systems. They will become familiar with how data is collected and properly assimilated, along with the basic analytical tools available through modeling and data analysis.

8/17/2011 – 8/20/2011

PHMSA-PL2288 Safety Evaluation of Breakout Tanks Course

Participants will be able to conduct meaningful safety evaluations of breakout tanks and their related pipeline, and be cognizant of the Office of Pipeline Safety ("OPS") inspectors' responsibilities versus those of the Environmental Protection Agency and Coast Guard inspectors. They will have a basic knowledge in specific technical areas regulated by 49 CFR Part 195, such as welding, cathodic protection, hydrostatic testing, under tank leak detection and safe repair, alterations and relocation of breakout tanks.

6/8/2010

PHMSA-PL3IC - Investigating and Managing Internal Corrosion of Pipelines Web Based Training ("WBT") Course

This WBT provides an overview of the causes, types, monitoring and remediation aspects of the corrosion process as it affects the interior walls of steel natural gas and hazardous liquid pipeline systems. Also covered are the mechanisms which trigger internal and bacterial corrosion, identification of locations where corrosion is most likely to occur, means and techniques of corrosion prevention and mitigation, field testing and sample collection, and laboratory analyses which may be utilized.

Q. Is the removal of EVPP an improvement to the safety of SWG's system?

A. Yes, Staff is an advocate of replacing these pipelines which have a history of failure or are not approved in the current editions of federal and/or state code.

Q. What does Staff recommend regarding the replacement of the EVPP, from a Pipeline Safety perspective?

A. Staff supports this project, from a safety perspective. However, with regard to Staff's position on how this should be treated from a ratemaking perspective, that will be discussed by other Staff witnesses.

USED AND USEFUL

Q. Have you examined the SWG's system with regard to used and useful?

A. Yes. During the 2011 Standard Annual Audit conducted by our office, I visited seven of the SWG districts and visited numerous field locations and projects in each district.

Q. Did you find any of the SWG system to be not used and useful?

A. No

Q. Based on Staff's Pipeline Safety 2011 Standard Annual Audit of SWG, how would you describe the general condition of SWG's system?

A. Staff did identify some Probable Non-Compliance items during its audit of SWG, but Staff did not find any items of significance and SWG adequately addressed all items identified. Staff believes that SWG's system is in good condition.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

6/8/2010

PHMSA-PL3OQ Operator Qualification WBT Course

This WBT covers basic fundamental concepts concerning the regulations, protocols, and inspection forms for gas pipelines as they relate to operators of small gas systems.

9/21/2009 – 9/25/2009

PHMSA-PL3257 Pipeline Safety Regulation Application and Compliance Procedures Course

This course addresses proper enforcement procedures associated with 49 CFR Part 190 and related State requirements for enforcement. Guidelines for deciding and taking appropriate enforcement actions are stressed through class participation in mock enforcement cases. A special attempt is made to emphasize standardization of rule application and enforcement.

9/14/2009 – 9/18/2009

PHMSA-PL2258 Safety Evaluation of Hazardous Liquid Pipeline Systems Course

This course is designed as introductory training to describe the design and operation of a hazardous liquid pipeline system in relation to 49 CFR Part 195 requirements. The training allows attendees to participate in discussions of terms, definitions and specific pipeline regulation requirements. The course will also provide guidance and fundamental training for inspectors involved in evaluating hazardous liquid pipeline facilities.

9/15/2008 – 9/19/2008

PHMSA-PL3293 Corrosion Control of Pipeline Systems Course

This course provides instruction in principles of basic electricity and corrosion, techniques for cathodic protection ("CP"), electrical potential surveys, resistance and resistivity, current requirements and Federal pipeline safety code requirements. The course also provides hands on experience with test tanks and an outdoor corrosion lab.

7/22/2008 – 7/25/2008

PHMSA-PL4253 Liquefied Natural Gas ("LNG") Safety Technology and Inspection Course

Using the knowledge gained in this course and the appropriate use of National Fire Protection Association 59 and Title 49 CFR Part 193, participants will be able to monitor LNG systems to ensure compliance with the code and be able to evaluate LNG system compliance concerning design, construction, operation and maintenance.

6/23/2008 – 6/27/2008

PHMSA-PL3254 Joining of Pipeline Materials Course

This course will provide an in-depth evaluation of joining techniques. Plastic pipe, mechanical fittings and welding will be evaluated. Proper utilization of tools and equipment associated with different joining techniques will be addressed. Participants will have the opportunity to participate in actual "hands on" joining of materials.

5/6/2008 – 5/8/2008

PHMSA-PL1255 Gas Pressure Regulation and Overpressure Protection Course

This course is presented in a job related manner that allows the participants to relate closely to actual field conditions. The training provides both classroom lectures and laboratory demonstrations with student participation during both lecture and lab portions of the course. Lecturers include audio visual media.

2/11/2008 – 2/15/2008

PHMSA-PL3256 Pipeline Failure Investigation Techniques Course

This course identifies methods and investigative techniques utilized in evaluating incidents on pipeline facilities. Experts in metallurgy, photographic documentation, explosions and fires provide fundamental instruction to help the participants recognize the different types of pipeline failures. Appropriate pipeline regulations and standards are also reviewed.

10/29/2007 – 11/2/2007

PHMSA-PL1250 Safety Evaluation of Gas Pipeline Systems Course

This course is designed as introductory training to describe the design and operation of natural gas pipeline systems in relation to 49 CFR Parts 191 and 192. The training allows attendees to participate in discussion of terms, definitions and specific pipeline regulation requirements. The course also provides guidance and fundamental training for inspectors involved in evaluating gas pipeline facilities.

ORIGINAL

ATTACHMENT 2

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BEFORE THE ARIZONA CORPORATION C(

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AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS
MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

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 ITS PROPERTIES THROUGHOUT ARIZONA.	DOCKET NO. G-01551A-07-0504 **STAFF'S NOTICE OF FILING OF DIRECT TESTIMONY**

The Utilities Division ("Staff") hereby provides Notice of Filing of the redacted Direct Testimony of Ralph C. Smith; and the Direct Testimonies of Corky Hanson; Frank W. Radigan; David C. Parcell; Phillip S. Teumim; Robert G. Gray; Rita R. Beale; and Stephen L. Thumb.

RESPECTFULLY SUBMITTED this 28th day of March, 2008.

Maureen A. Scott, Senior Staff Counsel
Kevin O. Torrey, Staff Attorney
Charles H. Hains, Staff Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Original and thirteen (13) copies of the foregoing filed this 28th day of March 2008 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Arizona Corporation Commission
DOCKETED
MAR 28 2008
DOCKETED BY nr

. . .

DIRECT

TESTIMONY

OF

RALPH C. SMITH

CORKY HANSON

FRANK W. RADIGAN

DAVID C. PARCELL

PHILLIP S. TEUMIM

ROBERT G. GRAY

RITA R. BEALE

STEPHEN L. THUMB

DOCKET NO. G-01551A-07-0504

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

MARCH 28, 2008

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR 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 OPERATIONS THROUGHOUT ARIZONA.	))))))))))	DOCKET NO. G-01551A-07-0504

DIRECT

TESTIMONY

OF

CORKY HANSON

SENIOR PIPELINE SAFETY INSPECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

The Direct Testimony of Staff witness Corky Hanson addresses the concerns of the Arizona Corporation Commission's ("Commission") Office of Pipeline Safety ("OPS" or "Pipeline Safety") relating to the Southwest Gas request to include replacement cost of the Manors subdivision gas distribution system in Yuma, Arizona.

Staff recommends the costs discussed in Staff witness Ralph Smith's testimony be disallowed from consideration in these proceedings because SWG's original intention was to extend the service life of the pipeline system by installing a new cathodic protection ground bed before incorrectly connecting the wires backwards on the rectifier causing the pipeline to corrode at an accelerated rate.

INTRODUCTION

Q. Please state your name and business address?

A. My name is Corky Hanson. My business address is 2200 N. Central 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 Senior Pipeline Safety Inspector; I have been employed by the Arizona Corporation Commission ("Commission") for over 15 years.

Q. Please describe briefly your duties as a Senior 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, completing required reports associated with each inspection or investigation and providing testimony on behalf of the Commission.

Q. Have you previously testified?

A. Yes, I have previously testified on behalf of the Commission.

Q. What is the purpose of your testimony in these proceedings.

A. The purpose of my testimony is to express the concerns Pipeline Safety has relating to the cost and reasons for replacing the gas distribution system in the Manors subdivision ("Manors") in Yuma.

ANALYSIS

Q. Does the Pipeline Safety Section have any concerns with Southwest Gas Corporation ("SWG" or "Southwest Gas") that would effect this rate case?

A. Yes, SWG is seeking to recover costs for the replacement in the Manors subdivision in Yuma, Arizona steel pipeline gas distribution system. Pipeline Safety does not feel that SWG should be able to recover these costs. The circumstances that necessitated the immediate replacement of this system were the direct result of incorrect actions taken by SWG personnel resulting in the failure of this system.

Q. Explain the action taken by SWG personnel that caused the failure.

A. During the SWG annual code compliance audit in 2006, it was noted on the inspection report that SWG had not taken prompt remedial action to correct deficiencies of the Manors cathodic protection ("CP") identified during the annual CP monitoring. The CP deficiency was identified on March 26, 2004. Remedial action was not completed until February 28, 2006. Failure to provide adequate CP on a steel pipeline system can lead to deterioration of the pipeline resulting in leaks and ultimately the replacement of the pipeline. The technician responsible for making repairs to the CP rectifier system connected the wiring backwards (positive to negative / negative to positive). This action caused the pipeline to corrode at an accelerated rate resulting in multiple corrosion failures and necessitating the immediate replacement of the steel pipeline system. SWG management personnel did not identify this mistake until the system failed and required replacement.

Q. Briefly explain what cathodic protection is and its importance in protecting the pipeline.

A. Pipe corrosion is one of the leading causes of pipeline failures. CP is a procedure by which an underground metallic pipe is protected against corrosion. A direct current is impressed onto the pipe by means of either a sacrificial anode or a rectifier. CP monitoring is conducted once each calendar year to ensure that minimum CP is being maintained on the pipeline. The duration between inspections should not exceed 15 months.

Q. Briefly explain what a rectifier is, how it operates and the consequences of improper installation.

A. A CP rectifier is a device that converts alternating current ("AC") into direct current ("DC") for use with cathodic protection. The proper way to use a rectifier is to connect the positive (+) wire terminal to the anode, and the negative (-) wire terminal to the pipeline making the pipeline the cathode. In a properly installed system it is the anode that loses current taking material with it until its mass is depleted thereby mitigating corrosion on the cathode (pipeline). Reversing the wire connection (polarity) would cause the pipe to become the anode, resulting in accelerated corrosion of the pipeline. Southwest Gas claims that this rectifier was maintained and initialized by the same Southwest Gas employee who was responsible for the Company's failure to conduct the CP monitoring in 2006.

Q. Based on your experience, could the Manors steel pipeline system have lasted for many more years if adequate CP had been properly applied?

A. Yes, based on my CP training and experience both as an operator and Pipeline Safety Inspector, this system could have lasted for many more years. I also consulted with co-

workers Marion Garcia (Chemical Engineer) and Ryan Weight (Mechanical Engineer). Both also have extensive cathodic protection experience, and both agree with my assessment of this system. Pursuant to regulations, SWG had the option to either replace the pipeline with plastic pipe (which does not require cathodic protection), or install CP. Ground bed anodes on impressed current systems are normally designed to last, at a minimum, 20 years. When SWG made the decision to replace the ground bed instead of replacing the pipelines it was evident that the pipeline was in a condition that could be preserved. Clearly, the intent was to extend the service life of the system. For SWG to expend the cost and effort to replace the CP ground bed to restore CP to the Manors' steel system, it is obvious that SWG planned on these actions extending the service life of this system. Through only 11 months of operation using an incorrectly installed rectifier, the pipeline was corroded to the point of being no longer operable. It is true that the pipeline had been in service for 50 years. However, as SWG's service life extension efforts demonstrate, there was no present need to replace the pipeline. SWG's actions are consistent with Staff's belief that the pipeline had significant remaining life that could have been extended with proper cathodic protection.

But for the improper repairs made by an SWG field technician, the Company would not be incurring this expense. Customers should not have to pay for a new system when the Company's own mistakes and improper repairs lead to the system's failure and need for replacement.

Q. Have you reviewed the list of 68 contracts provided by SWG to determine whether the projects were used and are useful?

A. Yes.

Q. Does the Pipeline Safety Section have any additional concerns regarding the used and useful analysis of the list of 68 contracts that would affect this rate case?

A. No.

RECOMMENDATIONS

Q. What is your recommendation in this case?

A. I recommend that SWG be permanently disallowed from including the cost relating to the Manors replacement project for consideration in this rate case and any future rate cases. Staff witness Ralph Smith addresses the calculation of the disallowance in his testimony.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

SOUTHWEST GAS CORPORATION

MAR 15 2011

Jerome T. Schmitz, P.E., Vice President/Engineering

March 14, 2011

Steve Olea, Director Utilities Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Subject: Multiple Rate Customers

Dear Steve:

Thank you for meeting with Southwest Gas Corporation (Southwest) representatives on February 9, 2011 to discuss metering options for billing customers with multiple rates for different loads.

As we discussed, Southwest has several tariff rate schedules applicable to specific end-use applications for natural gas. These rate schedules provide cost-of-service pricing based on energy-efficient uses of natural gas. Included in these schedules is Rate Schedule No. G-40, which is applicable to natural gas used for air conditioning. In order for customers to receive the benefit of end-use specific rate schedule pricing, the volumes for the end-use appliance(s) must be separately metered. Furthermore, recent advances in technology have resulted in smaller scale gas air conditioning equipment increasing the likelihood that customers will choose to connect air conditioning appliances to their existing house line versus constructing a dedicated supply line. This may result in a mingling of loads beyond the outlet of Southwest's customer meter thus preventing the proper billing of the customer's gas air conditioning equipment.

As we discussed during our meeting, Southwest identified three options to address this billing and metering issue (see attachment). Based upon our discussions, it is Southwest's understanding that the preferred approach by all parties (Southwest, you, and your Safety Staff) are Options 1 and 3, depending upon the circumstances of the customer. For instance, Southwest may utilize custody transfer meters in situations where installation is feasible (Option 3). Where two Southwest custody transfer meters are infeasible for the specific end-use appliance(s), a Southwest-owned end-use meter downstream of Southwest's custody transfer meter may be used to obtain metered volumes for billing (Option 1). Notwithstanding the installation of an end-use meter pursuant to Option 1, the parties agreed that this should not result in any change in the

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P.O. Box 98510 / Las Vegas, Nevada 89193-8510 / (702) 876-7112
www.swgas.com

exercise of jurisdiction by your Safety Staff. The parties also agree that customer-owned end-use meters (Option 2) will not be utilized.

Thank you for the opportunity to discuss these items with you and your Safety Staff. Please confirm your agreement with our understanding of how to address this billing and metering issue by countersigning the enclosed copy of this letter and returning it to my attention.

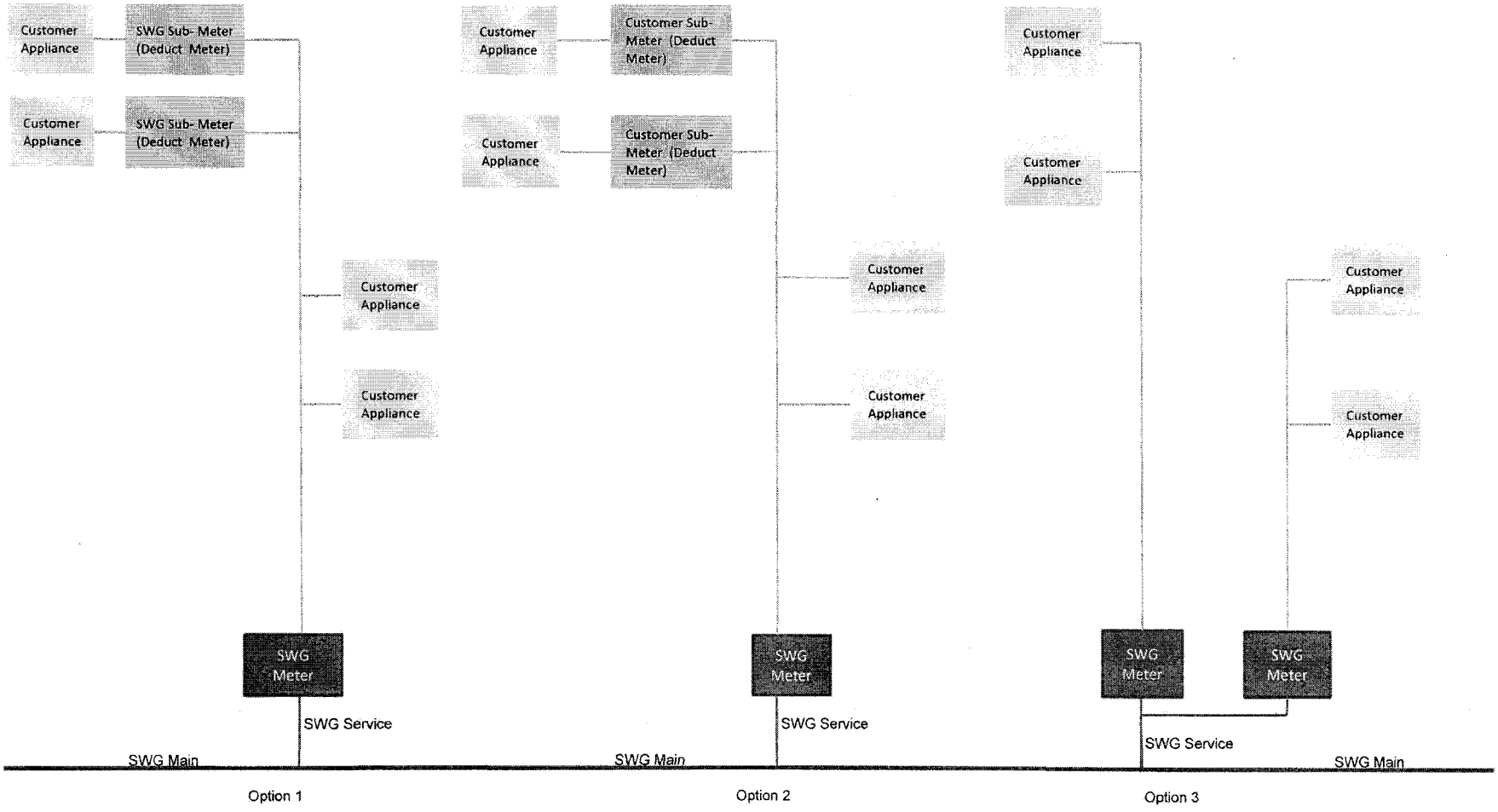
Sincerely,

Attachment

Reviewed and Agreed to by:

_____
Steve Olea, Director, Utilities Division
Arizona Corporation Commission

cc: Robert Miller, ACC
Corky Hanson, ACC
Debi Gallo, SWG
Jose Esparza, SWG
Randy Ortlinghaus, SWG
Ron Bassler, SWG
Brooks Congdon, SWG
Dan Bryant, SWG
Lynn Malloy, SWG


Customer Appliance
SWG Sub- Meter (Deduct Meter)
Customer Appliance
SWG Sub- Meter (Deduct Meter)
Customer Appliance
Customer Appliance
SWG Meter
SWG Service
SWG Main
Option 1
Customer Appliance
Customer Sub-Meter (Deduct Meter)
Customer Appliance
Customer Sub-Meter (Deduct Meter)
Customer Appliance
Customer Appliance
SWG Meter
SWG Service
SWG Main
Option 2
Customer Appliance
Customer Appliance
Customer Appliance
Customer Appliance
SWG Meter
SWG Meter
SWG Service
SWG Main
Option 3

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
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 ITS PROPERTIES THROUGHOUT ARIZONA	)	DOCKET NO. G-01551A-10-0458

DIRECT

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 10, 2011

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

Southwest Gas Corporation ("Southwest" or "Company") provides natural gas service to approximately a million Arizona customers in the following counties: Cochise, Gila, Graham, Greenlee, La Paz, Maricopa, Mohave, Pima, Pinal and Yuma. Southwest's customers are primarily Residential (945,000), but it also has 40,000 Commercial customers, as well as a small number of customers in other classes, such as Industrial, Irrigation, and Transportation.

In this testimony, Staff will address the Company's proposed Energy Efficiency and Renewable Energy Resources Technology Portfolio Implementation Plan. The Portfolio consists of ten programs designed to meet the Gas Utility Energy Efficiency Standards.

With respect to the Implementation Plan, Staff concludes the following:

- Based on the information and data currently available to Staff at the time of this testimony, it is Staff's belief that the pilot programs, as proposed, are not cost-effective.

- Cost-effectiveness analysis was performed by Southwest at the program level, making the information in the Implementation Plan (i) inconsistent with previous energy efficiency filings and (ii) insufficient for determining the benefit-cost ratios of new measures. Measure-level analysis and data are required in order to determine the cost-effectiveness of individual measures and their probable effect on the overall cost-effectiveness of a program or group of programs. The data currently available indicate that at least some of the proposed new measures are unlikely to be cost-effective.

- The complexity of the portfolio (10 programs, five of them new, multiple new measures), and the size of the proposed budget ($16.5 million), require a level and type of analysis such that a rate case may not be the best venue, particularly given the need for more data on the proposed pilot programs and new measure.

- Staff recommends that the Implementation Plan not be approved at this time, and that the Company refile its Implementation Plan in a separate docket.

- Staff recommends that the timing for application of the 2011 standard be determined in that separate docket.

- Staff also recommends that the demand-side management adjustor rate remain unchanged until further Commission action in the separate docket recommended above.

INTRODUCTION

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

A. My name is Julie McNeely-Kirwan. I am a Public Utilities Analyst IV employed by the Arizona Corporation Commission ("ACC" or "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 IV.

A. My duties as a Public Utilities Analyst IV include reviewing and analyzing applications filed with the Commission, and preparing memoranda and proposed orders for Open Meetings. In addition, my duties have included preparing written testimony in multiple rate cases, and testifying during the related hearings. I have also assisted in the management of rate cases and have performed evaluations of energy efficiency implementation plans.

Q. Please describe your educational background and professional experience.

A. In 1979, I graduated Magna Cum Laude from Arizona State University, receiving a Bachelor of Arts degree in History. In 1987, I received a Master's Degree in Political Science from the University of Wisconsin, Madison. I have been employed by the Commission since September of 2006. Since that time, I have attended a number of seminars and classes on general regulatory issues, including demand-side management and the gas and electric industries.

SCOPE OF TESTIMONY

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

A. Staff will address Southwest Gas Corporation's ("Southwest" or "Company") proposed Energy Efficiency and Renewable Energy Resources Technology Portfolio

Implementation Plan ("EE and RET Implementation Plan"), as filed within the 2010 Arizona General Rate Case for Southwest.

THE IMPLEMENTATION PLAN

Q. Did the Commission adopt new rules on energy efficiency for natural gas utilities?

A. Yes. On December 10, 2010, the Commission adopted new rules on energy efficiency ("EE") for gas utility companies ("Rules" or "Standards"), with standards requiring annual and cumulative savings. Pursuant to the rules, each affected gas utility is required to achieve cumulative annual energy savings, expressed as therms or therm equivalents, equal to at least 6 percent of retail sales for calendar year 2019, by December 31, 2020.

Q. Do the new rules require than an Implementation Plan be filed?

A. Yes. Section R14-2-2505 of the Arizona Administrative Code ("A.A.C.") requires that an Implementation Plan be filed by June 1 of each odd year, or annually, at the utility's election, describing how each utility plans to meet the EE Standard for the next one or two years. An exception was made for each utility's initial Implementation Plan, which was ordered to be filed within 30 days of the effective date of the new Standards (March 4, 2011).

Q. Did Southwest file an Implementation Plan?

A. Yes. In compliance with the new gas energy efficiency rules, Southwest filed an Implementation Plan as part of its general rate case application (filed on November 12, 2010.) Southwest requested that the Implementation Plan filed within the rate case be treated as its first Implementation Plan, under the Rules.

Q. What is the scope of the Implementation Plan?

A. The EE and RET Implementation Plan describes how Southwest intends to meet the new gas Standards over a two-year period.

THE NEW GAS STANDARDS

Q. Please describe the requirements of the new gas Standards and how they can be met by affected utilities.

A. Pursuant to A.A.C. R14-2-2504, by the end of 2011, Class A affected gas utilities are required to achieve energy savings equal to 0.50 percent of their retail energy sales in 2010. At least 75 percent of those therms, or therm equivalents must be saved through energy efficiency Demand-Side Management ("DSM") programs. In addition to their own energy efficiency programs, affected gas utilities may count the energy savings arising from any customer's self-directed DSM program or programs toward this portion of the requirement.

The remaining 25 percent of required therms, or therm equivalents, may be saved outside of energy efficiency DSM programs, meaning through Combined Heat and Power ("CHP") programs, renewable energy resource technology ("RET") programs, and through building codes and appliances standards.

Q. Please provide more detail regarding how a gas utility could meet 25 percent of its required therm savings through building codes, appliance standards and sponsorship of RET programs that displace gas.

A. An affected gas utility may count up to one-third of the energy savings resulting from energy efficiency building codes and appliance standards. In order to do this, a gas utility must demonstrate and document its efforts to support the adoption and implementation of

energy efficiency codes for buildings and appliances. Gas utilities may also count all energy savings resulting from its sponsorship of RET projects that displace gas. The gas utility may also count energy savings from RET projects not sponsored by that utility if the utility can demonstrate that its efforts facilitated the placement and completion of the RET project or projects.

Q. How does Southwest, specifically, propose to meet the new gas utility energy efficiency standard?

A. In its Implementation Plan, Southwest proposes to achieve most of its required therm or therm equivalent savings through the ten programs comprising its EE and RET Portfolio.

The Company plans to achieve the remainder of its required therm or therm equivalent savings though its efforts "to support the adoption and implementation of . . .energy efficiency building codes, as well as the Company's involvement in the placement of non-Company sponsored RET projects that displace gas. . . ."

PROPOSED BUDGET

Q. What is the proposed budget for the EE and RET portfolio, as described in the Implementation Plan?

A. The Company has proposed a budget of $16.5 million, an approximately $11.7 million increase from the currently approved approximately $4.8 million portfolio budget. The Company's per-program and per-category budget proposal, as proposed by Southwest, is attached as Exhibit 1.

Q. What is the rationale for the budget increase proposed by the Company?

A. Southwest explains that "[T]he proposed budget affords the Company a level of funding adequate to sustain the programs and allow the Company to achieve the goals set forth in the preliminary Standards."

The Company also states that the proposed budget maximizes the funding going to customers though education, training, incentives and technical assistance, and takes into account the costs of ramping up and administrative oversight.

THE PROPOSED SOUTHWEST EE AND RET PORTFOLIO

Q. Please generally describe the proposed Southwest Energy Efficiency and Renewable Energy Resource Technology Portfolio.

A. The proposed portfolio consists of ten new and existing programs, all named (or renamed) to reflect the Company's new *Smarter Greener Better* ("SGB") brand.

The portfolio consists of three Residential programs, four Non-residential programs, one Low-Income program (including weatherization and bill assistance components), one Educational program and one RET program.

Brief descriptions of each program are provided in the table below. Exhibit 2, attached herein, is an excerpt from the Company's filing, and provides a more detailed narrative description of each program.

Q. Does Southwest currently have an EE program in place?

A. Southwest has a DSM portfolio consisting of seven energy efficiency programs, three Residential (including one Low-Income program) and four Non-Residential.

Q. Why is the term "DSM" used to describe the current Southwest portfolio?

A. The terms "DSM" and "energy efficiency" are often used interchangeably, but "DSM" is actually a broader term that includes both energy efficiency and (for gas programs) CHP programs.[1]

Q. Please list the programs in Southwest's existing portfolio.

A. Southwest's current portfolio consists of the following programs : (i) Low-Income Energy Conservation (Residential; low-income); (ii) *SGB* Homes (Residential; new construction); (iii) Consumer Products (Residential; existing homes); (iv) Commercial Equipment (Non-residential; commercial cooking equipment); (v) Large Commercial Energy-Efficiency Boilers (Non-residential; boilers and boiler-related measures); (vi) Technology Information Center (Non-residential; energy efficiency newsletter) and (iv) Distributed Generation (Non-residential; CHP generation).

Q. What criteria are used when Staff reviews energy efficiency programs submitted for approval by utilities?

A. The main basis for evaluating energy efficiency programs or measures is cost-effectiveness on a measure level. The component measures for any new programs are each reviewed for cost-effectiveness, and measures being added to existing programs are reviewed individually for cost-effectiveness.

[1] Under the Gas Utility Energy Efficiency Standards, CHP can be counted toward meeting the Standard after at least 75% of the Standard has been met through energy efficiency.

Q. Can you describe how the proposed EE and RET portfolio differs from the Company's existing portfolio and indicate which programs are newly proposed, which are existing, and, for the existing programs, indicate which measures are newly proposed.

A. Yes, that is done in the table below.

Program Name	Sector	Type (New/Existing) and Description	Changes (for existing programs)
SGB Residential Rebates	Residential	**Existing.** Offers rebates to Residential customers to promote energy efficient appliances and weatherization for existing homes.	Proposed new measures: condensing water heaters, lavatory faucets, dishwashers, furnaces and boilers, and weatherization measures, including windows, insulation and duct sealing.
SGB Homes	Residential	**Existing**. Offers rebates to homebuilders to build Energy Star certified homes and install Energy Star appliances and insulation.	Proposed new measures: condensing water heater, clothes washer, clothes dryer, and insulation. Company also proposes to revise standards for existing measures, to meet Energy Star standards
SGB Residential Energy Assessments	Residential	**New (pilot)**. Offers rebates to homeowners for energy audits. Also offers direct install efficient showerheads and faucets.	N/A
SGB Business Rebates	Non-residential	**Existing.** Offers rebates to Non-residential customers for installing energy efficient appliances (boiler and commercial kitchen measures) and weatherization measures.	Proposed new measures: clothes washers, large vat fryers, convection ovens, conveyer ovens, dishwashers, windows, insulation, air curtains. Combines the existing Commercial Equipment and Boilers programs
SGB Custom Business Rebates	Non-residential	**New (not proposed as a pilot).** Offers rebates based on achieved annual energy savings.	N/A
SGB Business Energy Assessments	Non-residential	**New (pilot)**. Offers rebates for comprehensive energy audits.	N/A
SGB Distributed Generation	Non-residential	**Existing.** Offers rebates to Non-residential measures for installing high efficiency CHP technologies.	Proposes a large increase in budget to accommodate potential additional projects.
SGB Low-Income Energy Conservation	Low-Income	**Existing.** Provides weatherization measures to low-income customers. Includes bill assistance.	No significant changes are being proposed for this program
SGB Energy Education	Energy Education, Residential and Non-residential.	**New (pilot).** (Includes existing Technology Information Center program.) Provides customers with energy efficiency and conservation information.	N/A
SGB Solar Thermal Rebates	Renewable, Residential and Non-residential.	**New (not proposed as a pilot)**. Offers rebates to Residential and Non-residential customers to promote solar thermal systems for water heating and pool heating.	N/A

Q. Has Staff reviewed and performed any analysis of the Company's proposed EE programs?

A. Yes. Although the information provided in the Implementation Plan is insufficient to perform a full analysis regarding the cost-effectiveness of the proposed new programs and measures, Staff has been able to determine that there are basic issues with the Southwest Implementation Plan, both in terms of the data and analysis provided, and in terms of the probable cost-effectiveness of proposed new programs and measures.

Q. Based on Staff's review, what is Staff's recommendation?

A. Staff recommends that the Implementation Plan not be approved at this time, and that the Company refile its Implementation Plan in a separate docket, with cost-effectiveness analysis and data provided at the measure level, as required by the rules. Refiling in another docket will allow Staff the opportunity to perform its due diligence based on measure-level cost-effectiveness information.

Q. Please briefly explain Staff's issues with respect to the Company's Implementation Plan.

A. There are three basic issues that concern Staff with respect to the Southwest Implementation Plan: (i) limited data and lack of cost-effectiveness for DSM Pilot Programs; (ii) the program-level analysis of cost-effectiveness provided by the Company; and (iii) the appropriateness of a rate case as a venue for reviewing a portfolio of this size and complexity. All three of these issues are discussed in more detail below.

Q What pilot programs did Southwest propose as part of its Implementation Plan?

A. Southwest is proposing three energy efficiency pilot programs: *SGB Residential Energy Assessments, SGB Business Energy Assessments,* and *SGB Energy Education*. The energy

assessment programs provide incentives to Residential and Non-Residential customers for energy audits, and the education program is designed to promote energy efficiency and conservation among both Residential and Non-residential customers. (Please see Exhibit 1 for the pilot program budgets.)

Q. Please describe Staff's concern regarding the limited data and lack of cost-effectiveness for the pilot programs.

A. Southwest has interpreted the new gas Standards to mean that cost-effectiveness is not required for DSM pilot programs. The Company did not provide benefit-cost ratios for the three proposed pilots in its Implementation Plan, and provided only limited information regarding the costs and benefits for two of the pilots in either the Implementation Plan or the spreadsheets provided in response to data requests. The information provided by the Company so far indicates that, for all three pilot programs, costs greatly exceed benefits. (See Southwest's Table 1, attached as Exhibit 3 to Staff's testimony.)

Q. Is the Company's position correct?

A. No. Affected utilities are required to design each DSM program to be cost-effective and to provide cost-effectiveness data for each proposed DSM program or measure. (See R14-2-2503.A and R14-2-2507.) Pilot programs are not exempted from these requirements.

Although Southwest states that it is "optimistic" that the proposed pilot programs will be cost-effective, the information and data currently available to Staff do not indicate that these programs were either designed to be cost-effective or likely to become cost-effective in the future. In addition, Staff does not believe that the data provided meets the requirements under the rules.

Q. Please describe Staff's concern regarding the program-level cost-effectiveness analysis provided for the Company's portfolio of programs.

A. Southwest has provided cost-effectiveness analysis at only the program level, including for existing programs for which new measures have been proposed. Although some measure-level data has been provided, it is insufficient for purposes of producing a reasonable estimate of individual measure cost-effectiveness. Without the ability to reasonably estimate the cost-effectiveness of the new measures, Staff can not assess whether they represent a reasonable investment of ratepayer dollars, or determine their potential impact on the overall cost-effectiveness of the Company's DSM programs.

As with the pilot programs, Staff also does not believe that the data provided meets the requirements under the Rules.

Q. Please describe Staff's concern regarding the appropriateness of a rate case, in terms of evaluating a portfolio of this size and complexity.

A. The complexity of the portfolio (10 programs, five of them new, multiple new measures) and the size of the proposed budget ($16.5 million) require a level and type of analysis such that a rate case, with its timeline, may not be the best venue. This is particularly true in light of Staff's issues with the data provided so far in the rate case.

PILOT PROGRAM DATA AND COST-EFFECTIVENESS ISSUE

Q. Did Staff ask for the estimated cost-effectiveness of the pilot programs in its data requests?

A. Yes.

Q. Did Southwest provide Staff with the benefit-cost information Staff requested?

A. No. Southwest did not supply these estimates in its response, and stated that it "has not calculated cost-effectiveness for the DSM pilot programs proposed as part of the Implementation Plan." The Company went on to cite the following language from R14-2-2512.G of the Rules: ". . .pilot programs are not required to demonstrate cost-effectiveness."

Q. Was any information provided in response to Staff's data requests which shed light on the cost-effectiveness of the pilot programs?

A. Yes. In response to another data request, the Company provided electronic spreadsheets with program-level costs and benefits for the *SGB Residential Assessments* pilot program, and program-level costs only (with zero benefits) for the *SGB Commercial Assessments* and *SGB Education* pilot programs. The benefit-cost ratios, although not provided in the filing, appeared in the spreadsheets as 0.11 for the *SGB Residential Assessments* program, and as zero for the other two pilot programs.[2]

In its response to Staff's inquiry about whether these spreadsheets reflected the actual cost-effectiveness of the three pilots, the Company responded that "individual cost-effectiveness value is not calculated for each pilot program, [but] the costs to implement them are included in the portfolio cost-effectiveness calculation."

[2] In Response to ACC-STF-12-2 Southwest stated that "Although the individual cost-effectiveness value is not calculated for each pilot program, the costs to implement them are included in the portfolio cost-effectiveness calculation."

Q. Under the Standards, what cost-effectiveness data must be provided as part of every program proposal submitted to the Commission?

A. The Standards specifically state that each proposal "shall include" estimated societal benefits, and savings and costs, along with estimated customer participation and an estimated benefit-cost ratio, as well as other information.

Q. Do data requirements for Education programs differ from requirements for other programs?

A. No, but for Education programs, cost-effectiveness analysis is based on estimating the impact of increased awareness. The Standards state that "[e]ducational programs shall be analyzed for cost-effectiveness based on estimated energy and peak demand savings resulting from increased awareness about energy use and opportunities for saving energy."

Q. Was information on estimated energy and peak demand savings provided for the *SGB Energy Education* program?

A. No.

Q. Based on the information received from the Company to date, is there sufficient information for Staff to independently (and reasonably) estimate the benefit-cost ratios for any of the pilot programs?

A. No.

Q. Does Staff believe that the information provided by the Company in the spreadsheets indicates that the cost of the pilots greatly exceeds the benefits?

A. Yes.

Q. Does Staff agree with Southwest's interpretation of the language in R12-2-2512.G, which states that "pilot programs are not required to demonstrate cost-effectiveness"?

A. No.

Q. What is Staff's interpretation of this language?

A. The language of R12-2-2512.G is from the "Cost-effectiveness" section of the new gas Standards. It means that a program may be continued, even when it has not demonstrated cost-effectiveness during the pilot phase, if there is a reasonable expectation that the program will become cost-effective once fully implemented and active. Staff also interprets R12-2-2512.G to mean that a utility may recover prudently incurred DSM costs, even if a pilot program does not demonstrate cost-effectiveness in practice.

The language of R12-2-2512.G does not mean that a utility can simply label a proposed program as a "pilot" and thereby relieve itself from designing the program to be cost-effective, from determining its cost-effectiveness under the Societal Test, or from providing the information set out in the Standards under "Commission Review and Approval of DSM and RET Programs."

PROGRAM-LEVEL ANALYSIS ISSUE

Q. Is the cost-effectiveness analysis and data provided by the Company in its EE and RET Implementation Plan filing consistent with earlier Southwest filings for energy efficiency programs and measures?

A. No. Earlier Southwest filings for DSM programs, and for new measures being added to existing programs, provided cost-effectiveness analysis and data at the measure level.

Q. Can you provide examples?

A. Yes. Southwest filings with cost-effectiveness analysis and data provided at the measure level include Southwest's 2006 Demand Side Management Program Plan, filed in compliance with Decision No. 68487 (Docket No. G-01551A-04-0876), Southwest's Application to Continue and Modify the Demand Side Management Consumer Products Program (Docket No. G-01551A-08-0619), and Southwest's Proposal to Supplement and Modify its Arizona Demand Side Management Plan for Program Years 2009 and 2010 (Docket No. G-01551-09-0039).

Q. Did Southwest provide measure-level cost-effectiveness analysis, or estimated benefit-cost ratios, for the new measures proposed in its Implementation Plan?

A. No, but the Company did supply measure-level savings and incremental costs.

Q. Why is Staff concerned about the use of program-level analysis in the Southwest Implementation Plan?

A. Program-level analysis can mask non-cost-effective individual measures by combining the costs and benefits for multiple measures. Based on the incremental costs and savings for some measures, it is extremely unlikely that some of the new measures proposed by Southwest would be cost-effective. Other measures (with higher savings compared to costs) may be cost-effective, but the lack of a measure-level data and analysis leaves this uncertain.

Q. Why is Staff concerned about the lack of measure-level estimates for participation?

A. Without measure-level participation estimates, Staff can not reasonably allocate program costs for individual measures in some multiple-measure programs and can not, as a result, independently calculate cost-effectiveness.

The lack of estimates on measure-level participation also makes it impossible to reasonably estimate the potential impact of individual measures on cost-effectiveness of programs, or on the DSM programs as a whole.

Q. Please provide specific examples from Southwest's Implementation Plan of measures that are unlikely to prove cost-effective in practice.

A. Two examples from the *SGB Residential Rebates* program are the Standard and Compact Dishwasher Models. In its Implementation Plan, Southwest stated an incremental cost of $126 for the Standard Dishwasher Model, but only a 1.3 annual therm savings. For the Compact Dishwasher Model, Southwest stated a $100 incremental cost, but annual savings of only 1 therm. It is clear, even without calculating a benefit-cost ratio, that the payback for customers on the incremental costs would greatly exceed the lifespan of either measure (for dishwashers, generally up to 13 years).

Staff initially estimates a benefit-cost ratio for both measures (based on the limited information currently available) of 0.04, far below the 1.0 that would be required to make the measures cost-effective, without customer water savings. Annual customer water savings of 323 gallons and 215 gallons, respectively, would improve the benefit-cost ratios, but not by enough to approach cost-effectiveness.

Q. Please provide specific examples from Southwest's Implementation Plan of measures likely to prove cost-effective in practice.

A. Based on Staff's initial estimates, and the limited information currently available, Staff believes that the Residential Boiler measure may have a benefit-cost ratio of approximately 1.03. While the information provided by the Company in support of its incremental costs and therm savings for the *SGB Residential Rebates* program is not

sufficiently specific to verify. Staff's research determined that the Company's estimate on incremental cost was reasonable and may even have been conservative as to savings (suggesting that actual cost-effectiveness for this measure may be higher than 1.03.)

Q. Are there any other reasons to establish the per-measure cost-effectiveness of proposed measures?

A. Yes. Per-measure cost-effectiveness analysis highlights instances when non-incentive costs may be too high, and identifies which measures are likely to produce the most savings for the DSM dollars being invested. These opportunities to develop information allowing for the more efficient allocation of DSM dollars are lost without the per-measure analysis.

RATE CASE VENUE

Q. Does Staff believe that Southwest's Implementation Plan should be approved as part of the current rate case?

A. No. Due to the issues with the data provided, as discussed herein, and due to the size and complexity of the Company's EE and RET Portfolio, Staff believes that the Implementation Plan should be refiled in another docket.

OTHER ISSUES

Q. Other than the three main issues discussed herein, are there other Staff concerns with respect to the information provided in the rate case Implementation Plan filing?

A. Yes. The Company's methods for calculating projected energy savings are unclear, as is its basis for determining lifespans for multiple-measure programs. For this reason, Staff is unable to determine whether the Company's assumptions are reasonable.

COST-EFFECTIVENESS REQUIREMENTS UNDER THE NEW GAS STANDARDS

Q. Please describe the requirements for measure cost-effectiveness under the new gas Standards.

A. Each and every measure must be designed to be cost-effective or (as with education programs) designed to measurably enhance the cost-effectiveness of the EE portfolio as a whole.

Q. Why?

A. If a measure is not cost-effective, or can not measurably enhance the cost-effectiveness of an EE program or programs, there is no reason to use ratepayer dollars to promote that measure. Even in cases where a program or portfolio can absorb non-cost-effective measures and remain cost-effective on an overall basis, any non-cost-effective measure, or program, dilutes that cost-effectiveness.

Measure cost-effectiveness is also required to meet the requirements of the rules. R14-2-2512.A states that an affected utility "shall ensure that the incremental benefits to society of the affected utility's overall group of DSM programs exceed the incremental costs to society of the overall group of DSM programs." The only way to ensure that benefits exceed costs for DSM programs as a whole is to ensure the cost-effectiveness, or contribution to cost-effectiveness, of each component program, and the only way to ensure the cost-effectiveness of each program is to ensure the cost-effectiveness, or contribution to cost-effectiveness, of each component measure.

Q. Must each and every DSM program be designed to be cost-effective under the new gas Standards?

A. Yes. R14-2-2503.A (referred to elsewhere, herein) states that "An affected utility shall design each DSM program to be cost-effective."

REQUEST TO POSTPONE 2011 ENERGY EFFICIENCY STANDARD

Q. Does Southwest anticipate meeting the energy efficiency standards set for gas utilities for 2011?

A. No. In Paragraph 6.3 of its General Rate Case application, the Company states that it "does not anticipate that the EE and RET Plan will be approved and implemented in time for the Company to have a reasonable opportunity to achieve the .50 percent standard for the calendar year 2011." Based on its current DSM portfolio, Southwest anticipates therm savings of 2,281,000 during calendar year 2011.

Q. What level of savings would this equal, in terms of the new gas energy efficiency Standard?

A. Staff estimates that this level of savings, if achieved, would equal approximately 75 percent of the 2011 standard.

Q. Does Staff anticipate that Southwest will achieve additional savings during calendar year 2011 that would qualify under the new gas energy efficiency standard?

A. Yes. The Company states that it has worked, and continues to work, in support of the adoption and implementation of building codes. This work includes: (i) participating in the City of Phoenix Energy Phoenix program (which also leverages existing utility programs); and (ii) supporting adoption of the 2009 International Energy Conservation Code ("IECC") by the City of Mesa.

Under the gas energy efficiency rules, as discussed elsewhere in this testimony, one-third of the savings from these activities can be counted toward meeting the energy efficiency standards.

Q. Does Staff know the number of therms or therm equivalents that would be saved in 2011 through Southwest's efforts to promote energy efficiency?

A. No. The savings achieved would depend on factors such as participation and new home construction levels,[3] and would have to be documented and verified. Staff believes, however, that the potential savings from building codes are significant, even taking into account that only up to one-third of savings from this source can be counted toward the Standard.

Q. Why does Staff think the savings are potentially significant?

A. Energize Phoenix is a $25 million program to reduce Residential energy consumption by up to 30 percent and commercial energy consumption by 18 percent. With respect to Mesa's adoption of an enhanced building code, the 2009 IECC would increase energy savings for new homes by approximately 12-15 percent, as compared to the 2006 IECC.

Q. Does Staff anticipate that Southwest will achieve any other savings during calendar year 2011 that would qualify under the new gas energy efficiency standard?

A. Yes. Southwest is currently sponsoring RET projects to displace gas. Southwest states that "the Company will continue to work with its customers to deliver the most efficient unit of energy, including the installation of natural gas-displacing applications such as solar."

[3] 6,000 new homes are estimated for the Phoenix metropolitan area (which includes Mesa) in 2011.

Q. Has Southwest requested that the energy efficiency standards set for gas utilities for 2011 be permanently waived for Southwest?

A. No. Southwest requests that that it "be authorized to apply the 2011 standard to the first 12-month period following approval and implementation of the Company's EE and RET Plan."

Q. Does Staff agree with Southwest's request to apply the 2011 standard to the first 12-month period following approval and implementation of the Company's Implementation Plan?

A. No. Staff does not believe that Southwest's request to postpone application of the 2011 standard should be acted upon at this time. Instead, Staff recommends that the Implementation Plan not be approved at this time and that the Company refile its Implementation Plan in a separate docket. Staff also recommends that the timing for application of the 2011 standard (0.50 percent of previous year's retail energy sales) be determined in that separate docket. In addition, Staff recommends that the DSM adjustor rate should remain unchanged until further Commission action.

Removing the Implementation Plan from the rate case will allow the Company time to develop and file the additional data and analysis required for the Commission to adequately evaluate the proposed EE and RET portfolio, particularly the measure-level data and analysis required in order to determine whether individual measures are cost-effective and how adding these new measures and programs will impact overall portfolio cost-effectiveness. Removal to a separate docket will also afford the Company an opportunity to provide additional information and data concerning the pilot programs, and would provide the Commission with the time needed to evaluate the new information.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT 1 – Southwest Portfolio Annual Estimated Budget

Program	Rebates	Administration	Outreach	Delivery	Evaluation	Program Total Cost
Residential						
Residential Rebates	$3,850,000	$41,250	$330,000	$1,196,250	$82,500	$5,500,000
SGB Homes	$3,200,000	$160,000	$480,000	$80,000	$80,000	$4,000,000
Residential Energy Assessments	***$350,000***	***$17,500***	***$105,000***	***$210,000***	***$17,500***	***$700,000***
Total Residential	**$7,400,000**	**$218,750**	**$915,000**	**$1,486,250**	**$180,000**	**$10,200,000**
Non-Residential						
Business Rebates	$1,100,000	$90,000	$225,000	$495,000	$90,000	$2,000,000
Custom Business Rebates	$39,000	$5,550	$27,750	$72,150	$5,550	$150,000
Business Energy Assessments	***$350,000***	***$17,500***	***$105,000***	***$175,000***	***$52,500***	***$700,000***
Distributed Generation	$1,200,000	$55,000	$220,000	$220,000	$55,000	$1,750,000
Total Non-Residential	**$2,689,000**	**$168,050**	**$577,750**	**$962,150**	**$203,050**	**$4,600,000**
Low-Income						
L-I Weatherization[1]	$373,500	$67,500	$9,000	$ -	$ -	$450,000
L-I Bill Assistance[2]	$ -	$ -	$ -	$ -	$ -	$200,000
Total Low-Income	**$373,500**	**$67,500**	**$9,000**	**$ -**	**$ -**	**$650,000**
Education						
Energy Education	***$ -***	***$ -***	***$550,000***	***$ -***	***$ -***	***$550,000***
Total Energy Efficiency	**$10,462,500**	**$454,300**	**$2,051,750**	**$2,448,400**	**$383,050**	**$16,000,000**
Renewable Energy Resource Technology						
Solar Thermal Rebates	***$350,000***	***$15,000***	***$60,000***	***$67,500***	***$7,500***	***$500,000***
Total Portfolio	**$10,812,500**	**$469,300**	**$2,111,750**	**$2,515,900**	**$390,550**	**$16,500,000**

[1] L-I Weatherization delivery and evaluation are performed by the Arizona Commerce Authority and community agencies and therefore, the associated costs are incorporated into the administration budget category.

[2] L-I Bill Assistance is not a rebate program and does not adhere to the above budget categories. Program administration is capped at $15,000.

The below summary is an excerpt from the filing was provided by Southwest to describe the individual programs in its Energy Efficiency and Renewable Energy Resource Technology Portfolio.

Summary of Programs

"Smarter Greener Better Residential Rebates: Rebates will be offered to residential customers on qualified program measures and mailed to participating customers upon proof-of-purchase and installation. The measures include: ENERGY STAR@ water and space heating measures, ENERGY STAR@ clothes washers and high efficiency natural gas clothes dryers, ENERGY STAR@ dishwashers, and smart low-flow showerheads. The program also offers rebates on weatherization measures such as insulation, duct sealing and high efficiency windows.

Smarter Greener Better Homes Rebates: will be offered to homebuilders who build ENERGY STAR@ certified homes and install ENERGY STAR' water and space heating measures, ENERGY STAR@ clothes washers and high efficiency natural gas clothes dryers and attic insulation. The program will be available to all builders of new single-family subdivision and custom homes and individually metered multi-family homes featuring natural gas water and space heating.

Smarter Greener Better Residential Energy Assessments (Pilot): Southwest Gas proposes a joint residential energy assessment (energy audit) program with APS, SRP and/or TEP. All three of these utilities serve in Southwest Gas' Arizona service territory and have already developed their own residential energy audit programs. For all participating homes with natural gas water and space heating, Southwest Gas will pay rebates to homeowners for a portion of contractor costs and will provide direct-install measures such as smart low-flow showerheads and lavatory faucet accessories (aerators) and information for the Southwest Gas *Smarter Greener Better Residential Rebates* program.

Smarter Greener Better Business Rebates: Rebates will be offered to nonresidential customers on qualified program measures and mailed to participating customers upon proof-of-purchase and installation. The measures include: high efficiency space and water heating units (including boilers and boiler tune-ups), clothes washers, a full suite of commercial kitchen high efficiency products (including dishwashers, natural gas fryers, griddles, steamers, conveyor, convection and combination ovens) and commercial weatherization measures.

Smarter Greener Better Custom Business Rebates: Rebates will be offered to non-residential customers based on achieved annual energy savings. The program does not specify eligible measures in order to provide participants maximum flexibility in identifying potential projects. Participants may propose any measure that produces a verifiable natural gas usage reduction, is installed in

either existing or new construction applications, has a minimum useful life of seven years and exceeds minimum cost-effectiveness requirements. Qualifying measures include those that target cost-effective natural gas savings, such as retrofits of existing systems, improvements to existing systems and first time installations where the system's efficiency exceeds applicable codes or standard industry practice.

Smarter Greener Better Business Energy Assessments (Pilot): Rebates of up to $5,000 per non-residential customer will be provided to aid in offsetting the cost of conducting a comprehensive energy assessment (energy audit) for all, or a substantial portion of the customer's premises. The audit must meet or exceed the American Society of Heating, Refrigerating, and Air Conditioning Engineers (ASHRAE) Level 2, energy audit standards. The energy audit will study a customer's existing equipment and building envelope and identify potential energy conservation measures to reduce overall energy consumption and increase energy efficiency.

Smarter Greener Better Distributed Generation: The program provides rebates to non-residential customers to achieve significant fuel savings by promoting high efficiency electric generation, providing financial benefits during peak electrical demand periods, and demonstrating the use of new natural gas technologies that are being brought to market. The rebates are based upon the size and efficiency of the system being installed and range from $400 to $500 per kW.

Smarter Greener Better Low-Income Energy Conservation: The Low-Income Energy Conservation (LIEC) program provides income-qualified residential customers with money-saving weatherization measures that reduce energy use in their homes. The program will be available to households with annual incomes less than 150 percent of the federal poverty income guidelines, and will be administered by Southwest Gas in conjunction with the Arizona Commerce Authority (ACA - formerly dba Arizona Energy Office). The ACA manages the Department of Energy's (DOE) statewide Weatherization Assistance Program in Arizona and sub-contracts with local community agencies to install home weatherization measures. The home weatherization measures focus on four major categories: 1) duct repair; 2) infiltration control; 3) insulation (including attic, duct and floor); and 4) repair or replacement of appliances that are not operational or pose a health hazard.

Smarter Greener Better Energy Education (Pilot): The Energy Education program provides customers with energy efficiency and conservation information and recommendations to encourage the utilization of energy-efficient alternatives. In particular, the program focuses on specific energy efficiency or technology information that will help customers optimize natural gas usage. Print and radio mediums will be used to educate customers on the efficient use of natural gas

and energy in general.

Smarter Greener Better Solar Thermal Rebates: Rebates will be offered to residential and non-residential customers on qualified solar thermal systems, used for water heating or pool heating, upon proof-of-purchase and installation. The program objective is to increase public awareness of the benefits of solar thermal systems and to reduce customer natural gas usage by providing economically beneficial rebates to install the systems. Long-term customer energy savings will be realized throughout the life of the solar thermal systems.

To be eligible for participation in any of Southwest Gas' EE and RET programs, all new and existing residential, non-residential and low-income customers must have active Southwest Gas accounts, and residences and facilities must be within Southwest Gas' Arizona service territory. In addition, customers must also contribute towards the funding of these programs through the DSM rate adjuster.

EXHIBIT 3. SOUTHWEST SAVINGS AND BENEFITS TABLE

Table 1 – Portfolio Annual and Lifetime Therm Savings; Lifetime Societal Benefits, Costs and Net Benefits; and Cost-Effectiveness

Program	Annual Therm Savings	Lifetime Therm Savings	Societal Benefits	Societal Costs	Net Benefits	Cost-Effectiveness Ratio
			Residential			
Residential Rebates	640,000	12,800,000	$8,814,254	$6,783,333	$2,030,921	1.30
SGB Homes	570,000	15,960,000	$11,653,139	$5,066,667	$6,586,473	2.30
Residential Energy Assessments	19,000	190,000	$120,432	$1,050,000	$(929,568)	N/A[2]
Total Residential	**1,229,000**	**28,950,000**	**$20,587,825**	**$12,900,000**	**$7,687,825**	**1.60**
						Non-Residential
Business Rebates	580,000	8,700,000	$5,788,537	$2,733,333	$3,055,204	2.12
Custom Business Rebates	18,000	270,000	$179,644	$161,250	$18,394	1.11
Business Energy Assessments				$1,050,000	$(1,050,000)	N/A[2]
Distributed Generation	516,000	10,320,000	$7,106,492	$2,950,000	$4,156,492	2.41
Total Non-Residential	**1,114,000**	**19,290,000**	**$13,074,674**	**$6,894,583**	**$6,180,090**	**1.90**
						Low-Income
L-I Weatherization[1]	21,000	525,000	$374,859	$450,000	$(75,141)	0.83
						Education
Energy Education				$550,000	$(550,000)	N/A[2]
Total Energy Efficiency	**2,364,000**	**48,765,000**	**$34,037,358**	**$20,794,583**	**$13,242,774**	**1.64**
						Solar Thermal
Solar Thermal	87,000	1,479,000	$997,377	$616,667	$380,711	N/A[3]
Totals	**2,451,000**	**50,244,000**	**$35,034,735**	**$21,411,250**	**$13,623,485**	**1.64**

1L-I Bill Assistance is not included in this Table because there are no therm savings attributable to the program.
2Pursuant to Section R14-2-2512(G) of the Gas EE Standard, cost-effectiveness is not required for pilot programs.

3Pursuant to the Gas EE Standard, cost-effectiveness is not required for RET programs.