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SOUTHWEST GAS CORPORATION

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AZ CORP COMMISSION
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June 9, 2008

Docket Control Office
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007-2996

Subject: <u>Docket No. G-01551A-07-0504</u>

Southwest Gas Corporation (Southwest) hereby submits for filing an original and thirteen (13) copies of its Rejoinder Testimony in the above-referenced docket. In addition, a copy will be provided to parties of record.

Respectfully submitted,

Debra S. Gallo By

Debra S. Gallo, Director
Government & State Regulatory Affairs

c Ernest Johnson, ACC
Maureen Scott, ACC
Bob Gray, ACC
Stephen Ahearn, RUCO
Service List

Arizona Corporation Commission
DOCKETED
JUN -9 2008
DOCKETED BY nr

SOUTHWEST GAS CORPORATION

ARIZONA GENERAL RATE CASE

DOCKET NO. G-01551A-07-0504

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A

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

RANDI L. ALDRIDGE

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
Prepared Rejoinder Testimony
Of
RANDI L. ALDRIDGE

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
Of
Randi L. Aldridge

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Randi L. Aldridge. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same Randi L. Aldridge who sponsored direct and rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to specific aspects of the surrebuttal testimony presented by Mr. Ralph C. Smith, witness for the Arizona Corporation Commission Utilities Division Staff (Staff), and Mr. Rodney L. Moore, witness for the Residential Utility Consumer Office (RUCO), regarding their recommendations for ratemaking treatment of certain rate base and operating expense items.

Q. 4 Did you prepare exhibits to support your rejoinder testimony?

A. 4 Yes. I prepared the exhibits identified as Rejoinder Exhibit No.__(RLA-1) through Rejoinder Exhibit No.__(RLA-3).

Q. 5 Please summarize your rejoinder testimony.

A. 5 My rejoinder testimony will address the following:

(1) RUCO's proposal to exclude the Company's 2008 wage increase.

(2) Staff's proposal to exclude a portion of the Company's AGA dues.

(3) RUCO's proposal to exclude a portion of the Company's employee recognition expenses.

(4) RUCO's proposal to exclude a portion of the Company's miscellaneous general expenses.

(5) The Company's position regarding Staff's proposal on customer advances and customer deposits, as a result of RUCO's withdrawal of its proposed adjustment on the Company's uncollectibles expense.

(6) Staff's incorrect assertion that Southwest's MIP costs in this rate case are 76 percent higher than the last rate case.

2008 WAGE INCREASE

Q. 6 Has RUCO's position regarding the Company's proposal to include the 2008 wage increase in the cost of service changed since its direct testimony?

A. 6 No.

Q. 7 Do you have additional evidence to support the appropriateness of a three percent wage increase for

2008?

A. 7 Yes. In addition to the discussion in my rebuttal testimony at pages 2 and 3, which shows that the adjustment does not violate the matching principle and was prepared consistent with the methodology the Commission approved in the Company's last general rate case, Southwest's proposed 2008 wage increase is known and measurable. Attached as Rejoinder Exhibit No. __(RLA-1) is the Company's announcement to employees that Southwest's Board of Directors has approved salary increases to be effective June 23, 2008. The actual wage increase is identical to the estimated wage increase the Company proposed in its filing - three percent. Furthermore, Staff has not opposed the Company's request for the 2008 wage increase. For these reasons, the Commission should accept the Company's entire labor annualization adjustment as filed.

AGA DUES

Q. 8 Staff maintains that the final NARUC audit report and the Florida Cities Gas decisions should be considered by the Commission in determining the appropriate percentage of AGA dues that should be disallowed from operating expenses (Smith surrebuttal, page 33). Do either of these documents provide evidence to support Staff's position that AGA's cost for its Public Affairs and Corporate Affairs departments be disallowed in their entirety, and that 50 percent of AGA's General Counsel and Corporate Secretary functions be disallowed?

A. 8 No. Neither of these documents contain evidence supporting Staff's proposal to disallow amounts related to the Public Affairs, Corporate Affairs, General Counsel and Corporate Secretary functions.

Q. 9 Does the fact that an AGA dues exclusion of approximately 40 percent applied to a Florida utility have any bearing on this case?

A. 9 No. Staff's proposed 40 percent disallowance of AGA dues is purely arbitrary, and Staff has not presented any evidence or analysis demonstrating the reasonableness of its proposed disallowance or the inappropriateness of Southwest's adjustment. To the contrary, my direct and rebuttal testimony demonstrate the reasonableness of Southwest's proposed adjustment, which has also not been challenged by RUCO.

Q. 10 Has Staff discussed the functions of Public Affairs, Corporate Affairs, or General Counsel that would customarily be disallowed had they been conducted by Southwest directly?

A. 10 No. However, in Exhibit No.__(RLA-2) of my direct testimony, I provided AGA descriptions of its functional cost centers. In Rebuttal Exhibit No.__(RLA-1), I provided a narrative prepared by AGA which describes various functional cost centers in more detail and explains how customers benefit from the activities performed within each function. The General Counsel

Office is described on page 10 and the Public Affairs function is described on pages 11 through 13. I have demonstrated through these exhibits that customers benefit from AGA activities in excess of the dues that Southwest pays and it is reasonable for Southwest to recover the non-lobbying portion of these functions in rates.

Q. 11 Staff pointed out that the percentages that Southwest used for marketing and lobbying could be updated to 2008 values, and that a portion of AGA general and administrative costs (G&A) should be allocated to the advertising function (Smith surrebuttal, pages 34-35). Is Southwest opposed to this?

A. 11 No, these proposals are reasonable. Southwest agrees that an increase to its proposed adjustment to AGA dues for G&A and to reflect 2008 AGA budget percentages is reasonable. Accordingly, Southwest's proposed exclusion for AGA dues should be increased by $4,575.

EMPLOYEE RECOGNITION EXPENSES

Q. 12 RUCO disagrees with the Company's rationale that employee recognition expenses should be included in rates, as the expenses are "...additional compensation to its employees to perform work functions, some of which are county mandated, that should be considered a condition of employment." (Moore surrebuttal, page 10). Do you agree that the work functions that the employees may receive recognition awards for should be considered a condition of employment?

A. 12 No. First of all, Maricopa County's Trip Reduction Program ("TRP", the mandated program to which RUCO refers) does not mandate that Southwest's employees take alternative forms of transportation to and from work. Rather, the County mandates that Southwest offer incentives to encourage employees to make voluntary changes in their choice of transportation as part of the Company's participation in the TRP. It is unreasonable to expect Southwest to force employees to take alternative forms of transportation to and from work as a condition of employment.

Secondly, the other three employee recognition programs, described in my rebuttal testimony at pages 9 through 11, reward outstanding performance by employees. Outstanding performance of work functions goes above and beyond expected performance. It is unreasonable to have an expectation that all Southwest employees' performance should exceed expectations at all times, simply as a condition of their continued employment.

Finally, RUCO recognizes that it is important that Southwest "have proactive programs and policies on safety, productivity, and cost containment," (Moore surrebuttal, page 10), which provides validity to the Company's position that it is appropriate that Southwest offer these programs, and that it is inappropriate to make the performance rewarded by these programs a condition of employment. Southwest continues to recommend that the Commission allow the modest costs of these programs in rates since the benefits of these programs outweigh the costs, and these employees provide service to customers above and beyond a satisfactory level.

MISCELLANEOUS EXPENSES

Q. 13 Did RUCO recognize that it double counted gift certificates in its miscellaneous adjustment and its employee recognition adjustment?

A. 13 Yes, it did. RUCO increased operating expenses by $19,160 to correct for this.

Q. 14 RUCO states that it has "philosophical differences" (Moore surrebuttal, page 7) with Southwest regarding the appropriateness of cost recovery for the remaining items. Do you agree?

A. 14 In some cases this may be true. However, RUCO did not provide specific testimony as to why it disagreed with my rebuttal testimony, other than to state the fact that it has philosophical differences with Southwest. I don't believe that RUCO has raised a reasonable doubt that these expenses should not be appropriately included in rates. RUCO simply states that it believes these expenses are unnecessary. RUCO does not provide any evidence or analysis to support its conclusion.

Q. 15 Did you provide additional testimony in your rebuttal supporting the appropriateness of these expenses?

A. 15 Yes. I provided detailed descriptions of these items at pages 12 and 13 of my rebuttal testimony, and I have explained how these expenses provide customer benefits and/or cost savings, and are appropriately included in rates. Also, on page 14 (Q&A 27), I summarized the remaining categories of expenses that RUCO removed that it did not describe in its direct testimony or its surrebuttal testimony. Based on my rebuttal testimony, Southwest has met its burden of proof that these expenses are appropriately included in rates.

UNCOLLECTIBLES, CUSTOMER ADVANCES, AND CUSTOMER DEPOSITS

Q. 16 Since RUCO withdrew its proposed adjustment to uncollectibles expense in its surrebuttal testimony (Moore, page 10), does Southwest support Staff's proposed adjustment to customer advances and customer deposits?

A. 16 Yes. No party opposes Southwest's uncollectibles expense as filed. As such, Southwest supports Staff's proposal to use end of test year amounts for customer advances and customer deposits.

MANAGEMENT INCENTIVE PLAN (MIP) EXPENSE

Q. 17 On page 26 of Mr. Smith's surrebuttal testimony he asserts that Southwest's MIP expense is 76 percent higher in this rate case than in the prior case, is this correct?

A. 17 No. I have attached two exhibits showing recorded MIP expense since 2001. Exhibit No.__(RLA-2) is Southwest's response to a data request in the Company's 2004 rate case, which shows the recorded MIP expense in the 2004 rate case was $6,677,800, and not $3,366,667 as purported by Mr. Smith on p. 26 of his surrebuttal testimony. Exhibit No.__(RLA-3) is Southwest's response to a data request in the Company's current general rate case, which shows the recorded MIP expense in this rate case is $5,919,502. Contrary to Mr. Smith's assertion, the MIP expense has actually decreased from the test year in the 2004 rate case by approximately 11 percent.

Q. 18 Does this conclude your prepared rejoinder testimony?

A. 18 Yes, it does.

Human Resources News

Spotlight

SOUTHWEST GAS

Rejoinder Exhibit No.__(RLA-1)
Sheet 1 of 1

Companywide Distribution May 9, 2008

2008 WAGE AND SALARY INCREASE APPROVED

Southwest's Board of Directors has approved salary increases for both exempt and non-exempt employees. This increase, which is consistent with market compensation trends, will become **effective for the pay period beginning June 23, 2008 and will be reflected in the July 11th paychecks.**

An Overview of Total Compensation

Before we get into details about the pay increases and how they will work, we thought we'd share some information with you about the total compensation program at Southwest Gas. In 2008, wages and benefits compose almost 63% ($218 million) of our Operations and Maintenance Expense budget. Budgeted company contributions for 2008 include:

- $19 million for the pension plan;
- $17.3 million for the medical plan;
- $2.2 million for the annual step-rate increase (for employees not yet at Step 9); and
- $2.6 million for non-exempt wage adjustment (NEWA).

Total compensation encompasses the increases in health and welfare expenses like insurance premiums, retirement contributions and employer matching on your 401(k) contributions. We believe that the components of your total compensation that make up your complete package of wages and benefits must be balanced to ensure your overall well-being.

What Kind of Increase You Can Expect

Non-exempt (overtime eligible) employees will receive an increase based on your classification:

- If you are a Step 9 employee, you will receive a 3% non-exempt wage adjustment (NEWA).
- If you are a Step 1 through Step 8 employee, you will continue to receive "step increases" plus the 3% NEWA.

The following shows the exceptional salary increases received each year—**including NEWA—** starting at Step 1:

Year 1	20.1% increase
Year 2	17.7% increase
Year 3	9.5% increase
Year 4	9.1% increase
Year 5	8.7% increase
Year 6	8.4% increase

Docket No. G-01551A-04-0876
RUCO-2-13

Rejoinder Exhibit No.__(RLA-2)
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
MANAGEMENT INCENTIVE PROGRAM
TOTAL COMPANY COSTS FOR THE YEARS ENDED
DECEMBER 31, 2001 THROUGH 2004 AND THE TEST YEAR ENDED AUGUST 31, 2004
RESPONSE TO RUCO DATA REQUEST NO. 2-13

Description	2001	2002	2003	2004	TME 8/31/04
Recorded Amounts	$ 4,770,000	$ 5,000,000	$ 6,400,000	$ 5,850,000	$ 6,800,000
Less: Special Incentive Award	108,700	113,000	114,700	122,200	122,200
Management Incentive	$ 4,661,300	$ 4,887,000	$ 6,285,300	$ 5,727,800	$ 6,677,800

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
INCENTIVE PROGRAMS
IN RESPONSE TO DATA REQUEST NO. RUCO-1-10
UPDATED 3/25/08

	DATE		CORP		AZ	Account
MIP						
Eligiblity: Sr Mgrs and Above	2004	$	5,699,300			920
	2005		5,681,550			920
	2006		5,241,806			920
	12ME Apr 07		5,919,502			920
Exempt Special Incentive						
Eligibility: All non-incentive	2004	$	150,700			920
exempts with at least 6	2005		148,450			920
mos. service	2006		154,500			920
	12ME Apr 07		151,250			920
Service Planning						
Quality Incentive Award	2004	$	168,035	$	431,425	903
Eligiblity: service planners,	2005		140,171		465,150	903
their supvs and managers,	2006		143,865		367,534	903
industrial gas engineers	12ME Apr 07		137,522		290,004	903
Stock Option Expense						
Expense that must be	2004		-			n/a
recognized on Southwest's	2005		-			n/a
books	2006		1,493,694			920
	12ME Apr 07		1,507,520			920

B

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY
OF
ROBERT A. MASHAS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
Prepared Rejoinder Testimony
Of
ROBERT A. MASHAS

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
ROBERT A. MASHAS

INTRODUCTION

Q. 1 Please state your name and business address.

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

Q. 2 Are you the same Robert A. Mashas who previously sponsored direct and rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to specific aspects of the surrebuttal testimony presented by Arizona Corporation Commission Utilities Division Staff (Staff) witnesses Messrs. Ralph C. Smith, Corky Hanson, Phillip S. Teumim, and Residential Utility Consumer Office (RUCO) witness Mr. Rodney L. Moore, regarding their recommendations for ratemaking treatment of rate base, certain operating expense items, and the Company's line extension procedures and policies.

Q. 4 Did you prepare exhibits to support your rejoinder testimony?

A. 4 Yes. I prepared the exhibit identified as Rejoinder Exhibit No.__(RAM-1).

Q. 5 Please summarize your rejoinder testimony?

A. 5 My rejoinder testimony will address the following issues:

- Injuries and Damages: Staff's calculation of the 10-year average of self-insured retentions.
- Yuma Manors: Staff's proposal to disallow all gas plant required to replace 50-year old pipe.
- Gain on sale of Sundt Plant: Staff's calculation of the gain.
- Lead-Lag Study: Staff's calculation of preferred equity expense lag.
- Line Extension Policy: Staff's recommendation related to the Company's line extension policy.

INJURIES AND DAMAGES

Q. 6 Does Staff witness Mr. Smith concede that in the last rate case Staff, RUCO and Southwest agreed upon a methodology to derive the self-insured portion of injuries and damages?

A. 6 Yes.

Q. 7 Did Southwest use the same methodology to determine the appropriate level of self-insured expense in this rate case?

A. 7 Yes. Consistent with the methodology established in the Company's last general rate case, for ratemaking purposes, Southwest treats all self-insured costs as "system allocable" rather than direct jurisdictional expenses. The Company has two categories of self-insured expense. The first category is the self-insured retention for up to the first $1 million of claim expense for each incident, regardless of the number of incidents that may occur in a claim year (August 1 through July 31 of the following year). The second category is the self-insured aggregate amount per claim year, which covers claim expense above the first $1 million self-insured retention up to an aggregate not to exceed $5 million. The $5 million can come from more than one incident and is not jurisdictional-specific. Consistent with the agreed-to methodology in the last rate case, the Company used a 10-year average of both categories of self-insured expense. Finally, in order to determine an appropriate level of the $5 million aggregate expense, the Company needed to use the ten-year history of actual claims expense paid and not the amounts recorded on the Company's books during this period.

Q. 8 Did RUCO propose a methodology different from the one it agreed to in the Company's last general rate case?

A. 8 No. RUCO did not recommend a change in methodology from the one agreed to in the Company's last general rate case. However, in its direct case, RUCO is recommending that the Company's proposed self-inured expense level be increased by $283,664 to reflect the impact of an accounting error that occurred in June 2006.

Q. 9 Did the Company provide Staff with a comparison of the Company's current calculation to that agreed upon in the last rate case?

A. 9 Yes. The Company's response to Staff Data Request No. 13-14 provides a side-by-side comparison. A copy of Staff Data Request No. 13-14 is included in Staff's surrebuttal testimony as Attachment RCS 8, pages 25 through 32. The comparison is shown on page 30 of the Attachment.

Q. 10 Please discuss the three levels of claims expense detailed on Staff surrebuttal Attachment RCS 8, page 30.

A. 10 The first level of claims expense shown on line 1 is the ten-year total of claims resulting in amounts less than $1 million. Line two is the ten-year total of $1 million self-insured retentions. Both of these amounts were recorded on the Company's books. Line three is the ten-year total of claims expense that exceeded $1 million, but did not exceed $10 million in the last rate case, and was less than $5 million in the current rate case. Except for the May 2005 incident, none of these amounts were recorded on the Company's books since, prior to August 1, 2004, the Company had insurance coverage that indemnified it for these costs. However, on a going-forward basis, the Company is self-insured for the up to $5 million aggregate level of claims expense. Effective with the August 2004 plan year, to the extent claims expense exceeds $1 million, and up to the $5 million aggregate, these amounts are recorded on the Company's books.

Q. 11 Please compare the "Arizona allocated" derived in this rate case to that agreed to in the Company's last rate case.

A. 11 Staff Attachment RCS 8, page 30, line 8 shows the Arizona allocation in this rate case is $1,762,263 compared to the last rate case amount of $1,731,312. The allocation in this rate case is only $30,951 higher, or 1.8 percent.

Q. 12 Please compare the ratemaking adjustment required in this rate case to that required in the last rate case.

A. 12 Staff surrebuttal Attachment RCS 8, page 30, line 15, shows that in the last rate case, an adjustment of $1,168,760 was necessary to increase the recorded "positive" $562,552 to the $1,731,312 level of self-insured expense. In this rate case, an adjustment of $2,512,119 is necessary to increase the recorded "negative" $749,856 to the $1,762,263 level of self-insured expense.

Q. 13 Please explain why the adjustment in this proceeding is more than double the adjustment in the last rate case when the end result is only $30,951 higher.

A. 13 The current adjustment is $1,343,359 higher than the adjustment required in the last rate case proceeding primarily because of the difference in the two recorded test year amounts. The difference between the recorded test year amount of a positive $562,552 (2004 test year) and a negative $749,856 (2007 test year) equals $1,312,408. The remaining $30,951 is the increase in the level of self-insured expense.

Q. 14 Is it possible to have a "negative" claims expense on a going-forward basis?

A. 14 No. Actual claims expense will always be positive. However, liability claims can take years to process and during that time, an accrual for a "positive" accrual estimate recorded in one accounting period can result in a "negative" adjustment to a previous accounting period's accrual. Any negative adjustment will only be to a previous positive accrual. The negative adjustment will never exceed the positive accrual.

Q. 15 Is the dollar magnitude of the adjustment to recorded amounts indicative of the reasonableness of the end result?

A. 15 No. The end result determines the reasonableness. For instance, if the recorded expense happened to be $1,762,263 and no adjustment was required, it does not make the $1,762,263 any more reasonable, it just makes it less controversial.

Q. 16 Is Staff's proposed level of self-insured expense reasonable?

A. 16 No. Staff relies on recorded Arizona direct amounts and removes the only incident recorded on the Company's books related to the self-insured aggregate established in

August 1, 2004. Staff's calculation provides for "zero dollars" for this level of expense.

Q. 17 Staff removed the recorded $10 million amount related to the May 2005 Tucson, Arizona incident that was recorded as a System Allocable expense in December 2005. Staff describes this incident as extreme, unprecedented, extraordinary, and not expected to recur. Is this a fair characterization of this incident?

A. 17 No, not when the incident is put into the proper context. The May 2005 incident resulted from a leaking pipe in Tucson, Arizona. The self-insured aggregate level in place at that time was $10 million, which was recorded as a System Allocable common expense consistent with the ratemaking methodology agreed to by Staff, RUCO, and the Company in the previous rate case. The $10 million could have been recorded as a direct Arizona expense and it would have been, but the Company recorded it as system allocable to be consistent with the methodology agreed to by all the parties in the last Arizona general rate case. The Company acknowledges that the claims expense related to the May 2005 incident was the first time that the dollar impact of a jurisdictional-specific incident was recorded as a System Allocable expense. However, comparing that expense to the previously recorded System Allocable amounts is an "apples to oranges" comparison because prior to the last Arizona general rate case, System Allocable recorded amounts were limited to automobile or personal injury incidents involving corporate employees or facilities located at the corporate headquarters in Las Vegas, Nevada; not state specific incidents involving gas leaks. The potential dollar impact of an explosion caused by a gas leak is not comparable to an automobile or personal injury incident. Mr. Smith's proposal to exclude the impact of the Tucson incident because it is large, and when taken out of context, may appear extreme, unprecedented, extraordinary, and not expected to recur when compared to automobile accidents or personal injury claims, is improper.

Q. 18 During the ten-years ending April 2007, was the May 2005 incident the only time where claims paid reached the $5 million aggregate threshold?

A. 18 No. The $5 million threshold was met as a result of a January 2003 Arizona incident. In 1993, the Company had two incidents where the $5 million threshold was met. Furthermore, in 1997 and 1998, there were three incidents where the claims paid exceeded the $1 million self-insured retention, but did not exceed the $5 million threshold. Except for the May 2005 incident, all of the other incidents were not recorded on Southwest's books because the Company had insurance for claims expense above $1 million. Since August 1, 2004, the Company has been and continues to be self-insured for these amounts. Therefore, it is appropriate and necessary to provide for this level of self-insured expense. The methodology agreed to by Staff, RUCO, and the Company in the Company's last general rate case is as reasonable now as was then. Staff's proposed "zero dollar" level is not.

Q. 19 What adjustment to Staff's proposed cost of service is necessary in order to provide a reasonable level of both the up to $1 million self-insured retention and the not to exceed $5 million aggregate self-insurance?

A. 19 The $1,135,381 increase to pre-tax operating expense shown at the top of page 40 of Mr. Smith's Surrebuttal testimony is the adjustment necessary to provide a reasonable level of self-insured expense on a going-forward basis. The adjustment consists of two parts. The first part is an increase of $283,664 to reflect the impact of the accounting error referred to in RUCO's operating expense Adjustment No. 2. Both RUCO witness Rodney Moore and Company witness Randi Aldridge address this adjustment in their respective testimonies. The second part of the adjustment is the $851,717 reversal of Staff's proposed Adjustment No. C-12 Revised.

YUMA MANORS

Q. 20 Does Staff continue to propose that Southwest write-off 100 percent of the cost of replacing the 50-year old Yuma Manors steel pipe system?

A. 20 Yes. Staff witnesses Smith and Hanson continue to propose that 100 percent of the replacement cost of the 50-year old steel pipe system be excluded from rate base.

This exclusion will require the Company to permanently write-off the $1,231,762 spent to replace the 50-year old system.

Q. 21 Why does Staff believe that a ratemaking treatment considerably harsher than that approved by the Commission in similar cases where the premature replacement of pipe was addressed is appropriate in this case?

A. 21 Staff believes that the circumstances in the Yuma Manors are different than those of the four pipe replacement programs that I discussed in my Rebuttal testimony. Therefore, harsher punishment of Southwest is somehow warranted.

Q. 22 What are the differences noted by Staff witness Smith?

A. 22 Mr. Smith, on page three, line 17 of his surrebuttal testimony, states "… in the current rate case as a cost that has arisen as the direct result of incorrect actions taken by SWG personnel resulting in the failure of that system." On page 5, line 12 of his surrebuttal testimony, Mr. Smith further states, "With respect to Yuma Manors, as explained by Staff witness Hanson, the premature replacement was not attributed to defective material and/or installation, but rather to the actions of SWG employees." Staff places significant importance on the notion that a mistake by Southwest "employees" warrants a more extreme ratemaking treatment than replacement resulting from defective material and/or improper installation.

Q. 23 How many Southwest employees were involved?

A. 23 Only one Southwest employee was involved. Once all the facts were known, Southwest applied corrective and remedial actions. The employee also faced disciplinary action.

Q. 24 Were improper actions taken by Tucson Gas and Electric (TGE) personnel that resulted in the premature replacement of Aldyl A pipe?

A. 24 Yes. TGE used Aldyl A pipe as its primary gas distribution pipe material during the years 1967 through 1978. Southwest acquired the gas distribution system from TGE in 1979. In 1981-82, Southwest noted a significant number of pipe failures due to rock impingement. By 1983, Southwest determined that the large number of leaks was caused by TGE's use of: 1) improper backfill material; 2) improper pipe squeeze; 3) improper heat-fusion; and 4) problems with amp fittings and service tee caps. As a result of improper actions by TGE personnel during the ten years that Aldyl A pipe was installed by TGE personnel, Southwest began replacing Aldyl A pipe in the 1980s after only a ten-year average useful life. Approximately 50 percent of the nearly 1,300 miles of Aldyl A pipe, at a cost of approximately $40 million in 1980 dollars, was replaced.

Q. 25 Despite the improper actions of TGE personnel, did the Commission disallow 100 percent of the replacement cost?

A. 25 No. The Commission allowed the life extending benefit of the new pipe when compared to pipe that was ten to twenty years old. In the Company's last rate case, the Commission adopted a 40-year rule where, regardless of the reason - even improper installation, 100 percent of the cost resulting from the replacement of pipe that has served ratepayers at least 40 years will be included in rate base.

Q. 26 Are the circumstances similar with regard to the Aldyl HD replacement pipe?

A. 26 Yes. As part of the TGE acquisition, Southwest acquired TGE personnel who continued the same installation practices used to install Aldyl HD pipe from 1979 through 1981. In 1993, a gas leak resulted in an explosion causing bodily injuries and property damage. As a result of the ACC Pipeline Safety review of the incident, the Company undertook a significant pipe replacement program. The replacement program was completed in 1998.

Q. 27 Did the Commission disallow 100 percent of the cost to replace Aldyl HD pipe?

A. 27 No. Even though the replacement was undertaken for the improper installation practices of former TGE personnel acquired by Southwest, the Commission did not disallow 100 percent of the replacement cost. To the extent that the replacement pipe extended the life of the system, the betterment portion was included in rate base.

Q. 28 Was the mistake of one Southwest employee of significantly greater magnitude than the examples previously cited and relied on by the Commission so as to justify penalizing Southwest as recommended by Staff?

A. 28 No. One individual made a mistake and personally suffered the consequences of his actions. Southwest witness Jerome T. Schmitz, in both his rebuttal and rejoinder testimony, discusses in detail the events that led up to the replacement of the 50-year old steel pipe and the actions taken by Southwest.

Q. 29 Does the error made by this one individual warrant the extreme punishment of requiring a 100 percent write-off of the replacement of the 50-year old steel system?

A. 29 No. As detailed above, the Commission has dealt with considerably larger replacement programs that resulted from human error with more restrained and reasonable judgment than what the Staff is recommending in this proceeding.

Q. 30 Is the $320,779 adjustment to the cost of the replacement pipe that the Company is proposing appropriate?

A. 30 Yes. This represents nearly 25 percent of the replacement cost of the Yuma Manors system. The betterment is 100 percent when the 40-year rule is applied. No additional adjustment is warranted.

GAIN ON SALE OF SUNDT PLANT

Q. 31 Does the Company agree with Staff's proposed adjustment to share the gain on the sale of natural gas facilities to TEP?

A. 31 Yes. However, the Company notes that there is an error in Staff's calculation. Staff's Schedule C-16, Page 1, line 1, column (B) is $(67,937) and should be $(37,942). This will change the gain shown on line 3, column (E), from Staff's $609,825 to $579,623. The 50 percent three-year shared gain is $96,504 and not the $101,600 shown on Staff surrebuttal Schedule C-16.

Q. 32 Please explain Rejoinder Exhibit No.__(RAM-1).

A. 32 Rejoinder Exhibit No.__(RAM-1) is the Company's response to Staff Data Request No. STF-14-3, which illustrates the proper final calculation of the gain on the sale of the natural gas facilities to TEP.

LEAD-LAG STUDY: STAFF'S CALCULATION OF PREFERRED EQUITY LAG

Q. 33 Does the Company agree with Staff's calculation of preferred equity lag?

A. 33 Conceptually yes, but Staff's application is flawed. Staff Schedule B-3 Revised is its cash working capital calculation. Line 6 is described as Staff's interest calculation when in reality the $48,083,335 is the weighted cost of debt and preferred equity ($1,065,457,617 rate base x 4.512%(4.145% debt + 0.367% preferred equity). The 84.65 lag days shown on Staff Schedule B-3 Revised line 6, column (d) is the interest lag days. The weighted interest and preferred lag days is 79.50 as shown in my Rebuttal Exhibit No.__(RAM-3), Sheet 1 of 2. The 79.50 weighted interest and preferred equity lag should be applied to the weighted cost of interest and preferred equity shown on Staff Schedule B-3

Revised line 6, column (c).

Q. 34 Is the preferred equities calculation shown on Staff Schedule B-3 Revised line 7 appropriate?

A. 34 No. Based on the above, the calculation on line 7 is not appropriate. The lag on preferred equity is considered when the 79.5 lag days is substituted on line 6, column (d). Furthermore, the $7,772,141 is the total Company preferred equity cost and not the Arizona allocated portion. It is inappropriate to include the total Company expense in column (c) when all other amounts in column (c) are Arizona direct.

Q. 35 Did RUCO calculate the preferred equity lag correctly?

A. 35 Yes. RUCO used the 79.5 average interest and preferred equity lag days.

LINE EXTENSION POLICY

Q. 36 In his surrebuttal testimony, Staff witness Phillip S. Teumim continues to recommend that Southwest provide additional information on Southwest's line extension policy. Please comment.

A. 36 Southwest has presented extensive testimony and supporting documentation in this proceeding on its line extension policy. In response to a Commission directive in the Company's 2000 general rate case proceeding, Southwest provided testimony and documentation to support its line extension policy in its 2004 general rate case. No party in that proceeding expressed concerns with the Company's line extension policy. To the extent applicable, any changes in the Company's line extension policy that result from the ongoing hook-up fee investigation will be incorporated into the Company's line extension policy. In addition, Southwest is willing to meet with Staff to explain the Company's line extension policy on an informal basis at any time Staff requests.

Q. 37 Does this conclude your rejoinder testimony?

A. 37 Yes, it does.

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
****
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-14
(ACC-STF-14-1 THROUGH ACC-STF-14-3)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 21, 2008

Request No. ACC-STF-14-3:

Gain on sale of metering facility and piping to TEP related to Sundt bypass. Refer to the May 14, 2008 supplemental response to RUCO 7-2. Please confirm that SWG anticipates the sales prices and net gains upon sale of these assets, as of March 31, 2008, the expected sales date:

Net Book Value At Sales Date	Tentative Sales Prices	Net Gain
$ 114,156	$ 398,381	$ 284,225
$ 24,400	$ 350,000	$ 325,600
$ 138,556	$ 748,381	$ 609,825

If any of the above amounts, which were provided in, or derived from, the Company's 5/14.08 supplemental response to RUCO 7-2 are inaccurate, or have subsequently been revised or changed, please provide the most current information available and indicate whether it corresponds with the finalized transaction.

Respondent: Revenue Requirements

Response:

Attached is a worksheet that provides the final calculation of the sale of facilities to TEP. The final net book value at the time of sale for the metering facility is $144,150 and not the $144,156 reported in the supplement to RUCO 7-2 and the $114,156 shown on Staff Surrebuttal Schedule C-16, Page 1 of 1. The final net book value at the time of sale of the piping is $24,439 and not the $24,440 reported in the supplement to RUCO 7-2 and the $24,400 shown on Staff Schedule C-16 Page 1 of 1. The final total net book value is $168,589 and not the $168,596 sum of the two amounts in the Supplement to RUCO 7-2 and the $138,556 shown in Staff Schedule C-16, Page 1 of 1. The final sale proceeds are $748,212 and that is consistent with the Supplement to RUCO 7-2 and Staff Schedule C-16. The final net gain is, therefore, $579,623 and not the $609,825 shown on Staff Schedule C-16. The three-year normalization period to provide 50 percent of the gain to customers is $96,604 and not the $101,606 shown on Staff Schedule C-16.

SOUTHWEST GAS CORPORATION
ARIZONA
GAIN ON SALE OF CERTAIN FACILITIES TO TUSCON ELECTRIC COMPANY
AS OF MARCH 31, 2008
Docket No. G-01551A-07-0504
STF 14.3

Line No.	Description	Original Cost	Accumulated Depreciation	Net Book Value	Sales Price	Net Gain	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Gain on Sale of Utility Property						
1	High Pressure Steel Main	$ 28,526	$ 4,087	$ 24,439	$ 398,212	$ 373,773	1
2	Meter Set Assembly	182,093	37,943	144,150	350,000	205,850	2
3	Total	$ 210,619	$ 42,030	$ 168,589	$ 748,212	$ 579,623	3
	Sharing of Gain with Ratepayers						
4	Ratepayer sharing percent					50.00%	4
5	Ratepayer sharing amount of gain					$ 289,812	5
6	Normalization period, in years					3	6
7	Adjustment to pre-tax NOI for gain sharing					$ 96,604	7

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF ACCUMULATED DEPRECIATION ON ORIGINAL INVESTMENT
AS OF MARCH 31, 2008
Docket No. G-01551A-07-0504
STF 14.3

Line No.	Description (a)	Original Cost (b)	Month Placed In-Service (c)	Depreciation Rate (d)	Months (e)	Accumulated Depreciation (f)
	Gain on Sale of Utility Property					
1	High Pressure Steel Main	$ 28,526	Jun-04	3.82%	45	4,087
2	Meter Set Assembly	182,093	May-03	4.31%	58	37,943
3	Total	210,619				42,030

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION FOR PLANT SOLD TO TUSCON ELECTRIC COMPANY
AS OF MARCH 31, 2008
Docket No. G-01551A-07-0504
STF 14.3

Line No.	Description	Gross Plant	Depreciation Rate	Depreciation Expense	Line No.
	(a)	(b)	(c)	(d)	
	Gain on Sale of Utility Property				
1	High Pressure Steel Main	$ (28,526)	3.82%	$ (1,090)	1
2	Meter Set Assembly	(182,093)	4.31%	(7,850)	2
3	Total	$ (210,619)		$ (8,940)	3

C

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

JEROME T. SCHMITZ

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Prepared Rejoinder Testimony
Of
JEROME T. SCHMITZ

Southwest Gas Corporation
Docket No. G-01551A-07-0504

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
Jerome T. Schmitz

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Jerome T. Schmitz. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same Jerome T. Schmitz who sponsored rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to certain aspects of Arizona Corporation Commission Utilities Staff (Staff) witness Mr. Corky Hanson's surrebuttal testimony related to the replacement of the natural gas distribution pipe at Yuma Manors.

STAFF WITNESS MR. CORKY HANSON

Q. 4 Do you agree with Mr. Hanson's characterization of his direct testimony on page 1, lines 2-4 of his surrebuttal testimony?

A. 4 No. Mr. Hanson states that his direct testimony addresses pipe replacement associated with the "Company's negligence in making earlier repairs to the pipeline." This is an example of Mr. Hanson's vague and misleading statements regarding the Yuma Manors pipe replacement project. There is no evidence in this case that the Company was negligent nor did Mr. Hanson allege any negligence by Southwest in his direct testimony. On page 2, line 7 of Mr. Hanson's direct testimony, he attributes the pipe replacement to "incorrect actions" taken by Southwest personnel. The Company does not dispute that an employee made a mistake which may have contributed to the need to replace the steel pipe sooner than may have been required, but Southwest strenuously objects to Mr. Hanson's implication that the Company was negligent. Negligence is generally defined as "the failure to use such care as a reasonably prudent and careful person would use under similar circumstances."[1] An employee mistake is entirely different than "Company negligence" as Mr. Hanson incorrectly states.

Q. 5 Do you agree with Mr. Hanson's characterization of Rebuttal Exhibit No.__(JTS-1)?

A. 5 No. In his direct testimony, Mr. Hanson made the unsupported statement that "pipe corrosion is one of the leading causes of pipeline failures."[2] This quote is another example of Mr. Hanson's vague and misleading statements regarding this incident, as I mentioned in my rebuttal testimony. Mr. Hanson did not qualify his

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1 Black's Law Dictionary 930 (Fifth Edition 1979).
2 Hanson Direct, p. 3, line 3.

original statement as pertaining only to steel pipe, nor does he seem to recognize that corrosion leaks on distribution systems are generally not failures that result in incidents. The purpose of Rebuttal Exhibit No.__(JTS-1) was to simply put his statement into proper context and to demonstrate that there are numerous factors to consider when making conclusions regarding pipe failures.

CATHODIC PROTECTION

Q. 6 Can you provide a simple example of how pipe is protected?

A 6 Yes. Without any protection, bare steel in a natural environment tends to revert to its natural state through an electrochemical corrosion reaction, which is ferric oxide, or rust. In order to prevent this reaction from occurring, steel must be insulated from the environment by applying a pipe coating or by reversing the electrical current flow causing the reaction, or both. For example, steel pipe can be protected by applying a pipe coating to insulate the pipe from the environment and then by impressing a small direct electric current to reverse the electrical corrosion reaction process at locations where the coating has a defect that exposes the steel pipe to the environment.

Q. 7 Mr. Hanson continues to contend that had the Southwest employee connected the rectifier correctly, the Yuma

Manors distribution system had significant remaining life that could have been extended. Do you agree?

A. 7 No. Mr. Hanson has provided no analysis, studies or other evidence to support his conclusion that the pipe "had significant remaining life." Instead, he merely relies upon the fact that leak survey reports show a significant increase in leaks after the ground bed was placed back in service in 2006. His testimony continues to imply that impressed current is the only element required to protect pipe. As in the example I discussed above, two other elements, pipeline environment and the pipe coating, must also be considered to provide effective protection of pipe. Mr. Hanson recognizes that a pipeline does not operate in a constant environment; however, he does not provide any information as to why environment is an important consideration. Similarly, he does not discuss pipeline coatings, which provide an insulating barrier on the pipe against a potentially corrosive environment. Effective pipeline protection relies on both the pipe coating and the impressed current to counteract the effects of the environment in which the pipeline is installed.

Q. 8 Why is pipe coating an important consideration when analyzing cathodic protection?

A. 8 Pipe coating is critical to the overall protection of the pipe and is considered to be the first barrier of defense in preventing and mitigating corrosion. A structurally sound coating with few holes or cracks exposing the steel requires minimal impressed current. Pipe coating integrity ultimately determines the level of impressed current protection needed. When the coating fails, it compromises the protection of the pipe. Impressed current from the rectifier can be increased to a point to overcome a coating failure, but at some level the amount of impressed current to protect the pipe will actually accelerate the disbonding of the pipe coating to the point where the pipe can no longer be effectively protected. The power costs of providing the required impressed current will correspondingly increase.

Q. 9 Would you expect to see widespread corrosion damage if the pipe coating was sound and had few imperfections, even if the polarity was reversed?

A. 9 If the polarity was reversed, I believe corrosion would be accelerated at the coating hole or crack locations, but should not result in the widespread and general corrosion, as appeared to be the case in the Yuma Manors system.

Q. 10 Does the Company have any information related to possible coating problems?

A. 10 The tar coating on the steel pipe in Yuma Manors was "mature" and had been subject to over 50 years of environmental fluctuations, particularly in areas proximate to residential yards. As I address in more detail later in my rejoinder testimony, the pattern of leaks from the leak surveys are concentrated in one of the four subdivisions, which suggests that this particular area of the system had possible coating problems. It is also important to note, as I indicated in my rebuttal testimony, not all steel pipe connected to this rectifier had to be replaced, even though it was all the same vintage.

Q. 11 Do you agree with Mr. Hanson that "…properly installed, cathodic protection has the potential to extend the life of a buried pipe of any vintage?"

A. 11 No. As I indicated earlier, a number of things other than impressed current must be considered for adequate protection of buried steel pipe. For older piping, such as with Yuma Manors, the condition of the tar coating, and the nature of the environment in which the pipe is installed, may render additional cathodic protection inadequate sooner, rather than later, so that impressed current will not provide the needed protection.

YUMA MANORS SUBDIVISION

Q. 12 Please describe the distribution system in the Yuma Manors subdivision.

A. 12 As illustrated on the map included herewith as Rejoinder Exhibit No.__(JTS-1), the distribution system in the Yuma Manors subdivision is located within the geographic area generally bounded by 24^{th} Street on the north; Engler Avenue on the east; 26^{th} Place and San Marcos Drive on the south, and James Avenue on the west. The subdivision consists of 4 units: Manors 1, 2, and 3, and East of Pacific. The subdivision is divided by two canal rights-of-way, one of which runs north/south between Carol Avenue in Manors 1 and Mary Avenue in Manors 2, and one of which parallels the west side of Pacific Avenue. The distribution system was, and still is, served by a 4-inch steel main running along 24th Street. Prior to the pipe replacement project, the interior of the distribution system (excepting the 4-inch steel feeder main in 24th Street) consisted of steel mains. Many of the steel services in Manors 1 and most of the services in Manors 2 had been replaced with plastic pipe prior to 1985. The steel distribution system was protected by a rectifier (designated as "Y-18") located near the back of the lots on Mary Street and 26th Street near the canal right-of-way.

Q. 13 Please describe the history of the Yuma Manors system.

A. 13 As I indicated in my rebuttal testimony, the gas distribution system for the Yuma Manors was installed between 1954 and 1958 by Arizona Public Service Corporation (APS). Southwest's records show remaining steel services in Manors 1 and Manors 2 dating to 1955, and remaining steel services in Manors 3 and East of Pacific dating to the 1956 to 1958 time frame. It is not unreasonable to assume that the development of this subdivision occurred from Manors 1 and 2, first, then to Manors 3 and East of Pacific, last.

Q. 14 Are you aware of any other information germane to the discussion regarding the purported condition of the distribution system just prior to the rectifier being reversed?

A. 14 Yes. Southwest contacted the Yuma Mesa Irrigation and Drainage District and learned that flood irrigation was available to homes in the Yuma Manors until the early 1960s. This fact was also confirmed by a Southwest employee who grew up in the subdivision. This fact is germane to the discussion regarding the purported condition of the distribution system because, as discussed in more detail below, the cyclical wet/dry nature of the environment in residential yards will likely cause the pipe coating to deteriorate more quickly than in a more stable environment.

Q. 15 Do Southwest's records provide any additional information that pertains to historic replacements within the subdivision?

A. 15 Yes. Steel pipe, not plastic pipe, was utilized in the construction of gas distribution systems in the 1950s. It is noteworthy that many of the original steel services in Manors 1 and all but a few of the services in Manors 2 were replaced with plastic pipe prior to the replacement project undertaken in 2007 by Southwest. APS, the owner and operator of the system until 1984 when Southwest purchased the APS gas properties, apparently replaced many of the steel service lines with plastic pipe prior to 1984. APS' pipe replacement is reflected in the current Southwest maps.

Q. 16 Why did APS replace the steel services?

A. 16 The only reasonable conclusion I can draw is that the original steel services were replaced early due to leakage from corrosion. As I indicated in my rebuttal testimony, these steel lines had no cathodic protection until 1982.

Q. 17 Please describe Southwest's Yuma Manors replacement project.

A. 17 The replacement project challenged by Staff witness Mr. Corky Hanson, replaced all of the interior steel mains and steel services with plastic pipe. In some locations, the steel pipe was used as a sleeve into which the new plastic pipe was inserted; in others, mains were moved from the alley to the street to eliminate future maintenance challenges with backyard services. Existing plastic services were utilized and tied over to the new plastic mains where possible.

Q. 18 Was all of the distribution system within the Yuma Manors subdivision replaced?

A. 18 No. The 4-inch steel pipe along 24^{th} Street was not replaced and remains in service because it was determined to still be in good condition. Southwest also determined that unlike the service lines, any future replacement of this pipe could be done with little customer interference. Following the completion of the replacement project, the existing 4-inch steel pipe along 24th Street was connected to the Y-18 rectifier by a cable inserted into a 1200-foot plastic conduit running north along the canal right-of-way behind the homes on Mary Avenue from 26th Street to 24th Street.

Q. 19 Do you believe that the pipe that was replaced in Yuma Manors was poorly coated and would need replacement in the near future?

A. 19 Yes. I believe one can reasonably conclude that the cyclical wet/dry nature of the environment in residential yards caused the coating on steel services to deteriorate more quickly than in the more stable environment that would exist for mains under pavement in streets or alleys. As such, it was only a matter of time before these coating deficiencies would come to light. Furthermore, I believe that the inadvertent reversed polarity actually revealed this deficient coating. The leaks found during late 2006 and early 2007 were primarily concentrated in a single subdivision - Manors 3, and most of the leaks found prior to and during the replacement project occurred on services where the pipeline environment continually changed over the years, undergoing cycles of wet and dry environments. As noted above, flood irrigation was available to homes in this subdivision until the early 1960s. Furthermore, the fact that most of the leaks were found on services in Manors 3, a reasonable person can conclude that the effect of the reversed polarity at the rectifier simply identified the weak links in a system that were at or near the point where coating deterioration would have become evident in the near future. Accordingly, the employee's mistake did nothing more than expose this potential issue sooner than Southwest may otherwise have learned about it, which then resulted in a pipe replacement project that occurred sooner than it otherwise would have. Nothing more, nothing less.

Q. 20 If few leaks were found on mains, why did Southwest not just replace the service lines?

A. 20 Southwest did that initially. Given the facts and circumstances surrounding this distribution system, it did not make sense to continue service replacements on a piecemeal basis as leaks were found, considering that replacement of mains might be deferred for only a few years. A new main installation at a future date would likely require abandonment of some of these newer services because the main would be relocated from an alley (back of residence) to a street (front of residence). By completing the entire replacement at one time, service disruptions to customers were kept to a minimum. Additionally, the Company was able to relocate some services and mains to be more easily accessible and gained economic efficiencies related to a complete project. As a result, the customers benefit from the extension of life to an existing system and a new state-of-the-art system that has fewer maintenance requirements.

Q. 21 Does Mr. Hanson acknowledge that the Company acted as a prudent operator in replacing the entire Yuma Manors pipeline system?

A. 21 Yes. Mr. Hanson acknowledges that the Company acted as a prudent operator to maintain a safe and reliable system on page 2 of his surrebuttal testimony.

Q. 22 In the 2007 or 2008 Pipeline Safety Audits, did Staff cite to any probable noncompliance or violation of either federal or state pipeline safety regulations with respect to the Yuma Manors system?

A. 22 No.

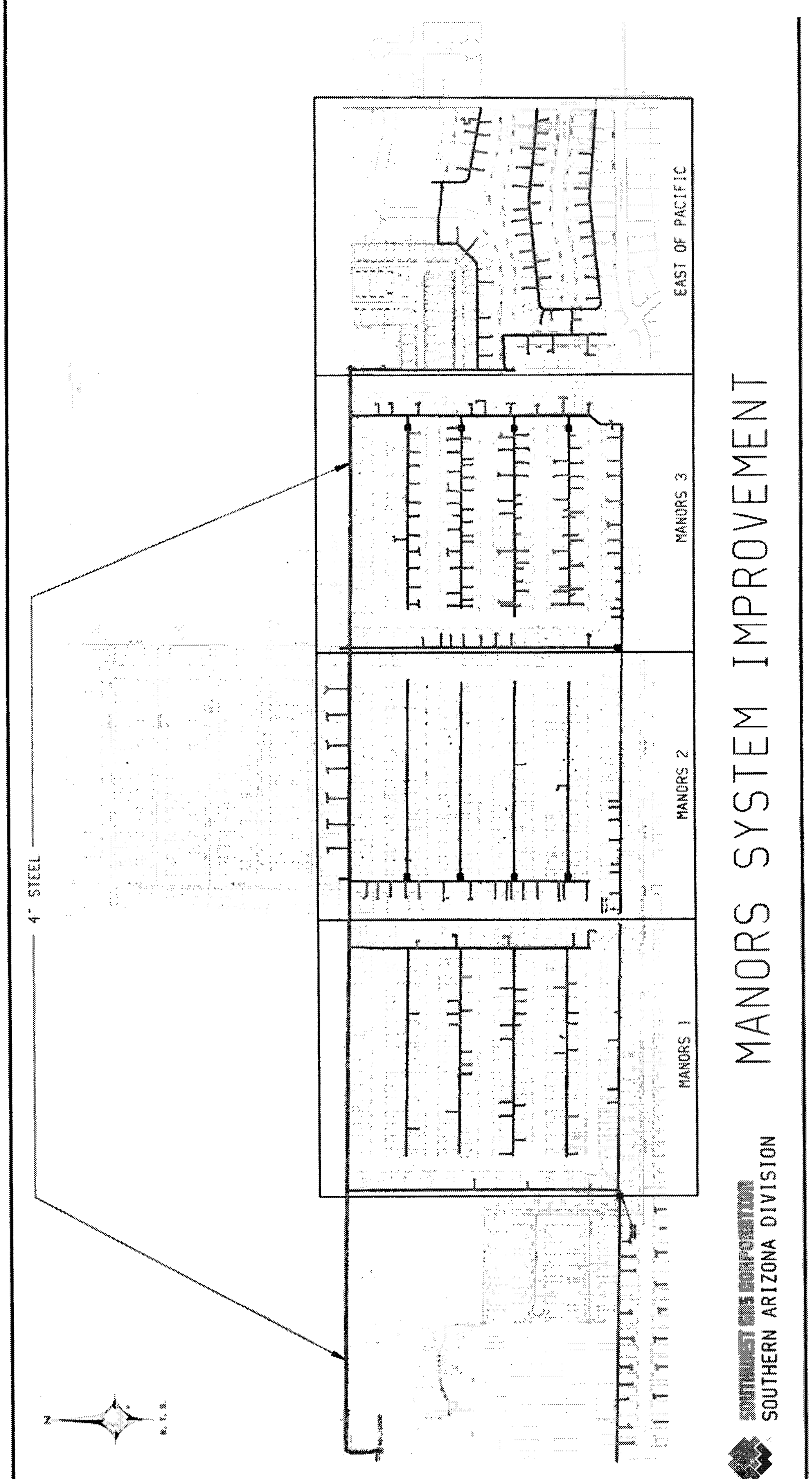
Q. 23 Does the replacement pipe provide any value to the customer?

A. 23 Yes. The replacement project results in betterment to the distribution system that should extend the useful life of the system for 40 or more years. The point that Mr. Hanson continues to ignore is that the replacement of the system is simply a timing issue. Given the facts and circumstances surrounding this system, it was only a matter of time before it would have been replaced. It was simply replaced sooner than it otherwise would have been, had the rectifier not been reversed. Yet, reading Mr. Hanson's testimony, one could reasonably conclude that the employee mistake ruined the entire Yuma Manors distribution system. As discussed above, this was not the case. The reversal resulted in increased leaks primarily in a concentrated area - service lines in Manors 3. The replacement project of the distribution system was much more extensive than Manors 3 due to the facts and circumstances surrounding the distribution system.

Q. 24 Does this conclude your prepared rejoinder testimony?

A. 24 Yes.

Rejoinder Exhibit No.__(JTS-1)
Sheet 1 of 1



D

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

LAURA LOPEZ HOBBS

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Prepared Rejoinder Testimony
Of
LAURA LOPEZ HOBBS

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
Of
LAURA LOPEZ HOBBS

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Laura Lopez Hobbs. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Did you sponsor direct and rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or Company) in this proceeding?

A. 2 Yes.

Q. 3 What is the purpose of your rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to aspects of the surrebuttal testimony presented by Ralph Smith, witness for the Arizona Corporation Commission Utilities Division Staff (Staff) regarding his recommendations and comments concerning the Company's executive compensation expenses.

Q. 4 Please summarize the specific issues your rejoinder testimony will address.

A. 4 My rejoinder testimony will address certain comments made by Mr. Smith in his surrebuttal testimony concerning the Company's Management Incentive Program (MIP), other stock-based compensation and

Supplemental Executive Retirement Plan (SERP) expenses.

MIP

Q. 5 Mr. Smith's testimony states that "SWG's employee salaries have continued to increase each year. Thus the MIP is an additional expense." Do you agree with this assertion?

Q. 5 No. I believe that Mr. Smith's assertion is flawed because the MIP is not an additional expense, but a reasonable necessary expense in order for Southwest to remain competitive and be able to attract, retain and motivate management employees. In 1994, Southwest contracted with the Wyatt Company (Wyatt) to conduct a study of management compensation. The study reviewed all compensation and benefit plans for 174 executives, managers and supervisors. Based upon this review, it was evident that the Company's total compensation was below market. Therefore, in order to be able to compete in the marketplace for the attraction and retention of qualified management-level employees, Southwest implemented its MIP in 1995. Rather than significantly increasing guaranteed base pay, management increased total compensation by adding a risk-based performance component that would pay only if certain measures were met. As such, Mr. Smith's assertion that the MIP is an additional expense is inaccurate.

Q. 6 Do you believe it is appropriate for the Commission to treat all utilities under its jurisdiction the same with respect to the equal sharing of utility incentive compensation expense?

A. 6 No. Although the Commission has previously ordered the equal sharing of utility incentive compensation for Southwest as well as other utilities, the Company believes that its situation is distinguishable from other Arizona utilities and thus, merits different treatment. Southwest has demonstrated in this proceeding that its total compensation expenses are conservative and reasonable, especially when compared to the Company's peers. See Hobbs Direct Testimony at pages, 3, 5-6. As a multi-jurisdictional utility, Southwest allocates the cost of executive compensation across a greater number of customers thereby significantly reducing the cost to Arizona customers. As such, the 50/50 sharing allocation is, in essence, punitive for Southwest since, unlike other Arizona utilities, its executive compensation expenses are already divided among three states.

Q. 7 Is Mr. Smith's contention that the Company's MIP expense in the current rate case is 76 percent higher than in its prior rate case correct?

A. 7 No, it is not. Mr. Smith appears to base his analysis on inaccurate data. Southwest's MIP expenses are actually lower in the current proceeding than in the last rate case. For further explanation, please see the rejoinder testimony of Southwest witness Randi Aldridge.

STOCK-BASED COMPENSATION

Q. 8 Why should the Company's stock-based compensation be allowed?

A. 8 As stated in my previous testimony, Southwest's total executive compensation is reasonable and conservative when measured against its peer group. Because the Company has demonstrated the reasonableness of its total executive compensation, I believe that stock-based incentive compensation should be allowed. Rather than disputing the reasonableness of such compensation, Mr. Smith's surrebuttal testimony merely reiterates his allegation that stock-based compensation could "potentially" incent Company employees to cut corners in order to enhance earnings. While acknowledging that there is no evidence that Southwest's management is performing in a manner that could negatively affect its quality of service, Mr. Smith continues to base his argument on the disallowance rationale in the most recent APS and UNS rate cases.

However, Southwest's controls make it highly unlikely that one person within a business unit of Southwest could exert such control and influence over budget decisions that the person's conduct could dramatically impact the stock price. And to the extent that any one person could significantly impact the amount of money expended on maintenance or other costs which affect the quality of service, the probability that such reductions in expenditures actually impact the stock price is virtually non-existent. There are numerous factors that impact stock price, and to suggest that the Company or any individual can manipulate the stock price by simply reducing expenditures is illogical. In addition, to the extent that the quality of service is reduced, customer satisfaction is likely to decline. Any such decline in customer satisfaction will directly impact the incentive pay, including stock, received through the MIP. The employees receiving stock-based compensation are the same employees that are eligible for the MIP, and any cost cutting measures that affect customer satisfaction will directly impact that employee's incentive pay.

Further, as explained in my prefiled direct testimony, the Company's stock-based incentive plans are paid out over a period of three years, which is designed to be incentive to retain employees. With the stock-based incentive plans being staggered over a three year period, even if an employee could hypothetically impact the stock price in the short term there is really no incentive to do so because the employee is not fully vested with his/her stock-based compensation. As such, Mr. Smith's argument regarding stock-based compensation is without merit.

SERP

Q. 9 Why should the Company's SERP expense be allowed?

A. 9 As Southwest has demonstrated, the Company's SERP expenses are a necessary cost of providing safe, efficient, and reliable service. In fact, both Staff and RUCO have acknowledged that every gas or electric utility of which they are aware, offers such a program. See Residential Utility Consumer Office's (RUCO) Response to SWG DR 2-5 and 2-6; Staff's Response to SWG DR 2-40 and 2-41, attached hereto. Without such a program, Southwest would be at a significant disadvantage in the competition for and the retention of qualified individuals.

Q. 10 Does this conclude your prepared rejoinder testimony?

A. 10 Yes, it does.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

RESIDENTIAL UTILITY CONSUMER OFFICE'S ("RUCO")
RESPONSE TO SOUTHWEST GAS CORPORATION'S
SECOND SET OF DATA REQUESTS

2.5 Please identify all gas or electric utilities that you are aware of that offer a qualified defined benefit pension plan, but that does not provide officers with a supplemental executive retirement plan.

Response: Rodney L. Moore

I am not aware of any.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

RESIDENTIAL UTILITY CONSUMER OFFICE'S ("RUCO")
RESPONSE TO SOUTHWEST GAS CORPORATION'S
SECOND SET OF DATA REQUESTS

2.6 Please identify all gas or electric utilities that you are aware of that do not provide officers with a supplemental executive retirement plan, regardless of whether they offer a qualified defined benefit pension plan.

Response: Rodney L. Moore

I am not aware of any.

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.

A utility's SERP expense was also disallowed in the Commission's recent decision in the rate case involving UNS Gas, Inc. See Decision No. 70011 (dated 11-27-07) 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.**

Consequently, Mr. Smith has recommended an adjustment related to SWG's SERP expense specifically to remove SWG's expense for the SERP, which is shown on Schedule C-5 and reduces O&M expense by $1.625 million.

40) Please identify all gas or electric utilities that you are aware of that offer a qualified defined benefit pension plan, but that do not provide officers with a supplemental executive retirement plan.

Answer: The number and/or specific identity of other gas or electric utilities that may have offered a qualified defined benefit pension plan, but that do not provide officers with a supplemental executive retirement plan, did not appear to be a consideration used by the Commission in Decision No. 68487 (February 23, 2006), in Southwest's last rate case, or in Decision No. 70011 (November 27, 2007), in the recent UNS Gas rate case, Docket No. G-04204-06-0463 et al, wherein the Commission disallowed Southwest's and UNSG's SERP expense, respectively, so Mr. Smith did not attempt to conduct such research.

41) Please identify all gas or electric utilities that you are aware of that do not provide officers with a supplemental executive retirement plan, regardless of whether they offer a qualified defined benefit pension plan.

Answer: The number and/or specific identity of other gas or electric utilities that may not have provided officers with a supplemental executive retirement plan, did not appear to be a consideration used by the Commission in Decision No. 68487 (February 23, 2006), in

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Southwest's last rate case, or in Decision No. 70011 (November 27, 2007), in the recent UNS Gas rate case, Docket No. G-04204-06-0463 et al, wherein the Commission disallowed Southwest's and UNSG's SERP expense, respectively, so Mr. Smith did not attempt to conduct such research.

42) Please produce copies of all responses, formal and informal, provided by Staff in response to data requests from any other party to this proceeding in the above-captioned docket.

Answer: None to date.

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IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

THEODORE K. WOOD

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Prepared Rejoinder Testimony
Of
THEODORE K. WOOD

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
THEODORE K. WOOD

INTRODUCTION

Q. 1 Please state your name and business address.

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

Q. 2 Did you sponsor direct and rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes.

Q. 3 What is the purpose of your rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to specific aspects of the direct testimony presented by David C. Parcell, witness for the Arizona Corporation Commission Utilities Division Staff (Staff) and William A. Rigsby, witness for the Residential Utility Consumer Office (RUCO), regarding their recommendations and comments concerning the ratemaking capital structure, Southwest's investment risk relative to other natural gas utilities, and the overall allowed rate of return.

Q. 4 Did you prepare any exhibits to support your rejoinder?

A. 4 Yes. I prepared the exhibits identified as Rejoinder Exhibit No.__(TKW-1) through Rejoinder Exhibit No.__

(TKW-10).

Q. 5 Please summarize your rejoinder testimony.

A. 5 My rejoinder testimony will address the following key issues:

- I will respond to Staff's comments regarding capital structure issues, including their opposition to utilizing the Company's requested target capital structure, which contains 45 percent common equity, 4 percent preferred equity and 51 percent long-term debt.
- I will also respond to comments from both RUCO and Staff related to Southwest's higher investment risk relative to the other natural gas utilities used to estimate the cost of common equity capital in this proceeding.
- I will also respond to comments from Staff regarding comparisons to average authorized returns on common equity for other natural gas utilities.

RECOMMENDED CAPITAL STRUCTURE

Q. 6 What is your general response to Mr. Parcell's comments in his surrebuttal testimony regarding the use of a hypothetical capital structure?

A. 6 Mr. Parcell does not differentiate the use of a hypothetical capital structure in past proceedings and the Company's requested use of a "target" capital structure in this proceeding. The hypothetical capital structure was used in past proceedings to adjust for the difference in financial risk associated with Southwest's lower common equity ratio versus the proxy group companies used to estimate the cost of common equity capital. In this proceeding, as stated in both my direct and rebuttal testimony, Southwest is requesting a "target" capital structure that the Company expects to actually achieve.

Q. 7 Has Southwest achieved the 45 percent common equity ratio as requested in its target capital structure?

A. 7 Yes. Displayed in the table below is the Company's actual capital structure as of March 31, 2008[1], actual capital structure at the end of the test period (April 30, 2007), and the Company's recommended "target" capital.

	Mar-08	Test Period Apr-07	Recommended
Long-Term Debt	50.6%	52.7%	51.0%
Preferred Equity	4.3%	4.4%	4.0%
Common Equity	**45.1%**	42.9%	45.0%
Total	100.0%	100.0%	100.0%

This table clearly demonstrates that in the eleven-month period since the end of the test period, the Company has continued to make significant progress in improving its capital structure and now has achieved a slightly higher common equity ratio than the requested "target" common equity ratio of 45 percent.

Q. 8 How does Mr. Parcell justify his position against the use of a "target" capital structure for Southwest?

1 Rejoinder Exhibit No.__(TKW-1)

A. 8 Mr. Parcell cites the following two differences between UNS Gas and Southwest to support his position that precedent established in UNS Gas is not appropriate for Southwest. First, UNS Gas was recently formed in 2003 compared with Southwest which has existed for many years. Second, UNS Gas is a subsidiary of UniSource Energy whereas Southwest has maintained its own publicly-traded capital.

Q. 9 Do these differences between UNS Gas and Southwest support Mr. Parcell's position against the use of a "target" capital structure for Southwest?

A. 9 No. The more relevant facts are that both UNS Gas and Southwest had common equity ratios in the mid 30 percent range in 2003 and have since achieved significant improvement in their respective common equity ratios. Moreover, both companies expect the improvement to continue and requested a target capital structure for ratemaking that reflects the capital structure expected to be in place on a going forward basis, which Southwest has now achieved. Mr. Parcell was the Staff witness in the UNS Gas general rate cases and the Commission did not adopt Mr. Parcell's recommendation to use the actual test period capital structure in that proceeding. Similarly, the Commission should not adopt Mr. Parcell's capital structure recommendation in this proceeding.

Q. 10 On page 8 of Mr. Parcell's surrebuttal testimony, he comments on the Company's recently improved common equity ratio by stating: "Not coincidentally, this improvement in the equity ratio only occurred after continuing actions on the part of the Commission". What is your response to this comment?

A. 10 With all due respect to the Commission, Mr. Parcell erroneously assigns the impetus for the Company's improved common equity ratio to the Commission's decision in the last general rate case. The Company acknowledges and appreciates that, in past proceedings, the Commission has employed a hypothetical capital structure for ratemaking purposes. However, the decision in the Southwest's last proceeding, which required the Company to file a recapitalization plan on how it planned to obtain a 40 percent common equity ratio before its next general rate case, with the caveat that its efforts to achieve this level of equity would be evaluated for the continued use of a hypothetical capital structure, was not the impetus for the Company's improved common equity ratio. Southwest's position at the edge of an investment grade credit rating provides the Company with more than sufficient incentive to improve its common equity ratio.

In my direct testimony, pages 6-8 and Exhibit No.__(TKW-2), I describe how Southwest's capital structure improved between the test period (August 31, 2004) of the Company's previous general rate case and the test period (April 30, 2007) in this proceeding. A major component of the improved common equity ratio was achieved by the common stock issuances via the Company's equity shelf programs. Southwest entered into a sales agency financing agreement with BNY Capital Markets Inc. on April 22, 2004, associated with the $60 million equity shelf program. This agreement was executed seven months prior to the Company filing for a rate increase in 2004 (December 9, 2004) and 22 months prior to the final decision (February 23, 2006). On September 8, 2005, the Company completed its issuance under the $60 million equity shelf and in November 2005 management received approval from Southwest's Board of Directors for an additional $45 million equity shelf program. Contrary to Mr. Parcell's assertion, Southwest was proactively taking steps to improve its common equity ratio prior to the decision in the Company's last rate case.

Q. 11 What other tangible steps has the Company taken to improve its common equity ratio?

A. 11 During the 10-year period 1998-2007, the Company issued approximately 12.0 million shares of common stock in addition to the 3.4 million shares issued via the equity shelf programs, which has increased the number of common stock shares outstanding from 27.4 million (December 31, 1997) to 42.8 million (December 31, 2007), representing a 56 percent increase in shares outstanding. In addition, during the almost thirteen-year period of May 1994 through February 2007, the Company did not increase its common stock dividend.

Q. 12 Why did the improvement in the Company's common equity ratio not occur sooner?

A. 12 Over the past decade, Southwest was one of the fastest growing natural gas distribution utilities in the nation requiring significant infrastructure investment, while at the same time realizing one of the lowest average rates of return on common equity in the industry. The combination of rapid growth and low realized rates of return has severely impeded the Company's ability to improve its common equity ratio.

Q. 13 Are the negative capital structure impacts from low profitability unique to Southwest?

A. 13 No. Empirical financial research in capital structure theory confirms this same relationship between profitability and capital structure. In a recent study published in the Journal of Finance, the author states[2]:

> "Thus, an inverse relationship between leverage and profitability frequently found in the data and identified by Myers (1993) is perhaps the most pervasive empirical capital structure regularity,…"

SOUTHWEST'S HIGHER RELATIVE INVESTMENT RISK

RUCO's Investment Risk Assessment

Q. 14 What is your response to Mr. Rigsby's comments on pages 6-7 of his surrebuttal testimony, where he states that your position is that his final recommended cost of

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2 Ilya A. Stebulaev, 2007, "Do Tests of Capital Structure Theory Mean What They Say?", *Journal of Finance* Vol.62:4, 1747-1787.

common equity capital should have been 10.02 percent, which is the midpoint of his estimated range of 9.20 percent to 10.83 percent?

A. 14 I would like to clarify that I never stated that Mr. Rigsby should use the midpoint of his range of estimates for the cost of capital for Southwest. On page 9 of my rebuttal testimony, I simply provided an observation that his final cost of common equity capital of 9.88 percent for Southwest was below the midpoint of his stated range of return on common equity capital of 9.20 percent to 10.83 percent.

Q. 15 What is your response to Mr. Rigsby's comments on page 7 of his surrebuttal testimony, wherein he responds to your criticism for not adjusting his cost of common equity capital recommendation to account for Southwest's higher financial risk?

A. 15 Mr. Rigsby testifies that his support of the Company's requested target capital structure provides adequate compensation for the additional financial risk. Now that Southwest has an actual common equity ratio slightly greater than the target common equity ratio, this argument no longer has any merit. Even though the Company has now achieved the target common equity ratio, Southwest still has higher financial risk relative to the average of the proxy group companies. Mr. Rigsby has not accounted for this risk.

Q. 16 Please respond to Mr. Rigsby's comments on your use of the "Hamada" adjustment methodology to quantify the difference in financial risk of Southwest versus the proxy group companies.

A. 16 This methodology is used to quantify the impact on the cost of common equity capital by measuring the change in beta given differences in leverage as measured by the debt to equity ratio. To summarize the "Hamada" adjustment analysis reported on pages 10-13 of my rebuttal testimony, the analysis indicated that Southwest's relevered beta was 0.97 based on the Company's requested target common equity ratio of 45 percent. The average proxy group levered beta was 0.86. The estimated impact to the cost of common equity capital for the difference in financial leverage for Southwest versus the proxy group is estimated by multiplying the difference in beta 0.11 (0.97-0.86 = 0.11) by the equity risk premium.

Mr. Rigsby does not directly respond or rebut the results of the "Hamada" adjustment analysis, a method previously used by RUCO witness Steve Hill in the APS general rate case (Docket No. E-10345A-05-0816), but instead shifts his comments to the lower equity risk premiums used by Mr. Hill in his CAPM analysis for the APS case. Without addressing the appropriateness of Mr. Hill's equity risk premiums, using the 4 percent and the 6 percent equity risk premium still supports an upward financial risk adjustment in the equity return for

Southwest. Employing both the Hamada adjustment analysis and the equity risk premiums used by RUCO in the APS case, the estimated financial risk adjustment is in the range of 44 to 66 basis points. (Rejoinder Exhibit No.__(TKW-2) displays the calculation using the 4 percent and 6 percent equity risk premiums). In conclusion, RUCO admitted that Southwest has higher financial risk relative to the proxy group companies it used to estimate the cost of common equity capital. The "Hamada" methodology, which RUCO used in past proceedings, demonstrates that RUCO has not adequately considered Southwest's higher financial risk.

Staff's Investment Risk Assessment

Q. 17 What is your response to Mr. Parcell's comments on page 18 of his surrebuttal testimony, wherein he states you testified that Southwest has above average risk and should be awarded an above-average cost of capital?

A. 17 First, in both my direct and rebuttal testimony, I stated that the Company should be awarded an adequate overall rate of return that fairly compensates investors for Southwest's level of business, financial, and regulatory risk. I also provided evidence to support Southwest's higher relative investment risk compared to the proxy group companies used to estimate the cost of common equity capital. Second, Mr. Parcell agrees with the assessment that Southwest has higher relative investment risk as reflected by the 10 basis points adjustment relative to the Company's adjustment of 25 basis points to account for Southwest's higher investment risk. In addition, Mr. Parcell's surrebuttal Exhibit DCP-11, which displays investment risk indicators, confirms Southwest's higher relative investment risk.

Q. 18 On pages 7-8 of Mr. Parcell's surrebuttal testimony, he states that he believes Southwest's "lower credit ratings have been directly linked to the [Company's] lower equity ratios" resulting from Southwest's past financial strategy. What is your response to this comment?

A. 18 First, while the common equity ratio is an important measure of leverage, Mr. Parcell places undue weight on common equity ratio by directly linking it to the credit ratings. Credit rating agencies use other quantitative financial metrics as well as qualitative information in the process of developing a credit rating. Second, similar to the cost of capital concept, a credit rating is prospective in nature. Third, evaluating the Company's past financial strategy based on its historical and current financial position would require a full examination of both the historical regulatory framework and the operating environment in which Southwest has existed. Mr. Parcell has not provided any such analysis.

Q. 19 Please explain why Mr. Parcell's direct linkage of the Company's credit rating to the common equity ratio is overstated.

A. 19 Moody's Investor Services, in an attempt to have their rating process be more transparent, published its rating methodology for natural gas distribution companies[3]. Moody's analysis focuses on four core rating factors, which are further broken down into eight sub-factors and assigned a specific weight in the rating process. The factors, sub-factors, and corresponding weights are listed below:

Factor	Sub-Factor	Weighting
Sustainable Profitability	Return on Equity	15%
	EBIT/Customer Base	5%
Regulatory Support	Regulatory Support	10%
Ring Fencing	Ring Fencing	10%
Financial Strength And Flexibility	EBIT/Interest	15%
	RCF/Debt	15%
	Debt/Book Capitalization	15%
	Free Cash Flow/FFO	15%
Total Weighting		100%

As seen from the list of factors and sub-factors, the debt-to-book capitalization ratio (1 minus the common equity-to-book capitalization ratio) only accounts for 15 percent of the weight in the credit rating process. Additional factors are important, such as the financial metrics of sustainable profitability, which is assigned a weight of 20 percent and the qualitative measure of regulatory support, which is assigned a weight of 10 percent.

Q. 20 Did Mr. Parcell recognize or discuss regulatory risk as an important factor in the Company's credit rating?

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3 Moody's Rating Methodology, *North American Regulated Gas Distribution Industry*, Moody's Investor Services, October 2006. Rejoinder Exhibit No.__(TKW-3)

A. 20 No. Nowhere in Mr. Parcell's testimony did he acknowledge that credit rating agencies not only look at the financial metrics of a utility, but also the regulatory environment in which it operates. In addition to Moody's consideration of regulatory support, the importance of regulation in the overall creditworthiness of a utility can be found in the following statements from S&P[4]:

> "Indeed, Standard & Poor's views the regulatory and political environment in which a utility operates as one of the most significant factors in assessing the creditworthiness of regulated utilities.
>
> "Our ratings reflect our views on all of the factors that we believe will affect credit quality, including economic trends, the issuer's financial strength, and the regulatory environment. For regulated entities, however, the ability to generate revenues almost entirely depends on regulatory decisions. So in general, a ruling that enhances a utility's ability to recover costs in a timely manner will positively affect its overall credit quality."

As stated in my direct testimony on page 16, Moody's has assigned the regulatory support for Southwest as "Ba" or below investment grade. No other Company in the proxy groups used to estimate the cost of common equity capital in this proceeding received a regulatory support rating as low. Rejoinder Exhibit No.__(TKW-5) displays the

4 Standard & Poor's, Criteria: Influence of Regulatory and Policy Decisions on Utility Credit Quality Deepens, Demanding Timely Assessments From Standard & Poor's, May 15, 2007. Rejoinder Exhibit No.__(TKW-4)

Moody's regulatory support rating for the individual proxy group companies.

Q. 21 On page 18 of Mr. Parcell's surrebuttal testimony, he states that you have not provided any evidence that the Company's risk has increased since its last Arizona general rate case. Is Mr. Parcell correct?

A. 21 No. The increased risk is reflected in the Company's lower credit rating. Credit ratings provide important information to investors and thereby act as a signal of a utility's quality. On March 10, 2006, Moody's issued a press release stating that it had placed Southwest under review for a possible downgrade:[5]

> "Moody's Investor Services places under review for possible downgrade the Baa2/negative outlooks senior unsecured debt of Southwest Gas Corporation (SWX), following the company's recent announcement that the Arizona Corporation Commission (ACC) issued a final decision not to adopt the company's proposed rate design for balancing accounts, thereby exposing it to continuing earnings risks associated with weather volatility and declining customer use resulting from the effects of gas conservation."

As reported on pages 15 and 16 of my direct testimony, Moody's downgraded Southwest's bond rating from Baa2 to Baa3 just three months after being authorized a 9.5 percent return on common equity applicable to a 40 percent common ratio, but without any significant

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5 Moody's Rating Action: Southwest Gas Corporation, March 10, 2006. Rejoinder Exhibit NO.__(TKW-6)

improvement in rate design. Moody's rationale for the downgrade included the following:[6]

> "The downgrade reflects the view that the credit measures of SWX remain weak when compared with its gas utility peers in light of its continued rapid growth and sensitivity to decline in earnings on account of warmer than normal weather and the absence of revenue decoupling in Arizona (54% of gross margins) and Nevada (37% of gross margins) that would serve to protect this company from weather variation and customer conservation....
>
> While the company was able to obtain some rate relief in recent years, the fact that it is among the fastest growing gas utilities in the country (5% p.a. growth) continues to expose it to regulatory lag as rate cases in its key state of Arizona take at least a year to resolve and even then, typically deliver only part of the rate improvement necessary for it to earn its allowed rate of return."

Q. 22 What were the consequences of the downgrade by Moody's?

A. 22 The change in credit rating had an immediate estimated impact by increasing the Company's annual interest expense by $375,000. More importantly, the downgrade increases the incremental cost of new debt for Southwest. In addition, the downgrade impacts the cost of debt refinancing. Southwest has $575 million of long-term debt that will mature in the next five years (2008-2012), a large portion of which will require refinancing. When this debt is refinanced, it generally will be issued with

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6 Moody's Rating Action: Southwest Gas Corporation, March 30, 2006. Rejoinder Exhibit NO.__(TKW-7)

a long-term maturity of 10 to 30 years. As a result, the cost of this debt will be embedded in the Company's cost of capital for ratemaking purposes for a relatively long-period of time.

Q. 23 What is your response to Mr. Parcell's comments on pages 20-21 of his surrebuttal testimony, where he makes references to the recent Standard & Poor's published report for Southwest?

A. 23 Mr. Parcell highlights some of the positive factors for Southwest cited in the S&P report, but he fails to mention some of the other important comments from S&P. The following from the S&P, which was included on page 24 of my rebuttal testimony, bears repeating[7]:

> "..we view the ACC regulatory oversight as less supportive of credit than other jurisdictions due to its limitations on purchased gas recoveries and rate design that is solely based on gas throughput. This type of rate design exposes the company to reduced cash flows as volumes decline related to conservation."

Also, the importance of rate design for the Company's credit ratings can be found in the following statement[8]:

> "Despite strong historical customer growth statistics, annual total consumption has nevertheless dropped 1% per year, on average, since 2003, due to conservation efforts, making rate design a key credit driver for the company."

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7 Standard & Poor's Ratings Direct, Southwest Gas Corporation Report, April 24, 2008.

8 Id.

In addition, S&P cited as a weakness to the rating the elevated projected capital expenditures of about $290 million per year.

Q. 24 Are there other measures of risk which reflect the increase in Southwest's investment risk since its last Arizona general rate case?

A. 24 Yes. Both beta and the book-to-market ratio are indicators of investment risk. The decision for the Company's last general rate case, Decision No. 68487, was issued on February 23, 2006. The following table displays the 24-month change in beta and book-to-market ratio for Southwest and the average of the proxy groups[9] since February 23, 2006.

	March 2006	March 2008	Change
Southwest			
Value Line Beta	0.80	0.90	0.10
Book-to-Market Ratio	0.71	0.85	0.14
Proxy Group 1			
Value Line Beta	0.81	0.89	0.08
Book-to-Market Ratio	0.59	0.63	0.04
Proxy Group 2			
Value Line Beta	0.81	0.88	0.07
Book-to-Market Ratio	0.59	0.61	0.01

The reported changes in betas and the book-to-market

9 Proxy Group 1 - the proxy group of eight natural gas distribution companies developed and used by Company witness Mr. Frank Hanley, which both RUCO and Staff also used.
Proxy Group 2 - the additional proxy group of twelve natural gas distribution companies used by Staff.

ratios indicate that Southwest's investment risk has increased on both an absolute basis as well as on a relative basis compared to the average measures of the proxy groups used to estimate the cost of common equity capital. Rejoinder Exhibit No.__(TKW-8) displays the beta, book-to-market ratios, and corresponding change for the individual proxy group companies.

OVERRALL RATE OF RETURN RECOMMENDATION

Q. 25 On page 20 of Mr. Parcell's surrebuttal testimony, he states that the average authorized return on common equity for other natural gas utilities is below the 11.25 percent requested by Southwest. What is your response?

A. 25 On page 3 of Mr. Parcell's surrebuttal testimony, he lists the average authorized rates of return for natural gas distribution companies for the period 2003-2007. However, Mr. Parcell does not include the corresponding average authorized common equity ratio, which is an important factor in making comparisons to Southwest's requested return on common equity. The list of average authorized returns on common equity and the corresponding authorized common equity ratios for the more recent periods 2006-2007 and first quarter of 2008 are as follows:

Year	ROE	%Common
2006	10.43%	47.43%
2007	10.24%	48.37%
2008	10.44%	52.42%

Southwest's currently authorized common equity ratio of 40 percent and its requested target common equity ratio of 45 percent are below the average authorized common equity ratios. An accepted tenet of modern finance is that the required return on common equity is positively related to the debt-to-equity ratio of the firm. Dr. Stewart Myers, a prominent finance scholar who has published a number of studies on capital structure theory, states:

> "The cost of equity does depend on capital structure. Comparisons of cost of equity estimates or allowed or actual returns make sense only if differences in financial leverage are accounted for. When a given utility's debt ratio increases, the cost of equity also increases and the allowed return must be adjusted upwards. This adjustment is required to preserve a fair return to equity investors." [10]

To make comparisons between Southwest's requested return on common equity would require an adjustment for the Company's lower common equity ratio.

Q. 26 Is there a way to make an adjustment to account for the differences in leverage?

A. 26 Yes. Dr. Roger Morin reviews the results of a number of empirical and theoretical studies of the effects on leverage on the cost of common equity capital[11]. Based

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10 Stewart C. Myers, *"Capital Structure and the Cost of Capital for Regulated Companies,"* prepared for The New York Energy Collaborative, December 4, 1992.

11 Roger A. Morin, *New Regulatory Finance*, Arlington, Virginia: Public Utilities Reports, Inc., pages 468-469. Rejoinder Exhibit No.__(TKW-9)

on these studies, the cost of common equity capital is found to increase in the range of 7.6 to 13.8 basis points per one percentage point increase in the debt ratio. Using this information, I estimated the range of leverage adjusted authorized rates of returns based on the difference in the average authorized common equity ratio and Southwest's target common equity ratio. The results indicate that the average leverage adjusted authorized rates of return for 2007-2008 are in the range of 10.50 to 11.46 percent. The results are displayed in Rejoinder Exhibit No.__(TKW-10).

CONCLUSION

Q. 27 Do you have any concluding comments to your rejoinder testimony?

A. 27 Yes. The Company's current bond ratings are "BBB-" by S&P and "Baa3" by Moody's. These ratings are the lowest that still afford the Company an investment grade credit rating. Since its last general rate case, Southwest made significant progress in improving its common equity ratio. The Company's ability to sustain and continue to improve its financial profile is largely dependent on the regulatory support it receives in this proceeding.

Commission approval of the Company's requested capital structure and overall rate of return, accompanied with a significant improvement in rate design, will provide Southwest an opportunity to achieve an improved financial profile and credit ratings. This improvement benefits Southwest's customers by reducing the long-run average capital costs embedded in customer rates.

Q. 28 Does this conclude your prepared rejoinder testimony?

A. 28 Yes, it does.

Rejoinder Exhibit No.__(TKW-1)
Sheet 1 of 1

CAPITALIZATION, LIABILITIES AND DEFERRED CREDITS	AMOUNT	INCREASE (DECREASE) CURRENT MONTH	YEAR TO DATE	CAPITAL RATIOS %	%
CAPITALIZATION					
Common stock equity (a)					
Common stock, $1 par, 43,160,094 shares outstanding	$ 44,789,970	$ 90,170	$ 354,388		
Capital surplus and premium on capital stock	752,035,201	4,648,433	9,135,041		
Capital stock expense	(10,580,342)	-	-		
Retained earnings - NOTE 1	259,157,604	6,358,036	39,389,655		
Total common equity	1,045,402,433	11,096,639	48,879,084	45.1	45.1
Preferred securities - NOTE 2	100,000,000	-	-	4.3	4.3
Long-term debt, including current maturities - NOTE 3	1,170,715,585	(45,936,379)	(99,810,337)	50.6	50.6
Total capitalization	2,316,118,018	(34,839,740)	(50,931,253)	100.0	100.0
CURRENT AND ACCRUED LIABILITIES					
Notes payable	-	-	(9,000,000)		-
Accounts payable	139,695,283	(68,376,487)	(71,504,085)		100.0
Customers deposits	76,860,682	587,218	1,841,251		
Taxes accrued (including income taxes)	77,052,196	213,233	42,558,657		
Interest accrued	20,538,269	862,602	(752,153)		
Dividends declared	9,711,021	(9,234,182)	507,794		
Deferred purchased gas costs	16,135,770	29,611,878	3,994,202		
Other current and accrued liabilities	52,198,641	11,851,300	12,857,294		
Total current and accrued liabilities	392,191,862	(34,484,438)	(19,497,040)		
DEFERRED CREDITS					
Customer advances for construction	90,964,884	386,522	4,737,110		
Deferred investment tax credits	9,245,839	(72,298)	(216,894)		
Deferred income taxes	350,155,686	17,922,144	18,062,144		
Other deferred credits	92,423,740	1,026,370	2,236,054		
Total deferred credits	542,790,149	19,262,738	24,818,414		
TOTAL CAPITALIZATION, LIABILITIES AND DEFERRED CREDITS	$ 3,251,100,029	$ (50,061,440)	$ (45,609,879)		

(a) Stockholders' equity does not reflect the accumulated other comprehensive loss associated with pension calculations under SFAS No. 158 ($12.6 million at March 31, 2008 and $12.9 million at December 31, 2007).

Rejoinder Exhibit No.__(TKW-2)
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504
FINANCIAL RISK - HAMADA ADJUSTMENT METHOD

Line No.	Company	Beta[1]	2007 Average Common Equity[2]	2007 Average Market/Book Ratio[3]	2007 Average Market Value Debt / Equity Ratio[4]	2007 Average Tax Rate[1]	Unlevered Beta[5]	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	AGL Resources	0.85	46.0%	1.82	64.5%	37.6%	0.61	1
2	Atmos Energy Corp.	0.85	46.5%	1.31	87.8%	35.8%	0.54	2
3	Laclede Gas	0.90	43.3%	1.62	81.0%	33.4%	0.58	3
4	NICOR Inc.	1.00	58.4%	2.16	32.9%	30.0%	0.81	4
5	Northwest Natural Gas Co.	0.80	50.4%	2.05	47.9%	37.2%	0.62	5
6	Piedmont Natural Gas Co.	0.85	47.8%	2.04	53.5%	33.0%	0.63	6
7	South Jersey Industries	0.80	50.0%	2.25	44.4%	40.7%	0.63	7
8	WGL Holdings	0.85	54.7%	1.61	51.3%	39.1%	0.65	8
9	Average	0.86	49.6%	1.86	57.9%	35.9%	0.63	9
	Southwest Target Capital Structure							
10	Southwest Relevered Beta[6]	0.97	45.0%	1.45	84.4%	36.5%	0.63	10
11	Proxy Group Average Levered Beta	0.86						11
12	Difference In Beta	0.11						12
	Change in Cost of Equity[7]							
13	Equity Risk Premium = 4.00%	0.44%						13
14	Equity Risk Premium = 6.00%	0.66%						14

[1] Source: Value Line Investment Survey, March 14, 2008.
[2] 2007 average common equity ratio based on total capital structure. Source: Bloomberg
[3] 2007 average market to book ratio. Source: Bloomberg
[4] Market Value Debt / Equity Ratio = (1-common equity ratio) / (common equity ratio * M/B ratio)
[5] Unlevered Beta = Beta / (1+((1-tax rate) * market value debt / equity ratio))
[6] Relevered Beta = Unlevered Average Proxy Group Beta * (1+((1- tax rate) * market value debt / equity ratio))
[7] Change in cost of common equity = difference in beta * equity risk premium

Rejoinder Exhibit No.__(TKW-3)
Sheet 1 of 28

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North American Regulated Gas Distribution Industry (Local Distribution Companies)

Summary

The purpose of this methodology is to provide investors and other interested parties with a clear understanding of how Moody's assigns ratings to issuers and their obligations in the North American local gas distribution (LDC) sector. Our goal is to help the market understand the factors we consider most important for this sector and how they map to specific rating outcomes. Readers should be able to use this report to gauge a company's ratings within two notches.

This rating methodology covers 30 gas utilities in North America (Canada and the United States) all of whom are regulated by their provincial, state or municipal utility commissions. These are relatively small companies that are limited to a particular franchise territory and which ordinarily would not carry investment grade ratings were they not protected through regulation and assured the certainty of a positive gross margin in exchange for the public expectation of a reliable and safe gas distribution service.

Overall, Moody's analysis of gas utility companies focuses on the following core rating factors:

1. Sustainable Profitability
2. Regulatory Support
3. Ring Fencing
4. Financial Strength and Flexibility

In addition Moody's analyzes factors that are common across all industries such as liquidity, corporate governance, event risk, and legal structure.

About the Rated Universe

The focus of this rating methodology is on the "pure" gas LDCs in North America. We note that this methodology is concerned principally with operating utilities regulated by their local jurisdictions and not with gas utilities owned by parent holding companies that have other non-regulated businesses.

It is anticipated that a separate rating methodology will be forthcoming that would govern the ratings of such "diversified" gas companies including those that may have expanded through non-utility subsidiaries into other non-LDC businesses such as sales of unregulated electric power and gas contracts (energy marketing), gas pipeline transmission and storage, gas gathering and processing, exploration and production, energy trading or businesses that are non-energy related activities (e.g. real estate development or underground construction services).

Additionally, a third rating methodology would also be forthcoming for the gas pipeline companies, completing the three sub-sectors that make up the largely regulated natural gas transmission and distribution industry in North America.

In all Moody's rates 30 companies in the pure gas LDC sector in North America with EBITDA ranging from US$ 32 million to US$ 681 million and total assets ranging from US$ 382 million to US$ 5,974 million. The rated universe stretches from the east coast to the west and ranges in complexity from utilities with jurisdiction in a single state to those with multiple state jurisdictions (such as Atmos Energy Corporation, which has utility operations in 12 states).

Industry Overview

The guiding principle behind gas LDCs is that they are regulated entities within their jurisdictions and are expected to conform to the regulatory framework established by their regulators. The regulatory framework may specify a pre-approved level of capitalization, return on equity, the pass-through of certain cost components and the recognition of a specified level of regulated assets within the base rates established for customers, and the setting of a depreciation schedule based on the average life of plant and equipment. In Canada, regulators may operate at the provincial level. In the United States they might operate at the state or municipal level. As these companies are regulated by local authorities, there are tremendous variances in regulatory frameworks, some more favorable to the utility companies than others.

Allowed rates of return on equity are generally modest (ranging from 9%-12% in most cases depending on cost of capital). This creates certain tradeoffs that are meant to ensure a safe and reliable public service in return for stable and predictable levels of income and cash flow.

HIGHLY SEASONAL DEMAND AND WORKING CAPITAL REQUIREMENTS

The gas distribution business in North America is generally highly seasonal and sensitive to weather variations from one year to another. The vast majority of earnings are derived during the winter heating season (typically, the five months from November through March). In the summer months LDCs usually break even or lose money.

In addition, LDCs are typically subject to vast swings in working capital requirements, with the build-up of natural gas inventory in underground storages occurring during late spring and early summer, reaching a peak in November/December and falling during the course of the winter as gas is consumed. Accounts receivables begin to build in November and generally peak in late December or January. The buildup of short-term debt to meet seasonal working capital needs follows the same winter inventory build-up and accounts receivables financing pattern, with many LDCs completely out of short-term debt by April/May.

In an attempt to standardize the measure of heating days in the year, the industry has adopted the use of "heating degree days," commonly defined as the extent to which the daily average temperature falls below 65 degrees Fahrenheit, (generally assumed to be the point at which individuals would typically heat their homes). The number of heating degree days in a given year are compared against a historical "norm" specified by a regulatory commission in a specific jurisdiction to establish the degree of normalcy within a time frame. This time frame can range anywhere from 10 to 30 years, depending on the formulation approved by the utility regulators.

In some jurisdictions, the earnings impact of weather variations is neutralized through the establishment of weather mitigants as part of fundamental rate design. In its rate applications to the local regulatory commission, the local utility would request protection from weather that is warmer than normal for itself and for its customers when weather is colder than normal. Specifically, weather is compared with current deviations from historical norms as measured in heating degree days. The term often associated with this formal mechanism to compensate a utility for warmer than normal weather (or to compensate a consumer for colder than normal weather) is commonly referred to as a "weather normalization clause" or "WNC."

In jurisdictions that leave LDCs to their own devices, LDCs can either go "naked," or they can purchase weather derivatives or weather insurance to mitigate the effects of margin variations caused by fluctuating weather conditions.

PASS-THROUGH OF NATURAL GAS PRICES

In addition to the fact that gas LDCs are subject to regulation by local authorities, they also operate under the premise that their fixed and variable operatiing costs are borne by their firm demand customers (usually residential and commercial) who use gas for space heating, cooking, or a combination of both. Under the terms of the LDC operating structure, the LDC is not expected to assume the commodity risk of gas, but is able to pass this cost through to customers in monthly bills. Depending on the gas prices at any given time, the commodity price component of a residential customer's monthly bill could be as high as 80%. The remaining 20% would be the LDC's charge for operating and investing in the infrastructure of its gas distribution system (which are, primarily, its fixed costs of operation).

With the advent of third-party gas commodity marketers, this commodity charge is often provided by gas suppliers to consumers utilizing the LDC's gas delivery network. Under this mechanism of "distribution only" charges, the LDC can sometimes use the gas marketer to bill for its 20% of distribution charges, thereby transferring bad debt and risk of non-collection to the gas marketer. More often however, the LDC bills customers for both the gas marketer's commodity supply charges as well as its own delivery charge, retaining bad debt on its own books.

In several jurisdictions, utility regulators have granted LDCs a "bad debt" tracker, which allows them to recover the costs of non-collection via their customers' rate bases or as part of the PGA (purchase gas adjustment clause). Some states such as Pennsylvania and Tennessee have increased the amount of real-time bad debt that could be passed-through to the customer and are also allowing delivery termination for non-paying or delinquent customers to protect the margins of the LDC.

STABLE AND PREDICTABLE EARNINGS AND CASH FLOW

If weather variations are largely mitigated, cost of gas is a pass-though commodity cost, and regulators permit the company to recover its cost of investment and other operating costs for maintaining the gas distribution system, the earnings of the LDC should, theoretically, be largely predictable and cash flows should be stable year after year.

In reality however, LDCs' earnings are not stable, as customers continually find ways to conserve on heating bills, to purchase more efficient appliances or to build better insulated homes. All of these measures result in gas "conservation" and diminishing earnings (again, revenues are largely dependent on the volume of gas consumed). In areas of high growth — i.e. where the customer base is increasing at rates in excess of 3% p.a. — there is also the added pressure of rising operating and maintenance expenditures as well as the need to catch up with lagging capital investment recoveries. These pressures, coupled with rising cost structures and a volatile energy environment oftentimes require an LDC to file more frequent rate cases requesting cost recoveries or changes in fundamental rate design to account for secular changes in consumer behavior patterns that affect the operating margins of the gas utility.

Key Ratings Issues Going Into the Next Decade

The key rating issues affecting the near and medium term fall into three general areas:

- Rising gas prices
- The push for conservation
- The rise of mergers and acquisitions

RISING GAS PRICES

Gas prices follow many of the pressures that bear on oil prices, but also demonstrate characteristics of their own. Historically, North America was an abundant producer of natural gas. What the US could not supply from its own gas fields could be obtained reliably from Canada. Over the years, Canada has been consuming more of its gas, both to supply its own citizens' needs and to recover heavy oil lodged in sand formations where gas is burned underground to facilitate the oil recovery mechanism.

Also affecting the industry is a change in the pattern of the summer lull in gas prices. This is attributable to the fact that the electric power industry has been building new generation plants fueled by gas, mainly because of gas' clean-combustion characteristics. The vast majority of new electric generating plants built in the past few years have been fired by gas and these power plants burn more summer gas to generate electricity to meet cooling demands. As a consequence, the traditional lull in summer gas prices has become less reliable with the increased volatility in gas commodity pricing.

Rising demand for natural gas has also diminished the supply cushion to the point that hurricane disruptions such as those in the gas producing areas of the Gulf of Mexico in 2005 created logistical delivery disruptions to certain LDCs in the southeastern portion of the US. This confluence of increased gas demand and supply constraints is likely to maintain upward price pressure on natural gas prices over the medium term.

High gas prices have the undesirable effect of causing a rise in bad debt expenses and uncollectible receivables for many gas utilities, creating yet more need for rate design improvements.

THE PUSH FOR CONSERVATION

Another consequence of high gas prices is consumer motivation to burn less gas when possible. We have observed an impetus to reduce consumption in response to rising prices over the past decade. In North America this trend is most noticeable within the most rapidly growing home building areas, where homes are being built with better insulation. Another impetus for conservation is rising gas prices and warmer weather, where it is relatively easy for homeowners to turn-down the thermostat for extended periods of time, reducing gas margins earned by LDCs that are dependent on volumetric gas consumption for cost recoveries.

Conservation is an important component in balancing the region's gas supply and demand equation, but under traditional regulatory frameworks in many jurisdictions, few gas utilities have the incentive to encourage gas conservation or promote education in gas usage efficiencies among their customers. With the likelihood that gas prices will remain high and volatile, conservation will likely become a more formidable influence on gas consumption in the residential and commercial customer segments going forward.

In the US, utility commissioners in various states differ in their approaches to allowing their gas utilities to recover lost margins attributable to conservation-driven variations in consumption. Commissions with more supportive regulatory frameworks tend to allow mechanisms for revenue recoveries and their utilities generally have stronger financial profiles.

As more LDCs become aware of the impact that conservation initiatives have on their customers' gas usage and their own profitability, more are considering applying for the appropriate rate design changes. To do this, however, they must first build understanding and support at the grassroots level. Overall, utility rate designs that compensate gas LDCs for conservation-based margin losses (as with variations due to weather), should help to stabilize utilities' credit metrics and credit ratings. Utilities with these ratemaking mechanisms also tend to carry higher credit ratings.

THE RISE OF MERGERS AND ACQUSITIONS

With the repeal of the Public Utility Holding Company Act (PUHCA) in the US (February 2006) companies are finding fewer obstacles to mergers across state lines. Companies seeking to expand their service territories are now finding it easier to bid for companies seeking an opportunity to cash out (as price multiples are currently attractive for sellers in this industry).

The pace of industry consolidation as well as the introduction of new players could accelerate beyond 2006. From a credit standpoint, however, we note that mergers and acquisitions usually entail taking on more debt, attempts to create new operating synergies, and the need to apply for further rate relief from regulators. Previous periods of heightened mergers and acquisition activity were typically associated with increased numbers of ratings downgrades, as LDC debt levels and operating costs rose and rate recoveries lagged. While it is still early to predict whether past performance will repeat itself in the current merger-driven environment, the denigration of credit metrics remains a possibility.

In This Methodology

To explain Moody's approach to rating gas utility companies, we take the reader through the following steps:

IDENTIFICATION OF KEY RATING FACTORS

To determine the rating of a gas utility company we focus on the following factors:

1. **Sustainable Profitability**
   - Return on Equity
   - EBIT to Customer Base
2. **Regulatory Support**
   - Regulatory Support and Relationship
3. **Ring Fencing**
   - Ring Fencing
4. **Financial Strength and Flexibility**
   - EBIT/Interest
   - Retained Cash Flow/Debt
   - Debt to Book Capitalization (excluding goodwill)
   - Free Cash Flow/Funds from Operations

MEASUREMENT OF THE KEY RATING FACTORS

For each of the core factors cited, we present a set of metrics or "sub-factors" that enable the reader to determine exactly how we measure this factor. Each of the core factors is comprised of between one and four sub-factors, each of which are mapped to a rating or score. For example, we consider four different financial metrics within the Financial Strength and Flexibility Factor.

In total this rating methodology incorporates eight sub-factors. Where possible, we provide quantitative metrics derived from a company's financial statements. For some factors, however, non-statistical observation is necessary to determine the appropriate results. For each of the eight metrics, we assign a weight based on relative importance.[1]

Moody's applies a total weighting of 20% for non-financial observations and 80% for financial. (However, we weigh some sub-factors more heavily than others, as some sub-factors such as the ROE (return on equity) and the ones for Financial Strength and Flexibility weigh more heavily in determining the relative risk of a particular LDC in comparison with its peers). This is because, while regulatory design and support may differ from jurisdiction to jurisdiction, the financial metrics do not. This renders them more easily comparable across political boundaries and more quantifiable. Financial observations also tend to be lagging indicators, as they come at the end of a fiscal reporting period and serve as the final scorecard for the issuer. The two non-financial sub-factors tend to be less definitive and are more subject to interpretation. Applying the sub-factor weightings and scoring the rating assignment for each sub-factor in this manner results in ratings that track our assigned ratings within one or two notches in 93% of the cases.

While Moody's outlooks are forward looking, the rating process does make extensive use of historic financial statements. Historic results help us understand the pattern of a company's results and how it compares to peers. They also provide perspective, helping to ensure that estimated future results are grounded in reality. This document makes use of historic data primarily. However, if an LDC is undergoing a rate case or fundamental business transformation — negating the usefulness of past performance as a guide to future credit standing — we use projected financial results instead.

Where historical financial results are used, metrics are based on an average of the most recent three years. The 2003 through 2005 periods provide a good cross-section of the peaks and troughs that characterize individual company performance over a normalized period.

Where projected financial results are used, metrics are based on an average of the 2006 through 2008 periods, or in some cases, 2007 through 2009, depending on the implementation dates of rate increases or realization of expected merger combinations.

All measures incorporate Moody's standard adjustments to income statement, cash flow statement, and balance sheet amounts including under-funded pension obligations, recurring operating leases, and off-balance sheet commitments and contingencies.[2] Moody's Credit Opinion key indicator ratios will also incorporate these standard adjustments.

MAPPING OUR METRICS TO RATING CATEGORIES

After identifying the measurements for each factor, the potential outcomes for each of the eight factors/sub-factors are mapped to a Moody's rating category (i.e. Aaa, Aa, A, Baa, Ba, B, Caa). For example, we specify what level of ROE is generally acceptable for an Aa credit versus an A credit. We provide a range or description for each of the measurement criteria.[3]

COMPANY MAPPING/OUTLIER DISCUSSION

We next assign a rating to each company in our rated universe for each factor. We also show how this rating compares to the company's actual assigned rating. The results of this mapping appear in a summary table located in Appendix B, as well as in the results section under each factor.

We recognize that any given company may perform higher or lower on a specific factor than its actual rating level. These companies are identified as "outliers" for that factor. A company whose performance on a specific factor is more than two rating notches higher than its actual rating is deemed a positive outlier for that factor. A company whose performance is more than two notches below is deemed a negative outlier. We highlight those companies whose factor mapping is more than two notches higher or lower than its rating and offer a discussion of the general reasons for outliers within a given factor.

1. *See Appendices A and B for a summary of sub-factors and weightings for each sub-factor.*
2. Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations — Part I *(US/Canadian GAAP, February, 2006).*
3. *See Appendix D for non-financial sub-factor definitions.*

DETERMINING THE FINAL RATING

To determine the overall rating, each of the eight assigned sub-factor ratings is converted into a numeric value based on the following scale.

1	3	6	9	12	15	18
Aaa	Aa	A	Baa	Ba	B	Caa

Each sub-factor's numeric value is multiplied by an assigned weight (refer to the table below and/or Appendices A and B, for weights), and then summed. For information purposes, the table below also shows sub-totals and how much weight is given to each broad rating factor.

Factor	Sub-Factor	Weighting	Cumulative Weighting of the Relevant Sub-Factors
Sustainable Profitability	ROE	15%	20%
	EBIT/Customer Base	5%	
Regulatory Support	Regulatory Support	10%	10%
Ring Fencing	Ring-Fencing	10%	10%
Financial Strength and Flexibility	EBIT/Interest	15%	60%
	RCF/Debt	15%	
	Debt/Book Capitalization	15%	
	Free Cash Flow/FFO	15%	
Total Weighting		**100%**	

The total is then mapped to the table below, and an overall alpha-numeric rating is assigned based on where the score falls in the range. The outcome provides a good correlation, with indicated ratings falling at or two notches away from actual ratings.

Indicated Rating	Overall Score
Aaa	= 1
Aa	> 1 < 4.5
A	>= 4.5 < 7.5
Baa	>= 7.5 < 10.5
Ba	>= 10.5 < 13.5
B	>= 13.5 < 16.5
Caa	>= 16.5

The entire array of scores and mappings for each of the LDC companies is shown in Appendix B.

Factor Discussions

FACTOR 1: SUSTAINABLE PROFITABILITY

Why It Matters

Two subfactors provide good indications of a firm's ability to remain profitable and efficient despite the inherent volatility associated with the sector:

- **Return on equity (ROE)**, which is calculated for each year by taking a company's profitability in a given year and dividing it by an average equity of the current and previous year end. ROE serves as barometer of a company's general level of profitability — and when calculated over a period of years, serves as an indicator of its ability to sustain its profitability — and provides a good starting point for understanding the overall efficiency of the operations of the company.
- **Operating Income (EBIT)** relative to customer base provides another indicator of a gas utility's overall operating profitability relative to the number of customers being serviced. The higher this figure, the more each customer contributes to the company's "bottom-line." For purposes of this calculation, only firm demand customers of the residential and commercial categories are included, as industrial customers often have alternate

sources of fuel and are the first to be cut off by a utility in the event of gas pro-rationing (allocation as a percentage of available supply) or shortage.

The former calculates returns on a GAAP basis and the latter serves as a measure of overall operating efficiency. When an average of three years is used as the comparable period, these indicators reveal the company's relative profitability and ability to maintain this profitability and efficiency on a sustainable basis.

LDCs may differ in their rate design, the effectiveness, and the timeliness of rate design, but they ultimately culminate in an ROE scorecard that is an irrefutable indicator of the profitability that the firm has achieved (or in the case of projected figures resulting from a rate case filing or decision, projected profitability) given the business environment in which it operates. Similarly, the EBIT/customer base measures the relative operating efficiency of the company in achieving these operating results.

Among the risk factors reflected in ROE are the presence and effectiveness of the LDC's weather normalization clause (WNC), its ability to increase earnings despite customer gas conservation, the ability of the firm to pass through bad debt expenses, to true-up for underfunded pension liabilities, the frequency and degree of price adjustments for gas cost purchase adjustments, the ability to pass along financial and derivative hedging costs to consumers, to reimburse itself for environmental remediation expenditures, to use forward year test data in factoring in capital expenditure cost recoveries, and its ability to cover rising O&M (operating and maintenance) expenditures. The firm's effectiveness in dealing with these risks is distilled into an ROE calculation. Over time, this calculation provides a profile of the company's ability to generate consistent earnings that are capable of covering the cost of doing business and capable of doing so over an extended period of time. It also provides a benchmark measure of efficiency relative to other LDCs with similar business profiles.

It should be noted that in the use of ROE, the measure of profitability is indifferent as to whether an LDC employs multiple approaches to shielding itself from gas commodity price volatility (such as through use of various forms of financial derivatives) or if it relies primarily on underground gas inventory storage or long-term pipeline deliveries at fixed costs. Similarly, it does not impose a requirement that the LDC have a WNC in place to protect its gas margins against warmer than normal winters, as the company could achieve similar results by employing its own form of weather mitigants through the purchase of weather insurance or derivatives. The importance of achieving a desired target ROE is the fact that it signals management's effectiveness in employing all possible measures to achieve its business goals.

That said, the better the quality of an LDC's rate design or effectiveness in generating operating profits, the greater and more consistent its ROE. Very few businesses are assured a stable and consistent return on their capital by a regulatory body, but LDCs are (in theory, at least). To the extent they employ highly effective rate designs and business solutions in mitigating the known risk factors in the business, the better the ROE and efficiency of its operations.

Despite wide variations in individual utility rate designs therefore, ROE and EBIT/Customer Base appear to capture the level of profitability and efficiency in an LDC's operations and reflect its ability to generate profits over a sustainable period of time.

We note that profitability (ROE), operating income to customer base (EBIT/residential+commercial customers), interest coverage, retained cash flow to debt, debt to capital and free cash flow to funds from operation are the credit metrics that contribute the most to differentiating the stronger LDCs from the weaker ones. These also tend to be the "lagging" indicators as financial results are only available after the close of a fiscal quarter. Thus, they serve as a report card for the close of a given financial period, after all the events of the period have already transpired and all the initiatives of management are either completed or left undone.

Measurement metrics for this factor are as follows:

- **ROE** — profitability in a given year / average equity of the current and previous year.
  Weighting: 15%
- **(EBIT) to Customer Base:** For purposes of this calculation, only firm demand customers of the residential and commercial categories are included, as industrial customers often have alternate sources of fuel and are the first to be cut off by a utility in the event of gas pro-rationing (allocation as a percentage of available supply) or shortage.
  Weighting: 5%

Factor Mapping: Sustainable Profitability

	Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
Return on Equity	20%	15%	≥ 19%	14 – 19%	9 – 14%	5 – 9%	2 – 5%	0 – 2%	≤ 0%
EBIT/# of Residential & Commercial Customers		5%	> $350	$250 - $350	$150 – $250	$100 – $150	$50 – $100	$0 – $50	< $0

Company Mapping Results: Sustainable Profitability

Issuer Name	Current Senior Unsecured Rating	ROE	Indicated Rating: ROE	EBIT/# of Residential & Commercial Customers	Indicated Rating: Operating Ratio
Alabama Gas Corporation	A1	14 – 19%	Aa	$150 – $250	A
New Jersey Natural Gas Company (Sec Aa3)	A1	9 – 14%	A	$150 – $250	A
Wisconsin Gas	A1	5 – 9%	Baa	$100 – $150	Baa
Boston Gas Company	A2	2 – 5 %	Ba	$150 – $250	A
Brooklyn Union Gas	A2	9 – 14%	A	$150 – $250	A
KeySpan Gas East Corporation	A2	9 – 14%	A	$250 – $350	Aa
Northern Illinois Gas	A2	5 – 9%	Baa	$50 – $100	Ba
North Shore Gas Company (Sec A1)	A2	5 – 9%	Baa	$50 – $100	Ba
Peoples Gas Light and Coke Compa (Sec A1)	A2	5 – 9%	Baa	$100 – $150	Baa
Public Service Co. of North Caro	A2	5 – 9%	Baa	$150 – $250	A
Questar Gas Company	A2	9 – 14%	A	$50 – $100	Ba
Southern California Gas Company	A2	14 – 19%	Aa	$50 – $100	Ba
Washington Gas Light Company	A2	9 – 14%	A	$150 – $250	A
Terasen Gas Inc.	A3	9 – 14%	A	>$350	[redacted]
Colonial Gas Company (Sec A2)	A3	2 – 5 %	Ba	$250 – $350	[redacted]
Northwest Natural Gas Company	A3	9 – 14%	A	$150 – $250	A
Piedmont Natural Gas Company, In	A3	9 – 14%	A	$150 – $250	A
Connecticut Natural Gas	A3	2 – 5 %	Ba	$250 – $350	[redacted]
UGI Utilities, Inc.	A3	14 – 19%	[redacted]	$250 – $350	[redacted]
AGL Resources Inc.	Baa1	14 – 19%	[redacted]	$150 – $250	A
Cascade Natural Gas Corp.	Baa1	9 – 14%	A	$100 – $150	Baa
Indiana Gas Company, Inc.	Baa1	5 – 9%	Baa	$100 – $150	Baa
Laclede Gas Company	Baa1	9 – 14%	A	$100 – $150	Baa
Southern Connecticut Gas (Sec A3))	Baa1	2 – 5 %	Ba	$150 – $250	A
Laclede Group, Inc. (The)	Baa2	9 – 14%	A	$100 – $150	Baa
South Jersey Gas Company	Baa2	9 – 14%	A	$150 – $250	A
Yankee Gas	Baa2	2 – 5 %	Ba	$150 – $250	A
Atmos Energy Corporation	Baa3	9 – 14%	[redacted]	$50 – $100	Ba
Southwest Gas Corporation	Baa3	5 – 9%	Baa	$50 – $100	Ba
SEMCO Energy, Inc.	Ba2	<0%	Caa	$100 – $150	Baa

[redacted]
Negative Outlier

Observations and Outliers

ROE

Among the negative outliers are Boston Gas and Colonial Gas, two of six natural gas distribution companies owned by KeySpan Corp. Their low ROE reflects push down accounting relating to KeySpan's acquisition of Eastern Enterprises, whereby a portion of the acquisition debt and goodwill issued by the parent have been allocated to Boston Gas and Colonial Gas. The debt and parent financing of working capital and gas inventory through the utility money pool has resulted in noticeably increased debt and interest expense levels. Additionally, National Grid's recently announced plan to acquire Keyspan raises the possibility of an additional debt servicing burden being "pushed down" to these subsidiaries. The low ROE also reflects the lower efficiency of the rate design in these KeySpan subsidiaries. The lack of weather mitigation and conservation in the company's rate design leaves it vulnerable to weather and conservation exposure, which are being mitigated in part through the purchase of weather derivatives.

The Connecticut LDCs of Connecticut Natural Gas, Southern Connecticut Gas and Yankee Gas also have low ROEs relative to their assigned ratings, reflecting relatively poor regulatory support from the state commission on weather and conservation protections, and the ability to pass financial hedging costs to rate-payers as a means to mitigate gas price volatility. These LDCs are also smaller subsidiaries within larger electric power utility operations that may require additional forms of parental support for the LDCs.

In the case of Wisconsin Gas the company was approved for a rate base increase, effective January 2006, for an approved ROE of 11.2%, but historical returns had eroded because of a five-year rate freeze.

Among the positive outliers are UGI Utilities, AGL Resources and Atmos. Although UGI has a high ROE relative to its peer group, the overall rating is suppressed because of its affiliation with non-investment grade subsidiaries of the parent.

In the case of AGL and Atmos, the diversified earnings of the group include income from operations such as energy services. These tend to boost the group's returns even though the combined risk may indicate a less stable and predictable earnings stream.

EBIT to Customer Base

Northern Illinois Gas and North Shore Gas Company are negative outliers in this operating efficiency ratio, as they have been suffering from regulatory lag. However, the recent rate increase in the case of Northern Illinois Gas could help narrow the gap in its performance going forward.

On the other extreme, UGI appears to be a very efficient operator and is a positive outlier from a customer base standpoint. Although UGI has strong operating income (being supported by a higher than average customer growth rate — mostly attributable to organic growth), the overall rating is suppressed because of its affiliation with non-investment grade subsidiaries of the parent.

FACTOR 2: REGULATORY SUPPORT

Why It Matters

The fact that LDCs are subject to regulation by local authorities has a direct bearing on the success of their business operations. It is difficult for utilities to function without good community relations, as they depend on their local regulators and on the public's understanding to obtain the rate relief and cost recovery necessary for a gas distribution system's investments.

Of particular importance, regulatory requirements are often delineated not by law or by prescribed statutory requirement or ruling but rather by the expectation that traditional practices will continue and that LDCs — particularly the older and more established ones — will continue to act within established boundaries and in accordance with past practice. This necessitates a strong relationship with regulators who are, ideally, supportive.

Thus, when the regulatory relationship is strong and cooperative, utilities are able to engage in active dialogue with regulatory commissioners and staff to find mutually acceptable solutions to utility problems (such as rising account delinquencies in periods of gas shortages and price increases) or to educate customers about key initiatives such as gas conservation. In a strong relationship, the commission staff might also serve as a technical advisor to the utility commission in facilitating constructive discussions with the company — as opposed to playing the role of "consumer advocate" and countering LDC initiatives.

One very important component of the utility/regulator relationship is the ability of the utility to recoup allowed expenses in a timely manner and its ability to earn its fully-allowed rate of return (without having to file continuously for new rate cases).

Within this metric we also include the utility's relationship — both perceived and actual with the public and its approach to issues of safety, reliability and integrity.

This metric thus helps to define credit impact of the established operational "norms" and the operating framework. It is conceivable for a utility to maintain an investment grade rating with only limited support from its regulators if it has capable management that is able to find alternatives and solutions for its business needs, but the support of regulators on most matters of economic importance enable a company to operate with far more effectiveness. We note that, included in the definition of "regulatory environment" are regulatory staff, commission, interveners, consumer advocates and the public at large.

Measurement metrics for this factor are as follows:

- **Quality of Regulatory Support:** The regulatory relationship is measured on a scale from "Exceptional/Proactive" to "Inadequate/Weak." To assess the quality of the regulatory support we examine the strength of the regulatory relationship. This will include the speed and degree of willingness with which the regulatory commission approves requests for rate increases, approves and encourages rate design modifications that serve to help a utility recoup its operating and capital investment costs and whether regulators enable utilities to recoup such costs in a timely manner.
  Weighting: 10%

Notes on Measurement Criteria

This sub-factor is important and will have a direct bearing on the ultimate credit rating of the LDC, although it lacks the finality of the more formulaic financial sub-factors (regulatory decisions may be modified or reversed by future regulators or a court action, whereas ROE results, for example, cannot). Because regulatory support is often subject to interpretation and change over time as the actions and views of participants change, it is weighed less heavily than are financial metrics.

Factor Mapping: Regulatory Support

Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
10%	10%	*Exceptional Proactive Support* by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service; Utility commission always willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs' shareholders and consumers alike. Utility Commission grants all rate design features to allow LDC to recover costs on a complete and timely basis.	*Very Good Proactive Support* by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service; Utility commission highly willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs' shareholders and consumers alike. Rate design is near "bulletproof" cover for LDC risks. Requested rate increases tend to be approved in less than 9 months.	*Good Support* by Utility Commission to allow LDCs to amend rate designs. Company gets good support in proposing new solutions to deal with common utility problems such as conservation and weather variables; Differences between LDCs and utility commission are likely to be resolved. Rate filings tend to be approved under 12 months.	*Reasonable support* from Utility Commission to allow LDCs to recoup allowed expenses; Company gets some support in proposing new solutions to deal with common utility problems such as conservation and weather issues; Differences between LDCs and Utility Commission are reasonably resolved in a timely manner and rate cases tend to be approved in 12 – 15 months with at least 50% of LDC's target requests being granted.	*Inadequate support* from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner and/or staff tends to play the role of "consumer advocate" that often counters proposals or initiatives advanced by the LDC. Cases often take over 15 months to resolve or LDC is frozen out of rate filings for over 18 months.	*Inadequate support* from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner often plays the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC; Company is seldom involved with working on special task forces to deal with issues of rising account delinquencies or educating customers on conservation or warm weather issues. Utility suffers from increasing regulatory lag and lacks rate relief necessary to earn allowed ROE.	*Inadequate and weak support* from Utility Commission to allow LDCs to recoup allowed expenses. Utility commissioner always plays the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC; Company is hardly ever involved with working on special task forces to deal with issues of rising concern to utility or customers. Unsupportive commission/state legislature or consumer base. Utility can't earn allowed ROE.

Company Mapping Results: Regulatory Support

Issuer Name	Current Senior Unsecured Rating	Indicated Rating: Regulatory Support
Alabama Gas Corporation	A1	[redacted]
New Jersey Natural Gas Company (Sec Aa3)	A1	[redacted]
Wisconsin Gas	A1	Baa
Boston Gas Company	A2	Baa
Brooklyn Union Gas	A2	Baa
KeySpan Gas East Corporation	A2	Baa
Northern Illinois Gas	A2	Baa
North Shore Gas Company (Sec A1)	A2	Ba
Peoples Gas Light and Coke Compa (Sec A1)	A2	Ba
Public Service Co. of North Caro	A2	[redacted]
Questar Gas Company	A2	Ba
Southern California Gas Company	A2	A
Washington Gas Light Company	A2	Baa
Terasen Gas Inc.	A3	[redacted]
Colonial Gas Company (Sec A2)	A3	Baa
Northwest Natural Gas Company	A3	[redacted]
Piedmont Natural Gas Company, In	A3	[redacted]
Connecticut Natural Gas	A3	Ba
UGI Utilities, Inc.	A3	Baa
AGL Resources Inc.	Baa1	Baa
Cascade Natural Gas Corp.	Baa1	Baa
Indiana Gas Company, Inc.	Baa1	[redacted]
Laclede Gas Company	Baa1	[redacted]
Southern Connecticut Gas (Sec A3))	Baa1	Baa
Laclede Group, Inc. (The)	Baa2	[redacted]
South Jersey Gas Company	Baa2	[redacted]
Yankee Gas	Baa2	Ba
Atmos Energy Corporation	Baa3	Baa
Southwest Gas Corporation	Baa3	Ba
SEMCO Energy, Inc.	Ba2	Ba

[redacted]
Negative Outlier

FACTOR 3: RING FENCING

Why it Matters

- **Ring Fencing:** Many LDCs are owned by diversified energy companies engaged in non-regulated activities. For this reason, the degree to which an LDC is "ring-fenced" will have an impact on the quality and degree of protection afforded to the utility's assets and operating cash flows. Whether imposed by regulators, lenders, or by the parent company (self imposed) the ring-fencing must assure that the utility is self-standing and protected from non-regulatory businesses of the diversified parent group[4]. This is a common objective among regulators, lenders and consumers alike. Also, as in the case with weather mitigants, Moody's does not insist that there be explicit written statutes requiring the gas utility to be properly ring-fenced for the utility to be highly rated, as long as this is accomplished in an effective manner through other means.

  Among the contributors to a well ring-fenced utility are limitations on inter-company loans and advances to non-regulated affiliates or prohibitions on the commingling of funds through participation in diversified corporate money pools. These are important in ascertaining that the utility's operating assets and capital expenditures are justifiable to utility ratepayers.

  Other contributors to strong ring fencing are legal or regulatory requirements stipulating maximum leverage ratios for the LDC and requirements that an LDC remain investment-grade to preserve its service

4. *The expectation that non-regulated expenses incurred by affiliates engaged in other businesses will not be passed onto the utility (which would then attempt to seek recovery from its consumers) is intrinsic to the concept of ring fencing. For example, a diversified gas company with a gas trading operation is expected to deal with its regulated utility at arm's length. It is not expected that the company will allow the trading company to determine which entity should receive the best price quotes for gas purchase transactions or which should be chosen to book trading losses.*

franchise. By placing a limitation on leverage, regulators or lenders are implicitly limiting the level of dividends that a diversified parent company might extract from its utility, and discouraging the utility from using its balance sheet to raise debt for the benefit of non-utility affiliates or its diversified parent.

The utility's payment of dividends in excess of what the parent company may require for its public shareholders could also serve as an indication of poor ring fencing, as the surplus funds being paid as dividends by the utility could be viewed as a form of cash support for the parent company's non-utility affiliates. Well ring-fenced utilities typically raise their own funds and handle their own bank accounts, with non-utility affiliates establishing their own credit facilities and funding requirements separate and independent from the utility.

Weighting: 10%

- Less obvious, but also important are the proven resolve of management or a utility's board in erecting operating barriers that isolate the utility from its non-regulated affiliates. This might include, for example, dedicating separate utility gas purchasing agents from the group's energy trading arm or locating utility personnel at separate premises from those of the non-utility affiliates. These good corporate governance attributes are implied in having good ring-fencing measures.

  Utilities sometimes establish their own boards of directors, especially within a larger and more diversified company to ensure that their assets, cash flows and operating funds are properly separated and that attempts by the parent to distribute dividends to the holding company are fair and justified. Any weak corporate governance would typically become evident in reviewing a utility's ring fencing quality and manifest itself through lax policies and procedures in operations as well as in financial dealings, record-keeping and internal controls. Corporate governance therefore, is a related indicator for ring fencing quality.

  While such efforts as creating a permanent body to ensure the operating integrity of the utility could add to the strength of the ring fencing provisions, it is a further indicator that the utility stands on its own and is governed by a board that looks after its interest first rather than using the utility to advance the goals of the parent's diversified group. Ultimately, such efforts can enhance the utility's independent operating performance and credit rating.

  The utility's board may also require that it obtain its own credit facilities, issue its own bonds and only guaranty activities directly related to providing core utility services. Under this framework, the utility serves as its own profit center and allocates any expenses incurred on behalf of non-utility sister companies back to those affiliates for recovery, rather than burdening its own operating staff and the utility ratepayers.

Measurement metrics for this factor are as follows:

- **Ring Fencing:** This metric is assessed on a scale of "excellent ring fencing isolating utility from non-utility" to "inadequate and weak ring fencing: funds always commingled." In determining the degree of commingling of funds, LDCs range from having their own bank accounts and issuing their own debt and commercial paper to participating in combined cash money pools or engaging in making intercompany loans to non-utility affiliates on a frequent basis). Other indicators that we review for quality of ring fencing include: the level of dividends that are upstreamed by the utility to the parent vs. the parent to the public shareholders, the level of intercompany transactions, the ability of various operating entities to raise their own bank and public financing, the extent of any cross-default provisions or cross-guarantees, the presence of utility financial covenants that would enhance their ring fencing and signs of weak corporate governance.
  Weighting: 10%

Factor Mapping: Ring Fencing

Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
10%	10%	*Excellent* ring-fencing provisions isolating Utility from Non-Utility; No commingling of funds; Utility cash accounts are separated from rest of company; Inter-company loans never permitted between utility and non-utility; No portion of Utility dividend payment to parent ever ends up being allocated to non-utility. Strong	*Very Good* ring-fencing provisions; Utility and Non-Utility highly unlikely to commingle funds; Separate cash program or own utility money pool; Inter-company loans not permitted between utility and non-utility; Utility dividend payment to parent never end up being allocated to non-utility.	*Good* ring-fencing provisions; Utility and Non-Utility are unlikely to commingle funds; Separate utility money pool or utility accounts; Inter-company loans not permitted between utility and non-utility; Utility dividend payment to parent unlikely to be allocated to non-utility.	*Reasonable* ring-fencing provisions; Utility and Non-Utility may need to commingle funds via consolidated corporate money pool; Bond indentures or bank credit agreements may reasonably restrict the utility from financial dealings with non utility; Inter-Company loans between utility and non-utility rare.	*Inadequate* ring-fencing provisions; Utility often participates in corporate cash money pool that includes non-utility and funds are often commingled; Regulators usually do not have a requirement that LDCs remain investment grade. Bond indentures or bank credit agreements may not restrict the utility financial dealings with non- utility.	*Inadequate* ring-fencing provisions; Utility often participates in corporate cash money pool that includes non-utility and funds are generally commingled; No requirement for LDCs to remain investment grade. Bond indentures or bank credit agreements usually do not restrict the utility financial dealings with non- utility. Inter-company loans between utility and non-utility common place.	*Inadequate and weak* ring-fencing provisions; Utility and Non-Utility generally always commingle funds; No requirement for LDCs to remain investment grade; Bonds indentures/ bank agreements never restrict utility financial dealing with non-utility. Inter-company loans between utility and non-utility are common place; Utility dividends to parent may fund non-utility needs.
		Corporate Governance protecting utility interests which are treated as core operation.	Very Good Corporate Governance. May lack formal regulatory or creditor leverage restrictions or IG requirement for utility, but company has strong policy of ring-fencing utility.	Good Corporate Governance of utility	Satisfactory Corporate Governance. Gas utility contributes less than 90% of consolidated group EBIT and may not be primary growth engine.	Inadequate Corporate Governance protection for utility as stand-alone entity.	Inadequate Corporate Governance for utility as a stand alone entity.	Inadequate and weak Corporate Governance of utility interests.

Company Mapping Results: Ring Fencing

Issuer Name	Current Senior Unsecured Rating	Indicated Rating: Ring Fencing
Alabama Gas Corporation	A1	Baa
New Jersey Natural Gas Company (Sec Aa3)	A1	[redacted]
Wisconsin Gas	A1	Baa
Boston Gas Company	A2	Baa
Brooklyn Union Gas	A2	[redacted]
KeySpan Gas East Corporation	A2	[redacted]
Northern Illinois Gas	A2	Baa
North Shore Gas Company (Sec A1)	A2	Baa
Peoples Gas Light and Coke Compa (Sec A1)	A2	Baa
Public Service Co. of North Caro	A2	[redacted]
Questar Gas Company	A2	A
Southern California Gas Company	A2	[redacted]
Washington Gas Light Company	A2	[redacted]
Terasen Gas Inc.	A3	[redacted]
Colonial Gas Company (Sec A2)	A3	Baa
Northwest Natural Gas Company	A3	Baa
Piedmont Natural Gas Company, In	A3	[redacted]
Connecticut Natural Gas	A3	Baa
UGI Utilities, Inc.	A3	A
AGL Resources Inc.	Baa1	Baa
Cascade Natural Gas Corp.	Baa1	[redacted]
Indiana Gas Company, Inc.	Baa1	Baa
Laclede Gas Company	Baa1	A
Southern Connecticut Gas (Sec A3))	Baa1	Baa
Laclede Group, Inc. (The)	Baa2	Baa
South Jersey Gas Company	Baa2	[redacted]
Yankee Gas	Baa2	Baa
Atmos Energy Corporation	Baa3	Baa
Southwest Gas Corporation	Baa3	[redacted]
SEMCO Energy, Inc.	Ba2	Baa

[redacted]
Negative Outlier

Observations and Outliers

Ring Fencing

Most of the indicated ring-fencing ratings are compatible with issuer assigned credit ratings. The "Aaa" ring-fencing indicators are typically reserved for those companies whose jurisdictions have established explicit requirements for separation of utility and non-utility businesses, maximum leverage, specific requirements that the LDC remain investment-grade or have placed limitations on dividends to their parent failing certain capitalization requirements. Exceptions might include Washington Gas Light Company, where despite the absence of specific regulatory requirements, the company has a strict policy of not commingling the gas utility funds with those of the non-regulated operations of the parent and the LDC only remits dividends to the parent that are required for distribution to public shareholders, prohibiting its LDC from assisting or supporting the business needs of its non-regulated affiliates.

In the case of Piedmont Natural Gas, Cascade Natural Gas and Southwest Gas Corporation, the utility is the parent company and there is no need for ring-fencing against a diversified non-regulated affiliate.

Negative outlier Alabama Gas results from the LDC having no explicit ring-fencing provisions from regulatory or financing agreements other than broad restrictions under an Alabama state statute.

Regulatory Support

Several "A" rated companies have outstanding regulatory relations and support "Aaa." Some examples include New Jersey Natural Gas Company, Northwest Natural Gas Company and Piedmont Natural Gas Company, where each one of these names have pioneered in the introduction of innovative service concepts and novel rate design concepts such as those for "conservation decoupling" in their respective jurisdictions and all have previously obtained WNC from their regulators. The regulatory relationship for some of the "Baa" names have also improved to the point where they also scored high in this factor ("Aa"), such as Indiana Gas Company and Laclede Gas Company in Missouri, where these LDCs were the first companies to obtain weather protection mechanisms from their public utility commissions either in the form of formal WNC or through fixed demand charge rate design. Utilities that score high in this factor also tend to be leaders in scoring high on customer satisfaction responses to independent surveys, helping their utility commissioners forge solutions to common utility problems such as dealing with the cost of high gas prices, or providing safety and systems integrity solutions before major problems arise, while maintaining strong community relations.

FACTOR 4: FINANCIAL STRENGTH AND FLEXIBILITY

Why It Matters

Financial strength is an important indicator of an LDC's ability to meet its financial obligations, particularly in light of the volatile nature of the industry's performance[5]. The metrics we use to define this factor include the following:

- **Interest coverage** (EBIT/Interest) is a measure of financial flexibility in an LDC's credit agreement as some lenders require minimum coverage to maintain their credit lines (the concept being that a stable utility should, at a minimum, be able to pay its interest expenses if not amortize its debt over a reasonable time period).

  Interest coverage serves as an indicator of fixed charge coverage. We chose this coverage ratio as it is used in the financial covenants of many LDC bank credit agreements and bond indentures, and is, by extension, both conventional and accessible for comparative purposes. Naturally, the higher this fixed charge coverage, the greater the financial flexibility of the utility.

- **Retained Cash Flow to Debt** (RCF/Debt) is a measure of financial leverage as well as an indicator of the strength of a utility's funds from operations after dividend payments are made to service the debt. It serves as a measure of financial health as well as liquidity to cover debt obligations while also providing a measure of cash available for capital expenditures and to cover working capital needs. RCF/Debt also serves as a measure of leverage relative to operating cash available for debt service.

  The higher the level of retained cash flow relative to debt, the more cash the LDC has after paying dividends to support its capital expenditure programs. The stronger LDCs tend to have sufficient retained cash flow to cover capital expenditure needs, while the weaker ones tend to run cash "deficits" that must be covered through increased equity issuance or debt, or a combination of both. Usually, debt is issued first, followed by occasional equity issuance to meet specific project needs or to strengthen the balance sheet.

- **Debt to Book Capitalization (Excluding Goodwill)** is a more generic measure of financial leverage and has, in the past, been a good barometer with which to gauge the financial flexibility available for a utility to expand and grow in its operations when it has a debt load to service. This measure subtracts goodwill from capitalization because regulators typically do not give credit for premium paid on acquired assets.

  High leverage reduces a firm's operating flexibility not only because it raises interest expense but also because it limits the company's ability to raise additional capital to cushion the impact of poor business conditions. High leverage may also portend the approach of maximum allowed debt capacity under most bank credit agreements, which often set a 65% debt/capitalization borrowing limit for investment grade LDCs.

- **Free Cash Flow as a portion of Funds from Operations** (FCF/FFO) measures the amount of free cash flow as a percentage of funds from operations after dividends are paid, working capital changes are taken into account and capital expenditures are made. While this is a stringent indicator of a utility's cash flexibility, it is a good indicator of cash generating capability and flexibility to deal with unforeseen circumstances or emergencies (gas supply disruptions, production shortages, etc.) — and the accompanying side effect of rapidly rising gas commodity prices — while managing long-term dividend payouts, capital expenditure undertakings and possible upswings in working capital requirements.

  This ratio is generally negative for most LDCs, but it is nonetheless a measure of free cash generated from operating funds (net income + depreciation + deferred taxes +/- other non-cash charges). A ratio that is consistently positive would suggest that the LDC generates surplus cash from its operations. This is rare for LDCs to accomplish on a consistent basis (which is why there are few companies rated Aa or Aaa).

5. *To assess financial strength and flexibility Moody's "smoothes" credit metrics by averaging them over a three-year time horizon whenever possible. The three years chosen are usually in the past, unless the projected years incorporate highly probable events driven by rate changes.*

Measurement metrics for this factor are as follows:

- **Interest Coverage: EBIT/interest**
  Weighting: 15%
- **Retained Cash Flow to Debt**
  Weighting: 15%
- **Debt to Capitalization (Excluding Goodwill)**
  Weighting: 15%
- **Free Cash Flow to Funds from Operations**
  Weighting: 15%

Factor Mapping: Financial Strength and Flexibility

	Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
EBIT/Interest		15%	> 7x	5 – 7x	3 – 5x	2 – 3x	1 – 2x	0 – 1x	< 0x
RCF/Debt		15%	> 26%	21 – 26%	15 – 21%	10 – 15%	5 – 10%	0 – 5%	< 0%
Debt / Book Capitalization (Excluding Goodwill)	60%	15%	< 30%	30 – 40%	40 – 50%	50 – 65%	65 – 85%	85 – 90%	> 90%
FCF/FFO		15%	> 10%	10% – (15%)	(15) – (30%)	(30%) – (45%)	(45%) – (60%)	(60%) – (75%)	< (75%)

Company Mapping Results: Financial Strength and Flexibility

Issuer Name	Current Senior Unsecured Rating	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/ Book Capitalization (Excluding Goodwill)	FCF/FFO	Indicated Rating: FCF/FFO
Alabama Gas Corporation	A1	3 – 5x	A	> 26%	[redacted]	40 – 50%	A	(15%) – (30%)	A
New Jersey Natural Gas Company (Sec Aa3)	A1	> 7x	[redacted]	10 – 15%	Baa	40 – 50%	A	> 10%	[redacted]
Wisconsin Gas	A1	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	10% – (15)%	Aa
Boston Gas Company	A2	1 – 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(15%) – (30%)	A
Brooklyn Union Gas	A2	5 – 7x	Aa	10 – 15%	Baa	40 – 50%	A	(45%) – (60%)	Ba
KeySpan Gas East Corporation	A2	2 – 3x	Baa	21 – 26%	Aa	40 – 50%	A	10% – (15)%	Aa
Northern Illinois Gas	A2	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
North Shore Gas Company (Sec A1)	A2	3 – 5x	A	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Peoples Gas Light and Coke Compa (Sec A1)	A2	2 – 3x	Baa	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Public Service Co. of North Caro	A2	2 – 3x	Baa	15 – 21%	A	30 – 40%	Aa	(15%) – (30%)	A
Questar Gas Company	A2	3 – 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A
Southern California Gas Company	A2	5 – 7x	Aa	21 – 26%	Aa	50 – 65%	Baa	(15%) – (30%)	A
Washington Gas Light Company	A2	5 – 7x	Aa	15 – 21%	A	30 – 40%	Aa	10% – (15)%	Aa
Terasen Gas Inc.	A3	1 – 2x	Ba	5 – 10%	Ba	65 – 85%	Ba	(15%) – (30%)	A
Colonial Gas Company (Sec A2)	A3	3 – 5x	A	15 – 21%	A	50 – 65%	Baa	10% – (15)%	Aa
Northwest Natural Gas Company	A3	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
Piedmont Natural Gas Company, In	A3	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Connecticut Natural Gas	A3	3 – 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A

Company Mapping Results: Financial Strength and Flexibility

Issuer Name	Current Senior Unsecured Rating	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/ Book Capitalization (Excluding Goodwill)	FCF/FFO	Indicated Rating: FCF/FFO
UGI Utilities, Inc.	A3	3 - 5x	A	10 - 15%	Baa	50 - 65%	Baa	10% - (15)%	[redacted]
AGL Resources Inc.	Baa1	3 - 5x	A	10 - 15%	Baa	50 - 65%	Baa	(30%) - (45%)	Baa
Cascade Natural Gas Corp.	Baa1	2 - 3x	Baa	10 - 15%	Baa	50 - 65%	Baa	(15%) - (30%)	A
Indiana Gas Company, Inc.	Baa1	2 - 3x	Baa	5 - 10%	Ba	40 - 50%	A	(30%) - (45%)	Baa
Laclede Gas Company	Baa1	2 - 3x	Baa	5 - 10%	Ba	50 - 65%	Baa	(15%) - (30%)	A
Southern Connecticut Gas (Sec A3))	Baa1	2 - 3x	Baa	15 - 21%	A	50 - 65%	Baa	(15%) - (30%)	A
Laclede Group, Inc. (The)	Baa2	2 - 3x	Baa	5 - 10%	Ba	50 - 65%	Baa	(15%) - (30%)	A
South Jersey Gas Company	Baa2	3 - 5x	A	10 - 15%	Baa	50 - 65%	Baa	10% - (15)%	[redacted]
Yankee Gas	Baa2	1 - 2x	Ba	10 - 15%	Baa	50 - 65%	Baa	< (75%)	Caa
Atmos Energy Corporation	Baa3	2 - 3x	Baa	10 - 15%	Baa	50 - 65%	Baa	(15%) - (30%)	[redacted]
Southwest Gas Corporation	Baa3	1 - 2x	Ba	10 - 15%	Baa	65 - 85%	Ba	(45%) - (60%)	Ba
SEMCO Energy, Inc.	Ba2	1 - 2x	Ba	5 - 10%	Ba	> 90%	Caa	(45%) - (60%)	Ba

[redacted]
Negative Outlier

Observations and Outliers

Interest Coverage

This ratio is generally compatible with LDCs' assigned credit ratings. Among the positive outliers in the "A" rated names is New Jersey Natural Gas, whose credit measures have proven much stronger than those for most of its peers. During the past few years earnings and cash flow improvements have resulted in higher interest charge coverage and lower leverage for the company. On the other end of the spectrum, Boston Gas Company shows higher interest expense to service relative to other similarly-rated high names.

In the "Baa" rated category we find that South Jersey Gas Company is rated lower than its interest coverage might suggest. This reflects the transitional nature of the company as it contemplates the issuance of additional debt in the future to help fund its capital expenditure requirements.

RCF/Debt

A positive outlier in the "A" rated category is Boston Gas, which has been able to produce strong cash flow under a performance-based rate (PBR) formula approved by regulators in Massachusetts. Negative outliers in the "Baa" category include Laclede Gas Company, where retained cash flow has been negatively affected by a policy of increasing dividend payouts.

Debt to Book Capitalization (Excluding Goodwill)

Low leverage generally correlates with high credit ratings, but there are a few exceptions. The "Ba" leverage factor score for Boston Gas Company and Colonial Gas Company, both subsidiaries of KeySpan, could be explained by the parent's use of push-down accounting. Under this approach, the LDCs were assigned a proportionate share of the cost of their acquisition debt and goodwill when KeySpan purchased them in 2000. The effect of pushing down a portion of the parent company's acquisition debt and goodwill raised financial leverage for these LDCs. This occurred not only because of the added debt burden from the parent but also because the allocated portions of goodwill resulted in a lower capital base (Moody's practice is to subtract the goodwill from equity for the regulated gas sector).

FCF/FFO

The scores for the free cash flow ratio are generally compatible with those of the assigned company ratings. A notable outlier in the "A" category includes Brooklyn Union Gas, which scored a "Ba" in this factor. During the past three years this company has had its cash flows stressed by a combination of high capital expenditures, high working capital uses and high dividend remittances to its parent. Outliers in the "Baa" rated names include South Jersey Gas, which is in transition, and Yankee Gas, which is in need of further rate relief and rate design improvements despite its recent rate filings, especially as it makes capital outlays in advance of rate recovery as in its current capital expenditures for construction of an LNG facility.

Final Considerations

To determine the overall rating, each of the eight assigned sub-factor ratings is converted into a numeric value based on the following scale:

1	3	6	9	12	15	18
Aaa	Aa	A	Baa	Ba	B	Caa

Each sub-factor's numeric point value is then multiplied by an assigned weight (as shown in Appendix A), summed.

Factor	Sub-Factor	Weighting
Sustainable Profitability	ROE	15%
	EBIT/Customer Base	5%
Regulatory Support	Regulatory Support & Relationship	10%
Ring Fencing	Ring-Fencing	10%
Financial Strength and Flexibility	EBIT/Interest	15%
	RCF/Debt	15%
	Debt/Capitalization (Ex. Goodwill)	15%
	FCF/FFO	15%
Total		**100%**

The total is then mapped to the table below, and an overall alpha-numeric rating is assigned based on where the score falls in the range.

Indicated Rating	Overall Score
Aaa	= 1
Aa	> 1 < 4.5
A	>= 4.5 < 7.5
Baa	>= 7.5 < 10.5
Ba	>= 10.5 < 13.5
B	>= 13.5 < 16.5
Caa	>= 16.5

Sample Calculation

	Rating	Rating Score	% of Total	Factor Score
Factor 1: Sustainable Profitability				
Sub-Factor 1	Aa	3	15%	0.5
Sub-Factor 2	Baa	9	5%	0.5
Factor 2: Regulatory Support				
Sub-Factor 3	Baa	9	10%	0.9
Factor 3: Ring Fencing				
Sub-Factor 4	Aaa	a	10%	0.1
Factor 4: Financial Strength and Flexibility				
Sub-Factor 5	A	6	15%	0.9
Sub-Factor 6	Aaa	1	15%	0.2
Sub-Factor 7	A	6	15%	0.9
Sub-Factor 8	A	6	15%	0.9
			100%	**4.8 = A1**

If an LDC'S sub-factors sum to a score of 4.8, as shown above, an overall rating of A1 would be assigned. On this scale, a lower score indicates a stronger credit profile than a higher score. If the LDC's sub-factors sum to a total score of 9.0, an overall rating of Baa would be assigned. The LDC would be considered to have an average Baa2 rating profile because it falls in the middle of that category range.

In this methodology we cover 30 gas utility companies. After placing these companies through the rating factor grid,

- 7 companies (23%) map to their assigned ratings
- 14 companies (47%; 70% cumulatively) fall within one notch of their existing ratings.
- 7 companies (23%; 93% cumulatively) have indicated ratings that are within two notches higher or lower than actual ratings
- All but two companies have actual ratings that fall within two notches of their ratings on the grid, with two companies' ratings — those of South Jersey Gas and Boston Gas — falling within three and four notches, respectively, outside of their factor summaries.[6]

South Jersey Gas currently has an assigned rating of Baa2, although the Moody's methodology suggests an A2 rating (reflecting, primarily, that recent past performance may differ from future results). When one factors the company's recent rate case capitalization assumptions with the appropriate adjustments made by Moody's, leverage rises, retained cash flows decline (on account of higher dividend payouts) and coverage ratios are reduced. The company remains solidly in the investment grade category. However, the financial metrics for this company are currently in transition as implied by the methodology and the ratings based on recent historical data may not be applicable for the future.

Boston Gas is rated A2 senior unsecured compared to the model rating of Baa3. This reflects the results of push-down accounting relating to KeySpan's acquisition of Eastern Enterprises, whereby a portion of the acquisition debt and goodwill issued by the parent was allocated to Boston Gas. Additionally, as KeySpan is currently under review for possible downgrade, following the announcement that it is being acquired by National Grid Plc, a UK gas and electricity transmission business, in a transaction valued at $7.3 Billion (£4.2 Billion). The transaction may put pressure on the regulated subsidiary to support the additional debt.

While there may be outliers from time to time under the gas LDC rating methodology, the vast majority of the companies rated by Moody's do fall within the two rating notches targeted by this methodology, and their credit ratings could be explained by the relevant factors. At any given time, we could assume that one or more issuers are in a state of transition and may therefore find themselves positioned as outliers relative to their assigned ratings when compared against the ratings implied under the gas LDC methodology (i.e. the deviations are either higher or lower by more than the two desirable notches).

6. *See Appendix C for Summary Chart on Moody's Public Rating versus Indicated Model Rating.*

Related Research

Special Comments:

Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings, June 2006 (98022)

Update On The Gas Supply and Liquidity Needs of Gas LDCs Post Hurricane Katrina, September 2005 (94440)

Impact Of Conservation On Gas Margins And Financial Stability In The Gas LDC Sector, June 2005 (92787)

Comparative ROE Attributes of US Local Gas Distribution Companies, July 2004 (87301)

Gas Utility Cash Management Practices Reflect the Diversity of their Credit Ratings, October 2003 (79828)

Negative Rating Trend For Local Gas Distribution Companies: Impact Of Diversification And Warm Weather, October 2002 (76344)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Appendix A

CONSOLIDATED GAS UTILITY RATING GRID

		Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
Sustainable Profitability	Return on Equity		15.0%	> 19%	14 – 19%	9 – 14%	5 – 9%	2 – 5%	0 – 2%	< 0%
	Ebit / # of Residential & Commercial Customers	20%	5.0%	> $350	$250 – $350	$150 – $250	$100 – $150	$50 – $100	$0 – $50	< $0
Regulatory Support	Regulatory Support and Relationship	10.0%	10.0%	*Exceptional Proactive Support* by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service; Utility commission always willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs' shareholders and consumers alike. Utility Commission grants all rate design features to allow LDC to recover costs on a complete and timely basis.	*Very Good Proactive Support* by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service; Utility commission highly willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs' shareholders and consumers alike. Rate design is near "bulletproof" cover for LDC risks. Requested rate increases tend to be approved in less than 9 months.	*Good Support* by Utility Commission to allow LDCs to amend rate designs. Company gets good support in proposing new solutions to deal with common utility problems such as conservation and weather variables; Differences between LDCs and utility commission are likely to be resolved. Rate filings tend to be approved under 12 months.	*Reasonable support* from Utility Commission to allow LDCs to recoup allowed expenses; Company gets some support in proposing new solutions to deal with common utility problems such as conservation and weather issues; Differences between LDCs and Utility Commission are reasonably resolved in a timely manner and rate cases tend to be approved in 12 – 15 months with at least 50% of LDC's target requests being granted.	*Inadequate support* from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner and/or staff tends to play the role of "consumer advocate" that often counters proposals or initiatives advanced by the LDC. Cases often take over 15 months to resolve or LDC is frozen out of rate filings for over 18 months.	*Inadequate support* from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner often plays the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC; Company is seldom involved with working on special task forces to deal with issues of rising account delinquencies or educating customers on conservation or warm weather issues. Utility suffers from increasing regulatory lag and lacks rate relief necessary to earn allowed ROE.	*Inadequate and weak support* from Utility Commission to allow LDCs to recoup allowed expenses. Utility commissioner always plays the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC; Company is hardly ever involved with working on special task forces to deal with issues of rising concern to utility or customers. Unsupportive commission/state legislature or consumer base. Utility can't earn allowed ROE.

		Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
Ring-Fencing	Ring-Fencing Quality (regulated or self-imposed)	10.0%	10.0%	*Excellent* ring-fencing provisions isolating Utility from Non-Utility; No commingling of funds; Utility cash accounts are separated from rest of company; Inter-company loans never permitted between utility and non-utility; No portion of Utility dividend payment to parent ever ends up being allocated to non-utility. Strong	*Very Good* ring-fencing provisions; Utility and Non-Utility highly unlikely to commingle funds; Separate cash program or own utility money pool; Inter-company loans not permitted between utility and non-utility; Utility dividend payment to parent never end up being allocated to non-utility.	*Good* ring-fencing provisions; Utility and Non-Utility are unlikely to commingle funds; Separate utility money pool or utility accounts; Inter-company loans not permitted between utility and non-utility; Utility dividend payment to parent unlikely to be allocated to non-utility.	*Reasonable* ring-fencing provisions; Utility and Non-Utility may need to commingle funds via consolidated corporate money pool; Bond indentures or bank credit agreements may reasonably restrict the utility from financial dealings with non utility; Inter-Company loans between utility and non-utility rare.	*Inadequate* ring-fencing provisions; Utility often participates in corporate cash money pool that includes non-utility and funds are often commingled; Regulators usually do not have a requirement that LDCs remain investment grade. Bond indentures or bank credit agreements may not restrict the utility financial dealings with non- utility.	*Inadequate* ring-fencing provisions; Utility often participates in corporate cash money pool that includes non-utility and funds are generally commingled; No requirement for LDCs to remain investment grade. Bond indentures or bank credit agreements usually do not restrict the utility financial dealings with non- utility. Inter-company loans between utility and non-utility common place.	*Inadequate and weak* ring-fencing provisions; Utility and Non-Utility generally always commingle funds; No requirement for LDCs to remain investment grade; Bonds indentures/ bank agreements never restrict utility financial dealing with non-utility. Inter-company loans between utility and non-utility are common place; Utility dividends to parent may fund non-utility needs.
				Corporate Governance protecting utility interests which are treated as core operation.	Very Good Corporate Governance. May lack formal regulatory or creditor leverage restrictions or IG requirement for utility, but company has strong policy of ring-fencing utility.	Good Corporate Governance of utility	Satisfactory Corporate Governance. Gas utility contributes less than 90% of consolidated group EBIT and may not be primary growth engine.	Inadequate Corporate Governance protection for utility as stand-alone entity.	Inadequate Corporate Governance for utility as a stand alone entity.	Inadequate and weak Corporate Governance of utility interests.
Financial Strength & Flexibility	EBIT/Interest		15.0%	> 7x	5 - 7x	3 - 5x	2 - 3x	1 - 2x	0 - 1x	< 0x
	RCF/Debt		15.0%	> 26%	21 - 26%	15 - 21%	10 - 15%	5 - 10%	0 - 5%	< 0%
	Debt / Book Capitalization (Excluding Goodwill)	60.0%	15.0%	< 30%	30 - 40%	40 - 50%	50 - 65%	65 - 85%	85 - 90%	> 90%
	FCF/FFO		15.0%	> 10%	10% - (15%)	(15) - (30%)	(30%) - (45%)	(45%) - (60%)	(60%) - (75%)	< (75%)

Appendix B

CONSOLIDATED FACTOR MAPPING RESULTS

Issuer Name	Current Senior Unsecured Rating	ROE	Indicated Rating: ROE	EBIT/# of Residential & Commercial Customers	Indicated Rating: Operating Ratio	Indicated Rating: Regulatory Support	Indicated Rating: Ring Fencing	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/ Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/Book Capitalization (Excluding Goodwill)	FCF/ FFO	Indicated Rating: FCF/FFO
Alabama Gas Corporation	A1	14 – 19%	Aa	$150 – $250	A	[redacted]	Baa	3 - 5x	A	> 26%	[redacted]	40 – 50%	A	(15%) – (30%)	A
New Jersey Natural Gas Company (Sec Aa3)	A1	9 - 14%	A	$150 – $250	A	[redacted]	[redacted]	> 7x	[redacted]	10 – 15%	Baa	40 – 50%	A	> 10%	[redacted]
Wisconsin Gas	A1	5 - 9%	Baa	$100 – $150	Baa	Baa	Baa	3 - 5x	A	10 – 15%	Baa	40 – 50%	A	10% – (15)%	Aa
Boston Gas Company	A2	2 - 5 %	Ba	$150 – $250	A	Baa	Baa	1 - 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(15%) – (30%)	A
Brooklyn Union Gas	A2	9 - 14%	A	$150 – $250	A	Baa	[redacted]	5 - 7x	Aa	10 – 15%	Baa	40 – 50%	A	(45%) – (60%)	Ba
KeySpan Gas East Corporation	A2	9 - 14%	A	$250 – $350	Aa	Baa	[redacted]	2 - 3x	Baa	21 – 26%	Aa	40 – 50%	A	10% – (15)%	Aa
Northern Illinois Gas	A2	5 - 9%	Baa	$50 – $100	Ba	Baa	Baa	3 - 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
North Shore Gas Company (Sec A1)	A2	5 - 9%	Baa	$50 – $100	Ba	Ba	Baa	3 - 5x	A	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Peoples Gas Light and Coke Compa (Sec A1)	A2	5 - 9%	Baa	$100 – $150	Baa	Ba	Baa	2 - 3x	Baa	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Public Service Co. of North Caro	A2	5 - 9%	Baa	$150 – $250	A	[redacted]	[redacted]	2 - 3x	Baa	15 – 21%	A	30 – 40%	Aa	(15%) – (30%)	A
Questar Gas Company	A2	9 - 14%	A	$50 – $100	Ba	Ba	A	3 - 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A
Southern California Gas Company	A2	14 - 19%	Aa	$50 – $100	Ba	A	[redacted]	5 - 7x	Aa	21 – 26%	Aa	50 – 65%	Baa	(15%) – (30%)	A
Washington Gas Light Company	A2	9 - 14%	A	$150 – $250	A	Baa	[redacted]	5 - 7x	Aa	15 – 21%	A	30 – 40%	Aa	10% – (15)%	Aa
Terasen Gas Inc.	A3	9 - 14%	A	>$350	[redacted]	[redacted]	[redacted]	1 - 2x	Ba	5 – 10%	Ba	65 – 85%	Ba	(15%) – (30%)	A
Colonial Gas Company (Sec A2)	A3	2 - 5 %	Ba	$250 – $350	[redacted]	Baa	Baa	3 - 5x	A	15 – 21%	A	50 – 65%	Baa	10% – (15)%	[redacted]
Northwest Natural Gas Company	A3	9 - 14%	A	$150 – $250	A	[redacted]	Baa	3 - 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
Piedmont Natural Gas Company, In	A3	9 - 14%	A	$150 – $250	A	[redacted]	[redacted]	3 - 5x	A	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Connecticut Natural Gas	A3	2 - 5 %	Ba	$250 – $350	[redacted]	Ba	Baa	3 - 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A
UGI Utilities, Inc.	A3	14 - 19%	[redacted]	$250 – $350	[redacted]	Baa	A	3 - 5x	A	10 – 15%	Baa	50 – 65%	Baa	10% – (15)%	[redacted]
AGL Resources Inc.	Baa1	14 - 19%	[redacted]	$150 – $250	A	Baa	Baa	3 - 5x	A	10 – 15%	Baa	50 – 65%	Baa	(30%) – (45%)	Baa
Cascade Natural Gas Corp.	Baa1	9 - 14%	A	$100 – $150	Baa	Baa	[redacted]	2 - 3x	Baa	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Indiana Gas Company, Inc.	Baa1	5 - 9%	Baa	$100 – $150	Baa	[redacted]	Baa	2 - 3x	Baa	5 – 10%	Ba	40 – 50%	A	(30%) – (45%)	Baa

Issuer Name	Current Senior Unsecured Rating	ROE	Indicated Rating: ROE	EBIT/# of Residential & Commercial Customers	Indicated Rating: Operating Ratio	Indicated Rating: Regulatory Support	Indicated Rating: Ring Fencing	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/ Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/Book Capitalization (Excluding Goodwill)	FCF/ FFO	Indicated Rating: FCF/FFO
Laclede Gas Company	Baa1	9 – 14%	A	$100 – $150	Baa	[redacted]	A	2 – 3x	Baa	5 – 10%	Ba	50 – 65%	Baa	(15%) – (30%)	A
Southern Connecticut Gas (Sec A3))	Baa1	2 – 5 %	Ba	$150 – $250	A	Baa	Baa	2 – 3x	Baa	15 – 21%	A	50 – 65%	Baa	(15%) – (30%)	A
Laclede Group, Inc. (The)	Baa2	9 – 14%	A	$100 – $150	Baa	[redacted]	Baa	2 – 3x	Baa	5 – 10%	Ba	50 – 65%	Baa	(15%) – (30%)	A
South Jersey Gas Company	Baa2	9 – 14%	A	$150 – $250	A	[redacted]	[redacted]	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	10% – (15)%	[redacted]
Yankee Gas	Baa2	2 – 5 %	Ba	$150 – $250	A	Ba	Baa	1 – 2x	Ba	10 – 15%	Baa	50 – 65%	Baa	< (75%)	Caa
Atmos Energy Corporation	Baa3	9 – 14%	[redacted]	$50 – $100	Ba	Baa	Baa	2 – 3x	Baa	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	[redacted]
Southwest Gas Corporation	Baa3	5 – 9%	Baa	$50 – $100	Ba	Ba	[redacted]	1 – 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(45%) – (60%)	Ba
SEMCO Energy, Inc.	Ba2	<0%	Caa	$100 – $150	Baa	Ba	Baa	1 – 2x	Ba	5 – 10%	Ba	> 90%	Caa	(45%) – (60%)	Ba

Negative Outlier

Appendix C

MOODY'S PUBLIC RATING VS. INDICATED MODEL RATING

Summary of LDCs Notch Difference

ACCURACY:

# of Companies in Methodology Study	30
# of Companies within Notching Range	28
% Companies within Notching Range	**93%**

0 Notch Difference	7
1 Notch Difference	14
2 Notch Difference	7
Outliers	2
Total Companies	**30**

Companies	Public Ratings	Model Ratings	Notch Difference
Alabama Gas	A1	A1	0
New Jersey Natural Gas	A1	Aa3	-1
Wisconsin Gas LLC	A1	A3	2
Boston Gas Company	A2	Baa3	4
Brooklyn Union Gas	A2	A3	1
KeySpan Gas East	A2	A1	-1
Northern Illinois Gas	A2	Baa1	2
NorthShore Gas	A2	Baa1	2
People Gas Light	A2	Baa1	2
Public Service Co of NC	A2	A1	-1
Questar Gas	A2	A3	1
Southern California Gas	A2	A1	-1
Washington Gas Light	A2	Aa3	-2
Colonial Gas	A3	A3	0
Northwest Natural Gas	A3	A3	0
Piedmont Natural Gas	A3	A2	-1
Connecticut Natural Gas	A3	Baa1	1
Terasen Gas Inc.	A3	Baa1	1
UGI Utilities Inc.	A3	A2	-1
AGL Resources Inc.	Baa1	A3	-1
Cascade Natural Gas	Baa1	A3	-1
Indiana Gas Company	Baa1	Baa1	0
Laclede Gas Company	Baa1	Baa1	0
Southern Connecticut Gas	Baa1	Baa1	0
Laclede group Inc	Baa2	Baa1	-1
[redacted]			
Yankee Gas	Baa2	Ba1	2
Atmos Energy	Baa3	Baa1	-2
Southwest Gas Corp	Baa3	Baa3	0
SEMCO Energy Inc.	Ba2	Ba3	1

[redacted]
Negative Outlier

Appendix D

SUMMARY OF NON-FINANCIAL LDC SUB-FACTORS

1. **Regulatory Support & Relationship**: While factor No. 1 measures the adequacy and effectiveness of the LDC's business model, this factor measures both the ***ability*** and ***willingness*** of the utility regulatory commission to grant the necessary support and protection that the LDC requests in its business plans. The utility commission must be willing to help the LDC establish a cooperative framework for discussions, hearings and staff relations with its indigenous utilities as well as have the state constitutional powers to put the necessary regulations or rate designs in place. While the LDC is interested in obtaining flexibility in regulatory growth and risk protection, the commission is usually focused on ensuring a stable utility operation with reliable customer service under reasonable prices. Questions to consider include
   a. Does the Company have good working relationship with the state regulators to recoup allowed expenses and the necessary trust of its regulators that it is doing the right thing for its customers and shareholders alike?
   b. Does the Company maintain an active dialogue with the commissioners and staff in discussing and proposing new solutions to common utility problems and working on special task forces to deal with common industry issues of rising account delinquencies as gas shortages rise and prices increase, or in educating customers as to gas conservation or safety?
   c. What is the role of the commission staff, to serve as a technical advisor to the utility commission in facilitating constructive discussions with the company or does it play the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC in an adversarial atmosphere for dispute resolutions.
   d. How are differences between the LDC and its utility commission typically resolved, do they have a "settlement" approach where various interveners and interested parties are brought together for amicable solutions or do they resort to court actions and counter-actions to achieve their ends?

5. **Ring Fencing Quality**: We find that either regulators or creditors or the companies themselves impose certain ring-fencing parameters on the financial operations of the LDCs. Generally, ring-fencing is a desirable attribute as the utility is assured a certain financial insulation from the non-utility operations of the parent company and is not susceptible to supporting the business of its non-utility affiliates. The greater the degree of ring-fencing, the more separated is the utility from its non-utility affiliates. The strongest ring-fencing requirements tend to come from legislative statutes and regulators, followed by bond indentures and bank creditors. Occasionally, LDCs have self-imposed guidelines that could be just as rigid as those regulated, but this would depend on the analysts' confidence in the utility's strict adherence to its own firewall policies and practices. A utility's self-imposed restrictions on its own operations and its attempts at insulating itself from other non-regulated affiliates could also be evident in its corporate governance policies and practices. Issues to consider include
   a. Are inter-company loans or advances permitted between utility and non-utility operations of the same corporate family?
   b. Does the utility participate in a corporate cash money pool that includes non-utility subsidiaries, such that it is possible for the utility to deposit its surplus funds in general corporate money pool which ends being used by the non-utility affiliates for their WC needs?
   c. Does the utility dividend payment to its parent (perhaps in excess of what the parent needs to pay public shareholders) have a portion that ends up being allocated to non-utility affiliates for their operating or investment needs?
   d. Do the regulators stipulate maximum leverage ratios for the LDC or have a requirement that the LDC remain investment-grade in order to preserve its service franchise?
   e. What is the quality of the LDC's corporate governance?

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Criteria:

Influence Of Regulatory And Policy Decisions On Utility Credit Quality Deepens, Demanding Timely Assessments From Standard & Poor's

Standard & Poor's Ratings Services expects to see many important utility rate-making decisions over the next several years, considering the sizable capital spending planned at many utilities around the U.S. Power companies will use the capital markets to raise funds for these projects, and the capital markets will look to us for opinions and commentary on the impact on utility industry creditworthiness of both rate-makers' decisions and legislation aimed at dealing with global climate change. The utility business is unique, in that in no other industry (with the possible exception of government finance) do legislative and regulatory pronouncements so significantly inform rating agency opinions.

Indeed, Standard & Poor's views the regulatory and political environment in which a utility operates as one of the most significant factors in assessing the creditworthiness of regulated utilities. Frequently, rate decisions pending before state commissions, or the evolving dynamics of a specific political situation, are of such consequence to a particular utility that the financial markets expect regular updates from us to clarify how these developments ultimately will affect the utility's creditworthiness.

Our role is to opine on the impact of utility rate decisions. Our ratings reflect our views on all of the factors that we believe will affect credit quality, including economic trends, the issuer's financial strength, and the regulatory environment. For regulated entities, however, the ability to generate revenues almost entirely depends on regulatory decisions. So in general, a ruling that enhances a utility's ability to recover costs in a timely manner will positively affect its overall credit quality. A decision that impedes timely cost recovery will usually have a negative impact on overall credit quality. As commentators on creditworthiness, we have an obligation to make either situation clear to market participants.

When a rate order or legislative decision is reached, utility investors and lenders look to Standard & Poor's to provide a rating opinion as quickly as possible--whether it is a rating or outlook change, or a ratings affirmation. Therefore, it is to be expected that we will publish our credit rating opinions, bulletins, and commentaries on utilities often--both in anticipation of important regulatory or rate-making decisions to indicate our opinion on the potential impact on credit quality, and just after those decisions are announced to elaborate on our analysis.

We do not publish rating reports in order that they be used in regulatory proceedings. But many times, we are asked to explain our methodology to regulators so that they can understand the factors we deem important in assessing credit quality, and so that regulators understand the importance of credit ratings to utilities as well as other participants in the public-debt markets.

It is important to note that we have no financial stake in the outcome of a rate case. Over the years, our ratings opinions have achieved wide investor acceptance as useful tools for differentiating credit quality because the market judges us to be objective and credible. The value of our ratings rests on our reputation for independence and objectivity, and our ability to opine on credit as a disinterested observer. Without these essential attributes, our ratings would cease to be meaningful to the market. Precisely because ratings are a global benchmark, the market

SOUTHWEST GAS CORPORATION
PROXY GROUP OF 12 VALUE LINE GAS DISTRIBUTION COMPANIES
MOODY'S REGUALTORY SUPPORT RATING

Line No.	Company (a)	Regulatory Support Rating (b)	Line No.
1	AGL Resources	Baa	1
2	Atmos Energy Corp.	Baa	2
3	Energen Corp.[1]	Aaa	3
4	Laclede Gas	Aa	4
5	New Jersey Resources Corp.	Aaa	5
6	NICOR, Inc.[2]	Baa	6
7	Northwest Natural Gas Co.	Aaa	7
8	Piedmont Natural Gas	Aaa	8
9	South Jersey Inds.	Aa	9
10	Southwest Gas Corporation	Ba	10
11	UGI Corp.	Baa	11
12	WGL Holdings Inc.	Baa	12

[1] Regulatory support rating of Alabama Gas Corporation
[2] Regulatory support rating of Northern Illinois Gas

Moody's Investors Service

Global Credit Research
Rating Action
10 MAR 2006

Rejoinder Exhibit No.__(TKW-6)
Sheet 1 of 1

Rating Action: Southwest Gas Corporation

MOODY'S PLACES THE Baa2/NEGATIVE OUTLOOK SENIOR UNSECURED DEBT OF SOUTHWEST GAS CORPORATION UNDER REVIEW FOR POSSIBLE DOWNGRADE

Approximately $1.2 BN of Debt Affected

New York, March 10, 2006 -- Moody's Investors Service places under review for possible downgrade the Baa2/negative outlook senior unsecured debt of Southwest Gas Corporation (SWX), following the company's recent announcement that the Arizona Corporation Commission (ACC) issued a final decision not to adopt the company's proposed rate design for balancing accounts, thereby exposing it to continuing earnings risks associated with weather volatility and declining customer use resulting from the effects of gas conservation. At the same time, the company declared that 2005 was one of the 10 warmest years on record and that it lost approximately $17MM in operating margins, primarily as result of lower gas usage. Consolidated net income for 2005 declined 23% from 2004, largely on account of loss in operating margins resulting from warmer than normal weather. Arizona accounts for approximately 55% of SWX's gas distribution business and the ACC decision weighs heavily on the company.

In its review, Moody's will consider what other options may be available to the company in terms of mitigating the effects of warmer than normal weather, loss of operating margins on account of gas conservation by customers, the reduction of regulatory lag in dealing with high capital expenditures in a fast-growing service territory and rising operating expenses. Also under review will be the impact of these factors on the company's credit metrics and future financial performance.

Ratings of SWX under Review are as follows:

Southwest Gas Corporation - Baa2 senior unsecured

Southwest Gas Capital II - Baa3 preferred trust securities

Southwest Gas Corporation - (P) Ba1 preferred shelf

Southwest Gas Corporation is headquartered in Las Vegas, Nevada, and provides natural gas service to over 1.7 million customers in Arizona, Nevada and California.

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Moody's Investors Service

Global Credit Research
Rating Action
30 MAY 2006

Rejoinder Exhibit No.__(TKW-7)
Sheet 1 of 2

Rating Action: Southwest Gas Corporation

MOODY'S DOWNGRADES SENIOR UNSECURED DEBT OF SOUTHWEST GAS CORPORATION TO Baa3 FROM Baa2; OUTLOOK IS STABLE

Approximately $ 1.2 Billion of Debt Securities Affected.

New York, May 30, 2006 -- Moody's Investors Service downgraded the senior unsecured long-term debt ratings of Southwest Gas Corporation (SWX) to Baa3 from Baa2 with stable outlook. This action concludes the rating review initiated on March 10, 2006. The downgrade reflects the view that the credit measures of SWX remain weak when compared with its gas utility peers in light of its continued rapid growth and sensitivity to decline in earnings on account of warmer than normal weather and the absence of revenue decoupling in Arizona (54% of gross margins) and Nevada (37% of gross margins) that would serve to protect this company from weather variation and customer conservation. The company's heightened sensitivity to warmer than normal weather is exacerbated by the fact that in 2005 it experienced one of the 10 warmest years on record with 2003 being one of the warmest years in over 100 years. The cumulative effects of this warmer than normal weather has continued into the recent quarter ending March 31, 2006 which was mostly responsible for the company's loss of $9 million in operating margin.

While the company was able to obtain some rate relief in recent years, the fact that it is among the fastest growing gas utilities in the country (5% p.a. growth) continues to expose it to regulatory lag as rate cases in its key state of Arizona take at least a year to resolve and even then, typically deliver only part of the rate improvement necessary for it to earn its allowed rate of return. While the company has been encouraged in certain jurisdictions to further pursue discussions with interested parties as to the possibilities of adopting some form of weather normalization clause protection or conservation tracker, these efforts will take more time before they could be implemented even if agreed upon by all the stakeholders concerned.

KEY RATING DRIVERS

For a few years the company has been performing at the lower end of its peers in terms of the financial rating indicators employed by Moody's which include, as example, fiscal 2005 return on equity of 6.0%, EBIT/Interest Expense coverage of 1.7, Retained Cash Flow to Adjusted Debt of 10.0% and Adjusted Debt to Adjusted Cap. of 62.5%. The comparable ratios for Baa2 peers averaged 8.9% ROE, 2.8 EBIT/Interest Exp. coverage, 13% RCF to Adj. Debt and 55% Adj. Debt to Cap. In addition, cash flow from operations after dividend payments has been insufficient to cover the active level of capital expenditures, a trend that has existed for several years and which is likely to continue into the foreseeable future given the company's very rapid growth rate. In addition, operating expenditures rose 14% in fiscal 2005 and 6% in the first quarter of 2006, reflecting the impact of general cost increases and incremental costs associated with providing service to a growing customer base, pressures that are expected to continue in the foreseeable future.

The challenges for this company which bear directly on the aforementioned financial indicators are the ability to obtain the most comprehensive rate design possible to protect against warmer than normal weather, the reduction of regulatory lag by incorporating forward period test data along with pursuing more profitable growth alternatives, the correction for margin losses on account of customer conservation, and exercising strong control over operating expenses.

RATING OUTLOOK

The stable outlook anticipates a gradual improvement on the key rating drivers mentioned above that have negatively impacted the company's credit metrics and have prompted this rating adjustment.

Downgraded Ratings of SWX are as follows:

Southwest Gas Corporation -- to Baa3 from Baa2 senior unsecured;

Southwest Gas Capital II -- to Ba1 from Baa3 preferred trust securities;

Southwest Gas Corporation --to (P) Ba2 from (P) Ba1 preferred shelf.

Southwest Gas Corporation is headquartered in Las Vegas, Nevada, and provides natural gas service to over 1.7 million customers in Arizona, Nevada and California.

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SOUTHWEST GAS CORPORATION
PROXY GROUP OF 8 VALUE LINE GAS DISTRIBUTION COMPANIES
CHANGE IN BETA AND BOOK-TO-MARKET RATIO

Line No.	Company	Value Line Beta			Book-to-Market Ratio[3]			Line No.
		March 2006[1]	March 2008[2]	Change	March 2006	March 2008	Change	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	AGL Resources	0.90	0.85	(0.05)	0.57	0.66	0.08	1
2	Atmos Energy Corp.	0.70	0.85	0.15	0.80	0.93	0.13	2
3	Laclede Gas	0.80	0.95	0.15	0.56	0.62	0.06	3
4	NICOR, Inc.	1.15	1.00	(0.15)	0.48	0.64	0.16	4
5	Northwest Natural Gas Co.	0.70	0.90	0.20	0.63	0.55	(0.08)	5
6	Piedmont Natural Gas	0.75	0.85	0.10	0.50	0.50	(0.00)	6
7	South Jersey Inds.	0.65	0.85	0.20	0.53	0.48	(0.05)	7
8	WGL Holdings Inc.	0.80	0.85	0.05	0.65	0.68	0.03	8
9	**Proxy Group Average**	**0.81**	**0.89**	**0.08**	**0.59**	**0.63**	**0.04**	9

[1] Source: Value Line Investment Survey, March 17, 2006.
[2] Source: Value Line Investment Survey, March 14, 2008.
[3] Source: Bloomberg

SOUTHWEST GAS CORPORATION
PROXY GROUP OF 12 VALUE LINE GAS DISTRIBUTION COMPANIES
CHANGE IN BETA AND BOOK-TO-MARKET RATIO

Line No.	Company	Value Line Beta			Book-to-Market Ratio[3]			Line No.
		March 2006[1]	March 2008[2]	Change	March 2006	March 2008	Change	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	AGL Resources	0.90	0.85	(0.05)	0.57	0.66	0.08	1
2	Atmos Energy Corp.	0.70	0.85	0.15	0.80	0.93	0.13	2
3	Energen Corp.	0.80	0.90	0.10	0.40	0.31	(0.09)	3
4	Laclede Gas	0.80	0.95	0.15	0.56	0.62	0.06	4
5	New Jersey Resources Corp.	0.80	0.85	0.05	0.49	0.52	0.03	5
6	NICOR, Inc.	1.15	1.00	(0.15)	0.48	0.64	0.16	6
7	Northwest Natural Gas Co.	0.70	0.90	0.20	0.63	0.55	(0.08)	7
8	Piedmont Natural Gas	0.75	0.85	0.10	0.50	0.50	(0.00)	8
9	South Jersey Inds.	0.65	0.85	0.20	0.53	0.48	(0.05)	9
10	Southwest Gas Corporation	0.80	0.90	0.10	0.71	0.85	0.14	10
11	UGI Corp.	0.85	0.85	-	0.55	0.54	(0.01)	11
12	WGL Holdings Inc.	0.80	0.85	0.05	0.65	0.68	0.03	12
13	**Proxy Group Average**	**0.81**	**0.88**	**0.08**	**0.57**	**0.61**	**0.03**	13

[1] Source: Value Line Investment Survey, March 17, 2006.
[2] Source: Value Line Investment Survey, March 14, 2008.
[3] Source: Bloomberg

NEW
REGULATORY
FINANCE

Roger A. Morin, PhD

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the Miller position to recognize that the various tax rates offset some, but not all, the corporate tax advantages of debt. Line (3) adds another refinement to recognize that the corporate tax rate declines with added debt financing as the firm's added interest burden lowers its taxable income and hence its tax rate. Line (5) on the graph, which represents the dominant view of academics, nets the personal and corporate tax effects against the costs of distress. At low levels of debt, the tax effects dominate and lower the cost of capital. As the debt ratio increases, distress costs intensify at an increasing rate and eventually overtake the tax advantages, and the cost of capital increases beyond that point. Point X on the graph shows that the optimal capital structure of the hypothetical company occurs at a debt ratio of 42%.

16.4 Empirical Evidence on Capital Structure

Several researchers have studied the empirical relationship between the cost of capital, capital structure changes, and the value of the firm's securities. Comprehensive and rigorous empirical studies of the relationship between cost of capital and leverage for public utilities, summarized in Patterson (1983), include Modigliani and Miller (1958, 1963), Miller (1977), Brigham and Gordon (1968), Gordon (1974), Robichek, Higgins, and Kinsman (1973), Mehta, Moses, Deschamps, and Walker (1980), Brigham, Shome, and Vinson (1985), and Gapenski (1986). Copeland and Weston (1993) provided a comprehensive summary of the empirical evidence. Although it is not easy in such empirical tests to hold all other relevant factors constant, the evidence partially supports the existence of a tax benefit from leverage and that leverage increases firm value. The evidence also strongly favors a positive relationship between leverage and the cost of equity, which is consistent with the ModiglianiMiller propositions. However, there is still some controversy over the acceptance of the linear formulation in Equations 16-3 and 16-6. Some investigators believe the relationship is curvilinear, others believe it is linear but has a slope less than $R - i$.

In a study of public utility capital structures, Patterson (1983) concluded that firm value rises with leverage and revenue requirements decline at low levels of leverage, and he confirmed the existence of a cost-minimizing capital structure. Whether this optimal capital structure also minimizes revenue requirements depends on the effectiveness of regulation in passing interest tax savings through to ratepayers. Patterson also found that utilities tend to operate at a debt ratio slightly less than the optimal level, in the interest of flexibility and maintaining borrowing reserves.

The empirical effects of leverage on common equity return are summarized in Brigham, Gapenski, and Aberwald (1987). Tables 16-4 and 16-5 show the

TABLE 16-4
EFFECTS OF LEVERAGE ON COMMON EQUITY: EMPIRICAL STUDIES

Study	Result
MM (1958)	115 basis points
MM (1963)	62
Miller (1977)	237
Average	**138**

TABLE 16-5
EFFECTS OF LEVERAGE ON COMMON EQUITY: THEORETICAL STUDIES

Study	Result
Brigham and Gordon (1968)	34 basis points
Gordon (1974)	45
Robichek, Higgins, and Kinsman (1973)	75
Mehta, Moses, Deschamps and Walker (1980)	109
Gapenski (1986)	72
Brigham, Gapenski, and Aberwald (1987)	117
Average	**76**

results of empirical studies and theoretical studies obtained when the debt ratio increases from 40% to 50%. The studies report that equity costs increase anywhere from a low of 34 to a high of 237 basis points when the debt ratio increases from 40% to 50%. The average increase is 138 basis points from the theoretical studies and 76 basis points from the empirical studies, or a range of 7.6 to 13.8 basis points per one percentage increase in the debt ratio. The more recent studies indicate that the upper end of that range is more indicative of the repercussions on equity costs.

Chapter 18 will show the results of a simulation model designed to investigate empirically the appropriate capital structure of a utility company using current market data and industry trends.

16.5 Conclusions

The benefits and costs of using debt, including taxes, agency costs, and distress costs, were identified and quantified by the various models of capital structure. Both the cost of debt and equity were seen to increase steadily with each increment in financial leverage. Despite the rise of both debt and equity costs with increases in the debt ratio, the WACC reaches a minimum as the weight of low-cost debt in the average increases. Beyond this optimal point, the low-cost and tax advantages of debt are outweighed by the rising distress costs,

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504
AVERAGE AUTHORIZED RETURNS ON COMMON EQUITY
NATURAL GAS UTILITIES

Line No.	Year		Average Authorized[1] ROE	Average Authorized[1] Equity %	Southwest Equity %	Equity % Difference	ROE Leverage Adjusted[2] 7.6 Low	ROE Leverage Adjusted[2] 13.8 High	Line No.
	(a)		(b)	(c)	(d)	(e)	(f)	(g)	
1	2006		10.43%	47.43%	40.00%	7.43	10.99%	11.46%	1
2	2007		10.24%	48.37%	45.00%	3.37	10.50%	10.71%	2
3	2008	[3]	10.44%	52.42%	45.00%	7.42	11.00%	11.46%	3

[1] Workpaper No. 21 of Company witness Frank J. Hanley
[2] Based on empirical studies of the effects of leverage on common equity returns (Morin Pages 468-469).
Low = ROE + (Equity % Difference x 7.6 basis points)
High = ROE + (Equity % Difference x 13.8 basis points)
[3] First Quarter 2008

F

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

FRANK J. HANLEY

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Table of Contents Of Prepared Rejoinder Testimony Of FRANK J. HANLEY

Southwest Gas Corporation

Docket No. G-01551A-07-0504

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
<u>FRANK J. HANLEY</u>

I. PURPOSE

Q.1 Please state your name, occupation and business address.

A.1 My name is Frank J. Hanley and I am a Principal and Director of AUS Consultants. My business address is 155 Gaither Drive, Suite A, Mount Laurel, New Jersey 08054.

Q.2 Are you the same Frank J. Hanley who previously submitted direct and rebuttal testimonies in this proceeding?

A.2 Yes, I am.

Q.3 What is the purpose of this testimony?

A.3 The purpose of this testimony is to address certain aspects of the surrebuttal testimonies of Arizona Corporation Commission Staff (Staff) Witness David C. Parcell and Residential Utility Consumer Office (RUCO) Witness William A. Rigsby concerning their comments related to my cost of common equity capital conclusions, the implications of the requested tariff tools including the Requested Decoupling Adjustment Provision (RDAP) and Mr. Parcell's comments related to my testimony regarding fair value rate base cost of capital. This testimony is organized by witness.

Q.4 Have you prepared exhibits in support of this rejoinder testimony?

A.4 Yes. I have prepared seven exhibits which have been marked for identification as Exhibits__(FJH-31) through (FJH-37).

II. SUMMARY

Q.5 Please briefly summarize your rejoinder testimony.

A.5 My testimony will address misstatements made by each witness resulting from misperceptions of my rebuttal testimony and will explain why their recommended common equity capital cost rates are significantly understated. Moreover, I will explain why their contention that a reduction in common equity capital cost rate would be appropriate if the Company's requested tariff tools were approved is incorrect. Also, I respond to Mr. Parcell's comments regarding my fair value rate base rate of return testimony (FVROR).

My testimony will address the following issues related to Staff Witness Parcell:

- I will explain why Mr. Parcell's comment regarding this Commission's awarded rate of return on common equity capital of 9.50 percent in Southwest's last rate proceeding, Decision No. 68487 dated February 23, 2006, is incorrect when he states, "Mr. Hanley's current recommendation recognizes neither the Commission's 9.5 percent ROE authorization for SWG in 2006 nor the decline in ROE since that time."
- I will show that Mr. Parcell's perception as to why the Company requests a larger increment to its cost of common equity capital is misguided.
- I will explain why Mr. Parcell's belief that the Commission is not obligated to "again use a hypothetical capital structure…" is moot.
- I will explain why Mr. Parcell's suggestion of the need to consider a rate reduction because of any "new" rate design mechanisms is incorrect. In addition, I will explain why, if the Company's requested rate design proposals are not adopted by this

Commission, the cost rate of common equity capital should be increased to reflect Southwest's added risk vis-à-vis the proxy gas distribution companies (LDCs).

- I will explain why Mr. Parcell's suggestion that I claim that the Company's risk "has increased dramatically" over the last 11 months is incorrect. Rather, it is the investors' required cost rate which has increased.
- I will explain why Mr. Parcell's perception of my rebuttal testimony at page 4, lines 19-21 and page 5, lines 2 and 3 is incorrect. Moreover, I will explain that his belief that Southwest's lower "security ratings" are directly linked to lower equity ratios is erroneous.
- I will explain why Mr. Parcell's criticisms of my application of cost of common equity capital methodologies are invalid as is his response to my criticism of his reliance upon the geometric mean for cost of capital purposes.
- I will explain why Mr. Parcell's advocacy of a zero percentage cost rate relative to the fair value increment of a fair value rate base is improper and also why his disagreement with my recommendation of a 2.05 percent rate of return applicable to the fair value increment is without merit.

My rejoinder testimony will address the following issues related to RUCO Witness Rigsby:

- I will correct a number of misstatements made by Mr. Rigsby resulting from his erroneous interpretations of sections of my rebuttal testimony.
- I will explain why Mr. Rigsby's suggestion that Southwest's outlook is actually quite positive and any upward adjustment to his recommended cost of equity capital is unwarranted and is misguided.

- I will explain why Mr. Rigsby's reliance upon a range of market risk premiums of 4.0 percent to 6.0 percent is without merit.
- I will show that Mr. Rigsby's CAPM cost rate is understated by 92 basis points.
- I will explain why Mr. Rigsby's presumption that it is correct to use a risk-free rate with a time horizon close to the period of time between rate cases is incorrect.
- I will explain why Mr. Rigsby's contention that a utility's market price should equal its book price over the long run, as well as his comparison of a utility stock being similar to a corporate bond, is incorrect.
- I will point out several significant invalid comparisons made by Mr. Rigsby utilizing his own data.
- As with Mr. Parcell, I explain why Mr. Rigsby's contention that it is proper to also utilize the geometric mean in a CAPM analysis when estimating the cost of capital is incorrect.
- I will show that Mr. Rigsby's belief that survivor bias results in an overstatement of equity risk premium is incorrect.
- I will explain why Mr. Rigsby's contention that application of the ECAPM model using adjusted betas is unfounded.
- I will explain why Mr. Rigsby's suggestion for a downward adjustment to common equity capital cost rate is without merit, based on his belief that the requested decoupling mechanism would guarantee achieving the authorized rate of return.

III. STAFF WITNESS PARCELL

Q.6 At pages 2 and 3 of his surrebuttal testimony, Mr. Parcell puts forth his reasoning as to why your recommended common equity capital cost rate should not be adopted. He states that you neither recognize the Commission's 9.5 percent ROE authorization in 2006 nor the decline in ROE since that time. Are his assertions correct?

A.6 No. I recognize that the awarded common equity capital cost rate in Decision No. 68487 of 9.50 percent was inadequate, especially without tariff tools that accommodate changes in weather as well as declining usage per customer. Without such tariff tools, the Company has little opportunity to earn any authorized ROE. The Company's inability to earn its authorized ROE in the Arizona jurisdiction is exemplified on Exhibit__(FJH-1), Sheet 5 of 5, which shows that during the ten years ended 2006, the Company earned only an average of 5.72 percent on its Arizona jurisdictional common equity capital, which is in stark contrast to the 11.83 percent earned by the proxy group of eight LDCs over the same period of time. Also, on the same Sheet 5 of Exhibit__(FJH-1), I show that the average yield on Baa rated public utility bonds of 7.13 percent during that period of time was greater than the average earned ROE of 5.72 percent on the Arizona jurisdictional common equity capital.

Mr. Parcell seems to suggest that just because his recommended 10.00 percent common equity capital cost rate is greater than the 9.50 percent awarded in Decision No. 68487, he has adequately recognized the cost rate necessary for common equity capital investment in Southwest's Arizona jurisdiction. He has not.

As a benchmark from which to measure whose recommendation more adequately recognizes the necessary cost rate for Southwest using data more current than in Decision No. 68487, i.e., Mr. Parcell's or mine, I observed this Commission's Decision No. 69663 dated June 28, 2007 re: Arizona Public Service Company (APS), a case in which Mr. Parcell was a witness for Staff. I prepared Exhibit__(FJH-31), which consists of 11 Sheets. On Sheet 1, I show a comparison between Southwest and APS as to bond ratings, S&P's business and financial profiles as well as the spread between 20-year U.S. Treasury Bond yields versus A and Baa rated utility bond yields. Sheets 2 through 11 contain the cover sheet of Decision No. 69663 and the cost of capital section of the Decision. Sheet 11 of 11 shows that the Commission awarded a 10.75 percent common equity capital cost rate relative to a common equity ratio of 54.5 percent. Sheet 1 shows that there has been a relative increase in the risk on lower rated utility bond yields by a virtual doubling of the spread over the 20-year Treasury Bonds for utility bonds rated Baa. Note that Southwest has an S&P bond rating of BBB- as does APS. Each had the same BBB- rating prior to Decision No. 69663. Currently, as well as prior to the APS decision, Southwest's Moody's bond rating has been Baa3, while APS has had a slightly better rating by Moody's of Baa2. Also note on Sheet 1 of Exhibit__(FJH-31), that both Southwest and APS have similar business and financial profiles, i.e., strong business profile as well as an aggressive financial profile. Note also that there has been an increase of approximately 26 basis points in the yield spread between A rated utility bonds and Baa rated utility bonds; meaning that the more risky Baa rated debt has become even more costly.

It is reasonable to assume that the cost rate of common equity capital would increase by a similar magnitude because the bond rating process is comprehensive and reflects all diversifiable business and financial risks. Thus, if we take the 10.75

percent awarded to APS and add approximately 25 basis points to reflect the increased risk related to the lower credit quality, as opposed to an increase in the risk of the entity itself, an approximate 11.00 percent common equity capital cost rate is indicated. I submit that my recommendation is substantially more accurate than is Mr. Parcell's, and indeed for that matter, the recommendation of RUCO Witness Rigsby.

Q.7 At pages 4-5 of his testimony of his surrebuttal testimony, Mr. Parcell suggests that your criticism of his allowance of 0.1 percent "to recognize SWG's lower common equity ratio is 'grossly inadequate' is without merit". Is his reasoning sound?

A.7 No, his reasoning is erroneous. It should be pointed out that at page 4, lines 12-16 of my rebuttal testimony, I stated that his allowance of 0.1 percent was not adequate to recognize Southwest's lower common equity ratio *and significantly lower debt ratings*. The need for an adequate adjustment to recognize the relative risk between the proxy LDCs and Southwest should be reflective of much more than just "a slightly lower equity ratio". Consistent with the basic principle of finance, reward, indeed the opportunity to earn for a public utility, should be commensurate with its risk. Evidence of the gross inadequacy of the award in Southwest's last rate case is contained in Exhibit__(FJH-32), which consists of 4 sheets. It is a copy of Moody's Investors Service's rating action reports of March 10, 2006 and May 30, 2006. As predicted in the last rate proceeding, if an inadequate cost of capital were awarded without proper tariff tools to afford a reasonable opportunity to earn an ROE award, a downgrading was likely. On Sheet 1 of 4 of Exhibit__(FJH-32), please note that on

March 10, 2006, Moody's placed Southwest's senior debt on <u>negative</u> outlook when it stated:

> Moody's Investors Service places under review for possible downgrade the Baa2/Negative Outlook senior unsecured debt of Southwest Gas Corporation (SWX) *following the company's recent announcement that the Arizona Corporation Commission (ACC) issued a final decision not to adopt the company's proposed rate design for balancing accounts, thereby exposing it to continuing earnings risks associated with weather volatility and declining customer use resulting from the effects of gas conservation.* (italics added for emphasis)

Then on May 30, 2006, little more than 3 months after Decision No. 68487, Moody's downgraded Southwest's debt to Baa3 from Baa2. Moody's stated, as shown on Sheet 3 of Exhibit__(FJH-32):

> *This action concludes the rating review initiated on March 10, 2006. The downgrade reflects the view that the credit measures of SWX remain weak when compared with its gas utility peers in light of its continued rapid growth and sensitivity to decline in earnings on account of warmer than normal weather and the absence of revenue decoupling in Arizona (54 percent of gross margins)...* [W]hile the company was able to obtain some rate relief in recent years, the fact that it is among the fastest growing utilities in the country (5 percent growth) continues to expose it to regulatory lag as rate cases in its key state of Arizona take at least a year to resolve and even then, typically deliver only part of the rate improvement necessary for it to earn its allowed rate of return. (italics added for emphasis)

I submit that in view of the foregoing and Southwest's historically documented gross inability to earn its authorized ROE, is much more related to its significantly lower debt ratings than the "slightly lower common equity ratio" suggested by Mr. Parcell. Clearly, Southwest requires approval of the requested tariff tools in order to have a reasonable opportunity to earn Commission-allowed rates of return on common equity capital.

Q.8 At page 6, lines 5-7 of his surrebuttal testimony, Mr. Parcell suggests that the Commission is not obligated "to again use a hypothetical capital structure with an ever higher equity ratio." Please comment.

A.8 I have been informed by management that as of March 31, 2008, Southwest's actual common equity capital ratio has already slightly exceeded 45%. Therefore, in the instant matter, the idea of using a hypothetical capital structure is moot. The actual capital structure at March 31, 2008 will be supported by Southwest Witness Theodore K. Wood.

Q.9 At the bottom of page 6 through line 2 on page 7 of his surrebuttal testimony, Mr. Parcell disagrees with your assertion that no common equity capital cost rate reduction is warranted should the requested tariff tools be approved by this Commission. Is he correct?

A.9 No. First, I must point out that Mr. Parcell distorts my testimony. I clearly state at page 5, lines 15 and 16 of my rebuttal testimony as follows:

> There is no question that the requested rate design proposals would help to reduce risk by stabilizing revenues and earnings.

Thus, Mr. Parcell's characterization of my testimony is in error when he states that I maintain that the requested rate design proposals should not be construed as risk-reducing to the Company. Rather, the essence of the matter is that overwhelmingly, the proxy LDCs have protections in place that have not been, and are not being, enjoyed by Southwest. For example, I show in Exhibit__(FJH-16), Sheet 2 of 2 (Update of Exhibit__(FJH-1), Sheet 4 of 5) all of the protections enjoyed by the proxy companies, the overwhelming majority of which have revenue normalization decoupling mechanisms and/or weather normalization adjustment clauses or other weather innovative rate designs in place. In essence, as shown graphically on Exhibit__(FJH-16), Sheet 1 of 2, about 7/8 of the proxy companies enjoy protections that have not been available to Southwest in its Arizona jurisdiction.

Mr. Parcell is incorrect when he suggests "we need to consider the extent to which any new rate design mechanisms are risk reducing to SWG in relation to its previous position." This proposition is incorrect. Ratemaking is prospective. The cost of capital is prospective. On a going-forward basis, the proxy companies from which a common equity capital cost rate is established, or will be established by this Commission, overwhelmingly have such protections. Thus, the risk reduction related thereto is already subsumed in the market prices and hence in the common equity capital cost rate derived therefrom. Consequently, if the requested tariff tools are not approved by this Commission, the requested rate of return on common equity capital should actually be *increased.*

Q.10 Are you able to provide any quantification of the extent to which the common equity capital cost rate should be increased if the requested tariff tools are not approved by this Commission?

A.10 Yes. Exhibit__(FJH-33) is a copy of the response by the Company to a Staff data request STF-2-14 dated December 19, 2007. The request was to indicate the degree to which Southwest's common equity capital cost rate would have to be adjusted upward if its rate design proposals are not approved by the Commission in this proceeding. As shown, the estimates ranged between 28 and 35 basis points. Even using the more conservative estimate of 28 basis points and with approximately 7/8 of the proxy companies having such protections in place would indicate, on a rounded basis, an upward adjustment of about 25 basis points, 0.25 percent. Such an estimate is consistent with estimates I have formulated in similar matters over the years. Thus, I believe that the common equity capital cost rate which should be allowed if the requested tariff tools are not approved is 11.50 percent (11.25 percent + 0.25 percent).

Q.11 Please comment on Mr. Parcell's surrebuttal testimony at page 6, wherein he suggests that it is your testimony that the risk of Southwest has increased dramatically over the past 11 months.

A.11 Mr. Parcell's statement is an entirely inaccurate description of my testimony. I have in no way suggested that Southwest's risk has increased dramatically in the last 11 months. Indeed, Southwest's risk is essentially the same as it has been in the past 11 months but does not reflect the May 30, *2006* Moody's downgrading discussed supra. Rather, investors' required returns for assuming *greater relative risk* vis-à-vis more secure debt and equity investments has increased. When times become more difficult and investor concerns about assuming the greater risk associated with the weaker investment vis-à-vis stronger investments, they require a greater rate of return for assuming the same level of risk than they did previously. Mr. Parcell would have this Commission ignore investors' assessment of risk, which is contrary to the basic financial principle of reward commensurate with risk assumed. Risk perception is not a constant thing. It is relative and changes over time and market conditions must not be disregarded. As discussed supra in connection with Exhibit__(FJH-31) at Sheet 1 of 11, the cost rate of capital for utilities which have the more risky debt in the Baa rated category has increased at a greater rate than it has for utilities with debt rated in the less risky A category. This means that the cost rate of capital for Southwest has also increased.

Q.12 At the bottom of page 7 and the top of page 8 of his surrebuttal testimony, Mr. Parcell addresses your rebuttal testimony at page 4, lines 19-21 and page 5, lines 2 and 3. Are his observations accurate?

A.12 No. He states that he believes the Company's lower debt security ratings have been directly linked to the lower equity ratios. As I have addressed above, debt security ratings have been linked to much more. I do not claim that historically the lower equity ratio was not a factor, but a major factor has been the Company's inability to cope with the vagaries of weather and declining per customer usage. This was demonstrated, <u>supra</u> related to the Moody's 2006 downgrading of Southwest's senior debt capital as a direct result of this Commission's Decision No. 68487 on February 23, 2006. Mr. Parcell also states that the Company's past financial strategy has impacted its ratings, which is true. For example, one past financial strategy of necessity was avoiding any increase in the common dividend payment for nearly 13 years in order to attempt to bolster its common equity ratio. Had the Company been afforded a reasonable opportunity to earn the awarded rates of return on common equity capital, it is likely that financial strategy would not have been necessary.

Q.13 At page 8 of his surrebuttal testimony, Mr. Parcell states "…there is no justification for 'adjusting' stock-priced based models such as DCF." Did you adjust your DCF results?

A.13 No, I did not.

Q.14 Please comment on Mr. Parcell's response to your disagreement with his position that the CAPM is generally superior to his risk premium method as he posits on page 9 and the top of page 10 of his surrebuttal testimony.

A.14 Mr. Parcell is incorrect. What he refers to as the simple risk premium method reflects all company-specific elements of risk that are reflected in the bond yield utilized which reflects all diversifiable business and financial risks which are incorporated in the bond rating process as can be verified by reference to Exhibit__(FJH-2), Sheets 3 through 9 of 15. In addition, with regard to the equity risk premium portion, I also have utilized beta (which is a major factor in the CAPM) which can be verified by reference to Exhibit__(FJH-29), Sheet 21 of 32 at line No. 8.

As stated at pages 32-33 of my direct testimony, beta, unfortunately, captures only a small percentage of company-specific risk. Mr. Parcell, at page 10, lines 7-8 of his surrebuttal testimony, acknowledges my evidence (shown on Exhibit__(FJH-20), Sheet 1 of 1) that beta only reflects on average about 32% of company-specific risk. Since, by definition, a risk-free rate cannot reflect any company-specific risk and beta only reflects on average 32% of company-specific risk, it does not follow that the CAPM can be superior to the risk premium method when it comes to measuring company-specific risk and hence common equity capital cost rate.

Q.15 At the bottom of page 10 of his surrebuttal testimony, Mr. Parcell takes issue with your claim that he performed two CAPM analyses. Please comment.

A.15 Technically, he may be correct. However, what he did do in estimating the market risk premium is he utilized market returns *and book returns*. The CAPM methodology requires the use of market returns and not book returns.

Q.16 At page 11 of his surrebuttal testimony, Mr. Parcell takes issue with your criticism of his inclusion of geometric mean returns in the determination of equity risk premium. He states that investors have access to both types of returns when they make investment decisions. Is he correct?

A.16 Yes, technically he is correct. However, we must assume under the Efficient Market Hypothesis (EMH) upon which the DCF model and indeed all market-based models are predicated that investors are rational, i.e., they are not stupid. Investors, under the EMH are fully aware of what constitutes risk. Even unsophisticated investors recognize that the greater the level of uncertainty, the greater the risk and the greater the return they demand for incurring the greater risk, a concept consistent with a basic principle of finance. It is very clear that the definition of the riskiness of an asset relates to the likely variability of future returns from an asset and that a common measure of risk is the standard deviation of yearly returns (these concepts are well-established in financial literature, as can be determined by reference to pages 28-29 of my rebuttal testimony). Consequently, when assessing risk in order to make a determination of whether to invest in an asset such as a common stock, it is essential that investors have perceptions into the standard deviation of yearly returns. This indicates that the only relevant mean which can provide such insight is the arithmetic mean.

Q.17 Mr. Parcell also indicates at page 11 of his surrebuttal testimony that large mutual funds show historic performance based on geometric returns as well as Value Line. Does that mean that when attempting to gain insight in order to make an investment in an asset on a prospective basis, keeping in mind that the cost of capital is prospective, that it is appropriate to rely upon geometric mean returns?

A.17 Absolutely not. As I said, investors are rational. They are not stupid. There is no way that they can formulate an opinion about prospective risk by looking at a geometric mean return which relates all past volatility into a constant, which by looking only at that constant (geometric mean), obviates all yearly variability. Hence, they could gain no insight into the standard deviation of yearly returns and therefore no proper insight into risk which is necessary in order to have an idea of the return demanded commensurate with the risk under consideration to be incurred.

Q.18 At the top of page 13 of his surrebuttal testimony, Mr. Parcell refers to the Commission's agreement that geometric returns should also be considered in calculating a Company CAPM in the recent UNS Electric case (Docket No. E-04204A-06-0783). What comment do you have to offer to the Commission relative to its decision in that UNS Electric case?

A.18 With all due respect, I would submit that it is not a good precedent. To establish the cost of common equity capital on a forward-looking basis (as opposed to some interesting constant historical mean), investors know that they must rely upon the arithmetic mean which is the only way they can gain insight into the standard deviation of yearly returns which provides the insight into the risk that they will be incurring if they commit their capital to the investment under consideration. I should note that there are other cost of common equity capital models of which investors are aware, but are not used by this Commission, such as the risk premium method and the ECAPM discussed in the financial literature. In addition, there are other types of models, such as the Arbitrage Pricing Theory that are not considered by this Commission, but of which investors are also aware when making investment decisions. Consequently, the Commission should consider only the arithmetic mean when establishing a common equity capital cost rate to be allowed on a going-forward basis.

Q.19 At page 14, lines 1 through 11 of his surrebuttal testimony, Mr. Parcell criticizes your comparable earnings method. He contends that any experience of unregulated companies "simply misses the point of public utility regulation." Please respond to Mr. Parcell's contention.

A.19 The Hope and Bluefield landmark decisions, in my layperson's opinion, do not specify that they must be public utilities. The decisions simply refer to companies which are similar in risk. Regulation is a substitute for the competition of the marketplace. The DCF methodology is based upon returns on market prices and not on book value. In other words, if an investor expects to earn 10 or 11 percent on market price and the market price differs from book value, the investor is not concerned with the application of his or her desired cost rate relative to the book value, but rather to the market value. In Exhibit__(FJH-22), I show that there is no correlation between the rates of earning on book equity and market-to-book ratios. Moreover, Phillips and Bonbright (see page 24 of my direct testimony), confirm that regulators can influence, but not control, market prices and that utilities should be able to achieve market-to-book ratios consistent with those of unregulated companies.

Q.20 Mr. Parcell suggests at the top of page 15 of his surrebuttal testimony, that you state that his proposed methodology regarding a fair value rate of return has been rejected by the Arizona Appeals Court. Is he correct?

A.20 No. He mischaracterizes my testimony. I say precisely on page 39 at lines 24-25 of my rebuttal testimony:

> Clearly, this methodology is not only illogical, but even worse than the methodology that has already been rejected by the Arizona Appeals Court Decision in Chaparral City Water Company (Appeals No. CA-CC-05-002).

It is very clear from looking at page 39 of my rebuttal testimony that what I refer to is Mr. Parcell's recommendation to include the increment above the original cost rate base (OCRB) as zero cost capital. Based upon Staff's revised rate bases and recommended operating incomes (as summarized on Schedule A, page 1 of 1 accompanying the revised surrebuttal testimony of Staff Witness Ralph C. Smith), the opportunity to earn net operating income is actually less using its revised FVRB and net operating income where the FVRB increment is considered as zero cost capital than it is under its OCRB proposal as follows:

<u>Net Operating Income Under ACC Staff's Revised OCRB</u>

A. OCRB	<u>$1,065,457,617</u>
B. Net Operating Income	<u>$94,366,814</u>

Net Operating Income Based Upon ACC Staff's Revised FVRB
<u>Where the Increment Above OCRB is Considered Zero Cost Capital</u>

C. FVRB	<u>$1,388,609,702</u>
D. Net Operating Income	<u>$94,286,599</u>
Difference in Net Operating Income Under Zero Cost Capital Methodology (C-D Above)	<u>($80,215)</u>

A method such as including the increment above OCRB as zero cost capital which will result in a dollar return $80,215 <u>less</u> than under a strictly OCRB basis is illogical and, in a literal sense, worse than a methodology which previously has been utilized that simply translates the OCRB rate of return to a lower percentage which, when applied to the fair value rate base (FVRB) produces the same dollars of operating income. Consequently, it seems to me that the FVROR adopted by the Commission in the two recent UNS cases was similar to the FVROR which was remanded to the Commission in the Chaparral City Water case.

Q.21 Please comment on Mr. Parcell's disagreement with your recommended rate of return of 2.05 percent on the fair value increment of rate base as improper.

A.21 Mr. Parcell provides absolutely no basis for suggesting that my net of inflation risk-free rate of 2.05 percent is improper to apply to the fair value increment of rate base. Indeed, Mr. Parcell *arbitrarily* suggests that any figure up to 2.50 percent would be acceptable. The basis of my 2.05 percent is not arbitrary, rather it is specific and explicit and fits well within the range acceptable to Mr. Parcell.

IV. RUCO WITNESS WILLIAM A. RIGSBY

Q.22 At page 6 of his surrebuttal testimony, Mr. Rigsby attempts to defend his recommended common equity capital cost rate by responding to your position that his recommendation is too low. How do you respond?

A.22 In responding to Mr. Parcell's testimony, supra, I have shown that, using the APS Decision as a benchmark, that the cost rate would be no less than 11 percent. However, I do not agree that 11.0 percent is the correct cost rate. It should be 11.25 percent if the requested tariff tools are approved and 11.50 percent if the requested tariff tools are not approved. In his comments, Mr. Rigsby suggests that I ignored any results lower than 9.60 percent. I have previously addressed this issue in my rebuttal testimony at page 30 in Question and Answer No. 34. As such, it need not be repeated here.

Q.23 At page 8 of his surrebuttal testimony, Mr. Rigsby contends that the outlook for Southwest is "actually quite favorable". Do you agree?

A.23 No. I have discussed, supra, Mr. Parcell's surrebuttal testimony, the Moody's May 30, 2006 downgrading and the rationale for that downgrading. The rationale for the downgrading is, at this moment in time, still very much a reality. Unless this

Commission approves the requested tariff tools, the major reason for the downgrading will continue to exist. Moreover, despite Mr. Rigsby's attempts to substantiate his claim from the S&P April 24, 2008 Credit Rating report, there is enough indication there to overturn his "quite favorable" conclusion. For example, it is evident from the information contained in lines 33-37 on page 8 of his surrebuttal testimony, that Southwest's cash flow is not adequate. S&P states:

> We could revise the outlook to Stable if financial performance deteriorates from current levels as a result of unfavorable regulatory actions, an increase in leverage, or material reductions in customer usage (either due to weather or efficiency) *without adequate regulatory protections.* (Italics added for emphasis.)

In addition, in Mr. Rigsby's Attachment B at original page 2 (which is an update of Data Request No. STF-2-7), S&P, in describing its rating rationale on April 24, 2008, states:

> *However, we view the ACC regulatory oversight as less supportive of credit than other jurisdictions due to its limitations on purchased-gas cost recoveries and rate design that is solely based on gas throughput. This type of rate design exposes the company to reduced cash flows as volumes decline related to conservation.* Decoupling, and alternate rate design, separates the utility's margins and cash flow from commodity sales and encourages conservation. These mechanisms are currently under consideration as part of the company's most recent rate case. (italics added for emphasis)

In view of the foregoing, the only way that I can conclude that Southwest's outlook is actually quite favorable is with approval of the requested tariff tools, which of course, RUCO opposes.

Q.24 At page 9 of his surrebuttal testimony, Mr. Rigsby discusses a range of market risk premiums of 4.0 percent to 6.0 percent. Do you have any comment regarding his support for that range?

A.24 Yes, I do. He cites the direct testimony of RUCO Consultant Stephen G. Hill in the APS rate case proceeding and includes an excerpt from it in Attachment C to his surrebuttal testimony, at page 46. On page 46 of Attachment C, there is a reference to Ibbotson and Chen. Roger Ibbotson, is the founder of Ibbotson Associates, which is now owned by Morningstar. I have prepared Exhibit__(FJH-34) which is the Morningstar publication, <u>Ibbotson SBBI – 2008 Valuation Yearbook</u>. Please note several important factors on Sheet 2. First, Ibbotson and Chen clearly specify that an arithmetic mean calculation is "most appropriate when discounting future cash flows." They show that the geometric mean through 2007 was 4.24 percent, but when converted to an arithmetic mean, it is 6.23 percent. Ibbotson and Chen state:

> *For use as the expected equity risk premium in either the CAPM or buildup approach, the arithmetic calculation is the relevant number.* (italics added for emphasis)

I believe that this provides further evidence that the arithmetic mean is the only mean to properly consider when estimating future cash flows in determination of the cost rate of common equity capital which is expectational, not retrospective, i.e., historic. Thus, using the arithmetic mean 6.23 percent market risk premium as discussed <u>supra</u> in Mr. Rigsby's CAPM calculations shown at the top of page 12, a 10.65 percent common equity capital cost rate is indicated as follows:

K = 4.61 percent + (0.97 (6.23 percent))

K = 10.65 percent

Such a cost rate is 92 basis points *higher* than Mr. Rigsby's CAPM finding of 9.73 percent.

In addition, I can state that I was also present in Washington, DC on April 19 and 20, 2007 and heard Professor Aswarth Damodaran, Ph.D. when he discussed estimates of market risk premium. Mr. Rigsby fails to mention that Dr. Damodaran stated that he did not follow utilities, had little knowledge about utilities, and could not speculate about a proper level of equity risk premium for utilities. Consequently, in view of the foregoing, and the emphasis of Ibbotson and Chen to utilize arithmetic mean data, any CAPM conclusion less than 10.65 percent is inappropriate. Moreover, using the 6.23 percent market risk premium to check on growth rate as utilized by Mr. Rigsby at lines 12 through 16 on page 14 of his surrebuttal testimony, a growth rate of 6.10 percent results. This produces the same cost rate as the CAPM discussed above, namely, 10.65 percent based upon a dividend yield of 4.55 percent plus a growth rate of 6.10 percent.

Q.25 At the top of page 15 of his surrebuttal testimony, Mr. Rigsby takes issue with your use of a 30-year U.S. Treasury Note as a proxy for a risk-free rate of return. He reasons a shorter period of time should be used, one that more closely approximates the time between utility rate cases. Is his reasoning supported by financial literature and/or logical?

A.25 It is neither. As I have shown by the financial literature citations on page 27 of my rebuttal testimony, the use of short period proxies as a risk-free rate in a CAPM for a going concern is incorrect and the use of very short periods such as 30- or 90-day Treasury Bill rates are empirically inadequate and theoretically suspect. Moreover, I believe there is an inconsistency in Mr. Rigsby's logic since he uses the sustainable growth method in his DCF methodology. How,can one advocate an interminably long future period of time for a proper growth rate in a DCF calculation, while at the same time, argue for a substantially short period of time such as a 30- or 90-day risk-free rate in a CAPM calculation, when both are used to estimate the long-term cost of capital for a price regulated public utility?

Q.26 At pages 16-17 of his surrebuttal testimony, Mr. Rigsby attempts to explain why he believes that if regulators allow a rate of return equal to the cost of capital, that the market-to-book ratio will tend toward 1.0 times. He footnotes a reference to Chapter 10 of Roger A. Morin's text, <u>Regulatory Finance – Utilities' Cost of Capital</u>. Have you had an opportunity to review Professor Morin's latest book entitled <u>New Regulatory Finance</u> and his discussion related to market-to-book ratios in the regulatory process?

A.26 Yes, I have. I have prepared Exhibit__(FJH-35) which consists of 6 sheets from Morin's book. Sheets 3 through 6 contain his discussion related to market-to-book ratios in the regulatory process. Of course, Morin's entire discussion is contained therein, but I would like to highlight below some of what I believe are his more salient comments as follows:

> The inference that M/B ratios are relevant and that regulators should set an ROE so as to produce an M/B of 1.0 is misguided. The stock price is set by the market, not by regulators. …Depressed or inflated M/B ratios are to a considerable degree a function of forces outside the control of regulators…
>
> …M/B ratios are determined by the marketplace, and utilities cannot be expected to compete for and attract capital in an environment where industrials are commanding M/B ratios well in excess of 1.0, while regulation reduces their M/B ratios toward 1.0.
>
> …Rate of return regulation is fundamentally a surrogate for competition. The fundamental goal of regulation should be to set the expected economic profit for a public utility equal to the level of profits expected to be earned by firms of comparable risk, in short to emulate the competitive result.
>
> …Competitive industrials of comparable risk to utilities have consistently been able to maintain the real value of their assets in

> excess of book value, consistent with the notion that, under competition, the Q-ratio will tend to 1.00 and not the M/B ratio.
>
> ...This suggests that a fair and reasonable price for a utility's common stock is one that produces equality between the market price of its common equity and the replacement cost of its physical assets. The latter circumstance will not necessarily occur when the M/B ratio is 1.0. ...It is quite plausible and likely that M/B ratios will exceed one if inflation increases the replacement cost of a firm's assets at a faster pace than historical cost (book equity).
>
> ...Are we to conclude that regulators have been systematically misguided all across the United States for all these years by awarding overgenerous returns, or are we to conclude that M/B ratios are largely immaterial in the context of ratemaking? The latter is more likely.

The foregoing by Morin, upon whom Rigsby relies, as well as the comments of Phillips and Bonbright as set forth on page 24 of my direct testimony, demonstrates the fallacy of Mr. Rigsby's argument.

Q.27 Please comment upon Mr. Rigsby's testimony at the bottom of page 17 and the top of page 18 of his surrebuttal testimony wherein he compares investment in a utility common stock with that of a bond.

A.27 What Mr. Rigsby seems to lose sight of is that a bond has a specified return and a specified maturity. Moreover, a corporate bond, depending upon its type, has either first claim on the assets of the issuing entity or certainly is much higher in the pecking order than common stock investors who are last in line on any claims on a company's assets and earnings. Moreover, investors care very much about the market-to-book ratio of an enterprise because it is a sign of financial strength. The stronger the market-to-book ratio, the stronger the indication of the financial strength of the enterprise. Brealey and Myers state that market value ratios show how the firm is valued by investors.[1] Consequently, investors care very much about market-to-book ratios.

Q.28 In your summary of this testimony, you indicated that Mr. Rigsby has made several invalid comparisons utilizing his own data. Would you please discuss those invalid comparisons?

A.28 Yes, of course. At page 18, lines 9-18 of his surrebuttal testimony, Mr. Rigsby discusses a CAPM calculated common equity capital cost rate which he performed on page 15 of 8.05 percent. He then compares that cost rate of 8.05 percent with the weighted average cost of capital (WACC) of 8.83 percent that he recommends. Of course, it is not valid to compare a WACC with a cost rate of common equity capital since the latter, on a weighted basis, represents only a portion of the WACC. Another incorrect comparison is based upon the information shown on page 24 of his surrebuttal testimony where he refers to a deduction to "the authorized rate of return" in a Baltimore Gas & Electric case. He then suggests how that deduction would lower his recommended cost of capital, or WACC, by 50 basis points from 8.83 percent to 8.33 percent. If Mr. Rigsby had carefully read Attachment E to his surrebuttal testimony, which was the source of his statement, he would see that, at the top of original page 12, the reduction to which he refers was in the authorized rate of return on common equity capital and not the overall cost of capital, or WACC. Of course, I have discussed <u>supra</u> why any reduction to the rate of return, whether the cost rate of common equity capital or WACC, on a forward-looking basis is incorrect

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[1] Richard A. Brealey and Stewart C. Myers, <u>Principles of Corporate Finance</u>, Fifth Edition, McGraw-Hill Companies, Inc., page 766.

and would be punitive because the comparable risk proxy companies enjoy the benefits of such tools.

Q.29 Please comment upon Mr. Rigsby's response to your criticism regarding his use of the geometric mean as set forth at page 18, line 22 through page 19, line 9 of his surrebuttal testimony.

A.29 Mr. Rigsby indicates that both means are published by Morningstar. However, he ignores what Morningstar says, that when discounting future cash flows for cost of capital purposes, it is only the arithmetic mean that is appropriate as discussed <u>supra</u> and in connection with Exhibit__(FJH-34) at Sheet 2 of 3 and also in Exhibit__(FJH-11), Sheets 2 through 4. Thus, the fact that they publish both the geometric and the arithmetic means is irrelevant when discounting future cash flows when estimating the cost of capital. As discussed <u>supra</u>, in response to Mr. Parcell, investors are not stupid and are aware of the distinction or relevance of each type of mean. Mr. Rigsby's statements at lines 5 through 9 on page 19 of his surrebuttal testimony actually confirm that it is the arithmetic mean that is appropriate. Mr. Rigsby points out that the geometric mean compounds the value of an investment and obviates the ups and downs which have occurred over a past period of time. That is why it is shown, because it represents a *constant* rate of growth over an historical time period.

Q.30 Please address the illustrated differences between the geometric and arithmetic means as set forth by Mr. Rigsby at page 19, line 11 through page 20, line 24 of his surrebuttal testimony.

A.30 Mr. Rigsby's illustrations actually demonstrate why the geometric mean is not appropriate when estimating the cost of capital. In the example set forth at lines 13 through 20 on page 19 and illustrated on page 20 of his surrebuttal testimony, if all one had was the geometric mean, one would think that the potential for loss is very negligible as indicated by the -2.02 percent. The geometric mean provides no indication at all that during the period held (2 years), the stock was extremely volatile with a potential for a 20 percent gain in one year and a 20 percent loss in the following year. As seen in Mr. Rigsby's illustrations on page 20, the only factors taken into account in the geometric mean are the beginning and terminal values and not the individual values which provide the insight into variance/standard deviation of returns.

Q.31 At page 21, line 12 through page 22, line 8 of his surrebuttal testimony , Mr. Rigsby discusses several factors which he believes affect the relevance of the arithmetic mean. He suggests that year-to-year returns are "actually correlated". Is this proposition correct?

A.31 No, it is not. At Sheets 5 and 6 of Exhibit__(FJH-11), Morningstar discusses in detail and empirically demonstrates that the serial correlation of large company stock total returns and equity risk premiums are random,.. Morningstar states on Sheet 6 of Exhibit__(FJH-11):

> The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values.

Q.32 At the top of page 22 of his surrebuttal testimony, Mr. Rigsby discusses what is characterized as "survivor bias". He goes on to state, "the Morningstar historical return series does not measure the failures, of which there are many. Therefore, the return expectations in the future are likely to be lower than the Morningstar historical averages." Does his contention have any merit?

A.32 No. Morningstar has addressed this issue of survivorship. I have prepared Exhibit__(FJH-36), which consists of three sheets from its 2008 Valuation Yearbook. Sheets 2 and 3 specifically address the survivorship issue. Morningstar comments upon the Goetzmann and Jorion study which looked at the question of survivorship based on returns from a number of world equity markets over the past century. Morningstar indicates that while survivorship bias evidence may be compelling on a world-wide basis, one can question its relevance to a purely U.S. analysis. It also points out that the non-U.S. equity risk premium was found to contain significantly more survivorship bias.

In short, it seems that survivorship bias is a moot issue regarding the U.S. equities market.

Q.33 At the bottom of page 22 and the top of page 23 of his surrebuttal testimony, Mr. Rigsby contends that using adjusted Value Line betas results in a double-count. Is his contention correct?

A.33 No. His contention is erroneous. At page 31 of my rebuttal testimony and in Exhibit__(FJH-21) and Exhibit__(FJH-23), particularly in Footnote 12 on Sheet 5 of 6, Morin and Brigham make it clear that:

- The ECAPM is a return adjustment.
- The Security Market Line (SML) is a line which reflects the degree of risk aversion.
- Beta does represent the slope of a line, but it is not the SML. Specifically, Brigham states in Footnote 12 on Sheet 5 of Exhibit__(FJH-23):

> Students sometimes confuse beta with the slope of the SML. This is a mistake. As we saw earlier in connection with Figure 6-8 and as is developed further in Appendix 6A, beta

> does represent the slope of a line, but not the Security Market Line.

In addition, Brigham and Gapenski in the same text, in Appendix 6A entitled, "Calculating Beta Coefficients", demonstrate the calculations where it can be readily seen that the beta, which accounts for regression bias and is not a return adjustment, is indeed based on the slope of a different line. I have prepared Exhibit__(FJH-37) which consists of 5 Sheets. Sheet 4 shows a graphical depiction of the calculation of beta and it is clearly not the Security Market Line. As Morin explains:

> The ECAPM is a formal recognition that the observed risk-return trade-off is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprise two separate features of asset pricing.

In view of the foregoing, Mr. Rigsby's contention is unfounded and should be disregarded.

Q.34 At page 23 of his surrebuttal testimony, Mr. Rigsby, in response to the question at lines 16-18, indicates that he agrees with you that this is simply a matter of common sense. Is his use of your words that "this is a matter of common sense" taken in context?

A.34 No. Reference to page 31, line 28 through page 32, line 9 of my rebuttal testimony indicates that my common sense comment related to Mr. Rigsby's contention that the implementation of the Company's requested decoupling adjustment provision (RDAP) would "essentially provide SWG with a guaranteed return on the Company's invested capital…" I believe strongly that the evidence presented at pages 32-34 of my rebuttal testimony and contained in Exhibits__(FJH-26), (FJH-27), and (FJH-28) affirm my assessment of his contention. Moreover, please note that the evidence presented at pages 32-34 of my rebuttal testimony and in Exhibits__(FJH-26) through (FJH-28) remains unanswered

Moreover, Mr. Rigsby's comments that common sense says if revenues are stabilized that risks are clearly shifted, etc., while correct, miss the point. The point is that the proxy LDCs relied upon by all witnesses in this proceeding overwhelmingly have been and continue to enjoy protections against the vagaries of weather and declining per customer usage. As discussed <u>supra</u> regarding Mr. Parcell's surrebuttal testimony, investors are aware of those risk-reducing elements. Thus, a common equity capital cost rate established therefrom already reflects said reduction. If the Company's requested tariff tools are approved by this Commission, it would be a punitive action to make a reduction to common equity capital cost rate as it would place Southwest at a competitive disadvantage right out of the starting gate vis-à-vis the proxy LDCs.

Q.35 Does this conclude your rejoinder testimony?

A.35 Yes, it does.

BEFORE THE

ARIZONA CORPORATION COMMISSION

EXHIBITS
(FJH-31) THROUGH (FJH-37)

TO ACCOMPANY THE

REJOINDER TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

CONCERNING

COMMON EQUITY COST RATE

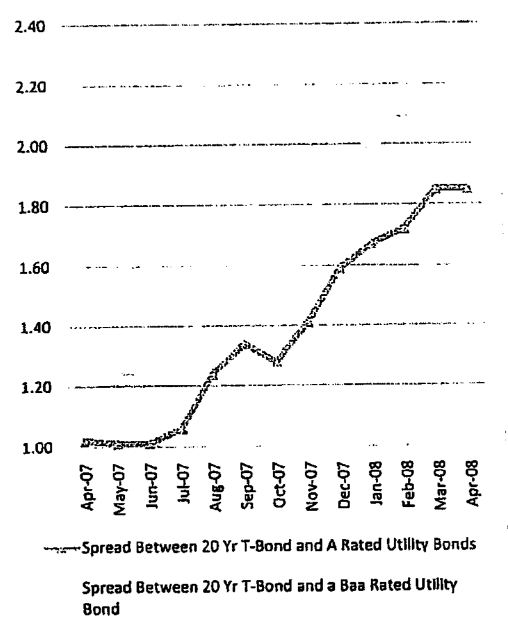
RE: SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

Southwest Gas Corporation
Bond Yield Spreads Compared to 20 yr US Treasury Bond
Since APS Case Order in Ime 2007

	Spread Between 20 Yr T-Bond and A Rated Utility Bonds	Spread Between 20 Yr T-Bond and a Baa Rated Utility Bond	Spread Between an A Rated Utility Bond and a Baa Utility Bond
Apr-07	1.02	1.29	0.27
May-07	1.01	1.25	0.24
Jun-07	1.01	1.25	0.24
Jul-07	1.06	1.30	0.24
Aug-07	1.24	1.51	0.27
Sep-07	1.34	1.61	0.27
Oct-07	1.28	1.53	0.25
Nov-07	1.41	1.71	0.30
Dec-07	1.59	1.94	0.35
Jan-08	1.67	2.00	0.33
Feb-08	1.72	2.11	0.39
Mar-08	1.85	2.32	0.47
Apr-08	1.85	2.38	0.53

Spreads between A and Baa Rated Public Utility Bonds Compared to 20 yr T-Bonds



	Southwest Gas Corporation Jun-07	Southwest Gas Corporation May-08	Arizona Public Service Jun-07	Arizona Public Service May-08
S&P Rating	BBB-	BBB-	BBB-	BBB-
Moody's Rating	Baa3	Baa3	Baa2	Baa2
Business Profile	4	Strong	6	Strong
Financial Profile	4	Aggressive	6	Aggressive

Sources of Information:

Federal Reserve Statistical Release H.15. Historical
Mergent Bond Record, May 2008 Volume 75, No. 5
Moody's Investor Services
Standard & Poor's Ratings Direct, May 7, 2008 U.S. Regulated Electric Utilities, Strongest to Weakest
Standard & Poor's Ratings Direct, May 8, 2008 U.S. Natural Gas Distributors and Intergreated Gas Companies, Strongest to Weakest

0000074350

BEFORE THE ARIZONA CORPORATION CC

Arizona Corporation Commission
DOCKETED
JUN 28 2007
DOCKETED BY nR

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827 DECISION NO. 69663 **OPINION AND ORDER**

DATES OF HEARING: October 5, (Pre-Hearing Conference), December 6, (Procedural Conference), October 10, 11, 12, 13, 16, 19, 20, 23, 24, 25, 26, 30, November 3, 6, 7, 8, 9, 20, 27, 28, 30, December 1, 4, 5, 6, 11, 12, 13, and 15, 2006.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Lyn Farmer

IN ATTENDANCE:
Jeff Hatch-Miller, Chairman
Mike Gleason, Commissioner
Kristin K. Mayes, Commissioner
William A. Mundell, Commissioner
Barry Wong, Commissioner

APPEARANCES: Mr. Thomas L. Mumaw, PINNACLE WEST CAPITAL CORPORATION, Ms. Deborah R. Scott, SNELL & WILMER, LLP, and Mr. William Maledon, OSBORN MALEDON, P.A., on behalf of Arizona Public Service

Company;

Mr. Scott Wakefield, Chief Counsel, and Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

Mr. Bill Murphy, MURPHY CONSULTING, on behalf of Distributed Energy Association of Arizona;

Ms. Laura Sixkiller, ROSHKA, DeWULF & PATTEN, PLC, on behalf of UniSource Energy Services;

Mr. Timothy Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, on behalf of Southwest Energy Efficiency Project and Western Resource Advocates;

Mr. Gary L. Nakarado, on behalf of Vote Solar and Arizona Solar Energy Industry;

Mr. Michael Grant, GALLAGHER & KENNEDY, P.A., on behalf of Arizona Utility Investors Association;

Mr. Kurt J. Boehm, BOEHM, JURTZ & LOWRY, on behalf of the Kroger Company;

Mr. C. Webb Crockett, FENNEMORE CRAIG, P.C., on behalf of the Arizonans for Electric Choice and Competition and Phelps Dodge Mining Company;

Lieutenant Colonel Karen S. White, on behalf of the Federal Executive Agencies;

Mr. Jay L Moyes, MOYES STOREY, on behalf of Az-Ag Group;

Mr. Andrew W. Bettwy, on behalf of Southwest Gas Corporation;

Mr. Douglas V. Fant, on behalf of the Interwest Energy Alliance and Distributed Energy Association of Arizona;

Mr. Lawrence V. Robertson, Jr., MUNGER CHADWICK, on behalf of Southwestern Power Group II, LLC, Bowie Power Station, LLC and Mesquite Power, LLC.

Mr. Christopher Kempley, Chief Counsel, Ms. Janet F. Wagner, Senior Staff Attorney, and Mr. Charles Hains, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

were authorized by Decision No. 67744. (APS Initial Brief, Exhibit 5, Schedule C-2, column 31).

z. Federal and State Income Tax

There is no dispute between the Company and Staff as to the Company's additional adjustment to the Company's original cost of service income tax expense to reflect a top-down calculation including permanent tax items to reduce test year income tax expense by $4,588,000. (APS Initial Brief, Exhibit 5, Schedule C-2, column 34).

3. Adjustments dependent upon final levels

a. Income Tax/ Interest Synchronization

There is no dispute as to the methodology to be used to reflect the synchronization of interest expense using the adjusted September 30, 2005 test year capital structure and the cost of long-term debt, as well as the use of the statutory income tax rate. Using the OCRB and cost of debt as determined herein, the appropriate adjustment is a $2,379,000 increase to test year income tax expense.[29]

b. Generation Production Income Tax Deduction

This adjustment reflects the tax benefits associated with the American Jobs Creation Act and reflects the cost of capital as determined herein. The appropriate adjustment is ($2,915,000).

C. **Summary of Net Operating Income**

Based on the foregoing, the following statement details the adjusted test year net operating income for ratemaking purposes:

Operating Income Summary

Operating Revenues	$2,609,930,000
Operating Expenses (per APS)	$2,415,481,000
Total Adjusted Operating Expenses	$2,439,648,000
Net Operating Income	**$ 170,282,000**

VII. COST OF CAPITAL

The cost of capital compensates investors for the use of their capital to finance the plant and equipment necessary to provide utility service. There are generally three steps to determining the appropriate cost of capital in a rate case proceeding: establishing the appropriate capital structure;

[29] Reflecting a $6,093,000 decrease to interest expense.

determining the appropriate cost of the utility's debt; and estimating a reasonable cost of equity for the utility.

A. **Capital Structure**

In estimating the cost of capital for a utility, the appropriate capital structure of the company must be determined. APS proposed using a capital structure consisting of 45.5 percent debt and 54.5 percent equity. Staff accepted APS' proposed capital structure, and RUCO recommended a capital structure of 50 percent debt and 50 percent equity.

RUCO recommends that the Commission adopt its proposed capital structure because it is similar to that of APS' parent and is therefore sound for the lower-risk utility; it has more common equity than APS has utilized in the past, which will provide additional financial security for the Company during its construction period; and it will provide a better balance of the interests of ratepayers and stockholders because it is a more economically efficient and less costly capitalization than requested by the Company.

The capital structure recommended by APS and accepted by Staff is the Company's adjusted September 30, 2005 capital structure of 45.5 percent long-term debt and 54.5 percent common equity. In response to RUCO's recommendation, APS argues that RUCO's witness improperly included short-term debt and financial ratios of companies with "junk" credit ratings, which distort the results. APS also believes that use of RUCO's proposed capital structure would result in a financially weaker APS with non-investment grade credit metrics.

We agree with APS and Staff that a 46/54 percent debt/equity capital structure is appropriate for determining cost of capital in this proceeding. It is the capital structure existing at the end of the test year[30] and will continue to support the Company's existing financial profile and maintain its investment grade profile.

B. **Cost of Debt**

All parties agree that a cost of long-term debt of 5.41 percent is the appropriate cost of debt.

[30] Staff Exhibit No. 8, Parcell Direct, p. 3.

C. Cost of Equity

APS, Staff, and RUCO all presented expert witnesses to evaluate cost of equity. Their recommendations are as follows:

Party	Range	Recommendation
APS - Avera	11.00 - 12.00%	11.50%
Staff - Parcell	9.50 - 10.75%	10.25 %
RUCO - Hill	9.25 - 9.75%	9.25%

The cost of equity cannot be observed directly because it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. The cost of equity must be estimated by analyzing information about capital market conditions, assessing company specific risks, and using various qualitative methods to find investors' required rate of return. Because APS is not a publicly traded company and because the cost of capital is an opportunity cost and is prospective, the cost of equity must be estimated. All of the expert witnesses agreed that no one single method or model should be used to determine a utility's cost of equity. All witnesses testified as to their understanding of the economic, financial, and legal principles that underlie the concept of a fair rate of return for a public utility.

All the expert witnesses conducted a Discounted Cash Flow Analysis ("DCF"). It is one of the oldest, as well as the most commonly used models for estimating the cost of common equity for public utilities.[31] DCF models are used to essentially replicate the market valuation process that sets the price that investors are willing to pay for a share of a company's stock. The DCF model is based upon the "dividend discount model" of financial theory, which maintains that the price of a commodity or security is the discounted present value of all future cash flows. The constant growth DCF model recognizes that the return expected or required by investors consists of two factors: the dividend yield (current income) and growth (future income).

APS' witness, Dr. Avera, applied the DCF model, risk premium methods, and the comparable earnings method to a proxy group of other electric utilities operating in the western United States.

[31] The Commission has long used the DCF model, as was indicated in APS' 1986 rate case: "As has been stated by the Commission on previous occasions, market measures of common equity costs are generally preferable to comparative analyses. Although both require the exercise of considerable subjective judgment, methodologies such as DCF entail fewer unproved (and sometimes unprovable) assumptions." Decision No. 55228 (October 9, 1986).

Dr. Avera's DCF analysis resulted in a cost of equity of 9 percent. Dr. Avera did not believe that his constant growth DCF results should be used as a reasonable cost of equity for APS, stating that it is a "blunt tool" that should never be used exclusively. He testified that the short-term growth rates used with the DCF model may be overly cautious, and that therefore, the DCF does not necessarily capture investors' long-term expectations for the industry. Dr. Avera also employed a risk premium analysis where the cost of equity is estimated by determining the additional return investors require to forego the relative safety of bonds and accept the greater risks associated with common stock, and then adding this "equity risk premium" to the current yield on bonds. He based his estimates of equity risk premiums on: surveys of previously authorized rates of return on common equity (10.7 - 11.4 percent); realized rates of return (9.8 - 11.0 percent); and alternative applications of the Capital Asset Pricing Model ("CAPM") (Forward-looking: 12.5 - 12.6 percent; and Historical: 10.9 - 11.9 percent). Dr. Avera also evaluated cost of equity using the Comparable Earnings Method ("CEM"). This method refers to rates of return available from alternative investments of comparable risk. In his direct testimony, Dr. Avera testified that the most recent edition of *Value Line* reports that its analysts expect an average rate of return on common equity for the electric utility industry of 10.5 percent in 2005 and 2006, and increasing to 11.0 percent over its three-to-five year forecast horizon. When Dr. Avera used a proxy group from the unregulated sector of the economy, the expectations averaged 15.7 percent. He concluded that the comparable earnings approach implied a fair rate of return on equity of 11.0 to 12.0 percent.

Dr. Avera concluded, based upon the results of his quantitative analyses and his assessment of the relative strengths and weaknesses inherent in each model, that the cost of equity for the electric proxy group ranges between 10.8 percent and 11.8 percent. He also added a "flotation cost" for the costs associated with issuing common stock of 20 basis points, for a range of equity of 11.0 percent to 12.0 percent, with a midpoint of 11.5 percent.

Dr. Avera criticized Staff's witness Parcell's use of the "spot dividend yield" instead of the end-of-period yield, which Dr. Avera says understates the cost of equity and leads to a "downward-bias" result. Dr. Avera testified that constant growth assumptions are not likely to be representative of real-world circumstances for utilities and he employed a multi-stage form of the DCF using Mr.

Parcell's reference group and calculated a 10.8 percent cost of equity.[32]

Staff's witness, Mr. Parcell, employed three recognized methodologies to estimate the cost of equity for APS. He used the DCF, the CAPM, and the CEM. He applied each of these methodologies to two proxy groups: his group of comparison electric utilities with similar operating and risk characteristics to APS and Pinnacle West; and to Dr. Avera's proxy electric companies. Mr. Parcell used five indicators of growth in his DCF analysis, including: five year earnings retention, or fundamental growth; average historic growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"); 2006-2010 projections of earnings retention growth; 2004-2010 projections of EPS, DPS, and BVPS; and 5-year projections of EPS growth. As a result of his DCF analysis, Mr. Parcell concluded the current DCF cost of equity for APS is between 9 and 10 percent. Mr. Parcell explained that the CAPM is a version of the risk premium method, but is generally superior because it specifically recognizes the risk of a particular company or industry. The CAPM is designed to describe and measure the relationship between a security's investment risk and its market rate of return. Mr. Parcell's CAPM analysis resulted in a cost of equity range of 10.5 to 10.75 percent. Mr. Parcell also conducted a CEM examination which is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. He conducted the CEM by examining realized returns on equity for several groups of companies and evaluated the investor acceptance of these returns by reference to the resulting market-to-book ratios. According to Mr. Parcell, it is generally recognized that utilities with a market-to-book ratio of greater than one (100 percent) reflect a situation where a company is able to attract new equity capital without dilution. His analysis was based upon market data and used prospective returns. The results indicated that historic returns of 9.9 - 11.7 percent have been adequate to produce market-to-book ratios of 139-161 percent. The projected returns on equity for 2006, 2007 and 2009-2011 ranged from 8.2 percent to 10.4 percent for the two proxy groups. Mr. Parcell concluded that based upon the recent earnings and market-to-book ratios, the cost of equity for APS using the CEM is no greater than 10 percent.

[32] APS Exhibit No. 42, Avera Rebuttal, p. 21, 28.

Staff's witness testified that although Arizona is a fair value state, he took into consideration the *Bluefield* and *Hope* decisions and considered the additional risk factor of APS' current bond rating and investor expectations in making his recommendation. (Tr. Vol. XVII, pp. 3259-60) Based on all of his cost of equity analyses, Mr. Parcell concluded that APS' cost of equity falls within a range of 9.5 percent to 10.75 percent, and he recommended a rate of 10.25, the approximate mid-point of the range. Staff recommends that the Commission not allow flotation costs because APS has not demonstrated that it has incurred any issuance costs, and an $8 million adjustment paid annually is excessive.

RUCO's witness, Mr. Hill, also conducted a DCF analysis using market data from a sample of electric utility companies similar in risk to APS. His DCF resulted in a cost of equity of 9.44 percent. He also used three other methods to corroborate his DCF results – the Modified Earnings-Price Ratio ("MPER") Analysis, the Market-to-Book Ratio ("MTB") Analysis, and the CAPM. The CAPM produced results that ranged from 9.23 percent to 10.56 percent; the MPER ranged from 9.13 percent to 8.79 percent; and the MTB ranged from 9.31 percent to 9.38 percent. Mr. Hill's estimate of the cost of equity for the sample group ranged from 9.25 percent to 9.75 percent, and because APS has a higher equity component in its capital structure than the sample group, Mr. Hill recommends an appropriate cost of equity of 9.25 percent. In response to Company criticism as to his reliance on the DCF model, Mr. Hill noted that the DCF is now and has been for over thirty years, the pre-eminent equity cost estimation methodology used in regulation because it works well. RUCO also criticized APS for placing primary emphasis on a method its witness has previously discounted, the risk premium method. Mr. Hill argues that the volatility inherent in the historical data used in Dr. Avera's risk premium analysis indicates that the determination of the historical period effectively determines the outcome of the analysis. Mr. Hill testified that the primary flaw in Dr. Avera's CAPM analysis is the risk premium, because APS used two estimates that are well above the current forward-looking risk premium as evidenced by the Company's own pension fund equity return expectations and current academic research.

Mr. Hill took into account not only the financial risks that the Company faces, but also the current economic environment, including anticipated interest rate increases by the Federal Reserve

Bank and the effect it would have on utility stock. RUCO argues that if the multi-stage DCF analysis is properly applied to restate RUCO's analysis, the result is an 8 percent return on equity, not the 10.7 percent claimed by APS.

AUIA supports the APS recommended 11.5 percent return on equity, with a 1.7 attrition allowance. It argues that Dr. Avera has provided a "current and real-world assessment of what investors expect given the depressed credit ratings, low earnings, growth challenges and dangers faced by APS." (AUIA Initial Brief, p. 5) AUIA's witness, Ms. Cannell, testified that investor expectations support the 11.5 percent recommendation. AUIA notes that since the Commission's Decision No. 67744 less than two years ago, "APS' business profile has increased, all three rating agencies have downgraded the Company, APS' critical FFO to Debt metric remains in non-investment grade territory, the Company sits one notch above a junk bond rating and it has a negative outlook from Moody's." (AUIA Initial Brief, p. 6) AUIA argues that investors cannot expect the same or less risk compensation as they did two years ago, contrary to Staff and RUCO recommendations.

The DCF model has long been favored by this and other Commissions as the appropriate way to estimate a regulated utility's cost of equity. As Staff witness Parcell explained, capital costs are currently low in comparison to the levels that have prevailed over the past three decades and it reasonably can be expected that DCF models currently produce returns that are lower than in previous years.

While the Company criticized RUCO's return on equity as "completely outside a reasonable range and is entirely inconsistent with mainstream benchmarks", RUCO argued that the Company placed its reliance on the market-based models that yielded the highest costs of equity, and placed no reliance on the model which RUCO believes provides the best indication of the cost of equity, the DCF. RUCO also criticized Dr. Avera's use of the CEM, stating that the updated CEM analysis highlights the inherent flaws of including companies that are unregulated and have substantially different risk from APS. They are not monopolies operating in a franchised service area and have much different market positions than APS, and it is unknown whether the returns used in the study are equal to the cost of capital, unless a market based analysis like the DCF is performed. RUCO believes that Staff's recommendation is also inflated because Mr. Parcell used the upper range results from his models, and because Staff's common equity ratio recommendation indicates that APS has less financial risk than the others in the sample group, the recommended cost of equity should be in the lower range of the estimate results.

The cost of equity recommendations from the parties vary from a low of 9.25 percent to a high of 11.5 percent. We continue to believe that market measures of common equity costs are generally preferable to comparative analyses, and we note that the DCF results from all witnesses tend to the lower end of the range. However, we compare those results with the results from the other methods, and believe that the DCF results alone would not result in an appropriate cost of equity in this case for APS. We are cognizant of APS' current bond rating as well as the Company's continued growth and the capital costs associated with that growth. After considering all the rate of return testimony, the legal and policy arguments how to determine cost of equity and its relationship to just and reasonable rates, we conclude that the appropriate cost of equity to be used to determine the cost of capital is 10.75 percent. We do not agree that a flotation adjustment or additional "attrition adjustment" to the cost of equity is reasonable or appropriate.

D. Cost of Capital Summary

	Percentage	Cost	Weighted Cost
Long-Term Debt	45.5%	5.41%	2.46%
Common Equity	54.5%	10.75%	5.86%
Cost of Capital			8.32%

VIII. AUTHORIZED INCREASE

A. APS' Revenue Enhancement Proposals

APS believes that the entire rate relief it requests is necessary and appropriate because according to the Company, the current rates: substantially under-collect the costs of providing electric service (particularly fuel and purchased power costs); do not adequately reflect certain non-fuel costs; and do not provide APS an opportunity to earn a reasonable rate of return on its invested equity. According to APS, it is the non-fuel cost recovery and return on equity issues that have led to "chronic under-earning by APS" and "have driven the Company and its customers to the very brink

Moody's Investors Service

Global Credit Research
Rating Action
10 MAR 2006

Rating Action: Southwest Gas Corporation

MOODY'S PLACES THE Baa2/NEGATIVE OUTLOOK SENIOR UNSECURED DEBT OF SOUTHWEST GAS CORPORATION UNDER REVIEW FOR POSSIBLE DOWNGRADE

Approximately $1.2 BN of Debt Affected

New York, March 10, 2006 -- Moody's Investors Service places under review for possible downgrade the Baa2/negative outlook senior unsecured debt of Southwest Gas Corporation (SWX), following the company's recent announcement that the Arizona Corporation Commission (ACC) issued a final decision not to adopt the company's proposed rate design for balancing accounts, thereby exposing it to continuing earnings risks associated with weather volatility and declining customer use resulting from the effects of gas conservation. At the same time, the company declared that 2005 was one of the 10 warmest years on record and that it lost approximately $17MM in operating margins, primarily as result of lower gas usage. Consolidated net income for 2005 declined 23% from 2004, largely on account of loss in operating margins resulting from warmer than normal weather. Arizona accounts for approximately 55% of SWX's gas distribution business and the ACC decision weighs heavily on the company.

In its review, Moody's will consider what other options may be available to the company in terms of mitigating the effects of warmer than normal weather, loss of operating margins on account of gas conservation by customers, the reduction of regulatory lag in dealing with high capital expenditures in a fast-growing service territory and rising operating expenses. Also under review will be the impact of these factors on the company's credit metrics and future financial performance.

Ratings of SWX under Review are as follows:

Southwest Gas Corporation - Baa2 senior unsecured

Southwest Gas Capital II - Baa3 preferred trust securities

Southwest Gas Corporation - (P) Ba1 preferred shelf

Southwest Gas Corporation is headquartered in Las Vegas, Nevada, and provides natural gas service to over 1.7 million customers in Arizona, Nevada and California.

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Moody's Investors Service

Global Credit Research
Rating Action
30 MAY 2006

Rating Action: Southwest Gas Corporation

MOODY'S DOWNGRADES SENIOR UNSECURED DEBT OF SOUTHWEST GAS CORPORATION TO Baa3 FROM Baa2; OUTLOOK IS STABLE

Approximately $ 1.2 Billion of Debt Securities Affected.

New York, May 30, 2006 -- Moody's Investors Service downgraded the senior unsecured long-term debt ratings of Southwest Gas Corporation (SWX) to Baa3 from Baa2 with stable outlook. This action concludes the rating review initiated on March 10, 2006. The downgrade reflects the view that the credit measures of SWX remain weak when compared with its gas utility peers in light of its continued rapid growth and sensitivity to decline in earnings on account of warmer than normal weather and the absence of revenue decoupling in Arizona (54% of gross margins) and Nevada (37% of gross margins) that would serve to protect this company from weather variation and customer conservation. The company's heightened sensitivity to warmer than normal weather is exacerbated by the fact that in 2005 it experienced one of the 10 warmest years on record with 2003 being one of the warmest years in over 100 years. The cumulative effects of this warmer than normal weather has continued into the recent quarter ending March 31, 2006 which was mostly responsible for the company's loss of $9 million in operating margin.

While the company was able to obtain some rate relief in recent years, the fact that it is among the fastest growing gas utilities in the country (5% p.a. growth) continues to expose it to regulatory lag as rate cases in its key state of Arizona take at least a year to resolve and even then, typically deliver only part of the rate improvement necessary for it to earn its allowed rate of return. While the company has been encouraged in certain jurisdictions to further pursue discussions with interested parties as to the possibilities of adopting some form of weather normalization clause protection or conservation tracker, these efforts will take more time before they could be implemented even if agreed upon by all the stakeholders concerned.

KEY RATING DRIVERS

For a few years the company has been performing at the lower end of its peers in terms of the financial rating indicators employed by Moody's which include, as example, fiscal 2005 return on equity of 6.0%, EBIT/Interest Expense coverage of 1.7, Retained Cash Flow to Adjusted Debt of 10.0% and Adjusted Debt to Adjusted Cap. of 62.5%. The comparable ratios for Baa2 peers averaged 8.9% ROE, 2.8 EBIT/Interest Exp. coverage, 13% RCF to Adj. Debt and 55% Adj. Debt to Cap. In addition, cash flow from operations after dividend payments has been insufficient to cover the active level of capital expenditures, a trend that has existed for several years and which is likely to continue into the foreseeable future given the company's very rapid growth rate. In addition, operating expenditures rose 14% in fiscal 2005 and 6% in the first quarter of 2006, reflecting the impact of general cost increases and incremental costs associated with providing service to a growing customer base, pressures that are expected to continue in the foreseeable future.

The challenges for this company which bear directly on the aforementioned financial indicators are the ability to obtain the most comprehensive rate design possible to protect against warmer than normal weather, the reduction of regulatory lag by incorporating forward period test data along with pursuing more profitable growth alternatives, the correction for margin losses on account of customer conservation, and exercising strong control over operating expenses.

RATING OUTLOOK

The stable outlook anticipates a gradual improvement on the key rating drivers mentioned above that have negatively impacted the company's credit metrics and have prompted this rating adjustment.

Downgraded Ratings of SWX are as follows:

Southwest Gas Corporation -- to Baa3 from Baa2 senior unsecured;

Southwest Gas Capital II -- to Ba1 from Baa3 preferred trust securities;

Southwest Gas Corporation --to (P) Ba2 from (P) Ba1 preferred shelf.

Southwest Gas Corporation is headquartered in Las Vegas, Nevada, and provides natural gas service to over 1.7 million customers in Arizona, Nevada and California.

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SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-2
(ACC-STF-2-1 THROUGH ACC-STF-2-22)

DOCKET NO.:	G-01551A-07-0504
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	DECEMBER 19, 2007

Request No. STF-2-14:

RE: statement on page 28, lines 11-14. Please indicate the degree to which Southwest Gas' rate of return must be adjusted upward if its rate design proposals are not approved by the Commission in this proceeding.

Respondent: Treasury Services

Response:

Absent any improvements in rate design, the Company will continue to be exposed to asymmetric risk in its returns. At a minimum, the adjustment should be the spread in utility bonds of adjacent credit rating categories, as utilities that have revenue stabilizing mechanisms are afforded higher credit ratings. The 10-year historical spread between utility bonds rated Baa and A is 28 basis points and the current spread (January 2, 2008) is 35 basis points, as shown below:

Average Baa Utility Bond Yield 1998-2007	7.14%
Average A Utility Bond Yield 1998-2007	6.86
10-Year Average Spread	0.28%
Current Baa Utility Bond Yield (1/2/2008)	6.32%
Average A Utility Bond Yield (1/2/2008)	5.97
Current Average Spread	0.35%

Exhibit__(FJH-34)
Sheet 1 of 3

Ibbotson® SBBI®

2008 Valuation Yearbook

Market Results for
Stocks, Bonds, Bills, and Inflation
1926–2007

SBBI

MORNINGSTAR®

Graph 5-15 compares the historical equity risk premium, which includes the P/E ratio, to the supply side equity risk premium calculated from 1926 to 2007 on a geometric basis. Contrary to several recent studies on equity risk premium that declare the forward-looking equity risk premium to be close to zero, or even negative, Ibbotson and Chen have found the long-term supply of equity risk premium to be only slightly lower than the straight historical estimate.

The supply side equity risk premium calculated earlier is a geometric calculation. An arithmetic calculation, as mentioned earlier in the chapter, is most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the buildup approach, the arithmetic calculation is the relevant number. There are several ways to convert the geometric average into an arithmetic average. One method is to assume the returns are independently lognormally distributed over time, where the arithmetic and geometric averages roughly follow the following relationship:

$$R_A = R_G + \frac{\sigma^2}{2}$$

$$6.23\% = 4.24\% + \frac{19.97\%^2}{2}$$

where:

R_A = the arithmetic average;
R_G = the geometric average;
σ = the standard deviation of equity returns.

As stated in IRS Ruling 59-60, although valuation is a forward-looking process, it must be based on facts available as of the required date of appraisal. Therefore, Ibbotson provides data critical to the valuation process as far back as 1926, such as the historical equity risk premium and size premium presented in Appendix A of this book. Similarly, Table 5-6 presents the supply side equity risk premium, on an arithmetic basis, beginning in 1926 and ending in each of the last 22 years.

Exhibit__(FJH-34)
Sheet 3 of 3

Table 5-6
Supply Side and Historical Equity Risk Premium Over Time
1926–2007

Period Length	Period Dates	g(P/E)	Supply Side Equity Risk Premium (arithmetic average)	Historical Equity Risk Premium (arithmetic average)
82 years	1926–2007	0.67%	6.23%	7.05%
81 years	1926–2006	0.63%	6.35%	7.13%
80 years	1926–2005	0.65%	6.29%	7.08%
79 years	1926–2004	0.83%	6.18%	7.17%
78 years	1926–2003	1.09%	5.93%	7.19%
77 years	1926–2002	1.17%	5.64%	6.97%
76 years	1926–2001	1.53%	5.71%	7.42%
75 years	1926–2000	1.49%	6.06%	7.76%
74 years	1926–1999	1.52%	6.32%	8.07%
73 years	1926–1998	1.40%	6.35%	7.97%
72 years	1926–1997	1.20%	6.37%	7.76%
71 years	1926–1996	0.88%	6.45%	7.50%
70 years	1926–1995	0.74%	6.47%	7.36%
69 years	1926–1994	0.59%	6.32%	7.04%
68 years	1926–1993	0.90%	6.17%	7.22%
67 years	1926–1992	1.15%	5.98%	7.28%
66 years	1926–1991	1.12%	6.11%	7.39%
65 years	1926–1990	0.67%	6.36%	7.16%
64 years	1926–1989	0.60%	6.71%	7.45%
63 years	1926–1988	0.32%	6.78%	7.21%
62 years	1926–1987	0.36%	6.73%	7.20%
61 years	1926–1986	0.63%	6.61%	7.36%

As mentioned earlier, one of the key findings of the Ibbotson and Chen study is that P/E increases account for only a small portion of the total return of equity. The reason we present supply side equity risk premium going back only 22 years is because the P/E ratio rose dramatically over this time period, which caused the growth rate in the P/E ratio calculated from 1926 to be relatively high. The subtraction of the P/E growth factor from equity returns has been responsible for the downward adjustment in the supply side equity risk premium compared to the historical estimate. Beyond the last 22 years, the growth factor in the P/E ratio has not been dramatic enough to require an adjustment.

This section has briefly reviewed some of the more common arguments that seek to reduce the equity risk premium. While some of these theories are compelling in an academic framework, most do little to prove that the equity risk premium is too high. When examining these theories, it is important to remember that the equity risk premium data outlined in this book (both the historical and supply side estimates) are from actual market statistics over a long historical time period.

NEW REGULATORY FINANCE

Roger A. Morin, PhD

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securities to the point at which new purchases would earn only the old cost of capital on their investments. The only beneficiaries would be those who happened to own the stock at the time the policy change was announced or anticipated.

12.5 M/B Ratios in the Regulatory Process

It is sometimes argued that because current M/B ratios are in excess of 1.0, this indicates that companies are expected by investors to be able to earn more than their cost of capital, and that the regulating authority should lower the authorized return on equity, so that the stock price will decline to book value. It is therefore plausible, under this argument, that stock prices drop from the current M/B value to the desired M/B ratio range of 1.0 times book.

There are several reasons why this view of the role of M/B ratios in regulation should be avoided.

(1) The inference that M/B ratios are relevant and that regulators should set an ROE so as to produce an M/B of 1.0 is misguided. The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce an M/B of 1.0 presumes that investors are irrational. They commit capital to a utility with an M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation. For example, assume a utility company with an M/B ratio of 1.5. If investors expect the regulator to authorize a return on book value equal to the DCF cost of equity, the utility stock price would decline to book value, inflicting a capital loss of some 30%. The notion that investors are willing to pay a price of 1.5 times book value only to see the market value of their investment drop by 30% is irrational.

(2) The condition that the M/B will gravitate toward 1.0 if regulators set the allowed return equal to capital costs will be met only if the actual return expected to be earned by investors is at least equal to the cost of capital on a consistent long-term basis and absent inflation. The cost of capital of a company refers to the expected long-run earnings level of other firms with similar risk. If investors expect a utility to earn an ROE equal to its cost of equity in each period, then its M/B ratio would be approximately 1.0 or higher with the proper allowance for flotation cost.

(3) A company's achieved earnings in any given year are likely to exceed or be less than their long-run average. Depressed or inflated M/B ratios are to a considerable degree a function of forces outside the control of regulators, such as the general state of the economy, or general economic or financial circumstances that may affect the yields on securities of unregulated as well

as regulated enterprises. The achievement of a 1.0 M/B ratio is appropriate, but only in a long-run sense. For utilities to exhibit a long-run M/B ratio of 1.0, it is clear that during economic upturns and more favorable capital market conditions, the M/B ratio must exceed its long-run average of 1.0 to compensate for the periods during which the M/B ratio is less than its long-run average under less favorable economic and capital market conditions.

Historically, the M/B ratio for utilities has fluctuated above and below 1.0. It has been consistently above 1.0 from the 1980s to the mid 2000s. This indicates that earnings below capital costs and M/B ratios below 1.0 during less favorable economic and capital market conditions must necessarily be accompanied with earnings in excess of capital costs and M/B ratios above 1.00 during more favorable economic and capital market conditions.

M/B ratios are determined by the marketplace, and utilities cannot be expected to compete for and attract capital in an environment where industrials are commanding M/B ratios well in excess of 1.0 while regulation reduces their M/B ratios toward 1.0. Moreover, if regulators were to currently set rates so as to produce an M/B ratio of 1.0, not only would the long-run target M/B ratio of 1.0 be violated, but more importantly, the inevitable consequence would be to inflict severe capital losses on shareholders. Investors have not committed capital to utilities with the expectation of incurring capital losses from a misguided regulatory process.

(4) Rate of return regulation is fundamentally a surrogate for competition. The fundamental goal of regulation should be to set the expected economic profit for a public utility equal to the level of profits expected to be earned by firms of comparable risk, in short, to emulate the competitive result. For unregulated firms, the natural forces of competition will ensure that in the long run, the ratio of the market value of these firms' securities equals the replacement cost of their assets. Competitive industrials of comparable risk to utilities have consistently been able to maintain the real value of their assets in excess of book value, consistent with the notion that, under competition, the Q-ratio will tend to 1.00 and not the M/B ratio. This suggests that a fair and reasonable price for a public utility's common stock is one that produces equality between the market price of its common equity and the replacement cost of its physical assets. The latter circumstance will not necessarily occur when the M/B ratio is 1.0. As the previous section demonstrated, only when the book value of the firm's common equity equals the value of the firm's equity at replacement assets will equality hold.

In an inflationary period, the replacement cost of a firm's assets may increase more rapidly than its book equity. To avoid the resulting economic confiscation of shareholders' investment in real terms, the allowed rate of return should produce an M/B ratio which provides a Q-ratio of 1 or a Q-ratio equal to that of comparable firms. It is quite plausible and likely that M/B ratios will exceed one if inflation increases the replacement cost of a firm's assets at a faster pace than historical cost (book equity). Perhaps this explains in part why utility M/B ratios have remained well above 1.0 over the past two decades. Are we to conclude that regulators have been systematically misguided all across the United States for all these years by awarding overgenerous returns, or are we to conclude that M/B ratios are largely immaterial in the context of ratemaking? The latter is more likely.

Historically, it has been highly unusual for utility stock prices to equal book value. Stock prices above book value are common for utility stocks, and indeed for all of the major market indexes. It is obvious that regulators, through their rate case decisions, and investors do not subscribe to the notion that utilities that have market prices above book value are over-earning. Otherwise, regulators would not grant rate increases for any utility whose stock price was above book value, and investors would never bid up the price of stock above book value. It is very difficult to accept the notion that, in a free-market economy with rampant competition, the vast majority of all publicly traded stocks are earning well in excess of their cost of capital.

In short, economic principles do not support the notion that the market value of utility shares should necessarily equal book value. A basic economic principle holds that, in the long run, market value should equal asset replacement cost in a given industry. In the presence of inflation and absent significant technological advances, replacement cost exceeds the original cost book value of assets. Consequently, it is quite reasonable for the market value of utility shares to exceed their book value and there is no reason to conclude that market value should equal book value when one recognizes that regulation is intended to emulate competition.

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1926–2007

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The discount rate is meant to represent the underlying risk of being in a particular industry or line of business. There are instances when a majority shareholder can acquire a company and improve the cash flows generated by that company. However, this does not necessarily have an impact on the general risk level of the cash flows generated by the company.

When performing discounted cash flow analysis, adjustments for minority or controlling interest value may be more suitably made to the projected cash flows than to the discount rate. Adjusting the expected future cash flows better measures the potential impact a controlling party may have while not overstating or understating the actual risk associated with a particular line of business.

Appraisers need to note the distinction between a publicly traded value and a minority interest value. Most public companies have no majority or controlling owner. There is thus no distinction between owners in this setting. One cannot assume that publicly held companies with no controlling owner have the same characteristics as privately held companies with both a controlling interest owner and a minority interest owner.

Other Equity Risk Premium Issues

There are a number of other issues that are commonly brought up regarding the equity risk premium that, if correct, would reduce its size. These issues include:

1. Survivorship bias in the measurement of the equity risk premium
2. Utility theory models of estimating the equity risk premium
3. Reconciling the discounted cash flow approach to the equity risk premium
4. Over-valuation effects of the market
5. Changes in investor attitudes toward market conditions
6. Supply side models of estimating the equity risk premium

In this section, we will examine each of these issues.

Survivorship

One common problem in working with financial data is properly accounting for survivorship. In working with company-specific historical data, it is important for researchers to include data from companies that failed as well as companies that succeeded before drawing conclusions from elements of that data.

The same argument can be made regarding markets as a whole. The equity risk premium data outlined in this book represent data on the United States stock market. The United States has arguably been the most successful stock market of the twentieth century. That being the case, might equity risk premium statistics based only on U.S. data overstate the returns of equities as a whole because they only focus on one successful market?

In a recent paper, Goetzmann and Jorion study this question by looking at returns from a number of world equity markets over the past century.[6] The Goetzmann-Jorion paper looks at the

6 Goetzmann, William, and Philippe Jorion. "A Century of Global Stock Markets," Working Paper 5901, National Bureau of Economic Research, 1997.

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survivorship bias from several different perspectives. They conclude that once survivorship is taken into consideration the U.S. equity risk premium is overstated by approximately 60 basis points.[7] The non-U.S. equity risk premium was found to contain significantly more survivorship bias.

While the survivorship bias evidence may be compelling on a worldwide basis, one can question its relevance to a purely U.S. analysis. If the entity being valued is a U.S. company, then the relevant data set should be the performance of equities in the U.S. market.

Equity Risk Premium Puzzle

In 1985, Mehra and Prescott published a paper that discussed the equity risk premium from a utility theory perspective. The point that Mehra and Prescott make is that under existing economic theory, economists cannot justify the magnitude of the equity risk premium. The utility theory model employed was incapable of obtaining values consistent with those observed in the market.

This is an interesting point and may be worthy of further study, but it does not do anything to prove that the equity risk premium is too high. It may, on the other hand, indicate that theoretical economic models require further refinement to adequately explain market behavior.

Discounted Cash Flow versus Capital Asset Pricing Model

Two of the most commonly used cost of equity models are the discounted cash flow model and the capital asset pricing model. We should be able to reconcile the two models. In its basic form, the discounted cash flow model states that the expected return on equities is the dividend yield plus the expected long-term growth rate. The capital asset pricing model states that the expected return on equities is the risk-free rate plus the equity risk premium.[8]

For the discounted cash flow model we can obtain an estimate of the long-term growth rate for the entire economy by looking at its component parts. Real Gross Domestic Product growth has averaged approximately three percent over long periods of time. Long-term expected inflation is currently in the range of three percent. Combining these two numbers produces an expected long-term growth rate of about six percent. Dividend yields have been between two percent and three percent historically. The discounted cash flow expected equity return is thus between eight percent and nine percent using these assumptions.

If we try to reconcile this expected equity return with that found using the capital asset pricing model, we find a significant discrepancy. The yield on government bonds has been about five percent. If the two models are to reconcile, the equity risk premium must be in the three to four percent range instead of the seven to eight percent range we have observed historically.

7 Note that the equity risk premium referred to in the Goetzmann and Jorion paper is not the same as the equity risk premium covered in this publication. Among other differences, their equity risk premium is based on a longer history of data and does not take dividend income or reinvestment into account.

8 The discounted cash flow model is a modification of the Gordon Growth model, which states that: where P_0 is the price of the security today, D_1 is the dividend from next period, k is the cost of equity, and g is the expected growth rate in dividends. The capital asset pricing model is stated as $k_i = \beta_i\,(ERP) + r_f$ where k_i is the cost of equity for company i, β_i is the beta for company i, ERP is the equity risk premium, and r_f is the risk-free rate. For the market as a whole, the capital asset pricing model can be written as $k = ERP + r_f$ because the market beta, by definition, is 1. For more information on these models, see Chapter 4.

Exhibit__(FJH-37)
Sheet 1 of 5

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Theory and Practice

Fourth Edition

Eugene F. Brigham
University of Florida

in collaboration with

Louis C. Gapenski
University of Florida

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6A Calculating Beta Coefficients

The CAPM is an *ex ante* model, which means that all of the variables represent before-the-fact, expected values. In particular, the beta coefficient used in the SML equation should reflect volatility of a given stock versus the market expected during some *future* period. However, people generally calculate betas during some *past* period and then assume that the stocks' relative volatility will remain constant in the future.

To illustrate how betas are calculated, consider Figure 6A-1. The data at the bottom of the figure show the historic realized returns for Stock J and the market for the last five years. The data points were then plotted on the scatter diagram, and a regression line drawn. If all the data points fell on a straight line, as they did in Figure 6-8 in Chapter 6, it would be easy to draw an accurate line. If they do not, then you can fit the line "by eye" as an approximation.

Recall what the term *regression line* or *regression equation* means: The equation $Y = a + bX + e$ is the standard form of a simple linear regression. It states that the dependent variable, Y, is equal to a constant, a, plus b times X, where b is the slope coefficient (or parameter) and X is the "independent" variable, plus an error term, e. Thus, the rate of return on the stock during a given time period depends on what happens to the general stock market, which is measured by $X = \bar{k}_M$.

Once the line has been drawn on the graph paper, we can estimate its intercept and slope, the a and b values in $Y = a + bX$. The intercept, a, is simply the point where the line cuts the vertical axis. The slope coefficient, b, can be estimated by the "rise over run" method. This involves calculating the amount by which $\bar{k}_J$ increases for a given increase in $\bar{k}_M$. For example, we observe (in Figure 6A-1) that $\bar{k}_J$ increases from -8.9 to $+7.1$ percent (the rise) when $\bar{k}_M$ increases from 0 to 10.00 percent (the run). Thus, the b, the beta coefficient, can be measured as follows:

$$b = \text{Beta} = \frac{\text{Rise}}{\text{Run}} = \frac{\Delta Y}{\Delta X} = \frac{7.1 - (-8.9)}{10.00 - 0.00} = \frac{16.0}{10.00} = 1.6.$$

Note that rise over run is a ratio, and it would be the same if measured using any two arbitrarily selected points on the line.

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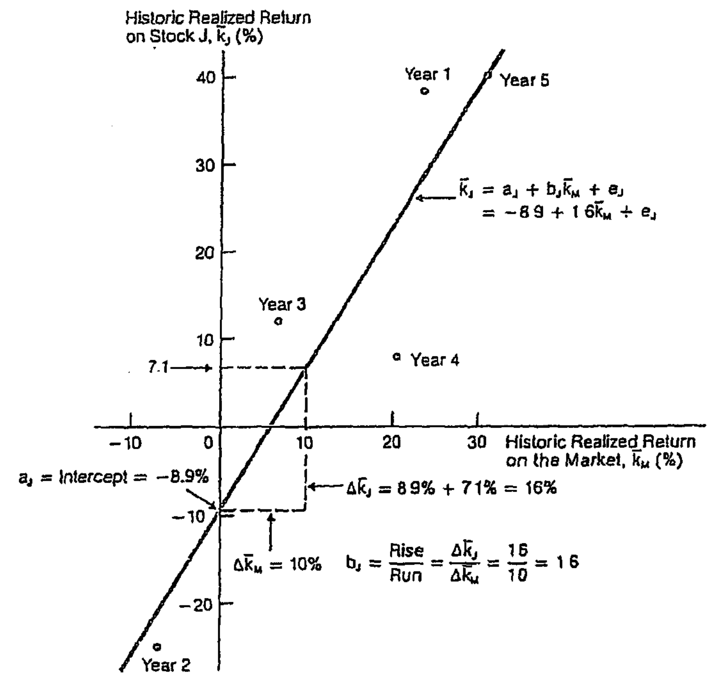
Figure 6A-1
Calculating Beta Coefficients



Year		Stock J($\bar{k}_J$)	The Market ($\bar{k}_M$)
1		38.6%	23.8%
2		−24.7	− 7.2
3		12.3	6.6
4		8.2	20.5
5		40.1	30.6
	Average $\bar{k}$	14.9%	14.9%
	$\sigma_{\bar{k}}$	26.5%	15.1%

The regression line, or equation, enables us to predict a rate of return for Stock J, given a value of $\bar{k}_M$. For example, if $\bar{k}_M$ = 15%, we would predict $\hat{k}_J = -8.9\% + 1.6(15\%) = 15.1\%$. The actual return would probably differ from the predicted return. This deviation is the error term, e_J, for the year, and it varies randomly from year to year depending on company-specific factors.

In actual practice, monthly rather than annual returns are generally used for $\bar{k}_J$ and $\bar{k}_M$, and five years of data are employed. Thus, there would be 5 × 12 = 60 dots on the scatter diagram. Also, in practice one would always use the *least squares method* for finding the regression coefficients a and b; the least squares procedure minimizes the squared values of the error terms, and it is discussed in statistics courses. Note also that the least squares value of beta can be obtained quite easily by computer or even with a calculator that has statistical functions.

Problems

6A-1 You are given the following set of data:

		Historic Rates of Return ($\bar{k}$)	
Year		NYSE ($\bar{k}_M$)	Stock Y ($\bar{k}_Y$)
1		4.0%	3.0%
2		14.3	18.2
3		19.0	9.1
4		−14.7	−6.0
5		−26.5	−15.3
6		37.2	33.1
7		23.8	6.1
8		−7.2	3.2
9		6.6	14.8
10		20.5	24.1
11		30.6	18.0
	Mean	9.8%	9.8%
	σ	18.7%	13.1%

a. Construct a "standard" graph showing the relationship between returns on Stock Y and the market; then draw a freehand approximation of the regression line. What is the approximate value of the beta coefficient? (If you have a calculator with statistical functions, use it to calculate beta.)
b. Give a verbal interpretation of what the regression line and the beta coefficient show about Stock Y's volatility and relative riskiness as compared with other stocks.
c. Suppose the scatter of points had been more spread out, but the regression line was exactly where your present graph shows it. How would this affect (1) the firm's risk if the stock were held in a one-asset portfolio and (2) the actual risk premium on the stock if the CAPM held exactly? How would the degree of scatter (or the correlation coefficient) affect your confidence in the likelihood that the calculated beta will hold true in the years ahead?
d. Suppose the regression line had been downward sloping, and the beta coefficient had been negative. What would this imply about (1) Stock Y's relative riskiness and (2) its probable risk premium?
e. Construct an illustrative probability distribution graph of returns on portfolios consisting of (1) only Stock Y, (2) 1 percent each of 100 stocks with beta coefficients similar to that of Stock Y, and (3) all

G

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

WILLIAM N. MOODY

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

Table of Contents Of Prepared Rejoinder Testimony Of WILLIAM N. MOODY

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
WILLIAM N. MOODY

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is William N. Moody. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same William N. Moody that sponsored rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or Company)?

A. 2 Yes, I am.

Q. 3 Do you have any corrections to your rebuttal testimony?

A. 3 Yes. I agree with Staff witness Rita R. Beale's surrebuttal assertion that I misattributed all of the fifteen Staff recommendations to Staff witness Stephen L. Thumb in my rebuttal testimony. I further agree with clarification beginning on page 1, line 23 through page 2, line 3.

Q. 4 What is the purpose of your prepared rejoinder testimony?

A. 4 I am responding to the surrebuttal testimony of the Arizona Corporation Commission Utilities Division Staff (Staff) witnesses Mr. Thumb and Ms. Beale.

Q. 5 Please comment on Mr. Thumb's surrebuttal testimony.

A. 5 Southwest believes that there is no remaining disagreement with the two issues mentioned in Mr. Thumb's surrebuttal testimony as previously rejected, Recommendations #2 and #5. Specifically regarding recommendation #2, Southwest has a quarterly review process for T-1 contracts and will continue in this process into the future. Southwest accepts Mr. Thumb's explanation of the current status of recommendation #5.

Q. 6 Did Southwest agree to any of the recommendations contained in Ms. Beale's direct testimony?

A. 6 Yes. As indicated in my rebuttal testimony, Southwest agreed with eight of the ten recommendations made by Ms. Beale. However, the Company disagreed with two of Ms. Beale's recommendations. The issues that Southwest accepted are referenced in Ms. Beale's surrebuttal testimony under Section II entitled "SUMMARY OF SOUTHWEST'S SURREBUTTAL TESTIMONY". However, Southwest still disagrees with two of Ms. Beale's recommendations.

SARBANES-OXLEY COMPLIANCE

Q. 7 Before discussing the two recommendations Southwest is rejecting, are there any other matters you would like to address?

A. 7 Yes. In her surrebuttal testimony, Ms. Beale implies that Sarbanes-Oxley requires gas procurement documentation and that Southwest is somehow deficient in this area.

First, the Sarbanes-Oxley Act of 2002 (Sarbanes-Oxley), requires management assessment of internal controls over financial reporting, not "...complete sets of internal policies and procedures reviewed and authorized by the Board of Directors". Furthermore, Company management, not the Board of Directors, is responsible to ensure that these controls are in place and operating effectively such that the failure of one or more controls does not result in a material error in the financial statements. The role of the Board of Directors, specifically the Audit Committee, is to ensure management has evaluated the effectiveness of its internal controls over financial reporting and that an audit of those controls is performed by an independent public accounting firm. The Board (Audit Committee) does not authorize and approve internal controls or as stated in Ms. Beale's terminology, "internal policies and procedures".

Q. 8 Is Southwest Sarbanes-Oxley compliant?

A. 8 Yes. Southwest has been under Sarbanes-Oxley review for four years and has received a clean opinion from the independent auditing firm, Pricewaterhouse-Coopers, finding no material weaknesses in the Company's internal controls for each of these years.

INDUSTRY BEST PRACTICES

Q. 9 Ms. Beale also implies in her surrebuttal testimony that the Company is deficient in meeting Industry Best Practices. Has the Commission reviewed Southwest for best practices in gas supply activities in the recent past?

A. 9 Yes. Southwest's gas supply and procurement practices were reviewed in the last general rate case (Docket No. G-01551A-04-0876). Staff's review resulted in a number of recommendations, including the preparation of a benchmarking study of Southwest's natural gas procurement practice. The benchmarking study is attached as Rejoinder Exhibit No.__(WNM-1). This comprehensive review did not find that Southwest policies and procedures for gas procurement where outside of best practices for the industry. Southwest has fully complied with all of Staff's recommended changes in policies and procedures. Staff's Report dated August 22, 2006, on Southwest's compliance is attached as Rejoinder Exhibit No.__(WNM-2).

RECOMMENDATIONS 6 AND 9

Q. 10 After reviewing Ms. Beale's surrebuttal testimony, have you changed your opinion regarding the two recommendations Southwest previously disagreed with?

A. 10 No, I have not. Ms. Beale's recommendations that Southwest continues to believe unnecessary are:

(6) Consolidate all strategies, policies, and

procedures into a minimal number of documents; and

(9) Designate the *Arizona Dispatch Guidelines* as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement in Company policies and procedures.

Q. 11 Why does Southwest believe implementing these recommendations is unnecessary?

A. 11 Southwest's policies and procedures are well documented in an appropriate manner in the pertinent Southwest publications. A regrouping of this documentation will produce minimal, if any, improvement in accessing these documents by Gas Supply personnel. The *Arizona Dispatch Guidelines* is not an appropriate document to utilize for buyers' limits and authorization. Southwest currently uses a system generated report from our Gas Transaction System to produce a daily/monthly economic dispatch list of available contracts. In addition, "Gas Day" provides a system generated daily load forecast multiple times a day to identify load limits. This information is used today as Ms. Beale suggests the *Arizona Dispatch Guidelines* document would be used.

Q. 12 Does that conclude your prepared rejoinder testimony?

A. 12 Yes, it does.

Southwest Gas Corporation

Natural Gas Procurement Practices and Benchmarking Study

July 2006

Natural Gas Procurement Practices and Benchmarking Study
Table of Contents

Natural Gas Procurement Practices and Benchmarking Study
Prepared for Southwest Gas Corporation
By Ralph E. Miller
July 5, 2006

Introduction and Overview

This report is a review of the gas acquisition practices of Southwest Gas Corporation (Southwest). The Arizona Corporation Commission expressed an interest in this topic in the hearings on Southwest's recent Arizona general rate case, Docket No. G-01551A-04-0876, and in Decision No. 68487 (issued February 23, 2006) it directed Southwest to continue to cooperate with the Commission Staff in Staff's investigation of this topic. Southwest requested the preparation of this report in response to the Commission's interest in this subject, and in furtherance of its cooperation with Staff's continuing investigation of this matter.

The author of this report is Ralph E. Miller. Mr. Miller is a recognized independent expert on natural gas supply, acquisition, and commodity purchasing, and he has been active in this field for more than 25 years. During this period he has reviewed the gas supply arrangements of more than 15 different gas utilities in numerous regulatory proceedings in seven states, and he continues to testify regularly on this subject in three state regulatory jurisdictions. Appendix A to this report contains a more detailed description of his expert qualifications in this area.

Southwest distributes natural gas to 1.6 million customers in Arizona, Nevada, and California. Southwest's total annual throughput in 2005 was approximately 249 million Dekatherms or Dth. This total includes 104 million Dth sold by Southwest to end-users connected to its distribution systems, and a further 145 million Dth that Southwest delivered to customers who purchased their gas supplies from vendors other than Southwest itself. These total system throughput quantities include sales and transportation deliveries to all customer classes including large commercial and special procurement customers.

Southwest's Arizona service territory encompasses central and southern Arizona, which includes the Phoenix and Tucson metropolitan areas. In 2005, Southwest sold 66 million Dth of natural gas to 877,000 end-use customers in Arizona. Southwest's Arizona sales were 63% of Southwest's total gas sales to end-use customers in all three states where Southwest provides gas distribution service.

This principal focus of this report is a review of Southwest's commodity gas procurement practices for its Arizona service territory. Commodity gas procurement is one of three major aspects of the gas supply activities typically conducted by a gas distribution utility, sometimes known as a "local distribution company" or LDC, and more recently in some states as a natural gas distribution company or NGDC.

The two other major aspects of a typical LDC's gas supply activities are load forecasting and capacity acquisition. To provide a proper context for the review of Southwest's commodity gas acquisition practices, this report begins with an overview of Southwest's load forecasting and capacity acquisition for its Arizona service territory. This overview is a description of the load forecasts that Southwest has prepared and the gas supply capacity that Southwest has acquired. It is not intended as an evaluation of the quality of the load forecasts or an assessment of the adequacy or cost of Southwest's portfolio of capacity resources.

Annual planning -- Southwest plans and manages its commodity gas procurement on an annual basis, with each annual period running from November of the current year through October of the following year. The use of an annual gas supply planning period is a standard practice.

In the gas industry, annual planning periods typically begin either in November or in April. November is the start of the winter heating season. April is the start of the "summer" season when utilities having access to seasonal storage resources typically begin their storage injections.

Load Forecasts

Load forecasting is important for commodity gas procurement because an LDC cannot make appropriate gas purchasing decisions unless it knows how much gas it is likely to need, and when it is likely to need that gas delivered.

A complete load forecast generally includes the following components:

- Annual, seasonal, and monthly loads under normal weather conditions

  Commodity gas procurement often involves advance purchase commitments for part of the gas supply that a utility expects to purchase under normal weather conditions. A forecast of the normal weather purchase quantities is needed to establish appropriate levels of advance purchase and hedging commitments.

- Design day, design week, and design winter season loads

  A utility needs to project the loads it is likely to experience under design weather conditions so that it can acquire sufficient gas supply capacity to serve those loads. The utility should also plan its commodity gas procurement to assure a sufficient and reliable supply of gas available for delivery under these design weather conditions. As an adjunct to its development of projected design condition loads, a utility should from time to time review its determination of the design weather conditions on which the design loads are based. Although changes in the range of likely weather conditions occur only slowly and are difficult to measure, a utility should not ignore the possibilities for change.

- Maximum and minimum daily loads that may occur in each calendar month

  The maximum daily load that may occur in any calendar month is the design daily load for that calendar month, and a utility needs to establish it for the same reason that it establishes an annual design day load. The minimum daily load in each calendar month determines the maximum quantity of gas that a utility can appropriately schedule for baseload delivery every day of that month. This maximum baseload quantity also limits a utility's advance commodity purchase commitments.

- No-notice and swing requirements

  For Southwest, as for other gas utilities, daily loads depend upon the weather, especially during the winter heating season. Weather forecasts are never perfectly accurate, and daily loads are also subject to other random influences. A utility must therefore arrange its gas supply activities to accommodate the variance between its actual load on a given day and the load that the utility forecasted when it made it gas purchases and supply nominations on the preceding day. That variance is typically accommodated through the use of a no-notice supply. The utility also needs swing supplies to accommodate differences from one day to the next in the forecasted load level, so that it can schedule or "nominate" its daily supplies to match its forecasted daily loads.

Southwest prepares a comprehensive load forecast analysis annually. The load forecast document includes the first three of the four components identified above: normal weather projected loads; design condition loads; and minimum and maximum daily loads in each calendar month. Table 1 shows data from Southwest's most recently completed forecast for its 2006/2007 gas year.

Southwest's swing requirements in each calendar month are simply the difference between the maximum and minimum daily loads for that month, and they are implicitly included in the load forecast. These swing requirements are the range within which Southwest must be prepared to schedule or nominate its daily gas supplies in each calendar month.

As this discussion indicates, Southwest's load forecasting process is complete and comprehensive, and it provides all of the requisite information for Southwest to have an informed commodity gas procurement policy. As noted in the introduction, this report makes no attempt to evaluate the methods that Southwest uses to prepare its load forecast analyses, or to comment on the quality (as opposed to the scope) of the results.

<u>Capacity Acquisition</u>

Southwest maintains a separate portfolio of capacity resources for its Arizona service territory. The shape of this portfolio is determined largely by one overriding factual consideration - at present, all of Southwest's Arizona city gates are connected only to the interstate pipeline facilities of El Paso Natural Gas Company (El Paso, or EPNG), and for most (if not all) of those city gates it would be extremely difficult and expensive to establish connections to other pipelines or sources of gas supply. Southwest's portfolio of capacity resources for its Arizona service territory therefore consists entirely of services provided by El Paso. Southwest has sufficient firm transportation (FT) capacity on El Paso to serve the Arizona design day load indicated in Table 1.

The shape of Southwest's capacity portfolio is further restricted by the relatively narrow range of services provided by El Paso, which does not offer any market-area storage services. Southwest's capacity portfolio for Arizona therefore consists entirely of FT on El Paso from the San Juan and Permian basin gas production areas. Some storage services are available in the production area, but they would not add to or substitute for FT capacity on El Paso, because Southwest would still need FT capacity from the production area to deliver any storage withdrawals, and that capacity could be used equally well to deliver gas supplies that Southwest purchased in the production area. Southwest could perhaps use production-area storage as an adjunct to its commodity supply arrangements, as discussed below; but it is not at this time a relevant capacity resource for Arizona.

Southwest continually reviews the availability of alternative methods for delivering firm gas supplies to Southwest's Arizona city gates. As is appropriate, Southwest analyzes these possibilities to determine whether it could use these new resources to supplement or perhaps replace some of its El Paso FT capacity. The consideration of alternative capacity resources is an important aspect of Southwest's gas supply planning, but it has no direct impact on Southwest's procurement of commodity gas supplies unless and until Southwest is able to acquire some alternative capacity on an economical basis.

Southwest is participating in a proposed Transwestern project that would include the construction of a new lateral from Transwestern's mainline to the Phoenix metropolitan area. If this project is built, service would not begin until the fall of 2008 at the earliest. The Transwestern capacity would provide Southwest with an alternative to El Paso for part of its Arizona load.

Southwest's Commodity Gas Procurement

Southwest maintains a separate portfolio of commodity gas purchases for its Arizona service territory. The shape of this portfolio is illustrated in Table 2, which is a chart showing Southwest's planned Arizona Supply-Demand Balance for the 2005/2006 gas year. Southwest's portfolio for its Arizona commodity purchases has five major components.

- **Fixed price purchases** for the Arizona Price Stability Program (APSP)

  The APSP is designed to help stabilize the gas costs for Southwest's "core customer" residential and small commercial gas sales load. In the past, Southwest has implemented the APSP with fixed price gas purchase contracts having terms ranging up to 12 months. These fixed price contracts have been baseload contracts with must-take provisions. Southwest's fixed price purchases for the APSP were 50% of Southwest's forecasted core customer load of 59 Bcf for the 2005/2006 gas year. Fixed price purchases for the APSP were approximately 61% of Southwest's actual total purchases for the 2004/2005 gas year.

- Term contracts for **firm baseload supplies** — winter season

Southwest also purchases some baseload supplies at prices reflecting current gas market conditions for first-of-the-month purchases. During the winter season, Southwest uses firm contracts with terms up to five months in length to ensure that these supplies will be available. Pricing is index-based. Some of the term contracts for baseload supplies also have limited monthly swing capabilities. Southwest's monthly baseload purchases under its winter season term contracts were approximately 4% of Southwest's total purchases in the 2004/2005 gas year.

- Term contracts for **peaking supplies** — winter season

As indicated in Table 1, there is a very wide range between the highest daily load that may occur in a winter month and the lowest daily load in that same month. Southwest cannot make baseload purchases for more gas than the lowest daily load that may occur during the month, because baseload purchases flow at a constant daily rate for the entire month, but Southwest must still be prepared to serve the highest daily load. To obtain the needed flexibility in its daily purchase quantities, Southwest obtains contracts that allow it to adjust its purchase quantities on a daily basis. The supplies purchased under these contracts are called "peaking supplies." As indicated graphically in Table 2, Southwest relies on its peaking supplies for more than half of the maximum daily load that it prepares to serve in each winter month.

Southwest's contracts for peaking supplies are firm contracts for the winter months. Under each contract, Southwest has the right to nominate a purchase quantity from zero up to the maximum contract quantity on each day. Some of the peaking supplies are shown in Table 2 as "Late Cycle Peaking" because they are purchased under contracts that allow Southwest to adjust its daily nomination after the gas day has begun. These "intra-day" nominations enable Southwest to respond to weather and other load changes as they occur, even within a single gas day.

Southwest's contracts for peaking supplies have index-based commodity charges, often accompanied by demand or inventory charges to support the swing features.

For the 2004/2005 gas year, Southwest used its peaking contracts for approximately 16% of its total commodity purchases. The commodity volume of Southwest's peaking supplies is much smaller than the commodity volume of Southwest's APSP and other baseload supplies (64%, as noted above), despite Southwest's reliance on peaking supplies for more than half of its daily supply availability, because the actual load on most days is much closer to the minimum load served with baseload contracts than it is to the maximum daily load that Southwest is prepared to serve. Southwest therefore uses its peaking contracts at a low load factor, whereas the baseload contracts are — by definition — used at a 100% load factor in each month.

- Monthly **baseload supplies** purchased at current (**spot**) prices — summer

  During the summer, Southwest purchases some baseload supplies at current market prices (in addition to the fixed price purchases in the APSP) under one-month contracts. These monthly baseload purchases are included in the "Spot" supply category in the chart in Table 2. Southwest's baseload supplies in the summer months were approximately 11% of Southwest's total purchases in the 2004/2005 gas year.

- Daily **spot purchases** for swing supplies — summer

  During the summer, when daily load variations are not so large as in the winter months, Southwest matches its daily supply to its daily loads by making daily purchases in the spot market. Southwest makes some of these purchases at negotiated (fixed) prices, and some at index-based prices. Daily spot purchases were about 8% of Southwest's total purchases in the 2004/2005 gas year.

<u>Term Structure of Southwest's Portfolio</u>

Southwest obtains term contracts for all of the commodity gas supplies that it purchases during the winter season, but it relies on monthly and daily purchases in the spot market for about half of the gas it purchases during the summer season. These arrangements are consistent with the practice of other LDCs. A useful report of the purchasing practices of other LDCs is the American Gas Association (AGA) annual survey of the winter season gas commodity purchasing arrangements used by its members. The AGA published its report of the 2005 survey on July 19, 2005 as Energy Analysis report EA 2005-01, "LDC Supply Portfolio Management during the 2004-2005 Winter Heating Season" (*2005 AGA Survey*). This report is attached as Appendix B.

In the *2005 AGA Survey,* slightly more than half the respondents indicated that they did not obtain any of their gas supplies for the peak month using monthly or daily contracts, which indicates that reliance on term contracts (more than one month) is the standard industry practice for the winter season. The *2005 AGA Survey* did not collect data on the term structure of commodity purchase arrangements for the summer season, but a reduced reliance on term contracts for summer purchases is typical of LDCs with which the author is familiar.

Baseload and Daily Purchases

Southwest's reliance on extensive use of peaking supplies (in winter) and daily spot purchases (in summer) is atypical, but it is a direct and necessary consequence of Southwest's portfolio of capacity resources. Most LDCs use storage withdrawals as the primary "swing" supply in the winter, and they do not require large day-to-day variations in their purchase quantities. In summer, they achieve the same stability of daily purchase quantities by swinging their storage injections up on days when loads are relatively low, and swinging injections down on days when loads are higher. Southwest cannot use this portfolio strategy because currently there are no operating natural gas storage facilities serving Southwest's Arizona market area.[1]

Southwest could purchase production-area storage. If Southwest did so, it could reduce its use of peaking supplies in winter and daily purchases in summer, and instead increase its baseload purchases during the summer. Southwest's total winter purchase quantity would decrease, because storage withdrawals would replace some of the purchases, and Southwest's total summer purchases would increase despite the reduction in daily spot purchases. Southwest has analyzed production-area storage proposals in the past, and it has found them to be uneconomic because the price of the storage service exceeds the commodity cost savings that it would have permitted. Most other LDCs have market-area storage, and it provides the added benefit of reduced pipeline transportation capacity costs that Southwest cannot achieve with production-area storage, as explained in the discussion of Southwest's capacity.

Pricing Arrangements for Baseload Purchases

Baseload purchases are purchases that flow at a constant daily rate for an entire month. Southwest, like other gas utilities, makes some baseload purchases on a monthly basis. Southwest also makes some baseload purchases under contracts that extend for more than one month. Contracts that extend for two or more months, up to 12 months, can be called intermediate-term baseload purchases, and they are a staple of Southwest's APSP. Baseload purchases extending for terms longer than one year are long-term purchases. Southwest does not generally make long-term baseload purchases, but Southwest does make intermediate-term baseload purchases at fixed prices for the APSP, with the gas to be delivered as far as 24 months into the future.[2]

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[1] While several Arizona market-area storage projects have been proposed, including two projects from El Paso, none have successfully been developed. Southwest continues to review storage and other infrastructure projects in Arizona for inclusion in its mix of resources.

[2] For example, Southwest might purchase gas in the summer of 2006 for delivery during the winter months December 2007 through February 2008. The term length of such a contract would be only three months, so it would be an intermediate-term contract, but the delivery dates would be approximately 18 months after the contract was negotiated.

Several different pricing arrangements are available for baseload purchases. One method is for Southwest to establish a fixed purchase price with the seller.

A second method is for Southwest to establish a "basis" component of the total price with the seller, and then add the NYMEX component of the total price reflecting the current NYMEX price for the applicable futures contract. The "basis" component of the total price is the difference between the price at Henry Hub in Louisiana, which is the location where physical volumes purchased under NYMEX futures contracts are actually delivered, and the location at which Southwest wishes to make its actual purchase. Basis differentials thus represent the local market conditions that affect the price of gas at specific locations where gas is purchased. Most gas purchase transactions are priced by combining a basis differential with a NYMEX component, either explicitly or implicitly.

If Southwest and the seller fix the NYMEX component of the total price at the same time they agree on the basis, the purchase becomes, in effect, a fixed price purchase. Alternatively, the parties can agree that the NYMEX component will be the settlement price on the last day the applicable month's NYMEX futures contract is traded, or they can establish some other formula for setting the NYMEX component of the total price. A variation on this arrangement is to complete the purchase with a fixed basis and a floating NYMEX component, but allow Southwest to "trigger" the NYMEX component at any time on the basis of the NYMEX price of the applicable month's futures contract at the time of the triggering.

A third major pricing method is index-based pricing. With index-based pricing, Southwest and the seller would agree that the purchase price will be based on a specific published index for first-of-the-month purchases at a specific location, such as the Bondad receipt point on El Paso in the San Juan basin production area. The actual purchase price could be agreed to be the published index, or it could be the index plus or minus a relatively small amount (typically up to a few cents per Dth) agreed upon in the purchase negotiations or obtained as a result of a competitive solicitation by Southwest for index-based bids.

Southwest uses all three of these major pricing methods, making some of its baseload purchases under each method. Some use of fixed prices or NYMEX-based pricing methods is important because these methods provide greater flexibility and an opportunity for Southwest to diversify the times at which its prices -- and especially their NYMEX component -- are established. When Southwest makes an index-based purchase, it must accept a price that is not yet known at the time Southwest commits to the purchase, and the index price that is eventually published will represent gas market conditions on the last trading day or during the last few days of the month prior to the one when the gas flows. The *2005 AGA Survey* indicates that index-based pricing is the principal pricing arrangement used by LDCs for monthly purchases. Southwest's reliance on fixed price contracts for most of its baseload purchases is a direct consequence of the relatively large size of the APSP, which is discussed below as an aspect of Southwest's price risk management arrangements.

In procuring baseload commodity gas supplies, it is important for the utility to engage in a competitive process, and Southwest does so. Southwest uses bid solicitations to obtain the best (*i.e.,* lowest) basis for its fixed price purchases, including those under the APSP. Southwest uses informal solicitations or the Intercontinental Exchange (ICE) trading platform to obtain NYMEX-based or index-based contracts for its monthly purchases. These procurement methods are consistent with the practices of other gas utilities.

<u>Pricing Arrangements for Swing and Daily Spot Purchases</u>

A swing purchase is a purchase contract covering one or more months, but with a contractual right for Southwest to nominate or change the purchase quantity on a daily basis. Southwest calls its swing purchases "peaking supplies," and that is the rubric under which they have been identified as part of Southwest's portfolio for its winter season purchases.

A daily purchase is a purchase of gas supplies to be delivered on a single day, or sometimes for more than one day but less than an entire calendar month. The difference between a swing purchase and a daily purchase is that the swing purchase contract is arranged in advance, whereas a daily purchase is arranged on an *ad hoc* basis when Southwest is ready to purchase the gas, typically the day ahead of the day the gas is to be delivered.

Two pricing arrangements are available for daily purchases -- fixed prices, and index-based prices. They are similar to the fixed price and index-based pricing arrangements for baseload purchases. The only important difference is that index-based prices for daily purchases are related to a published index of daily gas transaction prices, whereas the index-based prices for baseload purchases are related to published indexes of first-of-the-month prices. NYMEX-based pricing is not available for daily purchases because the NYMEX trades gas futures contracts only for baseload monthly purchases.

Southwest uses both of the available pricing methods for its daily purchases, sometimes negotiating a set or fixed price, and sometimes purchasing at an index-based price. This practice is consistent with the practices of other gas utilities.

The commodity pricing arrangement for swing purchases is generally index-based. Fixed price arrangements are not generally available because a swing purchase contract is, in effect, an option -- but not an obligation -- for Southwest to purchase gas on any day of the month or months covered by the swing purchase contract. If the price were fixed in advance, Southwest would exercise its option to nominate the full purchase quantity on days when the market price exceeded the contract price, causing a loss for the seller. On days when the market price was less than the swing contract fixed price, Southwest would not nominate any swing contract purchases, and would instead make a daily purchase in the market. The use of index-based pricing assures that Southwest will each day pay a price bearing some relationship to the market value of the gas that it nominates for purchase under the swing contract.

Southwest obtains swing purchase contracts sufficient to provide the daily supplies that it will need during the winter season, to ensure that these swing supplies are available when and as needed, especially on cold days. As explained above, this arrangement is consistent with the practice of other gas utilities. Swing purchase contracts often involve modest demand charges to compensate the seller for standing ready to provide the full contract quantity every day of the contract term, even though the seller has no assurance that it will actually sell any gas because Southwest can choose to nominate zero purchases every day. Swing contracts may also have small commodity price premiums above the published index for any quantities actually nominated. Southwest uses solicitations to obtain the best available terms -- lowest demand charges, and smallest commodity price premiums -- for its swing purchase contracts. The use of solicitations is consistent with the practice of other gas utilities.

Price Risk Management and the Arizona Price Stability Program

Price risk management is an attempt to avoid the unexpectedly high purchased gas costs that occur when gas prices reach unexpected heights. Price risk management necessarily involves some costs, because there is no "free lunch" in the market for natural gas. The most common way of "paying" for price risk management is by sacrificing some of the opportunity to benefit from unexpected gas price decreases. Price risk management is not -- and cannot be -- a strategy to achieve uniformly lower gas costs under all market conditions, because there is no such magic strategy.

Southwest manages its gas price risks by purchasing approximately half of its projected normal weather requirements under fixed price contracts with prices established (*i.e.*, fixed or set) up to 24 months in advance of the time Southwest receives the gas. Southwest thus avoids the risk of unexpected gas price increases on half of its purchases, because the prices for those purchases are fixed -- and therefore known -- in advance. But this arrangement also sacrifices the opportunity to gain from any unexpected gas price decreases on those same fixed price purchases. The effect of this fixed price purchase program is therefore to provide some stability for Southwest's purchased gas costs, and the fixed price purchase program is aptly called the Arizona Price Stability Program, or APSP.

As noted above, price stabilization does not achieve uniformly lower gas costs. But it does tend to reduce gas costs in a rising gas market. The price that Southwest pays for its fixed price purchases reflects the gas market conditions at the time the fixed price contract was established, which is (on average) about 12 months before the gas is received. In a rising gas market, prices from last year are lower than current prices, and a price stability program thus achieves lower purchased gas costs. But in a falling market, a price stability program tends to yield higher prices, because the benefit of the falling prices cannot immediately affect the supplies already purchased in advance of delivery under fixed price contracts.

The evaluation of Southwest's APSP involves three principal issues. The first is the size of the program, which for Southwest is approximately half of its projected total normal weather requirements. The second is Southwest's decision to fix the prices of some gas purchases in advance of delivery, rather than use other possible price risk management strategies. The third is Southwest's use of fixed price purchase contracts as the instruments for fixing the price of the purchases included in the APSP.

Size of the APSP -- Southwest's use of price protection for 50% of its projected annual purchases is towards the high end of the spectrum of typical commodity purchasing practices. A more typical strategy is to obtain price protection (using fixed price purchases, financial instruments, or a combination) for approximately 50% of the planned normal weather flowing gas purchases in the winter season, with less price protection (often none) for gas purchased in the summer season. Fixed price purchase programs that apply only or primarily to the winter season are common in Maryland, Michigan, and Pennsylvania, and only in Michigan is the fixed price purchase target typically set as high as 50% of projected normal weather purchases in the winter season. The *2005 AGA Survey* reports that fewer than half of the respondents used fixed prices for any of their purchases under long-term or mid-term contracts, and only one-fourth used fixed prices for at least 25% of their mid-term contract purchases. On the other hand, the same survey also indicated that 70% of the respondents used financial instruments to hedge some of their purchases for the 2004-2005 winter season, and almost half of all the respondents hedged up to 50% of their winter purchases.

The relatively large size of Southwest's APSP reflects Southwest's atypical commodity supply situation, which is in turn a direct consequence of Southwest's lack of seasonal gas storage resources in its gas supply portfolio. Other gas utilities automatically obtain greater pricing diversity than Southwest because their commodity purchases are spread more evenly throughout the year than Southwest's purchases. They obtain this diversity by purchasing part of their winter delivery requirements in the summer months and injecting those summer purchases into seasonal storage. Seasonal storage also improves price stability for supplies used during the winter season, because the cost of gas in storage is established at the time it is injected and therefore known before the winter season begins. Southwest's purchases, in contrast, are concentrated in the winter season because they must match Southwest's seasonal load pattern. Southwest's extensive use of fixed price purchases, in both the summer and winter, helps to offset the absence of storage resources.

Alternative price risk management strategies -- Southwest's use of fixed price purchase arrangements is not the only possible way to manage price risk. The principal alternative is the purchase of call options. The holder of a call option has the right -- but not the obligation -- to purchase gas at the "strike price" of the option. The advantage of a call option is that the holder can benefit from any unexpected gas price decreases, whereas the holder of a fixed price purchase arrangement is obligated to purchase gas at the price fixed in advance, even if market prices decline between the time the price is fixed and the time the gas is to be delivered. The disadvantage of a call option is that it involves an up-front (and non-refundable) cost to purchase the option itself.

When an LDC uses call options for risk management, it typically uses them to protect against large, and therefore unlikely, gas price increases. It is therefore common for most of an LDC's call options to expire without being exercised, but that does not mean that the LDC's initial purchase of its call options was unwarranted.

An alternative way to offset the cost of purchasing a call option is to write (*i.e.*, sell) a "put" option. A put option obligates the writer to purchase gas at the specified strike price if the holder of the option chooses to exercise it, but the writer of the option has no right to demand that gas. The combination of a put option and a call option is called a gas price "collar." For example, if the NYMEX futures price for gas to be delivered in February 2008 is $10.00 per Dth, an LDC could purchase a call option with a strike price of $11.50 and write a put option with a strike price of $9.00 per Dth. The LDC would end up paying the market price if it remained in the range between $9.00 and $11.50 per Dth; but it would exercise its call option and pay only $11.50 if the market price rose above that level; and it would be obligated to purchase at $9.00 if the market price fell below that level. The LDC's purchase price would be collared in the range from $9.00 to $11.50 per Dth.

When the cost of a call is completely offset by the proceeds from the sale of a put, it is called a "costless collar." Costless collars are typically asymmetric relative to prevailing market prices and, as a result, they require the consumer to bear more upside price risk than the potential benefit from falling prices. For example, if the NYMEX futures price for gas to be delivered in January was $12.00 per Dth, a costless collar may result in a range of $11.50 to $15.00. The LDC could participate in falling prices up to $0.50 per Dth but would be exposed to price increases up to $3.00 per Dth. Under present gas market conditions, collars that are reasonably symmetric around the current NYMEX futures price still require a cash outlay by the LDC, because the price (cost) of the call option exceeds the sales price received by the LDC for the put option. Even with an asymmetric collar, like the asymmetric example in the preceding paragraph (with the put option strike price closer to the current NYMEX futures price than the call option strike price), reasonably structured collars tend to involve an up-front purchase cost.

The opinion of the author is that an LDC should use fixed price purchase arrangements as the foundation for its price risk management program. The use of call options or collars is not necessary. If an LDC uses them, it should only be as a relatively small supplement to a fixed price purchase program. The only advantage of a call option is that it preserves the opportunity to benefit from gas price decreases. But if an LDC does not have any fixed price contracts, then it will obtain the benefit of any gas price decreases on 100% of its purchases. Sacrificing part of this benefit by entering into some fixed price purchase arrangements is the least painful way to pay for protection against the risk of gas price increases, and in the author's view it is far better than incurring an out-of-pocket cost for protection. On the other hand, if an LDC already has fixed the prices for a substantial portion of its projected purchases, then it has obtained its upside price protection by trading away the opportunity to benefit from any price decreases on those purchases. If further protection against upward price movements on an even larger fraction of the projected purchases is desired, such protection may justify the use of call options.

The author is not aware of any compilations or reports of the extent to which gas utilities use call options or collars (as opposed to fixed price purchase arrangements) for price risk management. In the author's experience, LDCs that use call options or collars do so for only a relatively small fraction of their projected purchases, typically around 10% or less. All of the LDCs that obtain price protection for as much as one-fourth of their winter purchases use fixed price purchase arrangements as their primary price risk management strategy.

Price risk management tools, and the use of financial instruments instead of fixed price purchase contracts -- Fixed price purchase contracts are not the only way for an LDC to establish fixed price gas purchase arrangements. Alternatives include various financial instruments that hedge future purchase prices in ways that enable Southwest to achieve the same result as it would with a fixed price gas purchase contract. For example, some financial intermediaries and other gas market participants will "sell" the to-be-published index price for some future month (such as February 2008) at a specified purchase location (such as the Bondad receipt point on El Paso in the San Juan basin production area) for a fixed price. If Southwest purchases this "swap" as a hedge against a future gas purchase, it has the same effect as entering into a fixed price contract now for delivery of the gas in the specified future month. Southwest pays the published index price for its actual purchase, but it receives the same published index price from its swap arrangement and pays the fixed price that it obtained when it first entered into the swap transaction.

Another alternative is the use of NYMEX futures contracts as hedges. Instead of purchasing the gas that it actually plans to receive in a future month, Southwest can purchase a NYMEX futures contract for the delivery of a corresponding quantity of gas at Henry Hub in Louisiana, which is the physical delivery point associated with all NYMEX gas futures contracts. Then, when Southwest purchases the gas that it actually plans to receive, typically in the week or two before the month when the gas is to be delivered, Southwest sells the NYMEX contract at the same time. Southwest's net cost from the two transactions is the cost of its actual purchase, less the sales price of the NYMEX on the same day as Southwest's actual purchase, plus the price at which Southwest originally purchased the NYMEX futures contract. The difference between the first two of these three components is the so-called "basis" for the location where Southwest actually purchases its gas (relative to Henry Hub), so Southwest's total cost for the purchase is the original cost of the NYMEX futures contract plus the current basis at Southwest's actual purchase location, typically in the Permian or San Juan basin gas production areas. The NYMEX futures contract is a good hedge against this purchase price because the basis differentials for the Permian and San Juan basin production area receipt points are subject to much less market price fluctuation than the NYMEX itself, so the purchase of a NYMEX futures contract removes most of the price risk from the future purchase of gas even in the Permian or San Juan basins. To "perfect" the hedging arrangement, Southwest could use a "basis swap" to lock in the basis differential between the NYMEX contract and the market area, in this case the Permian or San Juan basin. The basis swap protects against a basis blowout where prices in the purchase area rise much more than the NYMEX contract. A good example occurred during the winter of 2000-2001, when gas prices at the California border were significantly more volatile than at the Henry Hub.

Southwest is considering the use of financial instruments such as NYMEX futures contracts and swaps instead of fixed price purchase contracts for at least part of the APSP. If Southwest makes this change, the price hedging arrangements for the APSP would be divorced from the commodity purchases being hedged, and the commodity purchases for the APSP volumes would be moved into one or more of the other categories of Southwest's commodity purchases. A change in this direction is consistent with the practices being adopted by some of the more forward-looking LDCs at this time. The *2005 AGA Survey* indicated that slightly more than one-fourth of the respondents used swaps and slightly less than one-fourth used NYMEX futures contracts as hedges for some of their 2004-2005 winter purchases. These figures probably overstate the use of hedges to achieve the equivalent of fixed price purchases because some LDCs may have responded affirmatively as using both swaps and NYMEX futures, and some of the respondents may have been using swaps for purposes other than achieving the equivalent of fixed price purchases.

In the author's experience, several LDCs have within the past two years adopted or proposed plans to use financial instruments rather than fixed price gas purchase contracts to hedge their future purchases and achieve the equivalent of fixed price purchases. The author has generally supported these proposals in the proceedings in which they have been presented.

Financial instruments have two advantages over fixed price gas purchase contracts as price hedges. The first is that a fixed price gas purchase contract can only be used to purchase baseload supplies that flow at a uniform daily rate throughout the delivery month. Financial instruments, in contrast, can also be used to hedge swing or peaking supplies, because the hedging arrangements are divorced from the actual gas purchase contract. Of course, the financial instrument hedges only the first-of-the-month price, and the LDC is still subject to the risk of daily price fluctuations during the month.

The second advantage of using financial instruments is that it can help to reduce the risk of counter-party default. With a fixed price gas purchase contract, Southwest is dependent upon the survival and eventual performance of the seller. If Southwest uses NYMEX futures contracts for its hedges, then the counter-party bearing the performance risk is the NYMEX itself, which is most likely a safer arrangement than a fixed price gas purchase contract. Even with a swap, Southwest probably has the opportunity to be more selective about the identity of the counter-party than with a fixed price gas purchase contract.

Summary and Conclusion

Southwest's purchasing practices are generally consistent with the practices of well-managed gas utilities. Southwest employs a variety of different gas purchase contract term lengths, contract "shapes," pricing arrangements, and risk management tools for its commodity gas purchases. Some of Southwest's purchases are for terms as short as one day, others for terms as long as 12 months. Some of the purchases with terms of one or more months are baseload purchase contracts; others have swing provisions for Southwest's peaking supplies.

Southwest uses a competitive bidding process to secure fixed price and term contracts. Term supplies are obtained through an annual solicitation process which encourages the participation of a broad base of suppliers. Fixed price purchases for the APSP are acquired on a periodic basis, generally every four to six weeks, through a competitive bidding process. Southwest secures spot supplies through informal solicitations via the telephone or electronic medium (like email or instant messaging) or the ICE trading platform. All of these procurement methods are consistent with the practices of other gas utilities.

Southwest manages gas price risks through its APSP. In the APSP, Southwest purchases half of its commodity supplies under fixed price arrangements established at least a month in advance of the delivery date for the gas, and it arranges some of its fixed price purchases as much as 24 months in advance of delivery. Southwest's use of a price risk management strategy is consistent with the practice of most other gas utilities, but not all utilities make such extensive use of fixed price contracts. The large size of Southwest's APSP relative to other gas utilities is due to the lack of storage resources in Southwest's portfolio. Production-area storage would not benefit Southwest operationally, and at present there are no market-area storage facilities available to serve Arizona.

In the future, Southwest may wish to expand its APSP to include the use of financial instruments along with fixed price contracts. Some common instruments include price swaps, put and call options, NYMEX future contracts, and basis swaps. The use of these instruments, in a properly structured risk management program, may help Southwest to further reduce the short-term price volatility in its supply portfolio.

The other half of Southwest's purchases use pricing arrangements that reflect current gas market conditions at the time the gas is delivered. Southwest negotiates the prices for some of those current purchases, and it uses index-based pricing for other purchases. Southwest determines the relative importance of each of these different constituents of its commodity gas portfolio to match the loads that it serves at the best cost available within the constraints of the portfolio of pipeline transportation resources that Southwest uses to bring its commodity gas purchases to its Arizona city gates.

Table 1 - Projected Normal Weather Loads, November 2006 – October 2007
Southwest Gas Corporation, Arizona Service Area
(Volumes in Dekatherms (Dth))

	Projected Monthly and Seasonal Loads	Projected Average Daily Load	Projected Maximum Daily Load (Design Day)	Projected Minimum Daily Load	Projected Minimum as Percent of Average	Swing Requirement (Maximum Load Less Minimum)
November 2006	6,053,105	201,770	382,778	162,082	80%	220,696
December	9,847,886	317,674	604,204	165,948	52%	438,256
January 2007	9,571,375	308,754	627,248	166,964	54%	460,284
February	7,558,226	269,937	579,790	166,721	62%	413,069
March	6,601,901	212,965	441,730	166,094	78%	275,636
April	4,724,456	157,482	246,814	146,531	93%	100,283
May	3,749,076	120,938	162,059	119,678	99%	42,381
June	3,243,596	108,120	109,386	108,068	100%	1,318
July	2,991,128	96,488	96,488	96,488	100%	0
August	2,981,239	96,169	96,191	96,169	100%	22
September	3,021,000	100,700	101,002	100,700	100%	302
October	3,866,051	124,711	226,950	117,155	94%	109,795
Annual total	64,209,039	175,915	627,248			
Winter season total (November – March)	39,632,493	262,467	627,248		63%	

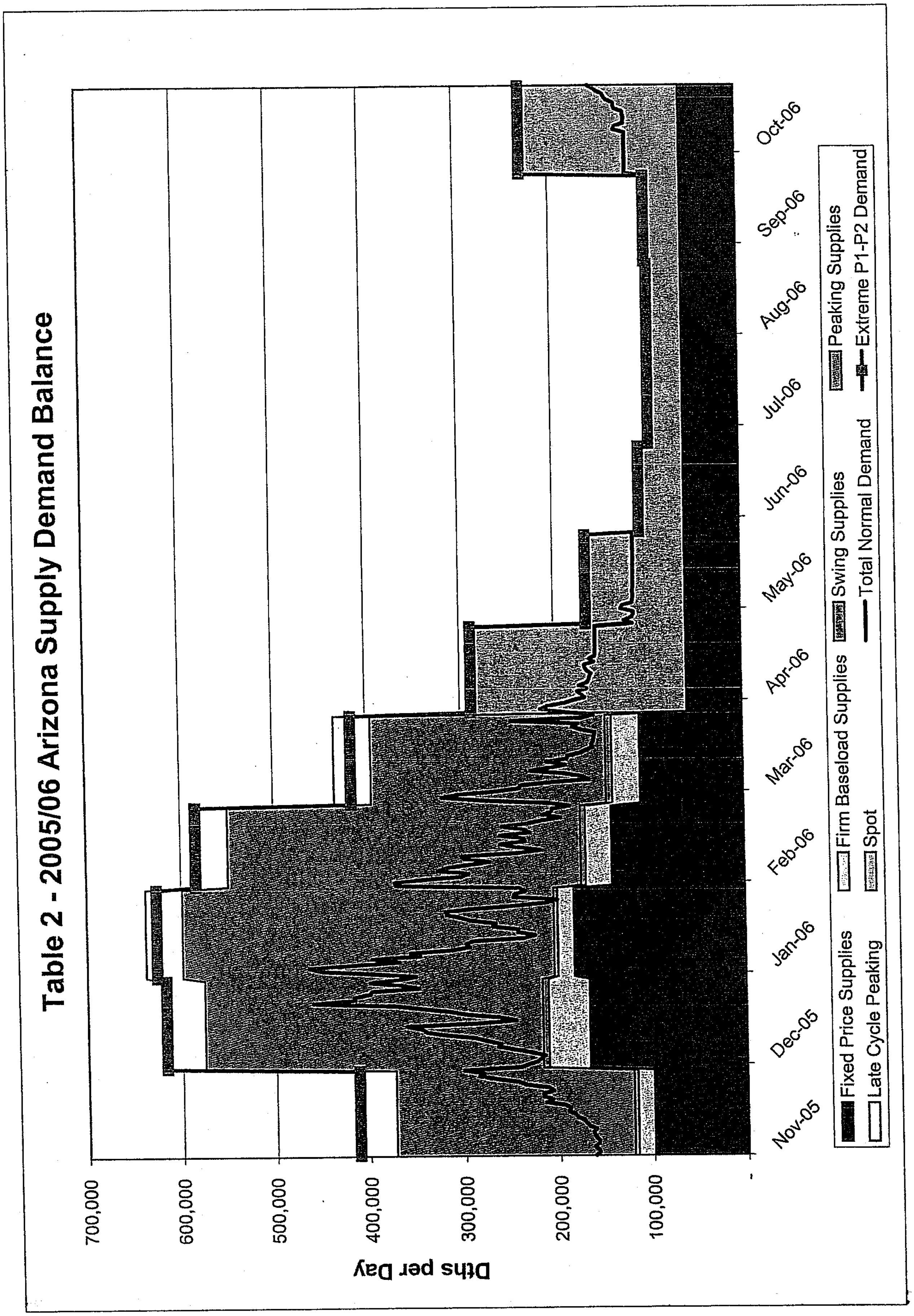
Table 2 - 2005/06 Arizona Supply Demand Balance
Dths per Day
700,000
600,000
500,000
400,000
300,000
200,000
100,000
-
Nov-05
Dec-05
Jan-06
Feb-06
Mar-06
Apr-06
May-06
Jun-06
Jul-06
Aug-06
Sep-06
Oct-06
Fixed Price Supplies
Late Cycle Peaking
Firm Baseload Supplies
Spot
Swing Supplies
Total Normal Demand
Peaking Supplies
Extreme P1-P2 Demand

Qualifications of Ralph E. Miller

Ralph E. Miller is an independent consulting economist who works in the fields of regulatory economics, industrial organization, and public policy towards business. He has more than 30 years of consulting experience in the public utility and energy sectors of the economy, and several additional years in government and on the faculty of a major university. He specializes in energy supply and demand analysis, especially natural gas supply and distribution; antitrust and market structure analysis, including the introduction of competition into previously regulated areas; public utility ratemaking, especially gas and electric utility cost allocation and rate design; and the economics of regulation. He is the author of several published reports and papers in these areas.

During the past 30 years, Mr. Miller has presented expert testimony in more than 300 public utility rate cases and other proceedings before the FERC and other federal agencies, U.S. District Court and state courts, and more than two dozen state regulatory commissions. Over the years, he has addressed almost all the aspects of gas and electric utility regulation, including rate of return, accounting and revenue requirements, rate design and cost of service, electric fuel and purchased gas cost recovery, industry structure and the role of competition, incentive ratemaking and other types of innovative rate designs, gas and electric supply planning and power plant licensing, productivity and efficiency, and the determination of marginal, incremental, and avoidable costs.

Mr. Miller has more than 25 years of experience in gas procurement analysis. He has reviewed the gas supply planning and/or gas cost recovery arrangements of more than 15 gas distribution companies (LDCs) in numerous regulatory proceedings in seven states, and he has extensive experience in gas pipeline cases at the FERC.

Mr. Miller has been an independent consultant for twenty years. He also has ten years of experience as president or vice president of two different consulting firms specializing in public utility and energy matters. Before that, he spent three years in the federal government, where he was employed in positions at the Federal Power Commission (now the Federal Energy Regulatory Commission, or FERC), the Antitrust Division of the U.S. Department of Justice, and the Federal Energy Administration (now part of the U.S. Department of Energy, or DOE). He was on the faculty of the University of California for three years, where he taught economics courses at both the graduate and undergraduate levels.

Mr. Miller did his undergraduate work at Harvard College, where he received the A. B. degree *summa cum laude* in mathematics in 1961, and he was elected to Phi Beta Kappa. He then went on to graduate work in economics at Harvard, where he received a Master's degree in 1963. He continued his graduate studies there until 1966, and he completed all of the course requirements for the Ph.D. degree, but not a doctoral dissertation.

Mr. Miller has been working on gas supply planning and purchased gas cost recovery cases since prior to 1980, and he has concentrated his attention on these areas since 1990. Beginning in 1981, he analyzed the way Southern Union Gas Company acquired gas supplies for its New Mexico distribution system, and he testified on aspects of this subject in U.S. District Court in 1982.

At the FERC, he reviewed requests by three interstate pipelines for recovery of take-or-pay buyout and contract reformation costs under Order No. 500. He has also testified in many pipeline rate proceedings and two pipeline gas inventory charge proceedings, and he reviewed the gas supply restructuring plans proposed by two pipelines as part of their Order 636 compliance. He also reviewed the implementation of Order 637 by two pipelines.

At the state level, he (along with one or more colleagues) has performed many management/performance audits of the gas purchasing practices and policies of gas distribution companies in Ohio, and the reports on these audits were submitted to the Public Utilities Commission of Ohio (PUCO). The companies that he has audited include three of the major LDCs in Ohio.

In Michigan, he has reviewed and testified on the gas supply plans and gas cost recovery (GCR) reconciliations of Consumers Energy Company and Michigan Consolidated Gas Company in each year since 1988, except for the three years when their GCR clauses were suspended. He has also reviewed and testified on many of the gas supply plans and GCR reconciliations of the other LDCs in Michigan during this period.

In New Jersey, he participated in the levelized gas adjustment clause (LGAC) proceedings as a consultant to the Ratepayer Advocate (or its predecessor, the Public Advocate) for ten years. He reviewed the LGAC filings and gas supply planning of each of the four New Jersey LDCs at least once during this period. He also participated extensively in the consideration of gas cost recovery issues in the unbundling proceedings and base rate cases of the New Jersey LDCs.

In Maryland, Mr. Miller has for more than 25 years been reviewing the gas supply planning and gas purchases of several Maryland utilities, including Baltimore Gas and Electric Company and Washington Gas Light Company, in a variety of proceedings. Other states in which he has done similar work include Pennsylvania, Nevada, and Utah.

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LDC SUPPLY PORTFOLIO MANAGEMENT DURING THE 2004 - 2005 WINTER HEATING SEASON

I. Introduction

As with the prior winter, the issue for consumers and local distribution companies (LDCs) purchasing natural gas during the 2004-2005 winter heating season (WHS) was not its availability but its cost. With supply and demand relationships in the market remaining tight, most pressure on commodity prices was upward pressure. In fact, to begin the winter heating season the NYMEX close (October 27, 2004) for November 2004 futures contracts was $3.17 per MMBtu higher than the November close one year earlier.

Even with that backdrop, natural gas supplies remained relatively strong throughout the 2004-2005 winter. A review of gas supply sources shows that underground storage exceeded the five-year average for inventories at winter's end, domestic production appeared to sustain itself and LNG was in the process of setting another annual record for imports (now accounting for about three percent of available supply). Still, market prices (at $6.00-7.00 per MMBtu and more) seem to point to high level issues for the longer-term regarding natural gas supply -- and questions emerge. For example, if increasing gas supply and infrastructure in the form of LNG (or even pipeline gas from Alaska) is viewed as a positive element for mitigating price volatility and possibly the absolute price level for gas consumers, how can the infrastructure be developed without long-term commitments to support such projects? Are purchasing practices beginning to demonstrate changes in contracting terms or lengths and are more companies using financial or other instruments to protect gas consumers from market price fluctuations?

This analysis describes critical elements of the 2004-2005 WHS and reports the results of the *Winter Heating Season Performance Survey*, which was conducted under the guidance of the AGA Gas Transportation and Supply Operations (GTSO) Task Force. Data for this report were acquired by surveying AGA member local distribution companies and concentrate on defining peak-day and peak-month supply practices, as well as certain regulatory and market hedging practices.

This year, responses (whole and part) were received from 54 LDCs with service territories in 30 states. Ten of the companies have service territories west of the Mississippi River, while the balance of the companies that responded are located in the east. The sample companies had an aggregate peak-day sendout of 43,391,052 Dekatherms (Dth), acknowledging that the peak-day did not occur on the same calendar day for each company. However, these same companies planned for an aggregate peak-day of 54,200,554 Dth, meaning only 80 percent of the planned peak volume for sendout was actually required during the 2004-2005 WHS. This is the second year in a row that the sample company actual peak-day sendout was only 80 percent of the design peak-day for the companies supplying responses to the winter heating season survey.

A list of companies returning surveys for this year's study is shown in Appendix A. The purpose of the survey is to document some gas delivery system operations during the past winter season and to provide insights into gas supply trends and procurement portfolio management. *The aggregated data presented in this report is in no way to be interpreted as establishing standards or best practices for gas supply management.* It is instead a snapshot of supply practices. In some cases, the report compares survey results for the 2004-2005 winter heating season with those reported in prior years. *It should be noted, however, that the compared samples are not identical and the data are not normalized in order to compensate for sample differences, weather or other factors.*

II. Executive Summary

The foundation for this report comes from survey responses submitted by 54 AGA member LDCs (compared to 43 one year ago). These companies had a non-coincident peak-day sendout of 43 million Dth and an average peak-day sendout of 803,538 Dth per company. The 54 companies reporting represent about 45 percent of the gas delivered by all AGA member companies during an annual period. Results of the winter heating season survey are generally presented as counts of companies that fit into percentage based categories (1-25 %, 26-50 %, and so forth) of supply volumes. The intent of this report is to document the data as a snapshot of current supply behavior by large purchasers of natural gas, in this case LDCs.

Weather

- Each month of the 2004-2005 winter heating season was warmer-than-normal, with the exception of March 2005, which was 5.1 percent colder-than-normal. For the period October 2, 2004 - April 2, 2005, heating degree day totals were 6.0 percent fewer-than-normal and thus the winter was warmer-than-normal on average for the nation as a whole.

- A view of heating degree days by region yields similar results. Only New England was colder-than-normal (1.2 percent), while every other region of the country was warmer for the 2004-2005 winter heating season. The central portion of the country was warmest when compared to normal for the cumulative winter heating season.

- For the country as a whole, temperature conditions were 6.0 percent warmer-than-normal and compares to the prior winter heating season (October 2003 – March 2004) when conditions were nearly the same – 5.0 percent warmer-than-normal.

Gas Supply Portfolios

LDCs build and manage a portfolio of supply, storage and transportation services, which include a diverse set of contractual arrangements to meet anticipated peak-day and peak-month gas requirements. For the 2004-2005 winter, sample companies planned for over 54 million Dth of required peak-day gas throughput but only 80 percent of that volume was actually required.

- It should be no surprise that purchases moved by firm transportation provided much of the gas to consumers for the peak-day and peak-month. Fifty-three of 54 companies indicated that firm supplies were a part of their gas supply portfolio, including 29 companies that showed between 26-50 percent of their required peak-day volumes coming from firm supplies.

- Forty-six companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage, while 34 companies also noted that up to 25 percent of the deliveries arriving at their citygate on a peak-day were earmarked for transportation customers on their system.

- Long-term agreements, defined as one year or longer, were used by 37 of 52 of companies within their peak-day gas supply portfolio (compared to 29 of 41 companies the previous year) and accounted for more than 50 percent of purchased gas for 15 companies on a peak-day (compared to 10 companies the previous year). Mid-term (more than one month, less than one year) agreements were utilized more often than one-month and daily agreements for 2004-2005 peak-day purchases.

- As a general statement, comparing 2004-2005 data to that collected two years ago (2002-2003 winter heating season with 65 companies responding to the survey), daily and monthly contract terms are less prevalent today than two years ago among the survey participants. This may be because recent daily pricing has been high relative to history. It may also be, however, that companies and Public Utility Commissions are becoming more comfortable with longer-term supply agreements as a part of a supply portfolio, remembering that a long-term deal today may be two years not 10 or 15 as in the past.

- When asked to describe the distribution of gas supply purchases among suppliers -- independent marketers, producers and producer marketing affiliates more than any other classes of supply aggregators, were cited by those responding to the winter heating season survey.

Supply Pricing Mechanisms and Hedging Issues

Several factors play a role in the market pricing of natural gas and of transportation services, including weather, storage levels, end-use demand, financial markets and various operational issues. When asked to identify the tools most effective to manage supply and price risk, survey respondents pointed to daily swing contracts, storage and LNG, weather-based calls and options, asset managers, fixed pricing and advanced purchases at fixed prices.

- When examining the purchase practices of companies during the past winter heating season, it is clear that first-of-the-month index pricing dominates the market for long- and mid-term supply agreements. However, this year's survey sample included references to fixed price, daily and other NYMEX-based arrangements.

- For long-term supplies (one year or more), 30 of 49 companies responding used first-of-the-month (FOM) pricing for a portion of their supplies, including 27 companies that used FOM for 51-100 percent of long-term gas purchases. Thirteen companies utilized some form of fixed long-term pricing.

- Mid-term purchases (more than one month, less than one year) were reported by 39 companies to most often be tied to FOM indices for significant volumes of gas. In addition, fixed-price (20 companies) and daily mechanisms (13 companies) were part of the mid-term pricing basket.

- Seventy percent of the companies responding indicated use of financial instruments to hedge at least a portion of their supply purchases. Even though this percentage is identical to last year, three years earlier only 55 percent of the companies responding had indicated the same. For this past winter, twenty-one of 37 companies providing data hedged up to 50 percent of their gas supply purchases during the winter.

- In addition, options (23 companies), fixed-price contracts (18 companies), swaps (16 companies) and futures (11 companies) were most often sited as financial tools used to hedge a portion of gas volumes delivered on a peak-day. This balance is similar to that of last year. The use of financial tools may be understated in this report inasmuch as some volumes delivered to LDCs from marketers and other suppliers are hedged by the third-party rather than the LDC or customer and may have been excluded from the LDC hedging calculation.

- On the physical side, in preparation for the 2004-2005 WHS 47 companies reported using storage as a primary hedging tool. Twenty-nine of those companies hedged between 26-50 percent of winter heating season supplies using underground storage compared to 22 companies last year. Several companies noted that storage (as a physical hedge) is the only hedge they employ, choosing not to use financial instruments at all.

- Companies use a portfolio of timed hedges to balance their approach to strategic price planning. When asked about the timing of hedging strategies, 25 of 38 companies (66 percent) responding indicated that they employ a six-month and less strategy for a portion of their hedges. Thirty-five of 38 companies utilized a 7-12 month strategy for a portion of their hedges, while 19 companies hedged forward for more than 12 months.

- Only seven survey respondents indicated that they used weather derivatives during the 2004-2005 winter heating season. This compares to six companies in 2003-2004 and eight companies during 2002-2003.

- When asked about their own regulatory environment, 37 of the companies responding to the question indicated that financial losses and gains were treated equally within their hedging plans. Only three noted that losses and gains were treated unequally.

- When asked about the relative ease of acquiring hedging products for 6-month or less hedges, thirty-eight companies saw current markets as less difficult or the same as the year before. Thirty-two companies said the same of hedges more than six months in duration. Very few companies indicated market conditions to be more difficult to operate within. This compares to last year's survey when up to a third of the companies viewed markets as more difficult to operate within.

- The majority of companies reported that acquiring financial hedges or implementing a strategy was no more or less difficult than the prior year. Thirty-one of the 54 companies responding indicated that for the 2005-2006 winter heating season they planned to hedge the same as this past winter heating season, eleven companies plan to hedge even more.

Gas Storage

Production and market area storage are key tools for efficiently managing LDC gas supply and transportation portfolios. However, it should be noted that storage practices are no longer dictated only by local utility requirements to serve winter peaking loads. Storage services now support natural gas parking, loaning, balancing and other commercial arbitrage opportunities that take place at market hubs and citygates.

- Forty-nine of 54 companies answering the question indicated that weather-induced demand compelled the respondents to utilize storage services. However, respondents also singled out no-notice requirements (42 companies), pipeline operational flow orders (20 companies), "must turn" provisions (35 companies) and arbitrage opportunities (18 companies) as reasons to maintain storage services within their gas supply portfolio during the 2004-2005 winter heating season.

- Must turn provisions may be in place for some storage contracts as a way to maintain facility integrity through an optimal pattern of injection and withdrawal in a storage field. During the 2004-2005 winter heating season, storage inventories were consistently higher than the prior five-year average. As a result, thirty-five of 54 companies (65 percent) singled out must turn provisions as influencing their use of storage this past winter – eighteen percent more than the prior winter.

- Forty-five of 54 companies used first-of-the-month index pricing to purchase gas for injection into storage with 20 of those companies indicating that 76-100 percent of gas into storage was based on FOM prices. Twenty-one of 54 companies (39 percent) used fixed-price schedules for some portion of their storage purchases – up from fourteen companies (33 percent) the year before. Twenty-five companies indicated that they purchased stored gas in the daily market compared to 18 companies the prior year. A majority of those 25 companies (15) acquired less than 25 percent of storage purchases in the daily market.

- Twenty-five companies indicated that they were actually constructing or examining the potential for physically adding underground storage, while 13 were considering peak shaving facility expansion during the next five years.

- For the nation as a whole, working gas inventories at the end of March 2005 were significantly higher than inventories from one-year prior (by 215 Bcf) and pointed to less gas required for net storage injections during the 2005 refill season.

LDC Transportation and Capacity Issues

Transportation-only customers have assumed a higher profile among all customers served by LDCs. Managing pipeline capacity efficiently is a challenge for many LDC's and can involve the release of capacity to the secondary transportation market.

- From April 2004 to March 2005, 20-26 of the companies (varying with the month) released between one and 25 percent of their pipeline capacity on a monthly basis to the secondary market, when that capacity was not needed to serve LDC customers. As many as 14 companies released between 26 and 50 percent of their capacity during the summer of 2004 compared to only 5 companies in the sample one year prior.

- Although not as active as two years prior when gas storage was under more stress, some operational flow orders (OFO) were issued during the 2004-2005 winter heating season. Twenty-two companies indicated impacts from OFOs. The median number of OFOs issued was 3 with a median duration of 3.5 days.

III. Weather

The 2004-2005 WHS started remarkably similar to the prior winter heating season as shown below in Table 1. For the October-December WHS kick-off, monthly heating degree days were fewer than normal in both years, resulting in warmer-than-normal cumulative conditions entering January. However, while January and February 2004 quickly turned colder-than-normal, January and February 2005 remained decisively warmer and, in fact, February was 10 percent warmer-than-normal for the nation as a whole.

Cumulative heating degree day totals eventually settled at 6.0 percent warmer-than-normal for the 2004-2005 WHS, even after a much colder-than-normal March, while the prior year winter heating season totals for temperature were 5.0 percent warmer-than-normal. For the 27-week period October 2, 2004 to April 2, 2005, only 10 weeks registered colder-than-normal conditions, on a national basis, with four of those weeks coming in March 2005. By winter's end and like the year before, only New England had seen greater heating degree day totals than normal (1.2 percent colder).

TABLE 1

MONTHLY COMPARISON OF NATIONAL HEATING DEGREE DATA
OCTOBER 2003 – MARCH 2005

MONTH	PERCENT CHANGE FROM NORMAL			
	2003 – 2004		2004 – 2005	
October	11.0%	Warmer	13.2%	Warmer
November	10.5%	Warmer	10.2%	Warmer
December	6.8%	Warmer	4.1%	Warmer
January	4.3%	Colder	6.5%	Warmer
February	2.2%	Colder	10.0%	Warmer
March	18.2%	Warmer	5.1%	Colder
TOTAL	5.0%	Warmer	6.0%	Warmer

Source: U.S. Department of Commerce, National Oceanic and Atmospheric Administration.

IV. Gas Supply Portfolios

LDCs build and manage a portfolio of supply, storage and transportation services to meet expected peak-day, peak-month and seasonal gas delivery requirements. The 1992 FERC Pipeline Restructuring rule (Order No. 636) increased competition in the interstate transportation market but introduced new risks to the process of acquiring natural gas and required pipeline capacity. In today's business environment, gas portfolio managers continually attempt to strike a balance between their need to minimize gas-acquisition risks and their obligation to provide reliable service at the lowest possible cost.

Given the reality of significant deviations from normal weather patterns (warm and cold), volatility in commodity prices and regulatory scrutiny of costs to consumers, local gas utility exposure to hindsight for gas supply practices has increased. Also, in some cases, the unbundling of gas sales and transportation services at the retail level have further prompted many LDCs to reassess the quantity of gas supplies they must contract for and at what cost.

Table 2 and Figure 1 illustrate the diversity of gas supply sources available to LDCs. It should be no surprise that purchases moved by firm transportation provided much of the gas to consumers for the peak-day and peak-month. Fifty-three of 54 companies indicated that firm supplies were a part of their gas supply portfolio, including 29 companies that showed between 26-50 percent of their required peak-day volumes coming from firm supplies. An additional eight companies showed 51-75 percent of peak-day supplies to be firm. But other categories of gas supply for peak-day deliveries are also important to the sample of companies.

For example, 34 companies out of 54 indicated that up to 25 percent of their citygate peak-day supplies were earmarked for transportation customers and 43 companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage. Eighteen companies indicated on-system storage as a supply source, also. Citygate purchases, local production and LNG or propane-air also provided up to 25 percent of peak-day supplies for 23, 8 and 19 companies out of 54, respectively. The visual impact of Figure 1 demonstrates that very few companies source a supply portfolio with all of their eggs in one basket. The table and figure show that the largest number of companies tend to employ a multiple supply source strategy in increments often amounting to 50 percent or less of their total supply package.

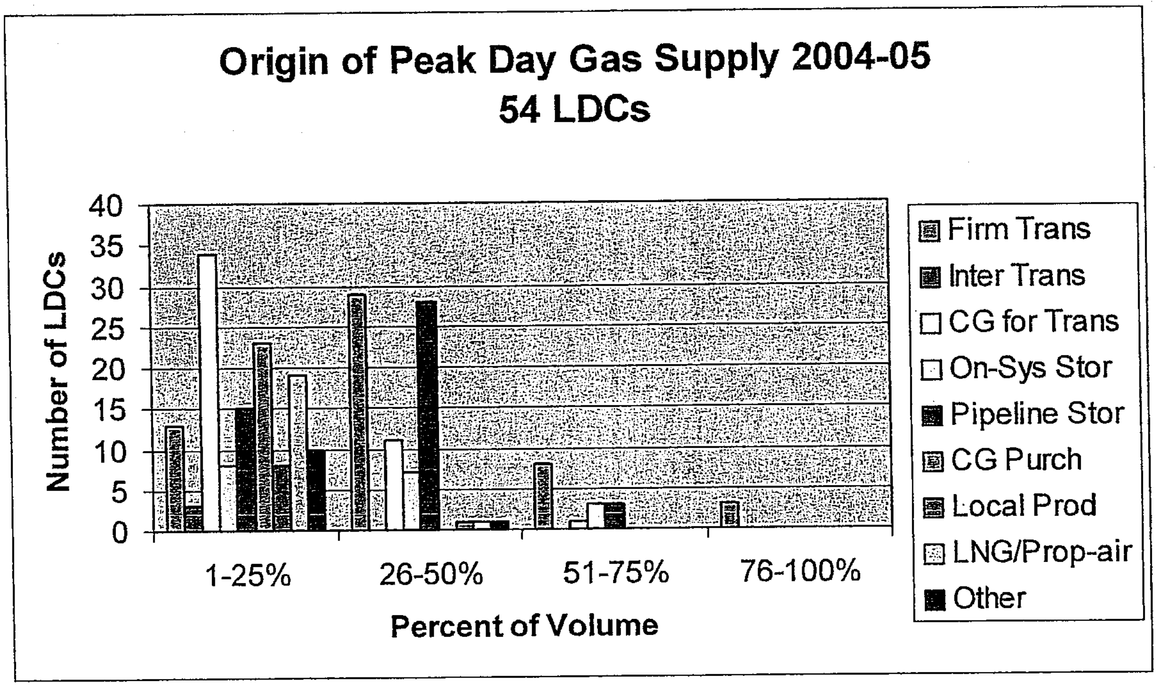
TABLE 2

ORIGIN OF LDC GAS SUPPLY
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

PERCENT GAS SUPPLY	PURCHASES VIA FIRM TRANS	PURCHASES VIA INTERRUPTIBLE TRANS	CITYGATE SUPPLIES FOR TRANS CUSTOMERS	ON-SYSTEM STORAGE	PIPELINE OR OTHER STORAGE	CITYGATE PURCHASES	LOCAL PRODUCTION	LNG PROPANE-AIR	OTHER
PEAK-DAY									
1 – 25	13	3	34	8	15	23	8	19	10
26 – 50	29	0	11	7	28	0	1	1	1
51 – 75	8	0	1	3	3	0	0	0	0
76 – 100	3	0	0	0	0	0	0	0	0
0	1	51	8	36	8	31	45	34	43
PEAK-MONTH									
1 – 25	7	2	22	7	30	19	6	15	4
26 – 50	22	0	19	8	13	0	2	0	2
51 – 75	15	0	0	2	1	0	0	0	0
76 – 100	5	0	0	0	0	0	0	0	0
0	1	48	8	33	6	31	42	35	44

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

FIGURE 1



According to Table 2, peak-month supplies were also heavily weighted toward purchases via firm transportation. Like peak-day supplies, peak-month supplies tended to be supplemented with pipeline and on-system storage, citygate purchases, citygate deliveries for transportation customers, LNG or propane-air and even some local production.

The diverse set of contractual arrangements that LDCs use to procure their gas supplies includes long-term, mid-term, monthly, and daily agreements. A mix of contracts allows the LDC to balance between competing needs, such as the obligation to serve its customers as the supplier of last resort and the need to maximize efficiency while minimizing costs. In many cases, longer-term contracts contribute to baseload obligations, while shorter-term contracts allow companies to respond to market changes. In the past, survey results reflected a transition toward shorter-term and spot contracts to meet peak requirements, which has been consistent with demands from consumers, regulators and the market, in order to pursue least cost options. However, recent developments in market volatility, particularly as they apply to natural gas acquisition prices is resulting in a reexamination by consumers and regulators of supply acquisition contracting with less emphasis on absolute least cost and more emphasis on price stability. Stability may mean a trend toward longer-term contracting and some argue that longer-term contracting will be necessary to underpin new supply sources in the future.

As a general observation, comparing 2004-2005 data to that collected two years ago (2002-2003 winter heating season with 65 companies responding to the survey), daily and monthly contract terms are less prevalent today than two years ago among the survey participants. This may be because recent daily pricing has been high relative to history. It may also be, however, that companies and Public Utility Commissions are becoming more comfortable with longer-term supply agreements as a part of a supply portfolio, remembering that a long-term deal today may be two years not 10 or 15.

Table 3 shows that long-term agreements, defined as one year or longer, were used by 37 of 52 companies (answering the question) and accounted for more than 50 percent of purchased gas for 15 companies on a peak-day. Last year's results produced only 10 companies that used long-term deals for more than 50 percent of their purchased gas on the peak-day. Mid-term (more than one month, less than one year) were utilized more often than one-month or daily agreements for peak-day purchases, also. This makes sense in an environment where daily gas prices tended to be high compared to recent history and many fluctuations in price were upward. In contrast, for peak-month gas purchases, 32 companies utilized mid-term agreements for between 26 and 100 percent of gas supplies, while 23 companies acquired the same range of supplies through long-term contracts. Monthly and daily agreements were used to some extent by 22 and 26 companies, respectively, for peak-month supplies – but like peak-day arrangements tended to be for 25 percent or less of volumes.

TABLE 3

CONTRACT TERMS FOR GAS PURCHASED
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

Percent Contracted	Long-Term	Mid-Term	Monthly	Daily
PEAK-DAY				
1 – 25	15	10	13	12
26 – 50	7	9	8	9
51 – 75	7	9	2	3
76 – 100	8	13	1	1
0	15	11	28	27
PEAK-MONTH				
1 – 25	14	8	11	20
26 – 50	8	12	7	3
51 – 75	6	5	2	3
76 – 100	9	15	2	0
0	13	10	28	25

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

When asked to describe the distribution of gas supply purchases among suppliers, 37 LDCs identified independent marketers as suppliers with producers (31 companies), producer marketing affiliates (29 companies) and pipeline marketing affiliates (9) providing the balance of gas supplies to LDCs. Table 4 also shows that LDC-owned production and purchases directly from pipelines played a very small role in supplying LDC customers with natural gas.

TABLE 4

PERCENT PEAK-DAY GAS DISTRIBUTED AMONG SUPPLY PROVIDERS
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

Percent Peak-Day Gas Supply	Producer	LDC-Owned Production	Producer Marketing Affiliate	Pipeline	Pipeline Marketing Affiliate	Independent Marketer	Other
1 – 25	9	1	7	0	8	11	7
26 – 50	9	1	8	0	0	17	1
51 – 75	9	0	9	0	1	6	2
76 - 100	4	0	5	0	0	3	6
0	21	50	23	52	43	15	36

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

V. Supply Pricing Mechanisms and Hedging

Pricing Mechanisms

Many factors play a role in the market pricing of the gas commodity and of transportation services, including weather, storage levels, end-use demand, pipeline capacity, operational issues, and functioning financial markets. Such market factors impact LDCs and other gas suppliers making it difficult for all players to plan. In order to deal with the inherent uncertainty of the market, supply planners use a portfolio approach to pricing gas supplies just as they use a portfolio approach for supply providers and transportation options. That said, when examining the purchase practices of companies during the past several winter heating seasons, it is clear that first-of-the-month (FOM) index pricing dominates the market for the largest portion of long- and mid-term supply agreements. Table 5 examines more closely the balance of pricing mechanisms among survey respondents during the 2004-2005 winter heating season. Figures 2-5 compare pricing mechanisms from this year's survey participants with last year's sample of companies.

Table 5 and Figure 2 show that for long-term supplies (one year or more agreement) 30 of 49 companies answering the question used first-of-the-month pricing for a portion of their supplies, including 27 companies that used FOM for 51-100 percent of long-term gas purchases. Thirteen companies utilized some form of fixed pricing for a portion of their long-term arrangements, which is interesting because two years ago when the survey included 65 respondents the number of companies citing fixed deals was only 10. A smaller number included daily, average-of-the-last-three-days and NYMEX based pricing mechanisms for small volumes within their gas supply portfolio. For those companies referencing fixed price mechanisms for gas supply, only five indicated that the arrangements lasted for more than two years. All others were of less duration. Using a scale of 1-10 %, 11-20 %, 21-30 % and so forth, the largest number of companies described their fixed-price deals as 11-20 percent of their supply portfolio.

Comparing Figures 2 and 3 (2004-2005 and 2003-2004, respectively) indicates that for the winter heating season just past there was slightly less diversity in pricing mechanisms for small volumes of gas but general agreement that the largest number of companies purchased the largest volumes of their supply using FOM pricing.

TABLE 5

GAS SUPPLY PRICING MECHANISMS 2004-2005
(NUMBER OF COMPANIES)

PERCENT GAS SUPPLY PURCHASED	FIRST-OF-THE-MONTH INDEX	WEEKLY	FIXED	DAILY	AVERAGE LAST 3 DAYS	NYMEX	OTHER
LONG-TERM							
ONE YEAR OR GREATER							
1 – 25	0	0	5	4	2	3	0
26 – 50	3	0	1	4	0	1	3
51 – 75	10	0	4	0	2	2	1
76 – 100	17	0	3	0	0	2	5
0	19	49	36	41	45	41	40
MID-TERM							
GREATER THAN ONE MONTH, LESS THAN ONE YEAR							
1 – 25	6	0	8	4	0	4	1
26 – 50	9	0	5	5	0	3	1
51 – 75	10	0	3	2	0	2	0
76 – 100	14	0	4	2	0	8	0
0	13	52	32	39	52	35	50
SHORT-TERM							
ONE MONTH OR LESS							
1 – 25	8	0	9	11	0	3	2
26 – 50	8	0	5	6	0	3	0
51 – 75	14	0	3	8	1	5	0
76 – 100	10	0	2	10	0	1	2
0	13	53	34	18	52	41	49

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

FIGURE 2

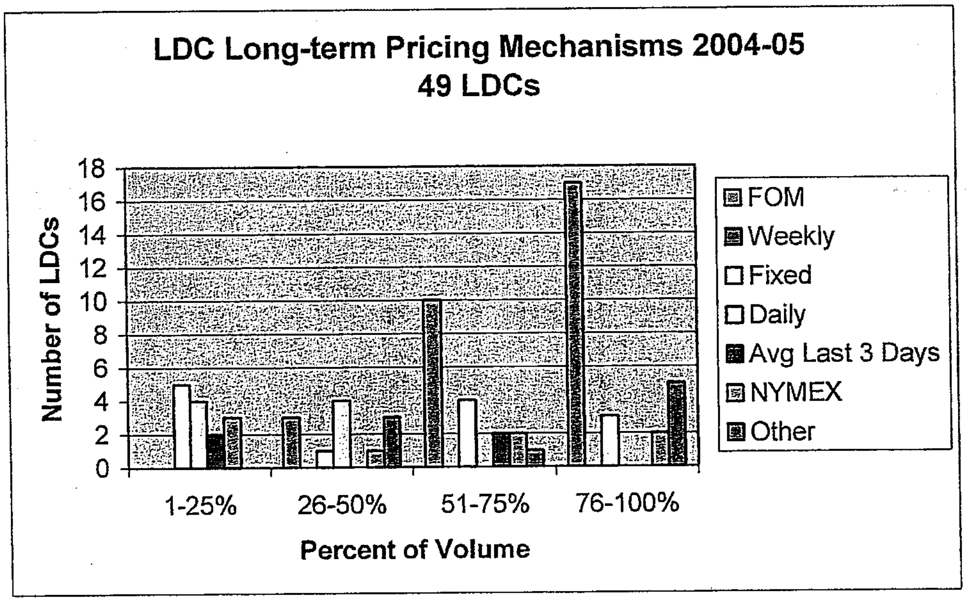
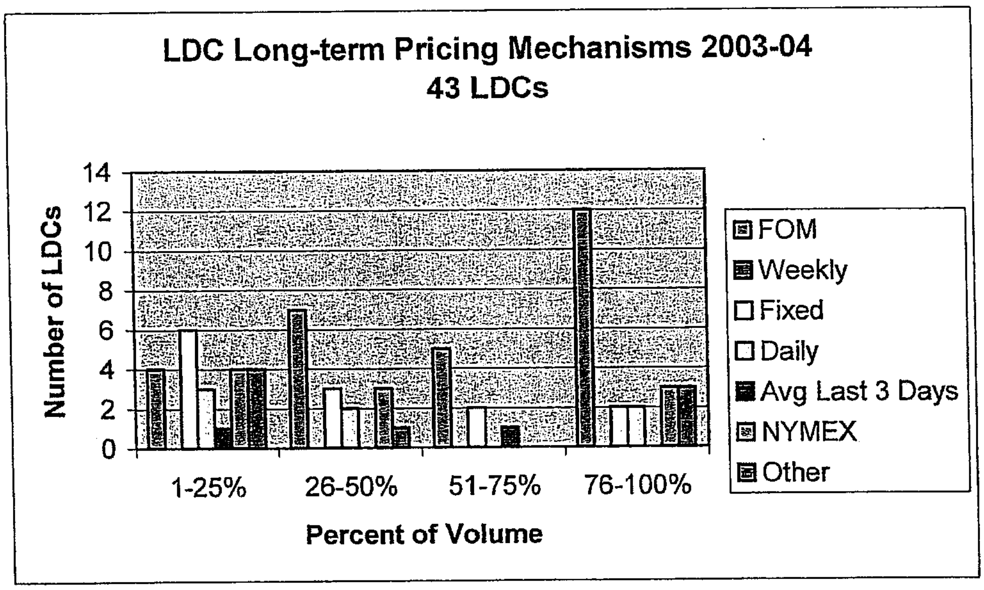


FIGURE 3



Mid-term purchases (more than one month, less than one year) were reported by companies to most often be tied to FOM indices for almost any volume of gas during the past two winter heating seasons, as shown in Figures 4 and 5. In addition, fixed-price, NYMEX and daily mechanisms were used to a greater extent for mid-term purchases than in the case of long-term purchases. Twenty companies reported using fixed pricing mechanisms for mid-term purchases compared to 13 companies for long-term and 13 used daily prices for mid-term purchases compared to eight for long-term purchases, which makes sense. In a volatile gas market, trading partners are more likely to limit the term of pricing arrangements because local utilities are encouraged by regulators to be in a position to capture lower gas prices when the market swings down, while suppliers are interested in capturing the high end of the market. However, there appears to be a growing undercurrent of concern among some gas market players that first-of-the-month indices are *over* relied upon and that index pricing of such large volumes of gas may need to change in the future. That could only happen if market players were willing to do so and regulatory support was forthcoming.

FIGURE 4

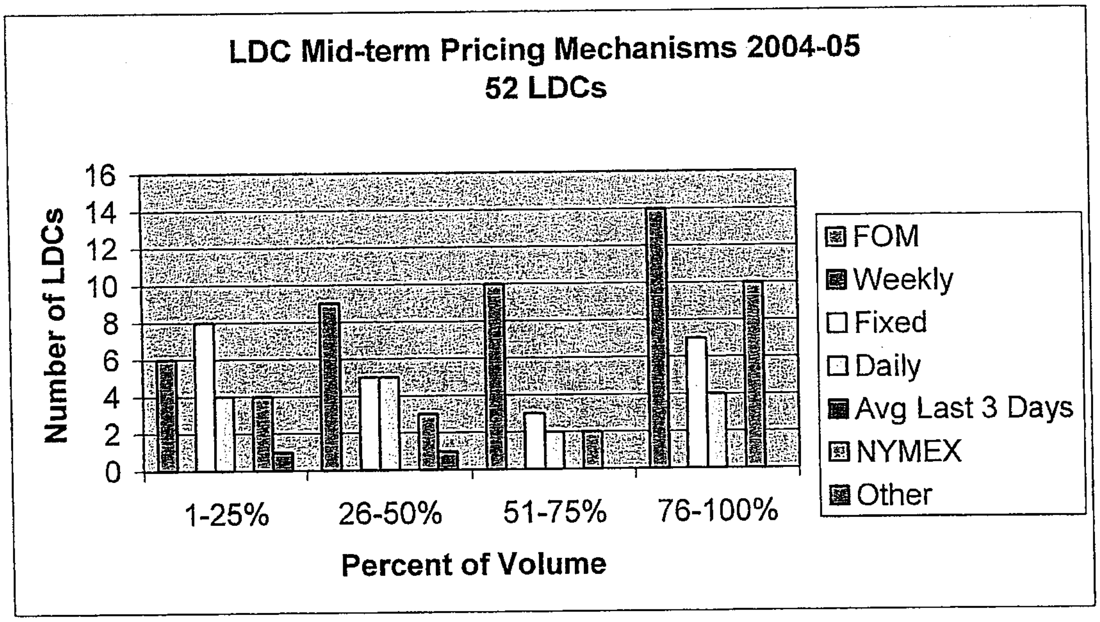
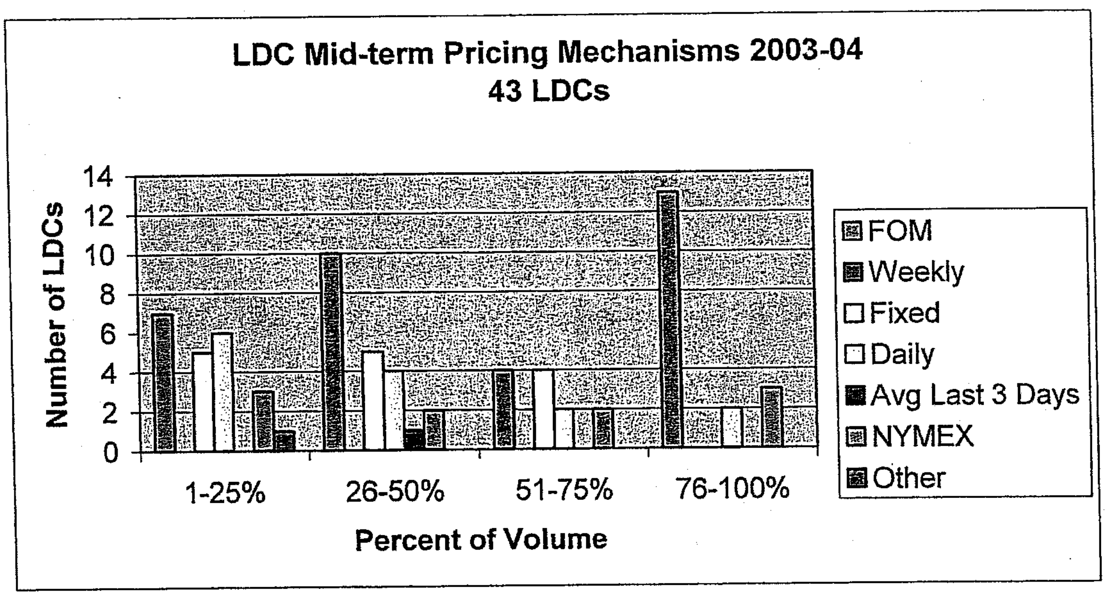


FIGURE 5



As expected, short-term purchases (one month or less) depended more heavily on daily pricing mechanisms but, also, were tied to first-of-the-month, fixed and NYMEX indices (see Table 5). It should be noted that LDCs build gas supply portfolios and pricing strategies based on prior and anticipated experiences. Even state regulatory approved pricing mechanisms can appear favorable one year and less attractive another. Flexibility and constructive review of policies, rather than second-guessing, can effect positive impacts on bringing natural gas and services to customers at the lowest possible cost.

Hedging Mechanisms

Market developments during the 1990s have expanded gas supply options, transportation capacity trading and the use of financial instruments. Today, industry players use futures contracts and other tools to offset the risk of commodity price movements. These financial instruments, which to some extent include fixed-price gas purchase contracts, futures, and options, allow gas supply portfolio managers to hedge or lock in a portion of the gas cost component of gas supplies. This is achieved particularly when the level of risk required and the rewards or benefits of managing the risk are properly balanced by the company, consumers and regulatory bodies.

Seventy percent of the companies responding to the AGA WHS survey said they used financial instruments to hedge a portion of their gas supply purchases during the 2004-2005 winter. That number is identical to the percentage last year and compares to 45 of 65 LDCs (69 percent) answering the question in the 2002-2003 survey and 55 percent in the 2001-2002 survey (remembering that the sample companies and sample size were different each year). For this past winter, twenty-one of 37 companies providing data hedged up to 50 percent of their gas supply purchases during the winter. Options (23 companies), fixed-price contracts (18 companies), swaps (16 companies) and futures (11 companies) were most often sited as financial tools used to hedge a portion of gas volumes delivered on a peak-day. This balance is similar to that of last year. The use of financial tools may be understated in this report inasmuch as some volumes delivered to LDCs from marketers and other suppliers are hedged by the third-party rather than the LDC or customer and may have been excluded from the LDC hedging calculation.

Only seven companies indicated that they used weather derivatives during the 2004-2005 winter heating season. This compares to six companies in 2003-2004 and eight companies in the 2002-2003 survey.

When asked about the timing of hedging strategies, 25 of 38 companies (66 percent) responding indicated that they employ a six-month and less strategy for a portion of their hedges. Thirty-five of 38 companies utilized a 7-12 month strategy for a portion of their hedges, while 19 companies hedged forward for more than 12 months. Of course, a single company may use one or all strategies simultaneously. The majority of companies also reported that acquiring financial hedges or implementing a strategy was no more or less difficult than the prior year. Thirty-one of the 54 companies responding indicated that for the 2005-2006 winter heating season they planned to hedge the same as this past winter heating season. Eleven companies plan to hedge even more of their purchased gas volumes. Thirteen of the companies reported that Public Utility Commissions were more receptive to hedging strategies than in the past, while 31 indicated PUC receptivity to be the same compared to last year.

On the physical side, companies view gas delivered to storage during the summer refill season as a price hedge against potential winter run-ups. In preparation for the 2004-2005 WHS, 47 companies reported using storage as a primary hedging tool. Twenty-nine of those companies hedged between 26-50 percent of winter heating season supplies using underground storage compared to 22 companies last year. Several companies noted that storage (as a physical hedge) is the only hedge they employ choosing not to use financial instruments at all.

When asked about their own regulatory environment, 37 of the companies responding to the question indicated that financial losses and gains were treated equally within their hedging plans. Only three noted that losses and gains were treated unequally. When asked about the relative ease of acquiring hedging products for 6-month or less hedges, thirty-eight companies saw current markets as less difficult or the same as the year before. Thirty-two companies said the same of hedges more than six months in duration. Very few companies indicated market conditions to be more difficult to operate within. This compares to last year's survey when up to a third of the companies viewed markets as more difficult to operate within.

Motivations behind hedging programs are varied among survey respondents. For some jurisdictions there are no formal standing plans. In some cases, however, companies are permitted to enter into fixed price deals well ahead of the delivery season (up to 2.5 years ahead) for a portion of their monthly requirements. Timing of a contract reflects historical price trends and demonstrates a desire to maintain diversity among market-based prices within a supply portfolio. In other cases, LDCs may be required to hedge portions of future gas supplies and those hedges must be in place by predetermined dates. Accelerating or slowing down the process occurs based on evaluation of market fundamentals. Variations on these themes are many and are shaped to fit the relationship between local distribution company, regulators and market conditions in a given area.

VI. Gas Storage

As noted earlier, LDCs are concerned with managing gas supply and transportation portfolios efficiently to reduce costs. Producing area and market area storage can help LDCs to meet such goals. The use of storage facilities helps LDCs to meet short-term swing opportunities, as well as, to satisfy peaking needs.

Table 6 shows storage levels as estimated by the Energy Information Administration for January-April 2005 compared to the same period in 2004. For the nation as a whole, working gas inventories during the January-April 2003 period were tested, eventually falling to 642 Bcf in total (a historic low). This occurred during a winter that was only 1.4 percent colder than normal nationally.

In contrast, the lowest volume of gas in storage for early 2004 was 372 Bcf higher than the previous year and the lowest point for storage inventories in 2005 was another 215 Bcf higher. This is consistent with the fact that the past two winter heating seasons were five and six percent warmer-than-normal, respectively. All of the additional gas in storage at the end of the 2003-2004 WHS was located in the Consuming Region East and Producing Region. By the first week in April 2005, higher inventories of natural gas in underground storage were distributed in all three regions of the U.S. and were more than 25 percent ahead of the prior five-year average and 20 percent ahead of the previous year.

Forty-nine companies answering the question indicated that weather-induced demand compelled the respondents to utilize storage services. However, respondents also singled out no-notice requirements (42 companies) and pipeline operational flow orders (20 companies) as reasons to maintain storage services within their gas supply portfolio. Thirty-five and 18 companies, respectively, also stated that both contractual "must turn" provisions and arbitrage opportunities influenced their storage decisions during the 2004-2005 WHS.

TABLE 6

AMERICAN GAS STORAGE SURVEY

WORKING GAS IN STORAGE

	2004 (Bcf)					2005 (Bcf)			
	Total	Prod	East	West		Total	Prod	East	West
Jan02	2567	753	1495	319		2698	802	1536	360
	2414	709	1412	293	Jan07	2610	783	1494	333
	2258	683	1297	278		2500	755	1438	307
	2063	633	1163	267		2270	692	1290	288
	1827	575	1009	243		2082	648	1155	279
Feb06	1603	512	880	211	Feb04	1906	599	1043	264
	1431	456	788	187		1808	576	984	248
	1267	406	689	172		1720	564	921	235
	1171	379	630	162		1613	571	838	224
Mar05	1143	376	619	148	Mar04	1474	523	737	214
	1097	371	575	151		1379	507	659	213
	1032	372	507	153		1290	487	592	211
	1014	380	474	160		1239	486	548	205
Apr02	1034	395	477	162	Apr01	1249	497	546	206
	1049	411	473	165		1293	521	562	210
	1077	423	483	171		1343	538	591	214
	1155	449	531	175		1416	558	636	222

Source: Energy Information Administration

For the previous year, only 20 of 43 companies (47 percent) noted must turn provisions as significant influences on their storage withdrawal strategy during the winter. Must turn provisions may be in place for some storage contracts as a way to maintain facility integrity through an optimal pattern of injection and withdrawal in a storage field. As such, once gas is stored portions must be removed within a scheduled cycle in order to manage the geologic nature of the reservoir properly. During the 2004-2005 winter heating season, storage inventories were consistently higher than the prior five-year average and, therefore, companies may have been faced with a need to cycle gas out of storage to meet the must turn provisions of their contract. As noted above, thirty-five of 54 companies (65 percent) singled out must turn provisions as influencing their use of storage this past winter – eighteen percent more than the prior winter.

Many influences were cited regarding decisions for storage injections during the Spring-Summer refill season in 2004. Price considerations were noted by 38 companies and were up from only 22 companies the year prior (2003). In addition, 46 companies sited operational issues as influencing storage injection patterns in 2004. Regulatory plans and mandates were reported by 21 companies, while 44 cited additional supply considerations as influencing storage injections.

TABLE 7

PRICING MECHANISMS FOR GAS INJECTED INTO UNDERGROUND STORAGE 2004
(NUMBER OF COMPANIES)

Percent Underground Storage Purchases	First-Of-The-Month Index	Weekly	Fixed	Daily	Average Last 3 Days	NYMEX	Other
1 – 25	5	0	11	15	1	3	0
26 – 50	8	0	6	6	0	3	2
51 – 75	12	0	3	2	1	3	0
76 – 100	20	0	1	2	0	2	1
0	7	52	31	27	50	41	49

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

FIGURE 6

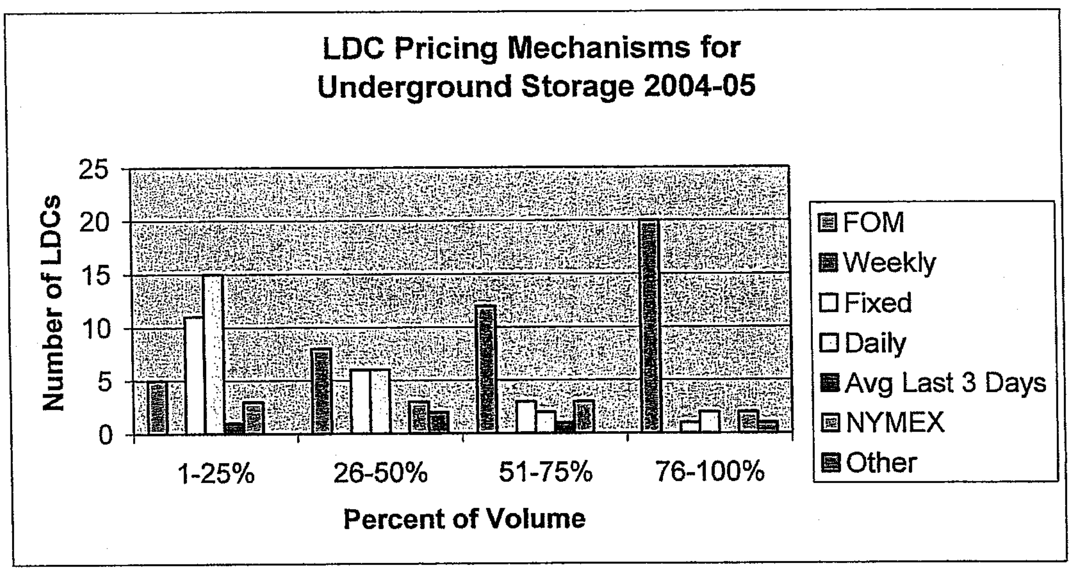


Figure 7

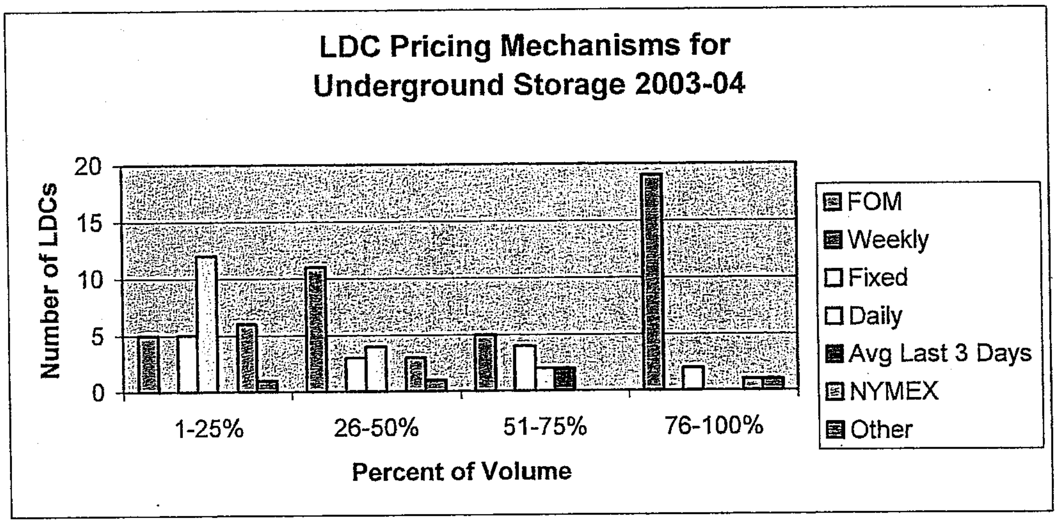


Table 7 and Figure 6 show that most gas purchases for storage injections during 2004 (preparing for the 2004-2005 winter heating season) were made based on *first-of-the-month* indices, although fixed price and daily priced gas was also prevalent for small volumes of gas destined for underground storage. The same is reflected in Figure 7 for the refill period in 2003. For 2004, twenty companies indicated that more than 75 percent of the supplies purchased for storage injections were FOM priced. Fixed schedules accounted for some storage volumes injected by 21 companies reporting, while daily pricing applied to 25 of the surveyed companies (compared to 18 companies in 2003). Generally, daily pricing was applied to 1-25 percent of gas purchased for underground storage, although four companies in 2004 indicated that between 51-100 percent of their stored gas was purchased on a daily basis.

Twenty-five companies indicated that they were examining options to build underground storage additions during the next five years or currently constructing expansions, while 13 companies were considering additions or expansions of peak-shaving facilities. Regarding contracted storage capacity, 10 companies plan to increase underground storage for the 2005-2006 winter heating season, while 33 companies reported plans to keep the same capacity as this past year.

VII. LDC Transportation and Capacity Issues

Transportation only customers have assumed a higher profile among all customers served by LDCs. As has been stated before, planning for transportation capacity and supply, in general, is ultimately held hostage to weather, economic activity and other factors that influence gas consumption. Managing pipeline capacity efficiently is a challenge for LDC's and can involve the release of capacity to the secondary transportation market, if events allow it to be so.

Table 8 takes a brief view of this issue. Companies were asked to identify the percentage of pipeline capacity held by the LDC and released to the secondary market by month from April 2004 to March 2005. In general, several elements can be noted by examining the table. First, most companies release no capacity or less than 25 percent of their capacity throughout the year. During the summer months, however, additional companies with capacity to release may have up to 50 percent of their capacity available to the secondary market. This makes sense, assuming that LDCs are less likely to have large blocks of excess capacity during the winter heating season months in order to meet seasonal heating loads.

The second item is that most capacity sales to the secondary market were for less than 25 percent of the LDC capacity portfolio. From April 2004 to March 2005, 20-26 of the 50 companies answering the question released between one and 25 percent of their pipeline capacity on a monthly basis to the secondary market, when that capacity was not needed to serve LDC customers. As many as 5 companies released up to 50 percent of their capacity during the winter of 2004-2005, which can be attributed to the warmer-than-normal conditions throughout the country for most of that period.

Regarding system operations, 22 of 53 companies (42 percent) in the 2004-2005 AGA Winter Heating Season Survey indicated that they had been impacted by the issuance of operational flow orders during the past WHS. That compares to 48 of 65 companies (74 percent) during the 2002-2003 WHS and 51 percent during the 2003-2004 winter. For those companies during 2004-2005, the median number of OFOs issued was 3. Duration for the orders ranged from one day to 45 days, however, the median duration was 3.5 days.

TABLE 8

PERCENT LDC PIPELINE CAPACITY RELEASED
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

	2004							2004		2005		
Percent Pipeline Capacity Released	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
0	16	13	13	15	14	13	14	18	21	21	21	20
1 – 25	24	24	23	20	22	22	24	26	23	24	23	25
26 – 50	9	12	13	14	13	14	10	5	5	4	5	3
51 – 75	0	0	0	0	0	0	1	0	0	0	0	1
76 - 100	1	1	1	1	1	1	2	1	1	1	1	2

Disclaimer

APPENDIX A

2004-2005 WINTER HEATING SEASON SURVEY PARTICIPANTS

AGL Resources
Ameren Corporation

Baltimore Gas & Electric Co.

Chattanooga Gas Company
Cinergy Corp.
Citizens Gas and Coke Utility
Clearwater Gas System, City of
Con Edison Co. of New York
Connecticut Natural Gas
Consumers Energy

Dominion – East Ohio Gas
Dominion Gas Delivery
DT Energy – Michcon

Equitable Resources

Hope Gas, Inc.

Indiana Gas Company
Intermountain Gas Company

KeySpan Energy Delivery-Long Island
KeySpan Energy Delivery-New England
KeySpan Energy Delivery-New York

LaClede Gas Company
Louisville Gas & Electric Company

MDU Resources Group, Inc.
Memphis Light Gas & Water
Mobile Gas Service Corp.
Mountaineer Gas Service Corp.

National Fuel Gas Distribution Co.
New Jersey Natural Gas
Niagara Mohawk Power Corp.
NICOR Gas
North Shore Gas Company
Northern States Power Company (Xcel Energy)
Northwest Natural Gas Company

PECO Energy
Peoples Gas Light & Coke Company
Peoples Gas System
Piedmont Natural Gas Co.
PNM Gas Services (Public Service of NM)
Public Service Co. of Colorado (Xcel Energy)
Puget Sound Energy

Questar Gas Company

Roanoke Gas Co.

San Antonio Public Service Board, City of
SEMCO Energy
Southern Connecticut Gas Company
Southern Indiana Gas & Electric Company
Southwest Gas Corporation

UGI Utilities

Vectren
Vermont Gas Systems, Inc.
Virginia Natural Gas, Inc.

Washington Gas Light Company
Wisconsin Public Service Company

Yankee Gas Services Co.

Rejoinder Exhibit No. __ (WNM-2)
(Sheet 1 of 12)

ORIGINAL

0000060865

30

MEMORANDUM

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: August 22, 2006

RE: STAFF REPORT ON SOUTHWEST GAS CORPORATION COMPLIANCE MATTERS RELATED TO ITS 2005 RATE PROCEEDING (DOCKET NO. G-01551A-04-0876)

Attached is the Staff Report for compliance matters related to its 2005 rate proceeding.

EGJ:BGG:red

Originator: Bob Gray

Attachment: Original and Thirteen Copies

Arizona Corporation Commission
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Docket No. G-01551A-04-0876

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STAFF REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

SOUTHWEST GAS COMPLIANCE MATTERS RELATED TO ITS 2005 RATE PROCEEDING

DOCKET NO. G-01551A-04-0876

AUGUST 22, 2006

STAFF ACKNOWLEDGMENT

The Staff Report for Southwest Gas Compliance Matters Related to Its 2005 Rate Proceeding, Docket No. G-01551A-04-0876, was the responsibility of the Staff members listed below.

Robert Gray
Senior Economist

TABLE OF CONTENTS

Introduction

On February 23, 2006, the Commission issued an order in Southwest Gas Corporation's ("Southwest") rate proceeding before the Arizona Corporation Commission ("Commission") in Docket No. G-01551A-04-0876. The order discusses a number of matters that require further actions by Southwest and discussions with Staff, followed by a report from Staff to the Commission. Specifically, ordering paragraphs on page 68 of the order state:

> "Southwest shall initiate discussions with Staff, within 60 days of this Decision, regarding stock ownership issues discussed herein, and to continue to cooperate with Staff regarding other procurement issues, including issues pertaining to El Paso and construction and ownership of laterals on the Company's system." (lines 18-21)

> "Staff shall file within 180 days of the effective date of this Decision, as a compliance item in this docket, a report or reports regarding stock ownership issues, procurement practices, benchmarking, and El Paso laterals issues discussed above." (lines 22-24)

Southwest did initiate discussions with Staff within 60 days of the decision, and this document is Staff's report to the Commission, as required within 180 days of the decision (by August 22, 2006). In this Staff Report, there is a brief discussion of each issue identified in the order for Staff to report on. In general, Staff believes that Southwest's efforts to comply with Decision No. 68487's requirements are consistent with the order.

Procurement Practices

During the rate proceeding, Staff recommended a number of changes regarding Southwest's procurement practices, including separating the contract award group from the invoice approval authority, eliminating the use of cell phones in term bidding and negotiating activities, and having a neutral party observe these activities. Southwest agreed to implement these changes during the rate proceeding.

On April 24, 2006, Southwest filed a letter in the rate case docket. The letter states that Southwest has completed making changes to implement the recommendations discussed above regarding procurement practices. Southwest has provided Staff with additional information, including internal memos, work orders, organizational charts and other information, documenting the changes Southwest agreed to make during the rate proceeding. Further, Staff anticipates making a future site visit to observe Southwest's acquisition practices, during which Staff could visually verify implementation of these changes.

Benchmarking Study

Southwest hired Ralph Miller, a consultant, to conduct a benchmarking study of Southwest's gas procurement practices. The report discusses various aspects of Southwest's procurement policies and procedures and compares them to industry practices. Areas covered by the review include load forecasting, capacity acquisition, and commodity procurement. The report includes discussion of an American Gas Association ("AGA") study on gas portfolio management during the 2004-2005 winter season by AGA members.

Southwest has an annual planning period which runs from November through December each year, a common industry practice according to the report. The report notes that Southwest's load forecast is comprehensive, including major components such as:

- Annual, seasonal, and monthly loads under normal weather conditions.
- Design day, design week, and design winter season loads.
- Maximum and minimum daily loads that may occur in each calendar month.

The report indicates that no-notice and swing requirements (used to meet short term fluctuations in customer demand for natural gas) are implicitly included in the components identified above. The report concludes that Southwest's load forecasting process is complete and comprehensive and provides the information needed for Southwest's gas procurement activities. The report notes that it does not address the specific methods Southwest uses to prepare its load forecast or the quality of the load forecast.

Regarding capacity acquisition, the report notes that Southwest's overriding consideration is that its Arizona city gates are connected only to the El Paso Natural Gas interstate pipeline system, and for most if not all city gates, it would be difficult and expensive to connect to another pipeline. The report does note the prospect of the Transwestern Pipeline Phoenix Project entering the Phoenix market in 2008. The report indicates that Southwest's capacity portfolio is further restricted by the limited services offered by El Paso and the lack of market area natural gas storage in Arizona. The report states that Southwest continuously reviews alternative options for gas delivery to Arizona, but notes that the consideration of alternative delivery options does not impact the actual procurement of gas supplies until such time as Southwest actually acquires alternative capacity.

The report discusses five components of Southwest's commodity purchase portfolio, including fixed price purchases, term contracts for firm baseload supplies in the winter season, term contracts for peaking supplies in the winter season, monthly baseload supplies at current spot prices in the summer season, and daily spot purchases for swing supplies in the summer season.

The report also compares a number of characteristics of Southwest's gas procurement activities to the results of the AGA's study of local distribution company ("LDC") practices during the 2004-2005 winter season. The report indicates that Southwest's structure of its term contracts is consistent with other LDCs. Southwest relies on peaking supplies and daily spot purchases much more than most other LDCs, but this is a necessary result given the lack of market area storage (storage in the areas where natural gas is consumed) in Arizona. The report indicates that Southwest has considered acquiring production area storage (storage where natural gas is produced) but found it to be uneconomic. The report discusses Southwest's use of intermediate term baseload purchases of one to twelve months, with such purchases being made either on the basis of a fixed purchase price, a use of a basis differential with a NYMEX component, and via index pricing. The report also talks about Southwest's use of swing and daily spot purchases. Southwest makes daily purchases using a combination of fixed pricing and index pricing, a common LDC practice.

The report also contains a section that deals with Southwest's price risk management efforts, which Southwest refers to as its Arizona Price Stability Program ("APSP"). The report indicates Southwest manages its price risk by acquiring approximately half of its gas supplies through fixed price contracts with prices established up to 24 months in advance. The report evaluates three aspects of the APSP, including the size of the program, alternative price risk management strategies, and the use of financial instruments instead of fixed price purchase contracts. The report states that Southwest's APSP is large but reflective of the unusual supply situation Southwest faces, given the lack of market area storage which many LDCs around the country have access to. The report indicates that Southwest's extensive use of fixed price contracts helps offset the lack of market area storage.

The report indicates that the other option for Southwest to manage price risk is for Southwest to acquire call options, which would allow Southwest to acquire gas at the strike price of the option or alternatives including puts and collars. The report discusses the pros and cons of these options before concluding that such options should generally only be a relatively small supplement to a fixed price purchase program and notes that LDCs the author is aware of only use such options for a small part of their portfolio.

The report then discusses the use of other financial instruments such as swaps and NYMEX futures contracts as other options to acquire natural gas at a fixed price. The report notes that Southwest has been looking into using such financial instruments, and this is consistent with movement by a number of LDCs around the country to make greater use of financial instruments. The report notes benefits from use of these financial instruments including the ability to hedge some swing or peaking supplies and the reduction in risk of a counter-party defaulting.

Attached to Southwest's report are a number of items, including several tables showing loads and demands, qualifications of the consultant, and the AGA's report on LDC Supply Portfolio Management During the 2004-2005 Winter Heating Season. Southwest also attached a document providing an overview of Southwest's financial hedging policy and processes for its gas supply portfolio. This overview document included five sections dealing with policy, governance structure, processes and controls, the hedge capture and control system, and the code of ethics.

The report summarizes with a number of conclusions about Southwest's gas procurement activities, including:

- Southwest's purchasing practices are generally consistent with practices of well-managed gas utilities.
- Southwest's use of a competitive bidding process to secure fixed price and term contracts, acquisition of fixed price purchases on a periodic basis, and use of informal solicitations to acquire spot purchases are consistent with the practices of other gas utilities.
- Southwest's APSP relies more heavily on fixed price purchases to hedge approximately half of its natural gas supplies. This reliance on fixed price purchases is greater than a typical gas utility due to the lack of natural gas storage facilities in the market area to assist in Southwest's hedging efforts.
- Southwest acquires the other half of its gas supplies using pricing arrangements that reflect current market conditions, including use of negotiated prices and index pricing.

Review of Gas Portfolio Evaluation Software

In the rate proceeding, Staff recommended that Southwest review its gas portfolio evaluation software. Southwest's July 7, 2006 report contains a discussion of Southwest's portfolio evaluation software review.

For many years Southwest has used a software package known as UPLAN-G, owned and developed by LCG Consulting. This software is used by Southwest to determine a least cost mix of resource contracts, taking into account a variety of factors including forecasted demand, available interstate resources, and contract pricing.

Southwest identified three groups of available software, including macroeconomic models, transactional models, and optimization and dispatch models. Macroeconomic software models flows of natural gas on a regional basis on the basis of supply, demand, price, and available infrastructure facilities. Transactional software enables an LDC to track transactions related to the purchase, transportation, and sale of natural gas. Southwest concluded that macroeconomic and transactional software would not enable Southwest to effectively optimize its portfolio of supply resources, due to the nature of these kinds of software.

Optimization and dispatch models enable an LDC to optimize its selection of resources. Southwest indicated that two optimization and dispatch models are currently available in the natural gas industry, UPLAN-G, which Southwest currently uses, and a software program named Sendout. Southwest states that a review of Sendout did not identify any functionality that would be gained by Southwest that would warrant switching from its current modeling software. Southwest indicated that it will continue to evaluate developments in modeling software and will inform Commission Staff of developments in this area.

Stock Ownership Issues

Southwest's Code of Business Conduct and Ethics currently contains a list of statements of things that Southwest considers to be in conflict with an employee's duties and contrary to Company policy. One of these statements says: "Holding any substantial stock or other financial interest in any competitor, supplier, contractor, or vendor or other organization with which an employee is engaged in a business relationship. If there is any question as to whether the interest is substantial, you should seek advice from the General Counsel."

In the rate proceeding, Staff expressed a concern with the lack of clarity regarding potential ownership of stock or other financial interests in counterparties, and Staff recommended that Southwest preclude stock ownership or other financial interest with any supplier or class of suppliers with which they do business. In early July Southwest provided Staff with a draft document providing a more clear definition of what Southwest viewed as being "substantial." In essence, this draft document indicated that if a Southwest employee owned more than 1 percent of the equity in a counterparty, that would be considered substantial.

Staff has had several follow-up discussions with Southwest regarding this issue. Staff has expressed concern that one percent of some counterparties, such as a major natural gas producer/marketer, could be a very large amount of money, while also recognizing that Southwest has a number of other policies and procedures in place that provide checks and balances on an employee possibly conducting procurement activities in a manner that would be inconsistent with Southwest or ratepayers' interests.

Southwest provided Staff with additional documentation regarding the Company's efforts to develop its stock ownership definition and how it fits within Southwest's overall controls and procedures.

In developing its stock ownership definition and related documents, Southwest cites a number of steps Southwest took, including:

- A review of the policies, procedures, and controls of the gas procurement and purchasing departments.
- A review of the Codes of Ethics and Business Conduct including the Conflict of Interest Policies of Unisource Energy Corporation and Arizona Public Service Company. Southwest found that its policies are similar to the policies of those companies.
- Via Southwest's Assistant General Counsel, Southwest queried approximately 30 other companies at a recent American Gas Association Legal Committee meeting, and none of the other companies' representatives indicated they had stock ownership restrictions beyond their code of ethics and business conduct.
- Development of a stock ownership disclosure form in addition to Southwest's existing conflicts of interest form that is distributed to all employees.

Regarding Southwest's gas procurement department, Southwest identifies a number of policies and procedures which help ensure that Southwest employees are not conducting themselves in a manner that could favor an entity they had a financial interest in, including:

- Southwest's strong motivation to buy the lowest price natural gas supplies due to competitive pressures.
- Periodic regulatory reviews of Southwest's purchasing practices.
- Use of a blind bid selection process for fixed price and first of the month purchases where the person awarding the contract does not know the identity of the supplier.
- For daily spot or term portfolio purchases, Southwest only purchases from the lowest priced qualified bidder.
- Solicitations are sent out to a standard list of suppliers by the department secretary, not the gas buyer and a neutral party observes the solicitation process.
- Periodic external and internal audits.
- Requiring employees to sign conflict of interest forms.

Southwest indicates that the purchasing department has similar controls to the gas procurement department. Southwest has not completed the process of designing its stock ownership policy and related materials, and Southwest has agreed to provide Staff with such further materials and documents when they are completed. Southwest has also agreed to have further discussions with Staff on these issues as necessary.

El Paso Lateral Issues

In the rate proceeding Staff had put forth a recommendation that Southwest should construct its own laterals (rather than having El Paso construct them) unless there is a compelling reason to do otherwise. Most of Southwest's load is served off of El Paso's lateral system in Arizona and proposals by El Paso in its on-going rate proceeding at the Federal Energy Regulatory Commission ("FERC") would make it difficult if not impossible for Southwest to access service from another pipeline or storage service provider for these loads. This recommendation came from Staff's on-going concern about El Paso's use of its lateral system as one of several means to stifle competition from potential third party storage and/or pipeline developers in Arizona. To the extent laterals are owned by Arizona entities, rather than El Paso, Arizona entities such as Southwest may be able to lessen the effects of such anti-competitive behavior. Staff has had discussions with Southwest and believes that Southwest and Staff have similar views on the issue of laterals.

Options available to Southwest to meet new or growing demand for natural gas in Arizona include construction of new laterals, expansion of existing laterals, and/or acquisition of existing laterals from El Paso. Southwest has acquired laterals from El Paso in the past, including 2001 acquisitions of the Buckeye, Rainbow Valley, Parker, and Elfrida laterals. Southwest has indicated that another factor influencing its possible acquisition of laterals is El Paso's positioning of itself in the Arizona market and that at times Southwest would like to acquire laterals from El Paso, but El Paso may not be interested in such transactions for a variety of reasons. Southwest weighs a variety of factors related to a possible acquisition from El Paso, including:

- The need for additional capacity.
- Bypass potential of Southwest's core customers.
- Potential higher delivery pressure benefits.
- Ability to access other supplies.
- El Paso's current limitations on Southwest's use of the lateral.
- Possible reductions in needed Southwest facility expansions on its distribution system.
- Reduced need for additional interconnects with El Paso.
- Benefits from acquisition of rights-of-way.

If Southwest makes a preliminary determination that an acquisition is cost-effective, it undertakes a detailed Acquisition Review Plan. The plan involves an analysis of pipeline capacity, original design and materials, installation records and practices, operational and maintenance records, compliance and safety issues, rights-of-way, environmental issues, modifications required for acquisition, and a final cost-benefit analysis. Southwest would then consider the totality of these issues and make a decision.

Staff understands and agrees with Southwest's approach to weigh all of these various factors when considering an acquisition from El Paso or other options and supports Southwest conducting a thorough evaluation of its alternatives. Staff still supports a policy of encouraging Southwest to own infrastructure rather than having El Paso construct, operate, and own infrastructure, while recognizing that Southwest, subject to the unique circumstances present in certain cases, may choose to not own or construct infrastructure sometimes and that such decisions may be in the best interests of Arizona ratepayers' long term interests. Staff and Southwest also discussed having further discussions in the future regarding Southwest's planning and actions to meet its current and future infrastructure needs.

Conclusions

Staff believes that Southwest's efforts in the areas described in this report are consistent with the requirements of Decision No. 68487 for Southwest to work with Staff on these issues, subject to further discussions and efforts as discussed herein. Some areas of interest in this report, including gas procurement related matters and El Paso lateral issues are matters of on-going interest as circumstances continue to develop in Southwest's Arizona service territory and across the region, and therefore Staff anticipates continued, on-going discussions with Southwest regarding these matters.

H

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

FRANK J. MAGLIETTI, JR.

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
FRANK J. MAGLIETTI, JR.

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
Frank J. Maglietti, Jr.

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Frank J. Maglietti, Jr. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same Frank J. Maglietti, Jr. who previously submitted prepared direct and rebuttal testimony in this Docket on behalf of Southwest Gas Corporation (Southwest or Company)?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rejoinder testimony?

A. 3 My rejoinder testimony responds to the surrebuttal testimony presented by Arizona Corporation Commission Operations Staff (Staff) witness Mr. Robert G. Gray related to Southwest's purchase gas adjustor (PGA) bandwidth in which he continues to recommend that the PGA bandwidth be increased from $0.13 per therm to $0.15 per therm instead of $0.24 per therm, as proposed by Southwest.

PGA BANDWIDTH

Q. 4 Mr. Gray states in his surrebuttal testimony that increasing the PGA bandwidth "must be balanced with the

Commission's interest in having oversight and involvement in situations where natural gas costs, and therefore, natural gas rates, are increasing significantly." Do you agree?

A. 4 Yes. However, Southwest does not believe that increasing the PGA bandwidth from $0.13 per therm to $0.15 per therm, as proposed by Staff, or to $0.24 per therm, as proposed by Southwest, changes the Commission's oversight authority or involvement in natural gas cost and rates.

The increased bandwidth proposed by the Company will provide the same level of price flexibility and Commission oversight that was originally provided by the Commission when it approved the implementation of the monthly gas cost adjustment mechanism in 1997.

Southwest currently provides the Commission with monthly gas purchase information as part of its monthly filing to adjust rates, and also provides the Commission with an annual report that details its annual purchases. In addition, the prudence of Southwest's gas cost purchases is reviewed by the Commission in each general rate case. These reporting requirements will continue to be in place, regardless of which bandwidth is approved by the Commission.

Q. 5 Although Mr. Gray states that establishment of the bandwidth requires the balancing of competing interests between the Company and Commission, he has not specifically addressed the interests of Southwest's customers. Why do you believe that Southwest's customer's interests are better served by the Company's proposed PGA bandwidth?

A. 5 Southwest's proposal to increase the bandwidth to $0.24 per therm is intended to smooth out the peaks and valleys of the PGA Bank Balancing Account, reduce price volatility for customers, and give customers a more accurate price signal, all of which benefit customers.

As I demonstrated in Rebuttal Exhibit No.__(FJM-1), if the $0.24 per therm bandwidth had been in place beginning in December 2005, Southwest would have been able to remove the $0.11 PGA surcharge in October 2007, before the 2007/2008 winter heating season. Instead, the surcharge remained in place throughout the winter and was not eliminated until May 30, 2008.

It is prevailing economic theory that prices established closer to actual cost will provide customers a more accurate price signal, which will lead to customer decisions that result in more efficient use of resources. This should, in turn, have a positive effect on conservation.

For each of the foregoing reasons, I believe Southwest's proposed PGA bandwidth better serves the interests of customers, the Commission and the Company.

Q. 6 Did Mr. Gray dispute or comment on Rebuttal Exhibit No.__(FJM-1) in his surrebuttal testimony?

A. 6 No, he did not.

Q. 7 Does this conclude your prepared rejoinder testimony?
A. 7 Yes, it does.

I

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

JAMES L. CATTANACH

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
JAMES L. CATTANACH

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
James L. Cattanach

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is James L. Cattanach. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same James L. Cattanach who sponsored direct and rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to reply to the surrebuttal testimony presented by Arizona Corporation Commission Utilities Division Staff (Staff) witness Mr. Frank Radigan regarding his statements related to declining residential consumption per customer.

RESIDENTIAL CONSUMPTION PER CUSTOMER

Q. 4 Did you prepare exhibits to support your rejoinder testimony?

A. 4 Yes. I prepared an exhibit identified as Rejoinder Exhibit No.___(JLC-1).

Q. 5 Please summarize your rejoinder testimony.

A. 5 I will reply to the statement made by Staff witness Mr. Radigan that "You cannot just conclude that because you see declining customer usage from one year to the next that it will continue to decline." (Radigan, Surrebuttal Testimony, Page 6, Lines 8 - 10, May 27, 2008). I will also respond to Mr. Radigan's statement, "In my opinion, Mr. Cattanach's testimony does not provide any of the information necessary for the Commission to make an informed decision on this matter. Mr. Cattanach's exhibits show average use per customer for selected historic years. It does not show that declining usage will continue, it does not show what the projected end level customer usage will be, and it does not demonstrate that energy conservation efforts are the cause for this declining usage, if in fact it exists." (Radigan, Surrebuttal Testimony, Page 7, Lines 7 - 12, May 27, 2008). I will provide analyses and historical data that suggests there is a significant likelihood that residential consumption per customer will continue to decline in the foreseeable future.

Q. 6 Could you briefly comment on Mr. Radigan's statement that "You cannot just conclude that because you see declining customer usage from one year to the next that it will continue to decline"?

A. 6 Yes. Although we do not know with 100 percent certainty that residential consumption per customer will continue to decline in the future, the long-term historical data trend provides insight into the likely trajectory of future consumption over the near term. I believe that a reasonable person would conclude after reviewing the historical consumption information provided in both my direct and rebuttal testimonies (Direct Testimony Exhibit No.__(JLC-1), Rebuttal Testimony Exhibit No.__(JLC-1)), a significant likelihood exists that residential consumption per customer will continue to decline for the foreseeable future. In the absence of being clairvoyant or having perfect vision of the future, economists must utilize history as a guide to help assess future trends in consumption per customer.

The historical data presented in this proceeding indicates that an expectation of future declines in residential consumption is not unreasonable. At page 8 of my prepared direct testimony in the Company's 2004 rate case, I testified as follows:

> Q. 13 Do you have any expectations regarding when this dramatic decline in residential consumption per customer will possibly slowdown or stop in the Arizona rate jurisdiction?
>
> A. 13 Unfortunately, no. However, reasonable conjecture would conclude a significant likelihood exists that the downward trend in residential consumption per customer will continue for the foreseeable future.

Indeed, consumption did decline from 347 therms in the 2004 rate case to 332 therms in the current rate case.

In my direct testimony in the current case, I stated an expectation that consumption would continue to decline. As outlined in my rebuttal testimony, residential consumption per customer has declined from 332 therms to 319 therms between the end of the test year (April 2007) and March 2008. My expectation is that based on the ongoing declines in residential consumption per customer, consumption will continue to trend downward for the foreseeable future.

Q. 7 Have you performed any empirical analyses that provide insight into the future trend in residential consumption per customer?

A. 7 Yes. Based on the 12-month moving totals of weather normalized residential consumption data used to construct the graph presented in my rebuttal testimony (Exhibit No.__(JLC-1), I estimated a statistical equation through the data set to quantify the trend in residential consumption per customer between January 1995 and March 2008. The graph of the data, the estimated statistical regression equation, and the regression statistics are presented in Rejoinder Exhibit No.__(JLC-1). The regression statistics indicate a statistically significant (T-Statistic=-64.49) negative trend in the residential consumption per customer data over the estimation period. The regression results suggest a strong statistical fit (Rsquare=.9636) to the data. On average, residential consumption per customer has declined approximately 7 therms per year over the estimated period. Since the consumption data is weather normalized (the impact of weather variations has been removed from the data), the estimated downward trend of 7 therms per year is a reasonable approximation of the impact of conservation-related factors on residential consumption per customer. Even though the statistical trend equation has underestimated the recent acceleration in consumption declines, it is a plausible expectation that residential consumption per customer will continue to decline by approximately 7 therms per year in the foreseeable future.

I do not think the recent acceleration in the declines is sustainable over a longer period. Therefore, I would expect to observe residential consumption per customer falling below 310 therms within the next couple of years. Although I would not want to use the estimated statistical equation to forecast declines in residential consumption per customer over a ten to fifteen year forecast horizon, the equation is a reasonable statistical tool to assess the trend in residential consumption per customer over the foreseeable future.

Q. 8 Have you performed any other quantitative studies that will provide insight into the direction of future changes in residential consumption per customer?

A. 8 Yes. Examining calendar year weather normalized residential consumption per customer data for a longer period (1985 through 2007), I compared consumption in a given year to the change (positive/negative) one and two years ahead. Based on this information, I constructed high level discrete probability distributions using the empirical or long-run relative frequency approach to probability assessment. Based on the constructed discrete probability distributions, there is approximately an 82 percent chance that residential consumption per customer will decline over the next year and an 86 percent chance of a decline two years ahead. In my opinion, these probabilities suggest a significant likelihood that residential consumption per customer will continue to decline in the foreseeable future.

Q. 9 Is it reasonable to assume that declines in residential consumption per customer will decelerate and find an equilibrium or base consumption level in the future?

A. 9 Yes, this is a reasonable assumption. However, when that deceleration or equilibrium will occur and at what level of consumption cannot be predicted with any certainty, but given the most recent data available to me, I do not believe this will occur in the foreseeable future. As a researcher, I can continue to monitor the trends and patterns in residential consumption data that will provide evidence of a deceleration to a base consumption or equilibrium level. In the meantime, the null hypothesis (nothing is different from the status quo) is that residential consumption per customer will continue to decline. When I see evidence through graphing techniques, statistical analysis and other supporting information (e.g., public policy) that the declines have ceased, I will reject the null hypothesis and change my opinion regarding further declines. Up to this point, I have observed no evidence that residential consumption per customer has reached a bottom or plateau. In fact, continued public policy at the federal, state and local levels that promotes energy conservation reinforces the reasonable assumption that residential consumption per customer will continue to decline. These policies include building codes, appliance standards, and utility DSM programs to reduce residential energy consumption and greenhouse gas emissions.

Q. 10 Do you agree with Mr. Radigan's assertion that Southwest has not provided any of the information necessary for the Commission to make an informed decision related to the matter of declining residential consumption per customer?

A. 10 I strongly disagree with Mr. Radigan's assertion. I have provided more than ample evidence in both direct and rebuttal testimony that Southwest has continued to experience declines in weather normalized consumption per customer. Although I did not, and cannot, provide an explicit estimate of the date in the future that residential consumption per customer will stop declining or at what level, I believe a reasonable person, even with no formal training in statistics or economics, would conclude after a careful review of the historical data and information provided in this case, that further declines are very likely.

Mr. Radigan also seems to be attempting to confuse the issue by questioning whether declines are actually due to conservation. With all due respect to Mr. Radigan, this is unreasonable speculation. It does not matter if you are examining the significant downward trends over the last thirty years in macro level data such as energy consumption per dollar of economic output in the United States, residential natural gas consumption per customer in the United States at the aggregate level, or natural gas consumption per customer in Arizona, the primary contributing factors have been continuing conservation related to improved efficiencies. In fact, the American Gas Association in at least two studies identified increasing efficiencies of natural gas appliances as the primary cause of declining residential consumption per customer since 1980.[1] The declines in weather normalized residential consumption per customer, which is an excellent proxy for the conservation-related declines in consumption, have occurred since the early 1980s in spite of the two longest peacetime economic

[1] The American Gas Association studies were provided to the parties in response to Staff data request 6-47.

expansions in the United States since the end of World War II and the upward trend in square footage of single-family homes in the United States. Mr. Radigan has presented no studies or analysis to suggest that residential consumption per customer will stop or even slow down.

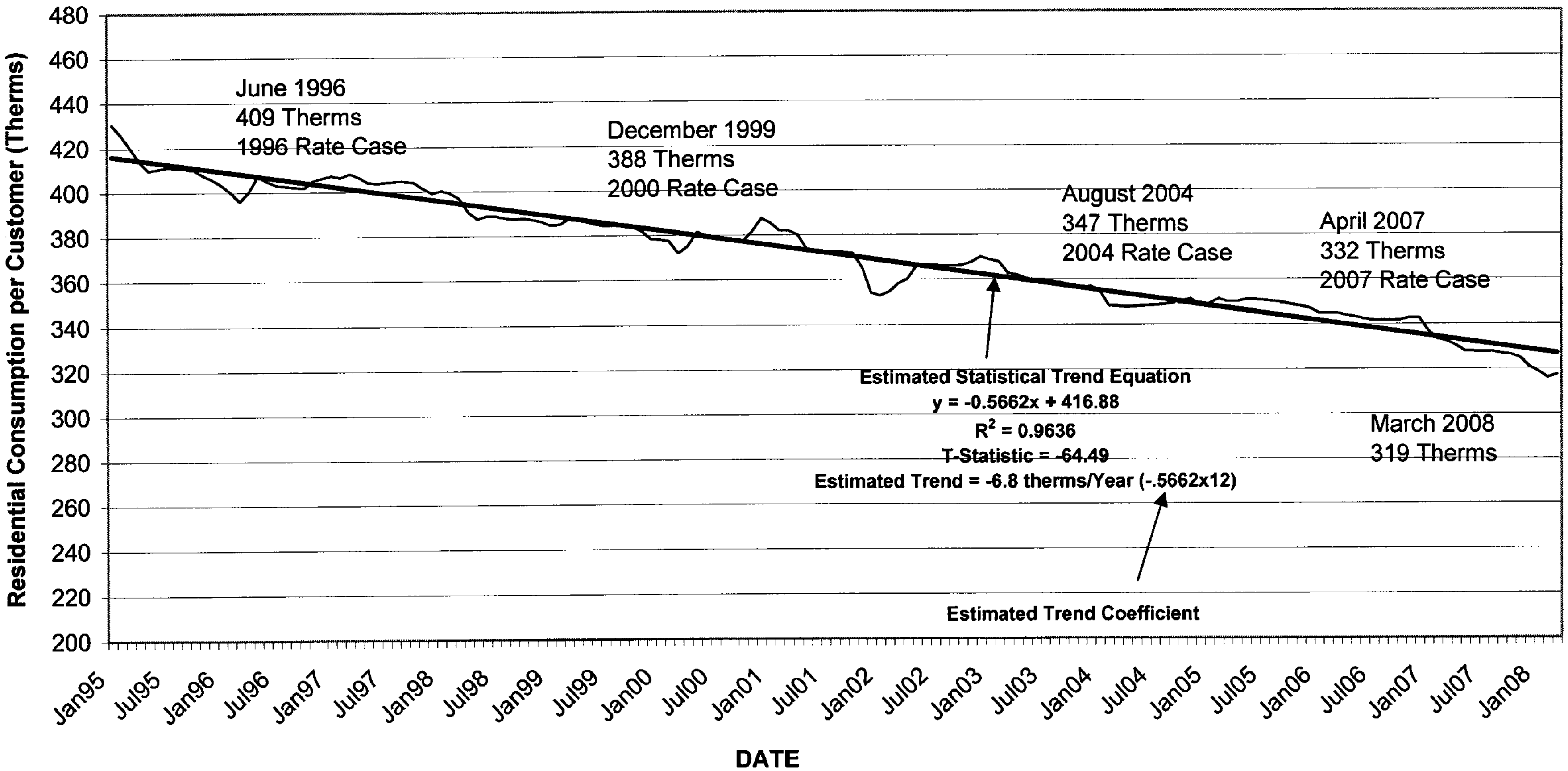
Q. 11 Could you please summarize your conclusions based on the information presented?

A. 11 Yes. Southwest has experienced statistically significant declines in weather normalized residential consumption per customer over the last twenty plus years, caused primarily by factors related to conservation. Based on the statistical analyses and information presented, there is a significant likelihood that residential consumption per customer will continue to decline for the foreseeable future, and there is no evidence presented in this docket to the contrary. The Company has provided sufficient data and analysis for the Commission to assess both the historical and near-term trends in residential consumption per customer.

Q. 12 Does this conclude your prepared rejoinder testimony?

A. 12 Yes, it does.

SOUTHWEST GAS CORPORATION
ARIZONA
RESIDENTIAL CUSTOMER CLASS (G-5 & G-6)
12-MONTH WEATHER NORMALIZED CONSUMPTION PER CUSTOMER & ESTIMATED STATISTICAL TREND EQUATION
JANUARY 1995 - MARCH 2008



10-Year Normal HDDs: 2007 Rate Case

J

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY
OF
RALPH E. MILLER

ON BEHALF OF
SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
RALPH E. MILLER

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
RALPH E. MILLER

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Ralph E. Miller. My business address is at 5502 Western Avenue, Chevy Chase, Maryland 20815.

Q. 2 Have you presented other testimony in this proceeding?

A. 2 Yes. My direct testimony was part of Southwest Gas Corporation's (Southwest or the Company) filing on August 31, 2007. My rebuttal testimony was filed May 9, 2008.

Q. 3 What is the purpose of this rejoinder testimony?

A. 3 I am responding to the May 27, 2008 surrebuttal testimony of Arizona Corporation Commission Utilities Division Staff (Staff) witness Frank W. Radigan, and to the May 30, 2008 revised surrebuttal testimony of Residential Utility Consumer Office (RUCO) witness Marylee Diaz Cortez. Both of these witnesses address Southwest's revenue decoupling proposals, which I supported in my direct and rebuttal testimony.

Q. 4 Can you provide an overview of this rejoinder testimony?

A. 4 In my rebuttal testimony, I presented a detailed point-by-point response to the arguments presented by Mr. Radigan and Mr. Rodney Moore (whose direct testimony was adopted by Ms. Diaz Cortez). In their surrebuttal, Mr. Radigan and Ms. Diaz Cortez have in many places repeated the material in their direct testimony, rather than responding to the substance of my analysis of that direct testimony. Rather than repeat my point-by-point response, I have organized this rejoinder testimony to address the principal themes in Southwest's revenue decoupling proposals and the principal arguments that Mr. Radigan and Ms. Diaz Cortez have presented against those proposals. These principal themes and issues are the WNAP, the RDAP, risk, the Commission's rejection of Southwest's decoupling proposal in Southwest's last rate case, and the stakeholder collaborative.

WNAP

Q. 5 What is your response to the Staff and RUCO surrebuttal testimony on the WNAP?

A. 5 Southwest's proposed WNAP is a win-win arrangement. Everyone agrees that the WNAP reduces the weather-related risk for Southwest, and that variations in the weather are the most important factor causing Southwest's income to fluctuate in the absence of a WNAP. Mr. Radigan and Ms. Diaz Cortez continue to claim that the WNAP would shift this weather risk from Southwest to its customers (Radigan SR 10:12, Diaz Cortez SR 9:2-3), but they continue to provide no support for this claim. Instead of responding to my demonstration in my direct and rebuttal testimony that the WNAP reduces the weather-related risk for Southwest's customers (direct Q&A 25, 11:6–12:1; rebuttal Q&A 38-39, pages 29-31), they merely repeat their unsubstantiated and indefensible allegations.

The most significant development on the WNAP issue in RUCO's surrebuttal testimony is RUCO's apparent abandonment of the claim in Ms. Diaz Cortez' direct testimony that weather is the "real cause for SWG's under-recoveries" (9:15-23), after I showed in my rebuttal testimony that this claim was unfounded. Ms. Diaz Cortez' rebuttal testimony no longer makes the claim that the WNAP would result in rate increases for Southwest's customers. Instead, she makes the illogical and strange claim that the WNAP should be rejected because it would have benefited customers if it had been in effect for the past ten years (SR 9:15–10:10). Southwest's 10-year weather normalization in its base rate cases has benefited Southwest because there has been a slight but discernible cooling trend in the winter weather in the Tucson area during the past ten years (see my rebuttal Chart REM-3; Phoenix [Chart REM-4] has been essentially flat). The WNAP would, therefore, have yielded net reductions in customer bills over the period as a whole, offsetting the effect of this slight cooling trend on customer bills.

Most importantly, Ms. Diaz Cortez's use of this 10-year average misses the entire point of the WNAP, which is to avoid year-to-year fluctuations in the total delivery charge amounts that customers pay to Southwest. The past ten years have included some years that were much colder than normal and some that were much warmer than normal. Absent the WNAP, customers paid much more in cold years, but they did not like it, and Southwest received less in warm years. The WNAP would have removed these year-to-year variations in the amounts paid by customers and received by Southwest, even though the actual effects of weather averaged out close to zero (but slightly in Southwest's favor) during the past ten years.

Q. 6 Can you provide additional insight into the weather risk issue?

A. 6 The following parable may be helpful. Imagine that in 2009, the Arizona legislature decided to involve everyone in a state lottery. Imagine that the legislature directed that a lottery be conducted each month, one of 21 ping-pong balls from a bowl (with replacement so that there would be 21 balls in each month's drawing). Imagine further that the 21 balls were labeled with numbers from –10 to +10, including zero. Now suppose that the legislature required the Water Utility to adjust its bills to all customers in each month by a percentage determined by that month's lottery drawing. If the drawing was a negative number, customers would receive a discount in the range from 1% to 10%, depending on the number drawn; and if the drawing was positive, there would be a surcharge.

The Water Utility did not like the lottery, because it did not like to see its revenues subject to random influences. Customers initially were indifferent, but they began to notice that their monthly water bills were varying unpredictably, and they too began to complain. Eventually the Public Utilities Commission (PUC) decided to act to undo the effects of the legislative lottery. It required the Water Utility to make a downward adjustment to its bills in each month that the lottery drawing was a positive number, so that the PUC's downward adjustment exactly offset the upward adjustment resulting from the lottery. The PUC also authorized the Water Utility to make an offsetting upward adjustment to its bills in months when the lottery drawing was a negative number. The end result was that the monthly water bills returned to where they were absent the lottery, and everyone — customers and the Water Utility — was happy.

Q. 7 How does this parable relate to the issue of weather risk?

A. 7 Certainly none of us expects the Arizona legislature to institute this type of lottery. But Mother Nature has already instituted just such a lottery, and it affects the gas bills of Southwest and all the other gas utilities whose residential and small commercial customers use gas primarily for space heating. Mother Nature conducts this lottery by arranging variations in weather; some months are colder than is normal for that season, and others are warmer than is normal for that season. We cannot do anything about the fact that customers use more gas when the weather is colder, and less when it is warmer. But Southwest's proposed WNAP would modify customers' bills each month to offset the effect of Mother Nature's lottery on customers' non-gas charges. Unfortunately, we have not yet found a way to offset the variations in purchased gas charges that customers must pay when their use of gas increases or decreases in response to Mother Nature's lottery, but elimination of the variations in non-gas charges certainly represents progress.

RDAP

Q. 8 What is your response to the Staff and RUCO surrebuttal testimony on the RDAP?

A. 8 The principal argument directed specifically against the RDAP is that it is a biased form of single-issue ratemaking because it addresses only usage per customer. Mr. Radigan claims that it ignores increases in usage that result from customer growth (SR 5:13–6:3), whereas Ms. Diaz Cortez focuses on factors that may enable Southwest to reduce its total costs (SR 2:22–3:4).

I would agree that this issue of ratemaking bias merits careful consideration, because I would agree that the RDAP can reasonably be expected to result primarily in higher revenues for Southwest through rate surcharges rather than rate credits. (The RDAP differs from the WNAP in this respect. I would contend that the WNAP can be expected to be revenue-neutral when averaged over a period of years, and I have explained that it would have yielded a slight net rate reduction over the past ten years.) I would also note, however, that Mr. Radigan tries to have it both ways on the RDAP. On the one hand, he claims that it yields an upward bias in Southwest's rates, and on the other hand, he insists that Southwest has failed to demonstrate that usage per customer is really declining. If usage per customer is not declining, then the RDAP cannot be biased in favor of

Southwest.

My first response to the question of bias in the RDAP is that the RDAP is cost-based. Southwest's non-gas costs do not decrease when usage per customer decreases. If revenue decreases when usage per customer decreases — as it does in any rate design with a non-gas commodity charge — then that rate design is a departure from cost-based rates. Straight-Fixed-Variable (SFV) rates would eliminate this departure from cost-based rates, and one cannot claim that they are a biased form of single-issue ratemaking, because they do not involve any change in rates beyond the end of the test year. I support rates with commodity charges on the grounds of fairness and equity among customers within a single customer class. Combining the RDAP with conventional rates (including commodity charges) preserves the fairness and equity of conventional rates and also achieves the cost-based revenue stability of the SFV rate design.

My second response is that regulatory lag is most likely to be disadvantageous to Southwest, even if the effect of declining usage per customer is removed by the RDAP. I explained in my direct testimony (Q&A 23, page 10) that customer growth does not solve the problem of decreasing usage per customer, and I pointed out in my rebuttal testimony that Mr. Radigan himself sees Southwest's cost recovery deteriorating for reasons other than declining usage per customer. The bottom line is that regulatory lag is biased against Southwest under present economic and natural gas industry conditions. The RDAP would remove some of this bias, but even with the RDAP in place, the end result would be a net remaining bias against Southwest.

My third response on the question of bias is that Southwest has informed me that it is willing to eliminate any possibility of favorable bias in the rates resulting from the RDAP. If the Commission adopts the RDAP and WNAP on a pilot basis, as proposed by Southwest, or the Commission approves the RDAP with weather protection, Southwest would agree that in any year when usage per customer declines, the RDAP surcharge would be capped at the revenue amount needed to yield Southwest's allowed rate of return.

RISK

Q. 9 Are risk considerations an appropriate argument against revenue decoupling?

A. 9 Definitely not. Mr. Radigan and Ms. Diaz Cortez both emphasize risk, but both focus on the risk to Southwest, not the risk to customers. (Radigan SR 4:3-14, 5:9; Diaz Cortez SR 7:13-18, 8:17–9:6.) That is a major shortcoming of their testimony, because the proper concern of customers (and their representatives) is the way customers are affected. The risks facing Southwest are relevant only for their effect on customers, but neither Mr. Radigan nor Ms. Diaz Cortez carries his or her analysis far enough to discern any effect on customers. All we have are the unsupported (and incorrect, as I have shown) claims that any reduction in risk to Southwest automatically shifts that risk to customers. (Diaz Cortez SR 9:2-4; Radigan SR 10:12, echoing his April 11 direct 7:15-16.) If Mr. Radigan and Ms. Diaz Cortez had examined the effect on customers, they would have found that customers benefit from the risk reductions that revenue decoupling would afford to Southwest, as I showed at pages 14-15 of my rebuttal testimony.

From a regulatory and a customer perspective, it is appropriate and even desirable that a utility be at risk for its own costs. The imposition of cost risk on a utility is desirable because it provides a direct and strong financial incentive for the utility to control and even reduce its costs.

Revenue risk is a different story. The imposition of revenue risk on a utility provides no benefit to customers or to regulators, except perhaps that of *schadenfreude (*a German word meaning: delight in another person's misfortune). Worse, the imposition of revenue risk may harm customers by causing an increase in the utility's cost of capital, which the customers must ultimately pay. The imposition of revenue risk also provides an incentive for the utility to <u>increase</u> its revenues (just as cost risk provides an incentive to reduce costs), and the incentive to increase revenues is <u>not</u> desirable.

Revenue decoupling would reduce Southwest's revenue risk, but it would have no effect on Southwest cost risk, and Southwest would continue to bear the entire risk of changes in its actual costs. The most that decoupling can possibly "guarantee" is recovery (in future years) of the test year revenue per customer amount allowed in the present rate case. It cannot possibly "guarantee the Company revenue requirement recovery", which is what Ms. Diaz Cortez falsely claims (SR 7:17-18).

The risk reductions that revenue decoupling would achieve for Southwest have no adverse effect on customers, and some aspects of those risk reductions are beneficial to customers. Southwest witness Hanley explains in his testimony that most of the companies in his proxy group already benefit from weather normalization adjustments, and that denial of the WNAP to Southwest would, if anything, require an increase in Southwest allowed rate of return.

<u>THE COMMISSION DECISION IN SOUTHWESTS'S LAST RATE CASE</u>

Q. 10 Mr. Radigan notes that the Commission rejected Southwest's revenue decoupling proposal (the Conservation Margin Tracker, or CMT) in its February 2006 order in Southwest's last rate case, and he asserts that it should do so again because Southwest has not presented anything new or addressed the Commission's concerns. (SR 5:1-5, 7:14–8:20, 9:11-22.) Do you have a response?

A. 10 Yes. Immediately after stating its rejection of the CMT, the Commission noted Southwest's suggestion that it (Southwest) would be open to other decoupling mechanisms, apparently inviting alternative proposals. (Decision No. 68487 [D-68487], pages 33-34.) And that is exactly what Southwest has done. The RDAP, WNAP, and the Volumetric Rate Design are three alternative ways of achieving some of the benefits of revenue decoupling. Southwest is proposing that all three be adopted, but the Commission can adopt any one or two of them without the other(s). Even without going into details about the CMT proposal in Southwest's last rate case, it is clear that this menu of choices is not just the CMT that the Commission rejected.

Two of these three proposals respond specifically to the Commission's concern that the CMT would have required "residential customers … to pay for gas that they have not used in prior years" (D-68487, 60:6-7), a concern echoed here by Mr. Radigan and Ms. Diaz Cortez. (Radigan SR 9:11-22 and Diaz Cortez SR 6:14-20, 8:9-15.) The Volumetric Rate Design does not involve anything that can be identified as a payment for gas not used. The WNAP does involve an adjustment that Mr. Radigan and Ms. Diaz Cortez characterize (I think unfairly, as I have explained) as payment for <u>the delivery of</u> gas not used in warmer than normal winters, but it balances this effect by providing <u>free delivery</u> of the additional volumes of gas that customers do use in colder than normal winters.

These same two proposals (the Volumetric Rate Design and the WNAP) are also responsive to the Commission's hesitancy to address Southwest's concerns about declining usage per customer in the absence of more extensive evidence about the causes and likely persistence of such a decline (D-68487, 60:3-5). These proposals address this concern because neither involves any adjustment related to declines in usage per customer. Only the RDAP responds to declines in usage per customer. I would add that it is specious to argue against the RDAP on the grounds that Southwest has failed to demonstrate conclusively that usage per customer will continue to decline as rapidly as in the past (Radigan SR 6:5-25), because the RDAP will respond only to the future declines in usage per customer that actually occur. If usage per customer does not decline any further, then there will be no RDAP surcharge, and adoption of the RDAP will have no effect on customers.

Finally, I would note that there is nothing wrong with taking a fresh look at important policy issues such as revenue decoupling, even if a particular aspect of that issue has recently been addressed and decided, because the world changes. In 1976 and again in 1977, I testified as the Minnesota PSC Staff witness on rate of return in base rate cases of Minnesota Power & Light Company (MP&L). One of the issues was whether the Commission should permit MP&L to recover in its rates, a return on its investment in a coal-fired generating station then under construction, rather than provide allowance for funds used during construction (AFUDC) on that construction work in progress (CWIP). I opposed MP&L's request for a current return, and the Commission declined to allow it. But a year later MP&L made the same request a third time. I was again the Staff rate of return witness, and I again opposed the request, but in the 1978 case the Commission decided that the time had come to allow MP&L a current return on its coal-plant CWIP. I would urge this Commission to reevaluate the revenue decoupling issue here, just as the Minnesota PSC reevaluated the AFUDC issue in 1978.

Q. 11 Do you have any further comment about the stakeholder collaborative on revenue decoupling?

A. 11 Yes. Staff and RUCO are, at present opposed to any form of revenue decoupling, and their opposition made it impossible for the stakeholder collaborative to reach any constructive solution to the problem of revenue risk and conservation incentives. Staff and RUCO are, of course, entitled to oppose all forms of revenue decoupling if they so choose, and to present their views to the Commission — which they have done extensively in this proceeding. But they cannot fairly claim that the inability of the stakeholder collaborative to resolve these problems is yet another reason for the Commission to reject all of Southwest's revenue decoupling proposals, when their own opposition to all of those proposals is the reason for the lack of forward progress in the stakeholder collaborative.

Q. 12 Does this conclude your prepared rejoinder testimony?

A. 12 Yes, it does.

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IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY
OF
A. BROOKS CONGDON

ON BEHALF OF
SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
A. BROOKS CONGDON

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
A. BROOKS CONGDON

INTRODUCTION

Q. 1 Please state your name and business address.

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

Q. 2 Are you the same A. Brooks Congdon who sponsored prepared direct and rebuttal testimony in this Docket for Southwest Gas Corporation (Southwest or the Company)?

A. 2 Yes, I am.

Q. 3 What is the purpose of your rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to the surrebuttal testimony presented by the following witnesses: Ms. Marylee Diaz Cortez, witness for the Residential Utility Consumer Office (RUCO); Messrs. Frank W. Radigan and Phillip S. Teumim, witnesses for the Arizona Corporation Commission Utilities Division Staff (Staff); and Mr. Jeffrey A. Schlegel, witness for the Southwest Energy Efficiency Project (SWEEP) regarding their recommendations and comments concerning Southwest's tariff and rate design proposals and the appropriate DSM funding level.

Q. 4 Did you prepare exhibits to support your rejoinder testimony?

A. 4 Yes. I prepared the exhibits identified as Rejoinder Exhibit No.__(ABC-1) and Rejoinder Exhibit No.__(ABC-2).

Q. 5 Please summarize your rejoinder testimony.

A. 5 My rejoinder testimony will address the following issues:

1) Staff's proposed revenue allocation.
2) Staff's and SWEEP's proposed DSM funding level.
3) RUCO's assertion that Southwest's proposed residential Volumetric Rate Design is not revenue neutral for customers.
4) Staff's assertion that Southwest's tariff and rate design proposals are "virtually the same proposals" as Southwest proposed in the last general rate case.
5) Staff's and RUCO's rejection of Southwest's RDAP, WNAP, and Volumetric Rate Design proposals.

<u>STAFF'S PROPOSED REVENUE ALLOCATION</u>

Q. 6 Mr. Radigan states in his surrebuttal testimony that revenue allocation should be done before rate design and the Company has it backwards. Please comment.

A. 6 Southwest has not performed rate design before revenue allocation. The Company used the results of its Class Cost of Service Study to allocate revenue responsibility to customer classes. The methodology that Southwest followed results in larger increases to those classes that are earning the lowest rates of return at present rates and smaller increases to those classes that are earning the highest rates of return at present rates. No party in this proceeding, including Staff, contested

Southwest's Class Cost of Service Study.

By comparison, Mr. Radigan has proposed a revenue allocation in which all customer classes receive a revenue increase within one percent of the system average increase. For all practical purposes, Mr. Radigan's revenue allocation gives no weight to the results of the Class Cost of Service Study and is an equal percent increase for all customer classes. It is Mr. Radigan, not Southwest, who has revenue allocation and rate design backwards.

STAFF'S AND SWEEP'S PROPOSED DSM FUNDING LEVEL

Q. 7 In your rebuttal testimony, you recommend that a Commission decision on the DSM funding level be removed from this rate case. How did the parties respond to this proposal?

A. 7 No party supported this proposal. Mr. Schlegel continues to propose that the Commission approve an increase in DSM funding to "at least $12 million annually". Mr. Teumim, who in his direct testimony did not propose any increase in the current DSM funding level of $4.4 million annually, proposed increased funding of $1 million per year for the years 2010 through 2012, bringing the DSM funding level to $7.4 million by 2012.

Q. 8 What is Southwest's response to these proposals?

A. 8 When Southwest proposed new DSM programs and a total funding level of $4.4 million in its last rate case, it did so with an expectation that the Commission would approve the Company's proposed Conservation Margin Tracker (CMT) tariff, thereby removing the financial disincentives for Southwest to aggressively encourage its customers to conserve natural gas. That didn't happen. In this proceeding, Southwest has proposed a variety of new rate design and regulatory mechanisms that would remove or mitigate the financial harm to the Company when customers use less gas. Staff and RUCO are opposed to Southwest's proposed rate design and tariff mechanisms. Although Southwest is firmly committed to the goal of maximizing conservation and energy efficiency for its customers, Southwest is opposed to any increase in the current $4.4 million DSM funding level, without affirmative relief to the financial pressure Southwest faces due to declining average residential usage.

<u>RUCO'S ASSERTION THAT SOUTHWEST'S PROPOSED RESIDENTIAL VOLUMETRIC RATE DESIGN IS NOT REVENUE NEUTRAL FOR CUSTOMERS</u>

Q. 9 RUCO witness Marylee Diaz Cortez asserts that customers are not revenue neutral under Southwest's proposed Volumetric Rate Design compared with a traditional average cost rate design. Please comment.

A. 9 Very simply, Southwest's proposed residential Volumetric Rate Design, as RUCO itself correctly points out, has <u>the same effective rate</u> per therm for all natural gas consumed as a traditional average cost rate design. Consequently, it is impossible for the two rate designs not to be revenue neutral. Ms. Cortez's Surrebuttal

Exhibit A purportedly demonstrates how smaller users will pay more under Southwest's proposed Volumetric Rate Design than they would under a traditional average cost rate design. However, Ms. Diaz Cortez's exhibit contains a significant error.

Q. 10 Have you prepared an exhibit correctly displaying the differences between Southwest's proposed Volumetric Rate Design and a traditional average cost rate design?

A. 10 Yes. Rejoinder Exhibit No.___(ABC-1) shows a comparison of non-gas cost and gas cost amounts residential customers would be billed under Southwest's proposed Volumetric Rate Design and under a traditional average cost rate design. Rejoinder Exhibit No.__(ABC-1) demonstrates that customers are, in fact, revenue neutral under the two rate designs. RUCO is correct that there is a shifting of recovery of non-gas costs from large users to small users of gas. However, Ms. Diaz Cortez's exhibit fails to show the offsetting shift in the recovery of gas costs from small users to large users as demonstrated in Rejoinder Exhibit No.__(ABC-1).

Q. 11 Please explain how Southwest's proposed Volumetric Rate Design more accurately recovers the cost of providing service than a traditional rate design when the effective rate per therm is the same in both rate designs.

A. 11 Once customers are connected to the system, Southwest's non-gas cost of providing service is fixed, and does not vary with changes in customer use. In that regard, it costs the Company the same amount to provide distribution service to a residential customer who uses 40 therms as it does to provide distribution service to a customer who uses 140 therms. Rejoinder Exhibit No.__(ABC-1) demonstrates that Southwest's proposed Volumetric Rate Design more accurately recovers the fixed cost of providing service to residential customers.

At the same time, Southwest's proposed Volumetric Rate Design shifts the amount of gas cost recovered from small users to large users. This shift in gas cost recovery is consistent with cost-based pricing principles because changes in the recovery of gas cost follow the movement in Southwest's cost of purchased gas associated with higher and lower gas demands. When gas demand increases, natural gas prices in the supply basins tend to increase, and the proposed Volumetric Rate Design will increase recovery of Southwest's gas cost as compared to a traditional average cost rate design.

STAFF'S ASSERTION THAT SOUTHWEST'S TARIFF AND RATE DESIGN PROPOSALS ARE "VIRTUALLY THE SAME PROPOSALS" AS SOUTHWEST PROPOSED IN THE LAST RATE CASE

Q. 12 Staff witness Mr. Radigan asserts, "In Southwest's last rate case, the Commission rejected virtually the same proposals, the Company is asking for here..." Please explain how Southwest's current proposals in this rate case differ substantially from the last case.

A. 12 Southwest's proposed WNAP and RDAP tariff mechanisms and its proposed residential Volumetric Rate Design are similar to Southwest's CMT and rate design proposals in its last rate case only to the extent they are intended to address the same issues of weather and non-weather volatility in revenue. Southwest's proposals in this proceeding have been designed to be responsive to Commission Decision No. 68487 and are very different from its proposals in the last case. Southwest's proposals in its last rate case and in this case have been juxtaposed in Rejoinder Exhibit No.__(ABC-2) to illustrate the differences. Some of these differences are also set forth below:

1) Accounting for weather-related revenue variations with a real-time weather adjustment mechanism, and accounting for non-weather variations with a separate deferred accounting provision addresses the concern that there could be large swings in rates from year-to-year due to weather effects.

2) Limiting the proposed increase to the residential basic service charge to a much lower percentage increase than the 50 and 100 percent increases proposed by Southwest in the last case; an increase which is only 10 percent greater than the increase authorized in Southwest's last rate case.

3) Eliminating Southwest's declining block rate design to address concerns about sending appropriate price signals.

RUCO'S AND STAFF'S REJECTION OF SOUTHWEST'S RDAP, WNAP AND VOLUMETRIC RATE DESIGN PROPOSALS

Q. 13 Given that Southwest has again demonstrated that customer usage continues to decline and that the Company seeks to reduce weather-related volatility in customer bills, please provide your perspective on Staff's and RUCO's rejection of all of Southwest's proposed remedies.

A. 13 Staff's and RUCO's proposals are premised on the notion there is nothing wrong with the status quo, and therefore, there is no need to strive for improved rate design and tariff mechanisms. However, the record is very clear that Southwest and its customers continue to be exposed to weather-related volatility, and the Company continues to experience significant erosion in cost recovery due to declining use per customer. In my rebuttal testimony, I commented on the fact that average annual residential usage has declined by 13 therms in the 11 months since the close of the test year in this rate case. In his Rejoinder Testimony, Southwest witness James Cattanach provides analyses and historical data suggesting that there is a significant likelihood that residential usage per customer will continue to decline in the foreseeable future. The status quo is not an acceptable solution for Southwest.

Q. 14 What are the potential consequences if the Commission does not accept Southwest's proposals and agrees with Staff and RUCO to essentially maintain the status quo?

A. 14 In the short-run, customers will be denied immediate relief from high winter bills due to colder than normal weather that would otherwise be provided under Southwest's proposed WNAP. In the long-run, customers will be denied potential benefits including: 1) longer periods of time between general rate cases, 2) reduced average capital costs and 3) greater flexibility in rate design.

Q. 15 Please comment on Mr. Radigan's surrebuttal testimony at page 5, lines 15-26, wherein he discusses that while continued declines in use per customer from the test year level used to design rates will result in additional financial pressure on Southwest, the Company has presented only one piece of the puzzle because it will also be allowed to retain any revenues associated with new customer growth.

A. 15 Mr. Radigan's inference that growth in margin derived from new customers will compensate for the loss in margin due to declining customer usage is a fallacy. Mr. Radigan is correct when he observes that declining use per customer from the test year level used to design rates will place additional financial pressure on Southwest. However, the fallacy in Mr. Radigan's discussion is that he fails to mention that new customers are not gifted to the Company at zero cost. As a result, the margin derived from customer growth is necessary to pay for the capital investment and additional operating expenses associated with serving those same new customers, and does not compensate Southwest for losses related to reduced customer usage. Thus, it is actually Mr. Radigan who presents only one piece of the puzzle.

Q. 16 Do you have any further comments?

A. 16 Yes. I completely agree with Mr. Schlegel's comment at page 3, lines 128 and 129 of his surrebuttal testimony, where he states "SWEEP suggests that the experience of pilot implementation will do more to resolve the differences among parties than continued debate in this or subsequent rate cases."

Q. 17 Does this conclude your rejoinder testimony?

A. 17 Yes, it does.

SOUTHWEST GAS CORPORATION
COMPARISON OF THE RESIDENTIAL BILL IMPACTS OF
AN AVERAGE RATE DESIGN AND SOUTHWEST'S PROPOSED RATE DESIGN
FOR WINTER SEASON BILLS

Description	Average (Normal) Rate Design	Southwest Proposed Rate Design	Difference Proposed less Average
Consumption			
20 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	11.08	17.61	6.54
PGA/Gas Cost	18.74	12.20	(6.54)
Total	$ 42.61	$ 42.61	$ -
40 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	22.15	30.82	8.67
PGA/Gas Cost	37.48	28.80	(8.67)
Total	$ 72.43	$ 72.43	$ -
55 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	30.46	30.82	0.37
PGA/Gas Cost	51.53	51.16	(0.37)
Total	$ 94.79	$ 94.79	$ -
60 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	33.23	30.82	(2.40)
PGA/Gas Cost	56.21	58.61	2.40
Total	$ 102.24	$ 102.24	$ -
80 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	44.30	30.82	(13.48)
PGA/Gas Cost	74.95	88.43	13.48
Total	$ 132.05	$ 132.05	$ -
100 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	55.38	30.82	(24.55)
PGA/Gas Cost	93.69	118.24	24.55
Total	$ 161.87	$ 161.87	$ -
120 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	66.45	30.82	(35.63)
PGA/Gas Cost	112.43	148.05	35.63
Total	$ 191.68	$ 191.68	$ -
140 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	77.53	30.82	(46.70)
PGA/Gas Cost	131.16	177.87	46.70
Total	$ 221.49	$ 221.49	$ -

	Average Rates	Proposed Rates
Basic Charge	$ 12.80	$ 12.80
Non-Gas Rates		
All Usage/First 35 Therms	$ 0.55376	$ 0.88069
Second Block		0.00000
Gas Cost Rates		
All Usage/First 35 Therms	$ 0.93689	$ 0.60996
Second Block		1.49065

	LAST RATE CASE		CURRENT RATE CASE
CMT:	1) Captures Weather plus Non-Weather-Related Changes in Usage	WNAP:	1) Captures Weather Only
	2) Applied Only to Residential Schedules		2) Real-Time Adjustment to Customer Bills
	3) Deferred Accounting with One-Year Lag on Recovery/Refund		3) Applied to Residential and Smaller General Service
		RDAP:	1) Captures Non-Weather Only
			2) Deferred Accounting with One-Year Lag on Recovery/Refund
			3) Applied to Residential and Smaller General Service
Rate Design With CMT:	1) 50% Increase to Basic Charge	Rate Design:	1) 32% Increase to Basic Charge
	2) $.59 Declining Block Rate with $.25 Tail Block		2) Flat Rate, i.e. Eliminate Declining Block Rate
			3) Accounting Changes for Non-Gas and Gas Cost Rate Components
Rate Design W/O CMT:	1) 100% Increase to Basic Charge		
	2) $.51 Declining Block Rate with $.15 Tail Block		