ORIGINAL NEW APPLICATION

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SOUTHWEST GAS CORPORATION

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AZ CORP COMMISSION
DOCKET CONTROL

August 31, 2007

Arizona Corporation Commission
DOCKETED

AUG 31 2007

DOCKETED BY

Mr. Ernest Johnson, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Re: Southwest Gas Corporation General Rate Case Application
Docket No. G-01551A-
G-01551A-07-0504

Dear Mr. Johnson:

Pursuant to Section R14-2-103 of the Arizona Administrative Code, Southwest Gas Corporation (Southwest) tenders for filing an original and thirteen (13) copies of its Application for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to its Operations Throughout Arizona (Application). The Application consists of Volume I – Application and Tariff Sheets; Volume II– Supporting Schedules; and Volume III – Testimony.

Witness Workpapers are being provided under separate cover to members of your Staff and the Residential Utility Consumer Office. Additional copies are available and will also be provided to all parties to the Docket.

Southwest is hopeful that Staff will be able to complete its sufficiency review within 30 days. Southwest will make appropriate personnel available to respond expeditiously to Staff's questions or requests for additional information regarding the Application. To further expedite the process, please contact me at (702) 876-7163 or debra.jacobson@swgas.com as soon as a potential deficiency is identified so that Southwest can cure any deficiency that may exist as quickly as possible.

Very truly yours,

Debra Jacobson

Debra Jacobson
Director/Government and State Regulatory Affairs

Enclosure

5241 Spring Mountain Road / Las Vegas, Nevada 89150-0002
P.O. Box 98510 / Las Vegas, Nevada 89193-8510 / (702) 876-7011
www.swgas.com

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-____

2007
ARIZONA
GENERAL RATE CASE

Volume I
APPLICATION

August 31, 2007

2007
ARIZONA
GENERAL RATE CASE

Volume I

APPLICATION
ANNUAL REPORT
PROPOSED TARIFF SHEETS
CURRENT TARIFF SHEETS

Volume I
Application

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT ARIZONA	)	DOCKET No. G-01551A-07-___

APPLICATION

Southwest Gas Corporation (Southwest or the Company) respectfully states and represents as follows:

Applicant

Southwest, a corporation organized and existing under the laws of the State of California, is engaged in the business of distributing and transporting natural gas in service territories located throughout the states of Arizona, California and Nevada.

Southwest is a public service corporation subject to the jurisdiction of the Arizona Corporation Commission (Commission) by virtue of Article XV of Arizona's Constitution and applicable provisions of Title 40 of the Arizona Revised Statutes (A.R.S.).

Southwest's certificated service territories in Arizona are located in portions of the counties of Cochise, Gila, Graham, Greenlee, La Paz, Maricopa, Mohave, Pima, Pinal and Yuma. For operational purposes, Southwest's Central Arizona Division is

headquartered in Phoenix, Arizona, and Southwest's Southern Arizona Division is headquartered in Tucson, Arizona. Approximately fifty-four percent (54%) of Southwest's customers are located in Arizona.

Corporate Headquarters; Communications

Southwest's corporate headquarters is located at 5241 Spring Mountain Road in Las Vegas, Nevada. Southwest's mailing address is P.O. Box 98510, Las Vegas, Nevada 89193-8510, and Southwest's telephone number in Las Vegas is (702) 876-7011.

Communications regarding this Application should be directed to the attention of Debra Jacobson, Director/Government & State Regulatory Affairs, at the above Las Vegas address and telephone number (702) 364-7163; and Karen Haller, Assistant General Counsel & Director of Legal Affairs, at the above Las Vegas address and telephone number (702) 364-3191.

Statutory Authority

This Application is made pursuant to Sections 3 and 14 of Article XV of Arizona's Constitution, A.R.S. §§ 40-250 and 40-251 and other applicable provisions of Title 40 of A.R.S. and Section R14-2-103 of the Arizona Administrative Code (A.A.C.).

Supporting Documentation

Southwest is a Class A utility within the contemplation of A.A.C. R14-2-103; accordingly, the schedules required by that Rule are a part of this Application. Also accompanying this Application is a copy of Southwest's 2006 Annual Report to Shareholders. Additionally, accompanying this Application are the testimony and exhibits which Southwest submits in support of this Application.

Nature of Relief Sought

Southwest seeks the establishment of rates and charges for the

provision of natural gas service in Arizona at just and reasonable levels to provide Southwest with a realistic opportunity to earn a fair and reasonable rate of return on the fair value of Southwest's properties devoted to its Arizona operations.

Circumstances Justifying Relief

Southwest's primary reason for filing this Application, which is based on the historical test year for the twelve months ended April 30, 2007, is that current rates and charges are not sufficient to provide Southwest with a reasonable opportunity to earn a fair and reasonable rate of return on its investment and to attract the capital necessary to ensure continuation of reliable service to present and future customers. The historical test year in Southwest's last general rate case was the twelve-month period ended August 31, 2004.

Southwest's adjusted test year shows a revenue deficiency of approximately $50.2 million and an earned return of only 6.68 percent on its investment to provide utility service. Southwest requests a capital structure consisting of 51 percent debt, four percent preferred equity, and 45 percent common equity, with a requested return on common equity (ROE) of 11.25 percent and an overall return on original cost rate base of 9.45 percent and a 7.04 percent fair and reasonable return on a fair value rate base.

The testimony and exhibits accompanying this Application reflect that approximately $20.6 million of the revenue deficiency is attributable to increased costs of capital. Although Southwest has been successful in its efforts to control costs and to improve productivity since its last general rate case, the Company's financial resources have been strained. Southwest's capital

expenditures for its Arizona operations from August 31, 2004, the end of the test year in its last general rate case, through April 30, 2007, the end of the test year in this general rate case, exceed $371 million. During this 32-month period, the Company significantly improved its capital structure, improving its common equity ratio by 8.8 percentage points, from 34.1 percent to 42.9 percent common equity. However, with substantial customer growth expected to continue for the foreseeable future, Southwest's need to access the financial markets to fund a portion of its capital expenditures will be reduced if the Commission grants the relief requested in this general rate case.

During this period of continuing customer growth, Southwest's customer-to-employee ratio, a key measure of Southwest's productivity, has continued to improve substantially. On August 31, 2004, the test year ending date in Southwest's last general rate case, Southwest was serving approximately 736 customers per Arizona employee. In comparison, on April 30, 2007, the test year ending date in this general rate case, Southwest was serving 857 customers per Arizona employee, a 16.4 percent increase in productivity. Despite this significant increase in its customer-to-employee ratio, customer satisfaction, as determined by an independent third-party, remains in excess of 95 percent. Southwest has successfully controlled costs while maintaining its commitment to customer satisfaction. Ensuring that the Company is sufficiently strong financially to provide safe and reliable natural gas service is in the best interests of Southwest's customers. Existing rates are unjust and unreasonable and their continuance threatens Southwest's financial integrity.

Overall Purpose

The overall purpose of Southwest's Application is to secure reasonable ratemaking treatment which recognizes and alleviates the combined detrimental effects of increased costs of capital, declining average residential usage, and the vagaries of weather. These combined effects impair Southwest's ability to recover its fixed costs of doing business and earn its authorized rate of return.

In his direct testimony, Roger C. Montgomery explains, from a broad policy perspective, why it is critical that Southwest have a reasonable and realistic opportunity to earn the rate of return authorized by the Commission in this proceeding. Among other things, Mr. Montgomery stresses the importance of approving a rate design and regulatory mechanisms that address weather volatility and the continued steady decline in average residential usage over the last two decades. This declining average use is due, in large part, to conservation efforts by consumers and increased energy efficiencies in housing stock and appliances.

As part of this Application, Southwest proposes a revenue decoupling mechanism to address the negative effects of declining average usage on fixed cost recovery and revenues. Southwest also proposes a weather normalization mechanism to lessen the harmful impacts to customers and the Company from the variability of bills and fixed cost recovery associated with weather volatility.

Consistent with the overall purpose, a central focus of this Application is Southwest's critical need to compete effectively in the financial markets to secure the capital required to meet growth demands in one of the fastest growing states in the country. Not

only has Southwest been unable to earn its Commission-authorized rate of return, but its authorized ROE is significantly below the rates of return approved for other Arizona investor-owned energy utilities. Therefore, Southwest is requesting an authorized ROE more closely aligned with comparable natural gas utilities.

Approval of the proposed rate design and regulatory mechanisms will increase energy cost predictability for customers, improve Southwest's financial strength over time, and help the Company achieve parity with other Arizona energy utilities. If the Commission adopts the proposed rate design and regulatory mechanisms, Southwest will have a more realistic and reasonable opportunity to earn its authorized rate of return. Over time, this will allow the Company to improve its credit ratings. Improvements in the financial metrics will assist Southwest in lowering the overall cost of debt, which benefits Southwest's Arizona customers.

Witness Testimony

A complete and accurate explanation of the circumstances and conditions upon which Southwest relied as justification for the proposed adjustments in rates and charges and the changes in other tariff provisions proposed in this Application is embodied in the following accompanying testimony:

(1) Roger Montgomery - Policy and general rate case overview;

(2) Robert Mashas - Overall deficiency/revenue requirement and various adjustments;

(3) Randi Aldridge - Cost of service and various adjustments;

(4) Laura Hobbs - Management Incentive Program (MIP) and Supplemental Executive Retirement Plan (SERP);

(5) Theodore Wood - Capital structure, cost of debt, and

overall rate of return;

(6) Frank Hanley - Cost of equity;

(7) Jamie Cattanach - Billing determinants and declining residential consumption per customer;

(8) Frank Maglietti - Class cost of service study and Purchased Gas Adjustment (PGA) mechanism;

(9) Ralph Miller - Revenue decoupling and energy efficiency; and

(10) A. Brooks Congdon - Rate design and regulatory/ratemaking mechanisms.

Request for Implementation of New Rates by October 1, 2008

Because Arizona uses a historical test year, the revenue requirement used to determine prospective rates in this proceeding reflects costs Southwest incurred in 2006 and the first four months of 2007. Combined with the August 31 filing date, the rates established from this proceeding will reflect costs approaching 24 months since first incurred and more than 14 months since the close of the test period, rather than reflecting the costs in Arizona at the time rates become effective. This delay contributes to the Company's inability to earn an authorized rate of return and highlights the need for timely relief.

Therefore, Southwest requests this Application be processed under a schedule which contemplates the implementation of new rates by October 1, 2008, prior to the winter heating season.

As indicated above, the rate of return experienced by Southwest from its Arizona operations for the test year ended April 30, 2007 was 6.68 percent. It is inevitable that, by October 1, 2008 [17 months after the end of the test year], Southwest's

earnings from its Arizona operations will have continued to erode.

WHEREFORE, Southwest respectfully requests that the Commission issue a special order pursuant to A.A.C. R14-3-101.C to establish notice, filing, discovery and hearing procedures.

Southwest further requests that, upon conclusion of the hearing, the Commission promptly issue a decision determining the fair value of Southwest's Arizona properties, authorizing a just and reasonable rate of return thereon, and establishing rates and charges designed to allow a reasonable opportunity for Southwest to realize the authorized rate of return.

RESPECTFULLY SUBMITTED this 31st day of August, 2007.

SOUTHWEST GAS CORPORATION

Karen S. Haller
Asst. General Counsel
& Director of Legal Affairs
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Las Vegas, Nevada 89150
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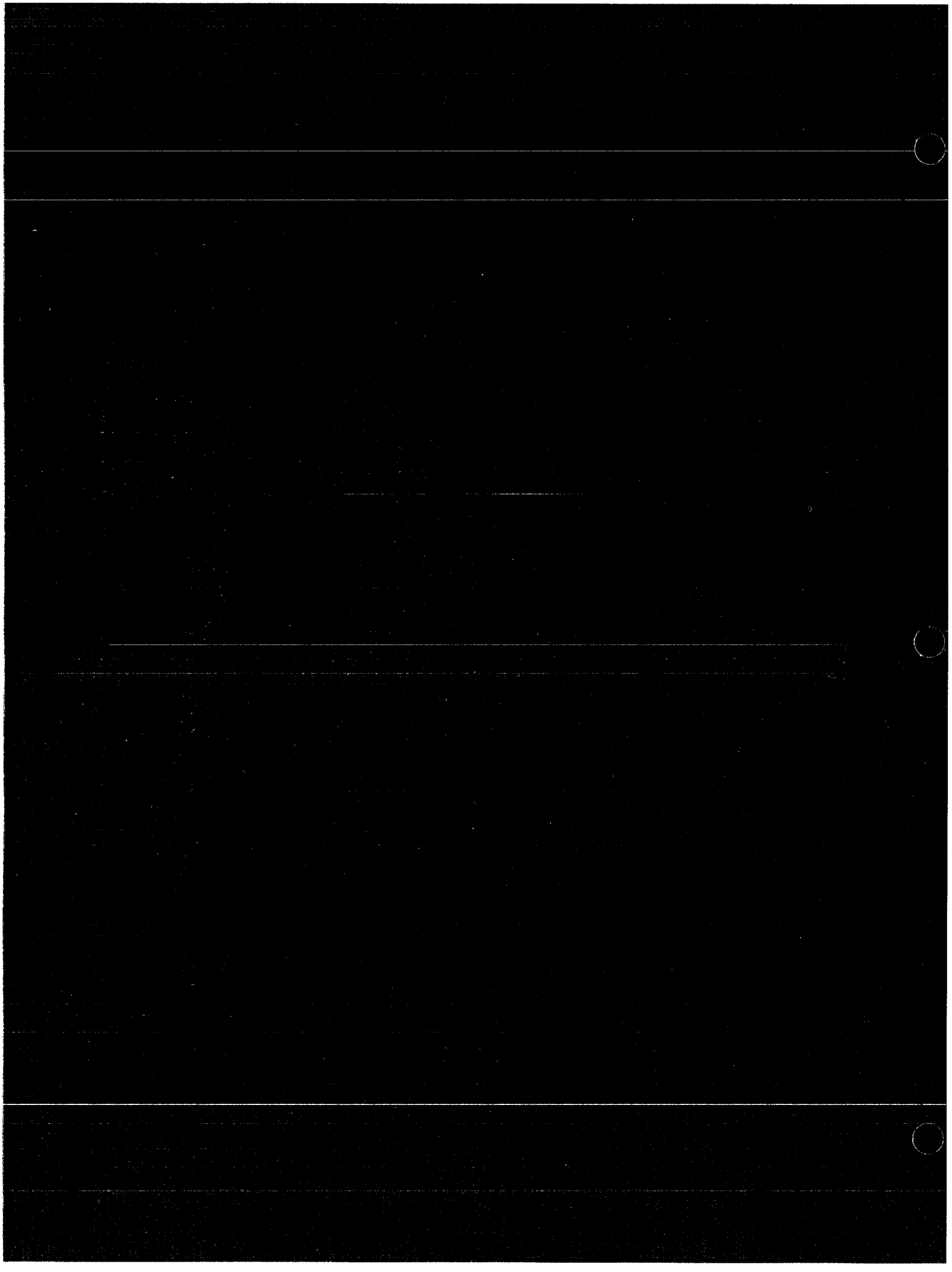
Volume I

Annual Report

"Stories Around the Fire Pit"
Southwest Gas Corporation
ANNUAL REPORT 2006



The youngest of 18 children of a Texas pioneer, Bill used a bowie knife as a teething ring and played with bears and other wild animals as an infant. After falling out of his parents' wagon near the Pecos River in Texas, he became lost and was raised by coyotes. In fact, he considered himself to be a coyote until a cowboy convinced him of his true identity.

After returning to civilized territory, Pecos Bill became the cowhand who invented all the tricks of the ranching trade. He taught gophers to dig postholes. He invented the branding iron to stop cattle rustling and the cowboy song to soothe the cattle. He killed snakes by feeding them mothballs filled with red pepper and nitroglycerin and, after inventing the lasso, he roped whole herds of cattle at a time. Once he used the entire Rio Grande to water his ranch, which included all of modern day New Mexico.

Pecos Bill used a rattle snake as a whip and rode everything in the West, including a mountain lion and a cyclone. His favorite steed, though, was named Widow-Maker and no one else could ride him. Pecos Bill's bride, Slue-Foot Sue, insisted on riding the horse on their wedding day. Widow-Maker threw Sue, who bounced so high on the hoops of her bridal gown that she hit her head on the moon. Sue bounced for days afterward with no signs of stopping. Pecos Bill realized that she would starve to death, so he shot her. Although Bill was married many times, he never did recover from the loss of Sue.

PECOS BILL

SASQUATCH

Called by a Native American word meaning "hairy giant," Sasquatch is renowned for its shy, reclusive nature. It forages for food at night, sleeps during the day and stays out of sight remarkably well given its size.

The beast is not known to be violent, but the humans who have encountered one report that it does pose an assault on the senses. First, the creature is fearsome to see. It stands between seven and eight feet tall and can weigh over 450 lbs. More than 700 footprints attributed to Sasquatch have been collected over the years. They average 15.6 inches long and 7.2 inches wide. Most people who have spotted Bigfoot or its counterparts have described the creature as being half-man/half-ape and having long, dark fur all over its body. Secondly, it is reported to have a very strong, very foul odor. In fact, in Florida, Sasquatch is known as the "Skunk Ape." Thirdly, the few humans who have heard Sasquatch's howl, say it is otherworldly. One outdoors writer described it as "The kind of scream no cougar or bear could ever squeeze from their throat...unless it was their last."

Other tall tales have encouraged the settlement of the American frontier. Perhaps the modern myths of Sasquatch are a reminder that we need not conquer the entire natural world – that its greater mysteries should remain unscathed.

Ordinarily, one stork can deliver several babies to their respective parents' homes. When Paul Bunyan was born, it took five giant storks, working overtime, to carry just him. Paul outgrew his father's clothes in a week and his own clothes were so large his parents used wagon wheels for buttons. A lumber wagon drawn by a team of oxen served as a baby carriage.

Paul cut his teeth on a peavy pole – used to roll logs – and, as a child, played with an axe and crosscut instead of more traditional toys. On his first birthday his father gave him a blue ox named Babe. Babe grew to be seven axe handles and a plug of tobacco wide between the eyes and, as a snack, would eat 30 bales of hay – wire and all. The tracks that Paul and Babe made gallivanting around Minnesota filled up and made the 10,000 lakes. Their travels took them West, too. They dug the Grand Canyon by dragging Paul's axe behind them, and created Mount Hood by piling rocks on top of their campfire to put it out.

They were famous for being so large – and for putting their weight into their work. Paul Bunyan could fell 23 trees with a single swing of his axe. And when he got his rhythm, he looked like a tornado in a toothpick factory. On one job – clearing North Dakota for Teddy Roosevelt – the winding road to the river slowed the crews. So Paul hooked Babe to the far end, and Babe marched in a straight line until that road ran as true as a crow flies.

and Babe
BIG BLUE OX

Fellow Shareholders, As another year passes, our story continues.

A marked improvement in operating results and positive movement in the Company's stock price combined for a very encouraging 2006. Much needed rate relief in Arizona, continued customer growth throughout our service areas, and another superb contribution from our pipeline construction subsidiary drove earnings to $2.07 per share, an increase of $0.92 per share over the $1.15 posted in 2005. The Company's stock price was positively affected by the rise in earnings and the strong performance of our industry sector and the overall market.

You will recall that the Arizona Corporation Commission (ACC) rendered its decision in the most recent Arizona general rate case in February 2006 and approved an annual increase in operating revenues of $49.3 million, effective March 1, 2006. While it will take a complete twelve months to capture the full benefit of this increase, that portion realized in 2006 went a long way toward improving the Company's financial results. Unfortunately, we were disappointed that the ACC did not approve the key rate design proposals the Company made to mitigate the effects of weather volatility and customer conservation resulting from higher natural gas prices and more efficient building standards in new construction. And while the weather improved over the prior year, it was still warmer than normal and, consequently, our operating margin in Arizona was negatively impacted.

As we mentioned in last year's report, to bring more stability to revenues and cash flows, the Company proposed several rate design alternatives in each of the most recent general rate cases in California, Nevada and Arizona. In California, the approved rate design substantially protects the authorized operating margin. In Nevada, while the approved rate design mitigates most of the exposure to weather variability, we continue to work with the commission and staff to further refine rate design and improve revenue stability. Although we were allowed to increase the monthly fixed basic service charge to customers in Arizona, the authorized rate design does not yet provide acceptable revenue stability. Fortunately, the ACC's final order acknowledged the need to study this issue further, and the Company was encouraged to continue pursuing rate design refinements with the ACC staff and other interested parties. We have established an ongoing dialogue with all interested parties on this important issue.

Effective marketing initiatives emphasizing the lifestyle benefits of natural gas appliances and amenities to builders have enabled the Company to consistently realize a system-wide average market share of new home construction in excess of 90 percent. This compares to an industry average of less than 70 percent.

Having experienced more than a decade of tremendous, near industry leading customer growth, we believe the management of growth has become one of our core competencies. In 2006, we experienced an increase of 71,000 customers throughout our service areas. This organic growth exceeded that of most natural gas distribution companies in the nation. The Company has aggressively managed this growth to ensure it is profitable. As the exclusive provider of natural gas in the areas we serve, we have the obligation to provide service to customers, subject to tariff requirements. However, when the economics for a sub-division do not meet the requirements under our tariffs, we require non-refundable contributions from builders in order to remain within our allowable capital investment. Furthermore, for nearly all residential sub-division developments, we obtain refundable advances from builders to cover the carrying costs of our significant infrastructure investments until meters are set and customers begin paying for service.

Based on the level of current builder commitments for 2007, the torrid growth levels of recent years appear to be moderating. However, given the projected, continued population growth in Arizona and Nevada, we are still anticipating a healthy growth rate going forward. Interestingly, Arizona recently surpassed Nevada as the fastest growing state in the nation in terms of percentage population growth...Nevada is now number two.

We are constantly analyzing our operating activities to improve efficiency and productivity. Through judicious investments in technology, we continue to realize significant improvements. For example, we launched a project this past summer to convert all customer meters to electronic meter reading. Over the past few years, the cost of the required technology decreased to a level that made the economics for the project compelling. The conversion is expected to be completed in 2009 and, through attrition and the use of temporary labor, we expect to complete the conversion with no adverse impact to remaining full-time employees.

During the fifteen years ended 2006, the Company more than doubled, adding 914,000 customers and, notably, only 282 employees...a ratio of 3,241 customers for every employee added. In 2006, we achieved an overall customer to employee ratio of 706 to 1, one of the top productivity ratios in the industry and, by this measure, more than a 50 percent improvement over the last decade. Furthermore, we experienced a decline in our operating costs per customer over the past three years, despite the rising costs of pipeline construction and compliance with new federal and state mandates. Remarkably, at the same time we've experienced these productivity and efficiency gains, the Company consistently achieved a customer satisfaction rating well above 90 percent... a tribute to the commendable efforts of our dedicated employees.

Northern Pipeline Construction Co., our wholly owned pipeline construction subsidiary, continued to post impressive operating results. Through profitable bid work, increased workload under existing contracts, the securing of new contracts and a positive equipment resale market, NPL achieved record net income of $12.4 million, or $0.31 per share during 2006. Given the initiatives NPL management has taken, and expected activity for 2007, we anticipate continued favorable operating results, although maybe not at record levels.

As you know, the Company has not increased the dividend on its common stock since 1994. The Board regularly reviews dividend policy and considers the adequacy and sustainability of the Company's earnings and cash flows; the strength of the Company's capital structure; the sustainability of the dividend through all business cycles; and whether the dividend is within a normal payout range for its industry. Based on the recent improvements in the Company's earnings, cash flows and capital structure, the Board of Directors determined that it would be appropriate and in the best interests of the shareholders to increase the dividend on common stock. At the February 27, 2007 Board meeting, the Company's annualized dividend was raised by $0.04 from $0.82 per share to $0.86 per share. The Board will continue to monitor the Company's earnings, cash flows and capital structure with an eye toward the possibility of further enhancing dividend payouts in the future.

We believe 2006 operating results confirm that our principal strategies are working. While we are very encouraged with our progress, there is still improvement to be made. We are determined to build on the momentum of our recent achievements by remaining focused on the following core strategies that have brought us success.

Continue to work closely with regulators to improve the level and stability of earnings and cash flows
Continue to aggressively manage growth
Continue to maximize efficiency and productivity
Continue to exceed our customers' expectations
Remain watchful and positioned to seize strategic growth opportunities

As we reflect on the 75-year history of our Company, we have been part of a remarkable story... one that truly is legendary. We acknowledge all those who have contributed toward building a company we can all be proud of. We believe the future is bright. The Board and management are committed to building on that legacy and maintaining and enhancing the value of your investment in Southwest Gas Corporation.

Sincerely,

LeRoy C. Hanneman, Jr.
Chairman of the Board

Jeffery W. Shaw
Chief Executive Officer

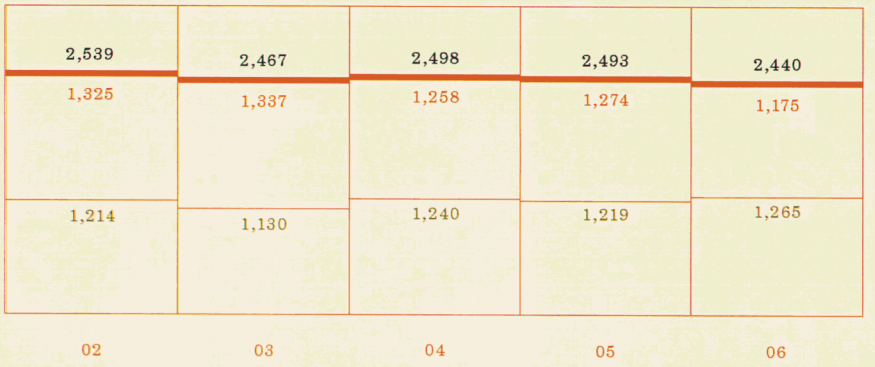
Stock Prices & Trading Volume Per Year

stock prices in dollars, volume in millions

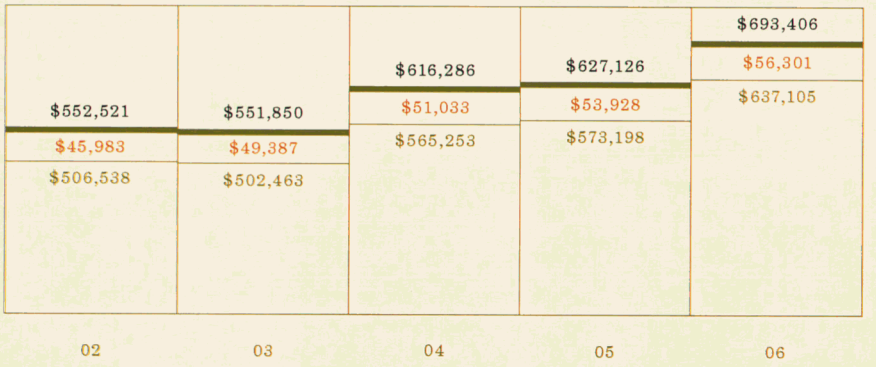
— High
····· Low
---- Volume

Financial Highlights

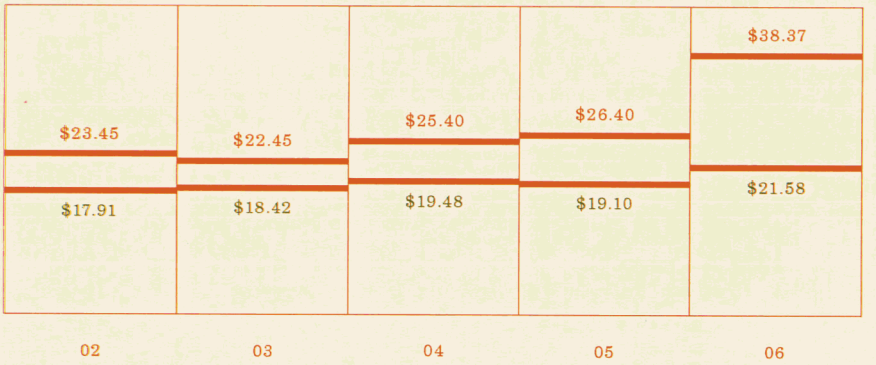
Throughput (in millions of therms)



Margin (in thousands of dollars)

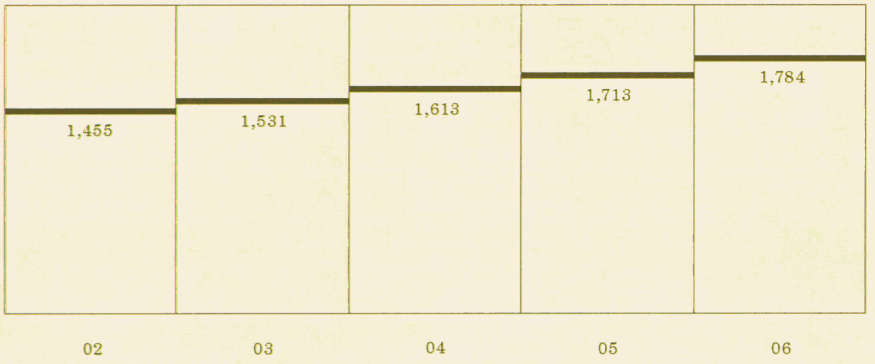


Market Price Relative to Book Value (in dollars)

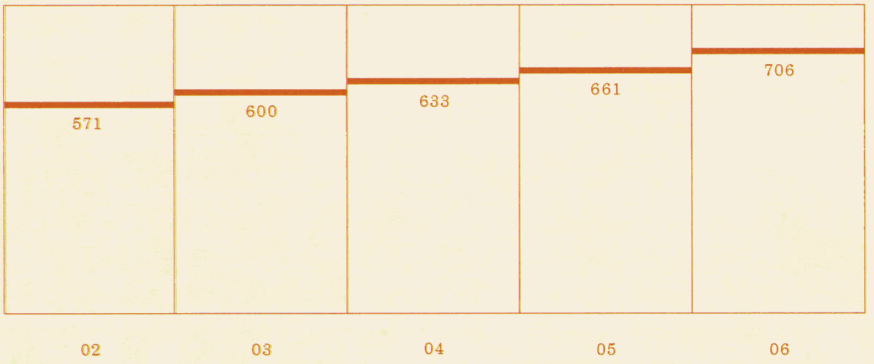


Financial Highlights

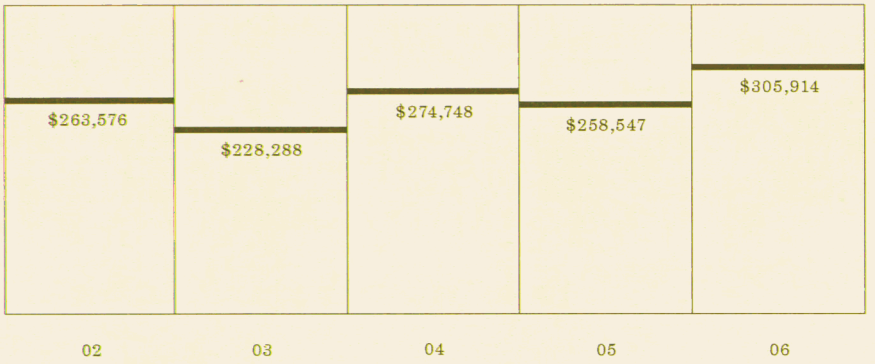
Number of Gas Customers (in thousands)



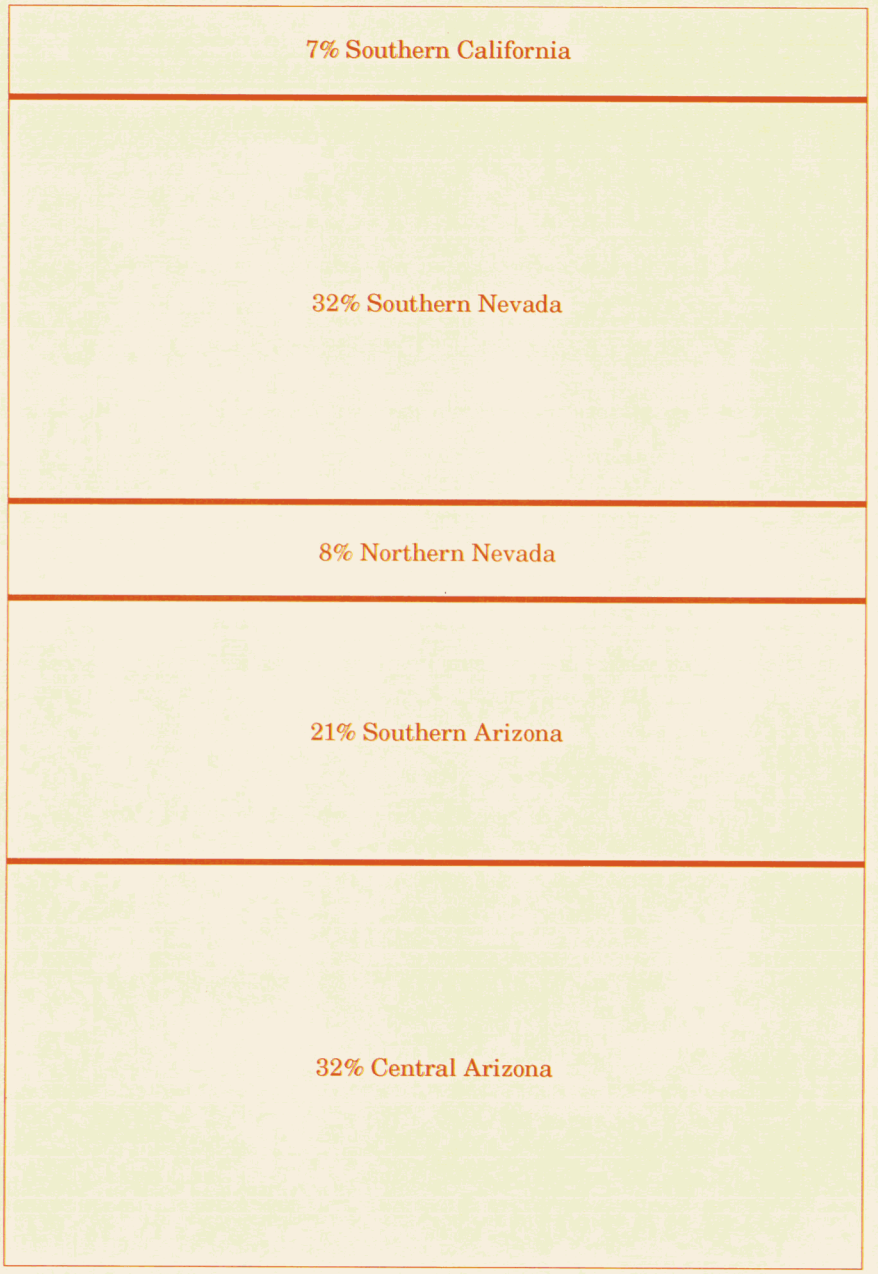
Customers per Employee



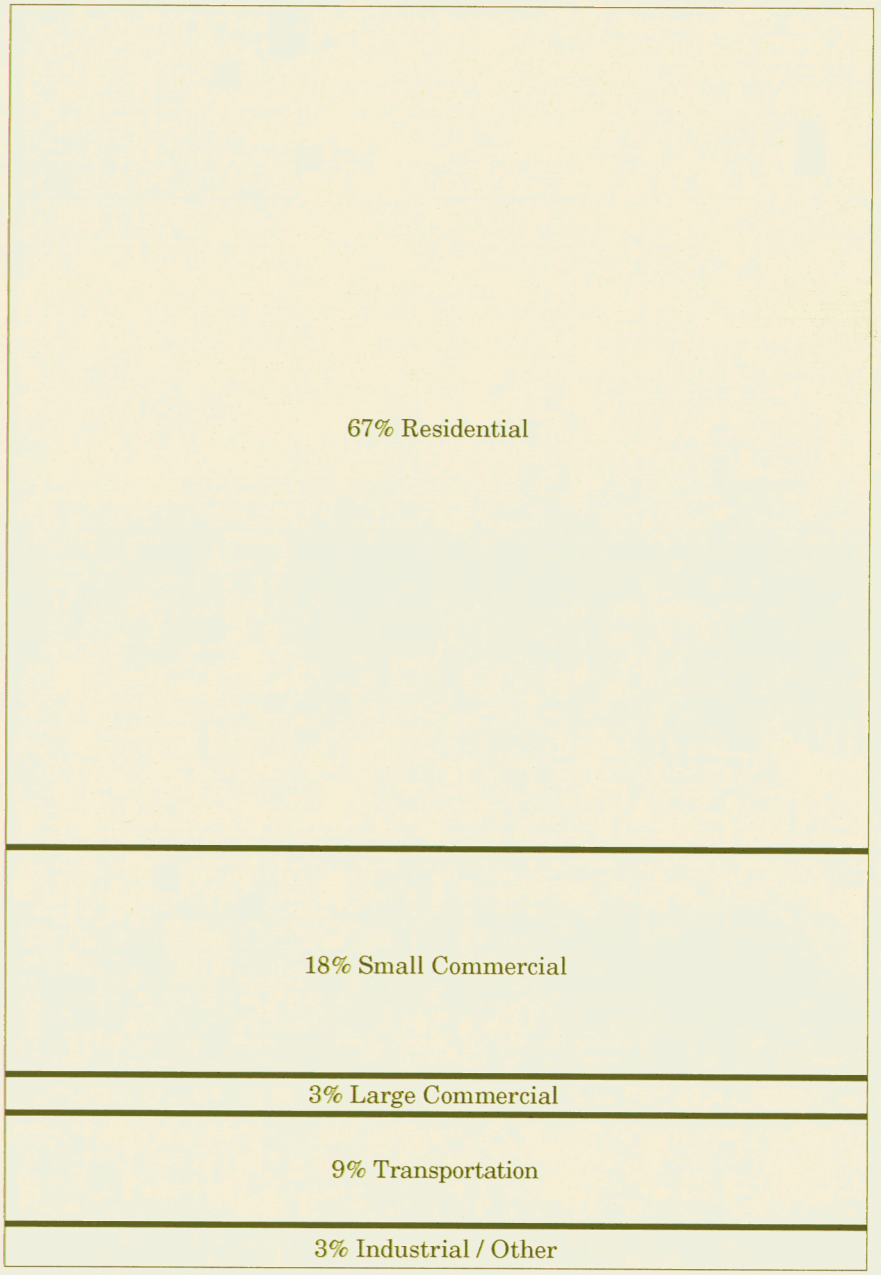
Construction Expenditures Gas Segment (in thousands of dollars)



Customers by Division
(December 31, 2006)

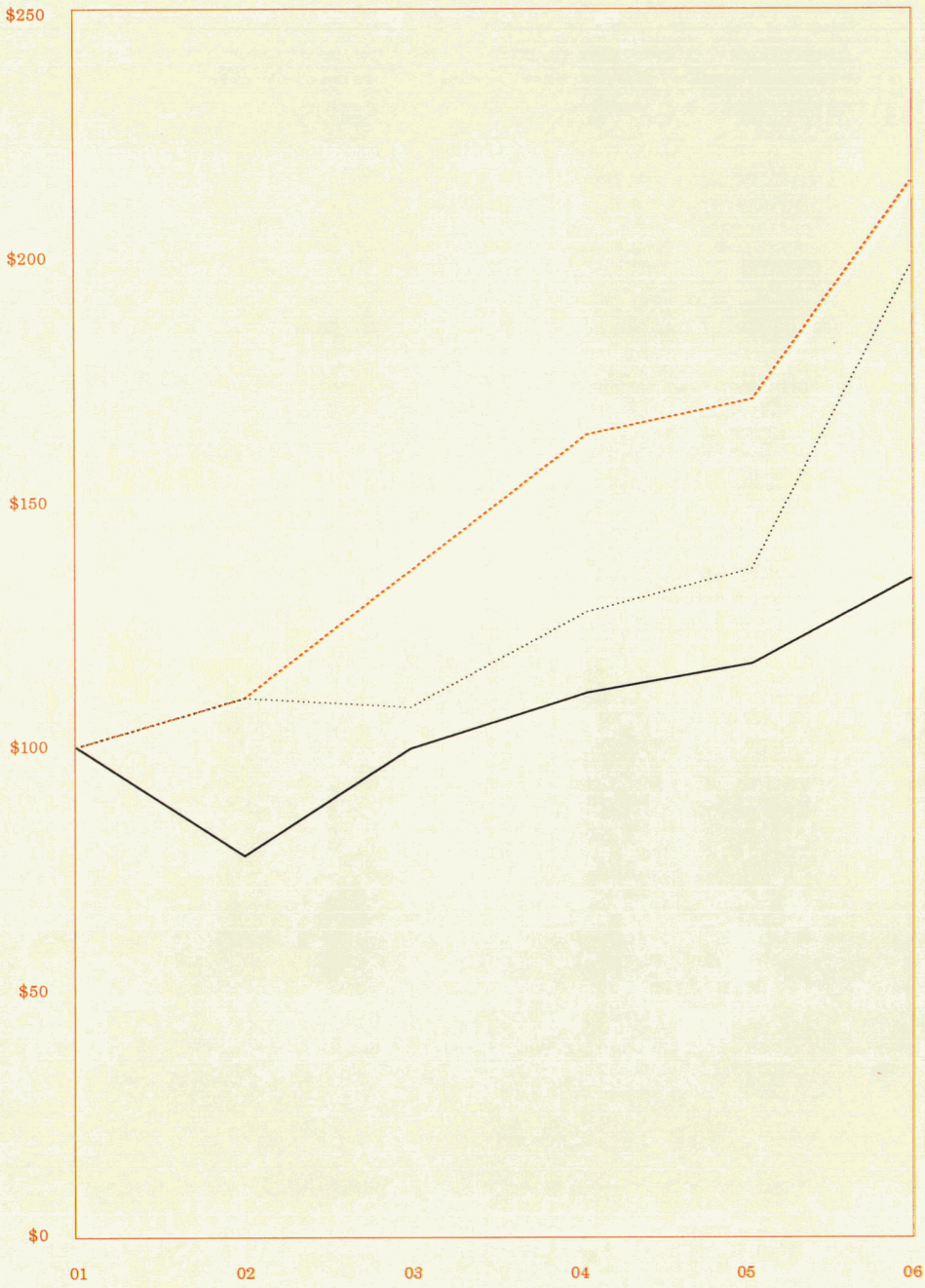


Margin by Customer Class
(2006)



Comparison of 5-Year Cumulative Total Returns

····· Southwest Gas
— S&P 500
---- S&P Small Cap Gas Index



The performance graph above compares the five-year cumulative total return on Company common stock, assuming reinvestment of dividends, with the total returns on the Standard & Poor's 500 Stock Composite Index ("S&P 500") and the S&P Small Cap Gas Index, consisting of the Company and ten other natural gas distribution companies.

(1) The Company is using the S&P Small Cap Gas Index as its peer-group index.
(2) The S&P Small Cap Gas Index, which is weighted by year-end market capitalization, consists of the following companies: Atmos Energy Corp.; Cascade Natural Gas Corp.; Energen Corp.; Laclede Group Inc.; New Jersey Resources Corp.; Northwest Natural Gas Co.; Piedmont Natural Gas Company; South Jersey Industries Inc.; Southern Union Company; the Company; and UGI Corp.

2006 Financial Data

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Consolidated Selected Financial Statistics

Year Ended December 31,	2006	2005	2004	2003	2002
(Thousands of dollars, except per share amounts)					
Operating revenues	$2,024,758	$1,714,283	$1,477,060	$1,231,004	$1,320,909
Operating expenses	1,815,576	1,563,635	1,307,293	1,095,899	1,174,410
Operating income	$ 209,182	$ 150,648	$ 169,767	$ 135,105	$ 146,499
Net income	$ 83,860	$ 43,823	$ 56,775	$ 38,502	$ 43,965
Total assets at year end	$3,484,965	$3,228,426	$2,938,116	$2,608,106	$2,432,928
Capitalization at year end					
Common equity	$ 901,425	$ 751,135	$ 705,676	$ 630,467	$ 596,167
Mandatorily redeemable preferred trust securities	—	—	—	—	60,000
Subordinated debentures	100,000	100,000	100,000	100,000	—
Long-term debt	1,286,354	1,224,898	1,162,936	1,121,164	1,092,148
	$2,287,779	$2,076,033	$1,968,612	$1,851,631	$1,748,315
Common stock data					
Common equity percentage of capitalization	39.4%	36.2%	35.8%	34.0%	34.1%
Return on average common equity	10.3%	5.9%	8.5%	6.3%	7.5%
Earnings per share	$ 2.07	$ 1.15	$ 1.61	$ 1.14	$ 1.33
Diluted earnings per share	$ 2.05	$ 1.14	$ 1.60	$ 1.13	$ 1.32
Dividends declared per share	$ 0.82	$ 0.82	$ 0.82	$ 0.82	$ 0.82
Payout ratio	40%	71%	51%	72%	62%
Book value per share at year end	$ 21.58	$ 19.10	$ 19.18	$ 18.42	$ 17.91
Market value per share at year end	$ 38.37	$ 26.40	$ 25.40	$ 22.45	$ 23.45
Market value per share to book value per share	178%	138%	132%	122%	131%
Common shares outstanding at year end (000)	41,770	39,328	36,794	34,232	33,289
Number of common shareholders at year end	23,610	23,571	23,743	22,616	22,119
Ratio of earnings to fixed charges	2.25	1.70	1.93	1.60	1.68

Natural Gas Operations

Year Ended December 31,	2006	2005	2004	2003	2002
(Thousands of dollars)					
Sales	$1,671,093	$1,401,329	$1,211,019	$ 984,966	$1,069,917
Transportation	56,301	53,928	51,033	49,387	45,983
Operating revenue	1,727,394	1,455,257	1,262,052	1,034,353	1,115,900
Net cost of gas sold	1,033,988	828,131	645,766	482,503	563,379
Operating margin	693,406	627,126	616,286	551,850	552,521
Expenses					
Operations and maintenance	320,803	314,437	290,800	266,862	264,188
Depreciation and amortization	146,654	137,981	130,515	120,791	115,175
Taxes other than income taxes	34,994	39,040	37,669	35,910	34,565
Operating income	$ 190,955	$ 135,668	$ 157,302	$ 128,287	$ 138,593
Contribution to consolidated net income	$ 71,473	$ 33,670	$ 48,354	$ 34,211	$ 39,228
Total assets at year end	$3,352,074	$3,103,804	$2,843,199	$2,528,332	$2,345,407
Net gas plant at year end	$2,668,104	$2,489,147	$2,335,992	$2,175,736	$2,034,459
Construction expenditures and property additions	$ 305,914	$ 258,547	$ 274,748	$ 228,288	$ 263,576
Cash flow, net					
From operating activities	$ 248,884	$ 214,036	$ 124,135	$ 187,122	$ 281,329
From investing activities	(277,980)	(254,120)	(272,458)	(249,300)	(243,373)
From financing activities	20,350	57,763	143,086	60,815	(49,187)
Net change in cash	$ (8,746)	$ 17,679	$ (5,237)	$ (1,363)	$ (11,231)
Total throughput (thousands of therms)					
Residential	677,605	650,465	667,174	593,048	588,215
Small commercial	309,856	300,072	303,844	279,154	280,271
Large commercial	128,255	111,839	104,899	100,422	121,500
Industrial/Other	149,243	156,542	163,856	157,305	224,055
Transportation	1,175,238	1,273,964	1,258,265	1,336,901	1,325,149
Total throughput	2,440,197	2,492,882	2,498,038	2,466,830	2,539,190
Weighted average cost of gas purchased ($/therm)	$ 0.79	$ 0.71	$ 0.57	$ 0.46	$ 0.38
Customers at year end	1,784,000	1,713,000	1,613,000	1,531,000	1,455,000
Employees at year end	2,525	2,590	2,548	2,550	2,546
Degree days—actual	1,826	1,735	1,953	1,772	1,912
Degree days—ten-year average	1,961	1,956	1,913	1,931	1,963

Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

The following discussion of Southwest Gas Corporation and subsidiaries (the "Company") includes information related to the Company's two business segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services. Southwest is engaged in the business of purchasing, transporting, and distributing natural gas in portions of Arizona, Nevada, and California. Southwest is the largest distributor in Arizona, selling and transporting natural gas in most of central and southern Arizona, including the Phoenix and Tucson metropolitan areas. Southwest is also the largest distributor of natural gas in Nevada, serving the Las Vegas metropolitan area and northern Nevada. In addition, Southwest distributes and transports natural gas in portions of California, including the Lake Tahoe area and the high desert and mountain areas in San Bernardino County.

Northern Pipeline Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

Executive Summary

The items discussed in this Executive Summary are intended to provide an overview of the results of the Company's operations and are covered in greater detail in later sections of management's discussion and analysis. As reflected in the table below, the natural gas operations segment accounted for an average of 83 percent of consolidated net income over the past three years. As such, management's discussion and analysis is primarily focused on that segment.

Consolidated Results of Operations

Year ended December 31, (Thousands of dollars, except per share amounts)	2006	2005	2004
Contribution to net income			
Natural gas operations	$71,473	$33,670	$48,354
Construction services	12,387	10,153	8,421
Consolidated	$83,860	$43,823	$56,775
Basic earnings per share			
Natural gas operations	$ 1.76	$ 0.88	$ 1.37
Construction services	0.31	0.27	0.24
Consolidated	$ 2.07	$ 1.15	$ 1.61

The main factors contributing to the increase in results of operations during 2006 include:

- higher operating margin resulting from the Arizona general rate increase;
- continued customer growth;
- a nonrecurring property tax settlement;
- increased contribution to net income from NPL; and
- 2005 included a $10 million pretax charge related to an injuries and damages case (see *Insurance Coverage* for additional information).

Partially offsetting the above positive factors was a 2.4 million increase in average shares outstanding between 2005 and 2006.

Principal Factors Affecting Operating Margin

Southwest's operating revenues are recognized from the distribution and transportation of natural gas (and related services) to customers. Operating margin is the measure of gas operating revenues less the net cost of gas sold. Management uses operating margin as a main benchmark in comparing operating results from period to period. The three principal factors affecting operating margin are general rate relief, weather, and customer growth.

General Rate Relief. Rates charged to customers vary according to customer class and rate jurisdiction and are set by the individual state and federal regulatory commissions that govern Southwest's service territories. Southwest makes periodic filings for rate adjustments as the costs of providing service (including the cost of natural gas purchased) change and as additional investments in new or replacement pipeline and related facilities are made. Rates are intended to provide for recovery of all prudently incurred costs and provide a reasonable return on investment. The mix of fixed and variable components in rates assigned to various customer classes (rate design) can significantly impact the operating margin actually realized by Southwest.

The following events highlight the impact of general rate relief on operating margin during 2006:

- In February 2006, the Arizona Corporation Commission ("ACC") rendered a general rate decision that increased rates in Arizona by $49.3 million annually effective March 2006. During 2006, general rate relief in Arizona provided a $35 million increase in operating margin.

- In June 2006, the California Public Utilities Commission ("CPUC") approved the Company's 2006 attrition year filing, granting annualized rate relief of $3 million, effective April 13, 2006, of which $2 million was recognized in 2006.

Weather. Weather is a significant driver of natural gas volumes used by residential and small commercial customers and is the main reason for volatility in margin. Space heating-related volumes are the primary component of billings for these customer classes and are concentrated in the months of November to April for the majority of the Company's customers. Variances in temperatures from normal levels, especially in Arizona where rates remain leveraged, have a significant impact on the margin and associated net income of the Company. Differences in heating demand, caused primarily by weather variations between 2006 and 2005, accounted for a $3 million increase in operating margin. Temperatures during both years were warmer than normal.

Customer Growth. As of December 31, 2006, Southwest had 1,784,000 residential, commercial, industrial, and other natural gas customers, of which 965,000 customers were located in Arizona, 642,000 in Nevada, and 177,000 in California. Residential and commercial customers represented over 99 percent of the total customer base. During 2006, Southwest added 71,000 customers, a four percent increase, of which 35,000 customers were added in Arizona, 29,000 in Nevada, and 7,000 in California. These additions are largely attributed to population growth in the service areas. Based on current commitments from builders, customer growth is expected to be over four percent in 2007. During 2006, 54 percent of operating margin was earned in Arizona, 36 percent in Nevada, and 10 percent in California. During this same period, Southwest earned 85 percent of operating margin from residential and small commercial customers, 6 percent from other sales customers, and 9 percent from transportation customers. These general patterns are expected to continue.

Incremental margin ($26 million in 2006) has accompanied this customer growth, but the costs associated with creating and maintaining the infrastructure needed to accommodate these customers have also been significant. The timing of including these costs in rates is often delayed (regulatory lag) and can result in a reduction of current-period earnings.

Management has attempted to mitigate the regulatory lag associated with growth by collecting contributions and advances from home builders and by being judicious in its staffing levels through the effective use of technology. Exemplifying this in recent years has been Southwest's expanded use of electronic meter reading technology. This technology eliminates the need to gain physical access to meters in order to obtain monthly meter readings, thereby reducing the time associated with each meter read while improving their accuracy. By the end of 2006, over 40 percent of Southwest customers' meters were being read electronically. Reductions in staffing levels associated with these efficiencies have been accomplished through normal attrition. Some of these experienced employees have been redeployed to expand service and construction capabilities. Over the next few years, Southwest will continue to invest in electronic meter reading technology to achieve additional efficiencies.

During the past decade, while adding nearly 692,000 customers, Southwest only increased staffing levels by 105. During this same period, Southwest's customer to employee ratio has climbed from 451/1 to 706/1, an increase of over 50 percent. It has accomplished this without sacrificing service quality. Additional examples of technological improvements over the last few years include electronic order routing, an electronic mapping system and a work management system.

Customer growth requires significant capital outlays for new transmission and distribution plant and results in higher service costs associated with operating and maintaining such facilities. The following financing activities supported continued construction during 2006:

- During 2006, the Company issued 2.4 million shares of common stock through its various stock plans, receiving over $70 million in proceeds.
- In September 2006, the Company issued $56 million in Clark County, Nevada 4.75% Industrial Development Revenue Bonds ("IDRBs") Series 2006A. The proceeds from the IDRBs were used by Southwest to expand and upgrade facilities in Clark County, Nevada.
- During 2006, Southwest partially offset capital outlays by collecting approximately $48.6 million in net advances and contributions from customers and third-party contractors.

The results of the natural gas operations segment and the overall results of the Company are heavily dependent upon the three components noted previously (general rate relief, weather, and customer growth). Significant changes in these components (primarily weather) have contributed to somewhat volatile earnings historically. Management continues to work with its regulatory commissions in designing rate structures that strive to provide affordable and reliable service to its customers while mitigating the volatility in prices to customers and stabilizing returns to investors. Such a rate structure is in place in California and progress has been made in Nevada. Southwest continues to pursue rate design changes in Arizona.

Property Tax Settlement

In April 2006, a settlement was reached regarding property tax valuation disputes in Arizona for tax years 2001-2005. A decrease to property tax expense of $3.7 million and an accrual of $746,000 of interest income was recorded. This entry resulted in nonrecurring after-tax income of approximately $0.07 per share in 2006.

Natural Gas Price Volatility

Southwest has experienced price volatility over the past five years, as the weighted-average delivered cost of natural gas

has ranged from a low of 38 cents per therm in 2002 to a high of 79 cents per therm in 2006. Price volatility is expected to continue throughout 2007. Sustained high prices can result in increased under-collected purchased gas adjustment ("PGA") balances and thereby temporarily reduce operating cash flows until rate relief is granted to recover the higher costs. During 2006, Southwest was able to increase gas cost recovery rates in all jurisdictions and has reduced uncollected PGA balances by $32 million since December 2005.

Stock-Based Compensation

During the first quarter of 2006, the Company began expensing all stock-based compensation costs. In 2006, gross expense was $4.9 million including $1.5 million for stock options and $3.4 million for performance shares. In 2005, expense related to stock-based compensation (performance shares) was $4.1 million.

2007 California Attrition Order

In October 2006, the Company made its 2007 annual California attrition filing requesting a $2.7 million increase in operating margin. The increase in customer rates was approved to be made effective January 2007. In connection with this filing, the Company also received approval to change the way operating margin is recognized under the Company's margin tracker mechanism. The change provides for authorized levels of margin to be recognized in equal monthly amounts throughout the year, rather than on a seasonally adjusted basis. This change will not impact the total amount of margin recognized annually; however it will affect the comparability of 2007 versus 2006 quarterly amounts. As a result, the $2.7 million authorized annual attrition increase to operating margin in 2007, as adjusted for the equalized margin tracker mechanism, is expected to result in the following year-over-year comparative changes (2007 versus 2006): a decrease of $7.7 million during the first quarter, and increases of $2.6 million, $7.4 million and $400,000 in the second, third and fourth quarters, respectively.

Results of Construction Services Operations

The Company's construction subsidiary, NPL, increased its contribution to consolidated net income by $2.2 million in 2006 when compared to the prior year. The increase was primarily due to overall revenue growth, coupled with an improvement in the number of profitable bid jobs, and a sustained favorable equipment resale market in the current year.

Results of Natural Gas Operations

Year Ended December 31, (Thousands of dollars)	2006	2005	2004
Gas operating revenues	$1,727,394	$1,455,257	$1,262,052
Net cost of gas sold	1,033,988	828,131	645,766
Operating margin	693,406	627,126	616,286
Operations and maintenance expense	320,803	314,437	290,800
Depreciation and amortization	146,654	137,981	130,515
Taxes other than income taxes	34,994	39,040	37,669
Operating income	190,955	135,668	157,302
Other income (expense)	10,049	5,087	1,611
Net interest deductions	85,567	81,595	78,137
Net interest deductions on subordinated debentures	7,724	7,723	7,724
Income before income taxes	107,713	51,437	73,052
Income tax expense	36,240	17,767	24,698
Contribution to consolidated net income	$ 71,473	$ 33,670	$ 48,354

2006 vs. 2005

Contribution from natural gas operations increased $37.8 million in 2006 compared to 2005. The improvement in contribution was primarily due to higher operating margin resulting from the Arizona general rate increase, a nonrecurring property tax settlement, and improved other income, partially offset by increased operating expenses and financing costs.

Operating margin increased $66 million in 2006 as compared to 2005. During 2006, the Company added 71,000 customers, an increase of four percent. New customers coupled with additional amounts from existing transportation and non-weather sensitive sales customers contributed $26 million in incremental operating margin. Rate relief in Arizona and California added $37 million. Differences in heating demand caused primarily by weather variations between periods resulted in a $3 million operating margin increase as warmer-than-normal temperatures were experienced during both periods (during 2006, operating margin was negatively impacted by $16 million, while the negative impact in 2005 was $19 million).

Operations and maintenance expense increased $6.4 million, or two percent, between periods reflecting general cost increases and incremental operating costs associated with serving additional customers. Factors contributing to the increase included insurance premiums, uncollectible expenses, employee-related costs, and incremental stock-based compensation costs. Operations and maintenance expense for 2005 included a $10 million nonrecurring provision for an injuries and damages case (see *Insurance Coverage* below for more information).

Depreciation expense increased $8.7 million, or six percent, as a result of construction activities. Average gas plant in service for 2006 increased $238 million, or seven percent, compared to 2005. The increase reflects ongoing capital expenditures for the upgrade of existing operating facilities and the expansion of the system to accommodate continued customer growth.

General taxes decreased $4 million, or 10 percent, primarily as a result of the nonrecurring property tax settlement (see *Property Tax Settlement* for additional information) and Arizona legislation signed in June 2006 that reduced property tax rates, retroactive to January 2006.

Other income (expense) increased $5 million compared to 2005. The current period includes a $2 million net increase in interest income primarily associated with the unrecovered balance of deferred purchased gas costs and $1 million of interest income on the property tax settlement discussed above.

Net financing costs increased $4 million primarily due to higher rates on variable-rate debt and an increase in average debt outstanding to help finance growth.

Income tax expense in 2006 includes a nonrecurring $1.7 million state income tax benefit.

2005 vs. 2004

Contribution from natural gas operations decreased $14.7 million in 2005 compared to 2004. The decrease was principally the result of higher operating expenses, including a nonrecurring provision for an injuries and damages case, partially offset by improved, but lower than expected, operating margin.

Operating margin increased approximately $11 million in 2005 as compared to 2004. During 2005, the Company added 81,000 customers (excluding 19,000 customers associated with an acquisition in the South Lake Tahoe area), a growth rate of five percent. New customers contributed $20 million in incremental margin. Differences in heating demand primarily caused by weather variations between periods resulted in a $17 million margin decrease as warmer-than-normal temperatures were experienced during 2005, especially in Arizona. Rate relief in California and Nevada provided $8 million in new operating margin.

Operations and maintenance expense increased $23.6 million, or eight percent, compared to 2004. A significant component of the variance related to a $10 million nonrecurring provision for an injuries and damages case (see *Insurance Coverage* below for more information). The increase also reflected general cost increases and incremental costs associated with providing service to a growing customer base. Factors contributing to the increase included higher insurance premiums, uncollectible expenses, employee-related costs, and compliance costs. Operations and maintenance expense for 2004 included $2.3 million in lease payments for an LNG facility which was purchased in December 2004.

Depreciation expense and general taxes increased $8.8 million, or five percent, as a result of construction activities. Average gas plant in service increased $248 million, or eight percent, as compared to 2004. The increase reflected ongoing capital expenditures for the upgrade of existing operating facilities, the expansion of the system to accommodate continued customer growth, and the purchase of the South Lake Tahoe properties.

Other income (expense) increased $3.5 million compared to 2004. Returns on long-term investments improved by approximately $1.2 million during 2005. Other income (expense) for 2005 also included an $800,000 improvement in interest income primarily associated with the unrecovered balance of deferred purchased gas costs and a $900,000 increase in the allowance for equity funds used during construction.

Net financing costs rose $3.5 million, or four percent, between years primarily due to an increase in average debt outstanding to help finance growth and higher rates on variable-rate debt.

Income tax expense in 2004 included $1.6 million of income tax benefits based on an analysis of current and deferred taxes following the completion of general rate cases and the closure of federal tax year 2000.

Rates and Regulatory Proceedings

Arizona General Rate Case. In February 2006, the ACC rendered a decision on the general rate case filed by Southwest in December 2004. The ACC approved a $49.3 million increase in operating revenues, effective March 2006. The decision did not include all of the rate design changes or the conservation tracker Southwest had requested. While the ACC did authorize an increase in the customer charge by $1.70 per month, the rate design approved for commodity sales continues to expose customers, investors and the Company to the risks associated with weather volatility. The ACC did however encourage Southwest to work with the ACC Staff and other interested parties prospectively to seek rate design alternatives that will provide benefits to all affected stakeholders. These collaborative discussions began during the third quarter of 2006 and will continue in the future. Southwest estimates that operating margin in 2006 reflected approximately $35 million of general rate relief in Arizona.

California Attrition Filings. In October 2005, Southwest made its 2006 annual attrition filing requesting a $4.5 million

increase in operating margin. The effective date of new rates was originally anticipated to be January 2006. The Division of Ratepayer Advocates ("DRA") filed a protest to the attrition filing disagreeing with certain aspects of the Company's calculation. As a result of the protest, the Energy Division suspended the filing. In December 2005, Southwest filed a motion requesting authorization to establish a memorandum account to track the related revenue shortfall between the existing and proposed rates in the attrition filing. The motion was approved effective April 13, 2006. In June 2006, the CPUC approved the revised 2006 attrition retroactive to the date of the memorandum account in April. Annualized rate relief of $3 million was granted of which approximately $2 million was recognized in 2006. Although the Company filed an application requesting that the memorandum account be made effective January 2006, consistent with the initial annual filing, this petition was denied during the fourth quarter, and as a result, the Company was unable to recover an estimated $1 million in operating margin resulting from the delayed effective date.

In October 2006, the Company made its 2007 annual attrition filing requesting a $2.7 million increase in operating margin. The increase in customer rates was approved to be made effective January 2007. In connection with this filing, the Company also received approval to change the way operating margin is recognized under the Company's margin tracker mechanism. The change provides for authorized levels of margin to be recognized in equal monthly amounts throughout the year, rather than on a seasonally adjusted basis. This change will not impact the total amount of margin recognized annually; however it will affect the comparability of 2007 versus 2006 quarterly amounts. As a result, the $2.7 million authorized annual attrition increase to operating margin in 2007, as adjusted for the equalized margin tracker mechanism, is expected to result in the following year-over-year comparative changes (2007 versus 2006): a decrease of $7.7 million during the first quarter, and increases of $2.6 million, $7.4 million and $400,000 in the second, third and fourth quarters, respectively.

Nevada Weather Normalization Adjustment Provision. In March 2005, Southwest filed an application requesting the Public Utilities Commission of Nevada ("PUCN") to approve a weather normalization adjustment provision in advance of the Company's next general rate case. This filing requested that winter season billing volumes for weather sensitive customers be adjusted to reflect consumption variations that can be attributed to departures from normal weather. In the second quarter of 2005, the PUCN opened an investigation/ rulemaking docket to address the issue of weather normalization, and in November 2005, the PUCN requested additional information. A joint report of the Regulatory Operations Staff and Bureau of Consumer Protection was filed in July 2006 recommending approval of a weather normalization adjustment provision. The PUCN subsequently declined to adopt the recommendation, effectively requiring the issue to be considered in future general rate case proceedings.

PGA Filings

The rate schedules in all of Southwest's service territories contain provisions that permit adjustments to rates as the cost of purchased gas changes. These deferred energy provisions and purchased gas adjustment clauses are collectively referred to as "PGA" clauses. Filings to change rates in accordance with PGA clauses are subject to audit by state regulatory commission staffs. PGA changes impact cash flows but have no direct impact on profit margin. However, gas cost deferrals and recoveries can impact comparisons between periods of individual income statement components. These include Gas operating revenues, Net cost of gas sold, Net interest deductions and Other income (deductions). In addition, since Southwest is permitted to accrue interest on PGA balances, the cost of incremental PGA-related short-term borrowings will be largely offset, and there should be no material negative impact to earnings.

Southwest had the following outstanding PGA balances receivable at the end of its two most recent fiscal years (millions of dollars):

	2006	2005
Arizona	$68.4	$ 46.8
Northern Nevada	1.1	12.6
Southern Nevada	4.1	39.4
California	3.4	10.6
	$77.0	$109.4

Arizona PGA Filings. In Arizona, Southwest adjusts rates monthly for changes in purchased gas costs, within pre-established limits measured on a twelve-month rolling average. During the first quarter of 2006, the ACC approved an increase in the pre-established limit from $0.10 to $0.13 per therm. In addition, the ACC approved the implementation of a temporary PGA surcharge of $0.11 per therm effective February 2006 to pass through higher costs of natural gas incurred during 2005. The PGA balance in Arizona has been steadily declining after reaching a high of $95.8 million in April 2006.

Nevada Deferred Energy Adjustment Filing. Nevada Senate Bill No. 238, which became effective in October 2005, provides for quarterly gas cost adjustments calculated on a twelve-month rolling average. Adjustments are subject to an annual prudence review and audit of the natural gas costs incurred. This new quarterly adjustment mechanism was effective in allowing Southwest to minimize the PGA balance by year end 2006.

California Gas Cost Filings. In California, a monthly gas cost adjustment based on forecasted monthly prices is utilized. Monthly adjustments are designed to provide a more timely recovery of gas costs and to send appropriate pricing signals to customers.

Other Filings

El Paso Transmission System. In June 2005, El Paso Natural Gas Company ("El Paso") filed a general rate case application with the Federal Energy Regulatory Commission ("FERC"). (Southwest is dependent upon El Paso for the transportation of natural gas for virtually all of its Arizona service territories, and through August 2006, part of its southern Nevada service territories.) As part of its application, which is the first since the conversion of full requirements customers like Southwest to contract demand services, El Paso proposed various tariff changes along with new service offerings. The annual increase in gas transportation costs to Southwest was approximately $19.1 million. The new rates became effective January 2006, subject to refund. However, the implementation of new services and certain overrun and imbalance penalty charges proposed in El Paso's application was phased-in during the period June 2006 through November 2006. In December 2006, El Paso filed a settlement offer with the FERC which would resolve many of the issues raised in the general rate case proceeding. Southwest expects to fully recover any increased costs resulting from a final order or settlement in the case.

Capital Resources and Liquidity

The capital requirements and resources of the Company generally are determined independently for the natural gas operations and construction services segments. Each business activity is generally responsible for securing its own financing sources. The capital requirements and resources of the construction services segment are not material to the overall capital requirements and resources of the Company.

2006 Construction Expenditures

Southwest continues to experience high customer growth. This growth has required significant capital outlays for new transmission and distribution plant, to keep up with consumer demand. During the three-year period ended December 31, 2006, total gas plant increased from $3 billion to $3.8 billion, or at an annual rate of seven percent. Customer growth was the primary reason for the plant increase as Southwest added 253,000 net new customers (including 19,000 customers acquired in the South Lake Tahoe area) during the three-year period.

During 2006, construction expenditures for the natural gas operations segment were $306 million. Approximately 76 percent of these expenditures represented new construction and the balance represented costs associated with routine replacement of existing transmission, distribution, and general plant. Cash flows from operating activities of Southwest (net of dividends) provided $215 million of the required capital resources pertaining to total capital expenditures in 2006. The remainder was provided from external financing activities and existing credit facilities.

2006 Financing Activity

The Company has a universal shelf registration statement providing for the issuance and sale of registered securities, which may consist of secured debt, unsecured debt, preferred stock, or common stock. At December 31, 2006, the Company had $95 million in securities available for issuance under the universal shelf registration statement.

In March 2006, the Company entered into a Sales Agency Financing Agreement with BNY Capital Markets, Inc. relating to the issuance and sale of up to $45 million aggregate amount of shares of the Company's common stock, from time to time over a three-year period ("Equity Shelf Program"). Sales of the shares are made at market prices prevailing at the time of sale. Net proceeds from the sale of shares of common stock under the Equity Shelf Program are used for general corporate purposes, including the acquisition of property for the construction, completion, extension or improvement of pipeline systems and facilities located in and around the communities Southwest serves. During 2006, approximately 947,000 shares were issued in at-the-market offerings through the Equity Shelf Program at an average price of $29.87 per share with gross proceeds of $28.3 million, agent commissions of $283,000, and net proceeds of $28 million.

During 2006, the Company issued approximately 1.5 million additional shares of common stock through the Dividend Reinvestment and Stock Purchase Plan ("DRSPP"), Employee Investment Plan, Management Incentive Plan, and Stock Incentive Plan. In addition, in 2006, Southwest offset capital outlays by collecting approximately $48.6 million in net advances and contributions from third-party contractors.

In September 2006, the Company issued $56 million in Clark County, Nevada 4.75% IDRBs Series 2006A pursuant to a financing agreement and indenture. The IDRBs were issued at a discount of 0.625% and are due September 1, 2036. The net proceeds from the IDRBs were used by Southwest to expand and upgrade facilities in Clark County, Nevada.

2007 Construction Expenditures and Financing

Southwest estimates construction expenditures during the three-year period ending December 31, 2009 will be approximately $880 million. Of this amount, approximately $337 million are expected to be incurred in 2007. During the three-year period, cash flow from operating activities (net of dividends) is estimated to fund over 90 percent of the gas operations' total construction expenditures, assuming timely recovery of currently deferred PGA balances. Southwest also has $43 million in long-term debt maturities over the three-year period. Maturities would increase to $50.5 million if an existing bondholder exercises a discretionary put option in 2007. The Company expects to raise $100 million to $125 million from its various common stock programs. Any remaining cash requirements are expected to be provided by existing credit facilities and/or other external financing

sources. The timing, types, and amounts of these additional external financings will be dependent on a number of factors, including conditions in the capital markets, timing and amounts of rate relief, growth levels in Southwest service areas, and earnings. These external financings may include the issuance of both debt and equity securities, bank and other short-term borrowings, and other forms of financing.

Contractual Obligations

Obligations under long-term debt, gas purchase obligations and significant non-cancelable operating leases at December 31, 2006 were as follows (millions of dollars):

		Payments due by period			
	Total	2007	2008-2009	2010-2011	Thereafter
Contractual Obligations					
Subordinated debentures to Southwest Gas Capital II (Note 5) (a)	$ 383	$ 8	$ 15	$ 15	$ 345
Long-term debt (Note 6) (a)	2,414	102	183	471	1,658
Operating leases (Note 2)	32	5	9	5	13
Gas purchase obligations (b)	519	422	97	—	—
Pipeline capacity (c)	667	105	195	189	178
Other commitments	17	6	6	2	3
Total	$4,032	$648	$505	$682	$2,197

(a) Includes scheduled principal and interest payments over the life of the debt.

(b) Includes fixed-price and variable-rate gas purchase contracts covering approximately 140 million dekatherms. Fixed-price contracts range in price from $6 to $11 per dekatherm. Variable-price contracts reflect minimum contractual obligations.

(c) Southwest has pipeline capacity contracts for firm transportation service, both on a short- and long-term basis, with several companies for all of its service territories. Southwest also has interruptible contracts in place that allow additional capacity to be acquired should an unforeseen need arise. Costs associated with these pipeline capacity contracts are a component of the cost of gas sold and are recovered from customers primarily through the PGA mechanism.

32 Estimated funding for pension and other postretirement benefits during calendar year 2007 is $24 million.

Liquidity

Liquidity refers to the ability of an enterprise to generate adequate amounts of cash to meet its cash requirements. Several general factors that could significantly affect liquidity in future years include inflation, growth in Southwest's service territories, changes in the ratemaking policies of regulatory commissions, interest rates, variability of natural gas prices, changes in income tax laws, and the level of Company earnings. Of these factors natural gas prices have had the most significant impact on Company liquidity.

Over the past five years the weighted-average delivered cost of natural gas has ranged from a low of 38 cents per therm in 2002 to a high of 79 cents per therm in 2006. Price volatility is expected to continue throughout 2007. Southwest periodically enters into fixed-price term contracts to mitigate price volatility. About half of Southwest's annual normal weather supply needs are secured using short duration contracts (one year or less). For the 2006/2007 heating season, fixed price contracts ranged in price from $6 to $11 per dekatherm. Natural gas purchases not covered by fixed-price contracts are made under variable-price contracts with firm quantities and on the spot market. Prices for these contracts are not known until the month of purchase. Southwest does not currently utilize other stand-alone derivative financial instruments for speculative purposes, or for hedging. During 2007, Southwest intends to supplement its current volatility mitigation program with stand-alone derivative instruments. The combination of fixed-price contracts and derivative instruments should increase flexibility for Southwest and increase supplier diversification. The costs of such derivative financial instruments are expected to be recovered from customers.

The rate schedules in Southwest's service territories contain PGA clauses which permit adjustments to rates as the cost of purchased gas changes. The PGA mechanism allows Southwest to request to change the gas cost component of the rates charged to its customers to reflect increases or decreases in the price expected to be paid to its suppliers and companies providing interstate pipeline transportation service.

On an interim basis, Southwest generally defers over- or under-collections of gas costs to PGA balancing accounts. In addition, Southwest uses this mechanism to either refund amounts over-collected or recoup amounts under-collected as compared to the price paid for natural gas during the period since the last PGA rate change went into effect. At December 31, 2006, the combined balances in PGA accounts totaled an under-collection of $77 million versus an under-collection of $109 million at December 31, 2005. See **PGA Filings** for more information on recent regulatory filings. Southwest has the ability to draw on its $300 million credit facility to temporarily finance under-collected PGA balances.

This facility runs through April 2011. Southwest has designated $150 million of the facility as long-term debt and the remaining $150 million for working capital purposes. Southwest currently believes the $150 million designated for working capital purposes is adequate to meet liquidity needs. At December 31, 2006, $147 million was outstanding on the long-term portion and no borrowings were outstanding on the short-term portion of the credit facility.

Off-Balance Sheet Arrangements

All Company debt is recorded on its balance sheets. The Company has long-term operating leases, which are described in **Note 2—Utility Plant** of the Notes to Consolidated Financial Statements. No debt instruments have credit triggers or other clauses that result in default if Company bond ratings are lowered by rating agencies. Certain Company debt instruments contain securities ratings covenants that, if set in motion, would increase financing costs. See discussion below for the impact of a recent credit rating change.

Securities Ratings

Securities ratings issued by nationally recognized ratings agencies provide a method for determining the credit worthiness of an issuer. Company debt ratings are important because long-term debt constitutes a significant portion of total capitalization. These debt ratings are a factor considered by lenders when determining the cost of debt for the Company (i.e., the better the rating, the lower the cost to borrow funds).

In May 2006, Moody's Investors Service, Inc. ("Moody's") lowered its rating on the Company's unsecured long-term debt to Baa3 from Baa2 and changed the outlook for the rating to stable from negative. The change in credit rating will result in an annualized estimated increase of $375,000 in interest expense on existing long-term debt. No debt covenants were affected by the downgrade. Moody's cited a long-term warming trend in the Company's service territories, regulatory lag, and weak credit measures as some of the factors behind the downgrade. Moody's applies a Baa rating to obligations which are considered medium grade obligations with adequate security. A numerical modifier of 1 (high end of the category) through 3 (low end of the category) is included with the Baa to indicate the approximate rank of a company within the range.

The Company's unsecured long-term debt rating from Fitch, Inc. ("Fitch") is BBB. Fitch debt ratings range from AAA (highest credit quality) to D (defaulted debt obligation). The Fitch rating of BBB indicates a credit quality that is considered prudent for investment.

The Company's unsecured long-term debt rating from Standard and Poor's Ratings Services ("S&P") is BBB-. S&P debt ratings range from AAA (highest rating possible) to D (obligation is in default). The S&P rating of BBB- indicates the debt is regarded as having an adequate capacity to pay interest and repay principal.

A securities rating is not a recommendation to buy, sell, or hold a security and is subject to change or withdrawal at any time by the rating agency.

Inflation

Results of operations are impacted by inflation. Natural gas, labor, consulting, and construction costs are the categories most significantly impacted by inflation. Changes to cost of gas are generally recovered through PGA mechanisms and do not significantly impact net earnings. Labor is a component of the cost of service, and construction costs are the primary component of rate base. In order to recover increased costs, and earn a fair return on rate base, general rate cases are filed by Southwest, when deemed necessary, for review and approval by regulatory authorities. Regulatory lag, that is, the time between the date increased costs are incurred and the time such increases are recovered through the ratemaking process, can impact earnings. See **Rates and Regulatory Proceedings** for a discussion of recent rate case proceedings.

Insurance Coverage

The Company maintains liability insurance for various risks associated with the operation of its natural gas pipelines and facilities. In connection with these liability insurance policies, the Company has been responsible for an initial deductible or self-insured retention amount per incident, after which the insurance carriers would be responsible for amounts up to the policy limits. For the policy year August 2004 to July 2005, the self-insured retention amount associated with general liability claims was $1 million per incident plus payment of the first $10 million in aggregate claims above $1 million in the policy year. In May 2005, a leaking natural gas line was involved in a fire that severely injured an individual. The leak is believed to have been caused by a rock impinging upon a natural gas line that was installed for Southwest Gas and that is owned and operated by the Company. In December 2005, the plaintiffs filed a complaint against the Company claiming $3.4 million in medical bills, $12 million in future medical expenses, and unspecified claims for general and punitive damages. By December 2005, the Company had recorded a total liability related to this incident equal to the Company's maximum self-insured retention level of $11 million. In the fourth quarter of 2006, the case was settled. The amount of the settlement that exceeded $11 million was covered by insurance. The Company's current insurance contracts limit the self-insured retention to $1 million per incident plus payment of the first $5 million in aggregate claims above $1 million.

Results of Construction Services

Year Ended December 31, (Thousands of dollars)	2006	2005	2004
Construction revenues	$297,364	$259,026	$215,008
Cost of construction	271,743	237,356	196,792
Gross profit	25,621	21,670	18,216
General and administrative expenses	7,377	6,672	5,742
Operating income	18,244	14,998	12,474
Other income (expense)	4,086	3,009	2,131
Interest expense	1,686	1,009	645
Income before income taxes	20,644	16,998	13,960
Income tax expense	8,257	6,845	5,539
Contribution to consolidated net income	$ 12,387	$ 10,153	$ 8,421

2006 vs. 2005

The 2006 contribution to consolidated net income from construction services increased $2.2 million from 2005. The factors that drove the favorable results include a 15 percent increase in revenues, an improvement in the number of profitable bid jobs, and a favorable equipment resale market.

Revenues increased $38 million due primarily to an increased workload under several existing contracts and an improvement in the amount and profitability of new bid work. Gross profit increased approximately $4 million, or 18 percent, as a direct result of the increase in revenues. The construction revenues above include NPL contracts with Southwest totaling $80.6 million in 2006, $71.8 million in 2005, and $61.6 million in 2004. NPL accounts for the services provided to Southwest at contractual (market) prices.

General and administrative costs increased $705,000 due primarily to incremental costs associated with growth including labor and other administrative expenses. Other income increased $1.1 million as a result of an increase in gains on sale of equipment. Interest expense increased $677,000 due to additional long-term borrowing for the purchase of new equipment and higher interest rates.

Construction activity is cyclical and can be significantly impacted by changes in general and local economic conditions, including interest rates, employment levels, job growth, and local and federal tax rates. The slow-down in construction activities observed in regional and national markets at the end of 2006, if sustained, could negatively impact the amount of work received under existing blanket contracts, the amount of bid work, and the equipment resale market in 2007.

2005 vs. 2004

The 2005 contribution to consolidated net income from construction services increased $1.7 million from 2004. The increase was primarily due to overall revenue growth, coupled with an improvement in the number of profitable bid jobs and a favorable equipment resale market in 2005.

Revenues and gross profit for 2005 reflect an increased workload under existing contracts and an increase in the quantity and profitability of bid work. Favorable working conditions in several operating areas facilitated additional construction activity.

General and administrative costs increased $930,000 due primarily to the depreciation expense related to the implementation of new computer systems and compliance costs. Other income (expense) increased $878,000 as a result of an increase in gains on sale of equipment. Interest expense rose $364,000 due to additional long-term borrowing for the purchase of new equipment and higher interest rates.

Recently Issued Accounting Pronouncements

Below is a listing of recently issued accounting pronouncements by the Financial Accounting Standards Board ("FASB"). See **Note 1—Summary of Significant Accounting Policies** for more information regarding these accounting pronouncements and their potential impact on the Company's financial position and results of operations.

Title	Month of Issue	Effective Date
SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140."	February 2006	January 2007
SFAS No. 156, "Accounting for Servicing of Financial Assets—an amendment of FASB Statement No. 140."	March 2006	January 2007
FIN No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109."	June 2006	January 2007
SFAS No. 157, "Fair Value Measurements."	September 2006	January 2008

Application of Critical Accounting Policies

A critical accounting policy is one which is very important to the portrayal of the financial condition and results of a company, and requires the most difficult, subjective, or complex judgments of management. The need to make estimates about the effect of items that are uncertain is what makes these judgments difficult, subjective, and/or complex. Management makes subjective judgments about the accounting and regulatory treatment of many items and bases its estimates on historical experience and on various other assumptions that it believes to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained, and as the Company's operating environment changes. The following are accounting policies that are critical to the financial statements of the Company. For more information regarding the significant accounting policies of the Company, see **Note 1—Summary of Significant Accounting Policies**.

Regulatory Accounting

Natural gas operations are subject to the regulation of the Arizona Corporation Commission, the Public Utilities Commission of Nevada, the California Public Utilities Commission, and the Federal Energy Regulatory Commission. The accounting policies of the Company conform to generally accepted accounting principles applicable to rate-regulated enterprises (including SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation") and reflect the effects of the ratemaking process. As such, the Company is allowed to defer as regulatory assets, costs that otherwise would be expensed if it is probable that future recovery from customers will occur. The Company reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. If rate recovery is no longer probable, due to competition or the actions of regulators, the Company is required to write-off the related regulatory asset (which would be recognized as current-period expense).

Regulatory liabilities are recorded if it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. The timing and inclusion of costs in rates is often delayed (regulatory lag) and results in a reduction of current-period earnings. Refer to **Note 4—Regulatory Assets and Liabilities** for a list of regulatory assets and liabilities.

Unbilled Revenues

Revenues related to the sale and/or delivery of natural gas are generally recorded when natural gas is delivered to customers. However, the determination of natural gas sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, revenues for natural gas that has been delivered but not yet billed are accrued. This unbilled revenue is estimated each month based on daily sales volumes, applicable rates, analyses reflecting significant historical trends, weather, and experience. In periods of extreme weather conditions, the interplay of these assumptions could impact the variability of the unbilled revenue estimates.

Accounting for Income Taxes

The income tax calculations of the Company require estimates due to known future tax rate changes, book to tax differences, and uncertainty with respect to regulatory treatment of certain property items. The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Regulatory tax assets and liabilities are recorded to the extent the Company believes they will be recoverable from or refunded to customers in future rates. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The Company regularly assesses financial

statement tax provisions and adjusts the tax provisions when necessary as additional information is obtained. A change in the regulatory treatment or significant changes in tax-related estimates, assumptions, or enacted tax rates could have a material impact on cash flows, the financial position, and/or results of operations of the Company.

Accounting for Pensions and Other Postretirement Benefits

Southwest has a noncontributory qualified retirement plan with defined benefits covering substantially all employees. In addition, Southwest has a separate unfunded supplemental retirement plan which is limited to officers. The Company's pension obligations and costs for these plans are affected by the amount of cash contributions to the plans, the return on plan assets, discount rates, and by employee demographics, including age, compensation, and length of service. Changes made to the provisions of the plans may also impact current and future pension costs. Actuarial formulas are used in the determination of pension obligations and costs and are affected by actual plan experience and assumptions about future experience. Key actuarial assumptions include the expected return on plan assets, the discount rate used in determining the projected benefit obligation and pension costs, and the assumed rate of increase in employee compensation. Relatively small changes in these assumptions (particularly the discount rate) may significantly affect pension obligations and costs for these plans.

Due to an increase in market interest rates for high-quality fixed income investments, the Company raised the discount rate to 6.00% at December 31, 2006 from 5.75% at December 31, 2005. The weighted-average rate of compensation increase was raised to 3.75% from 3.30%. The Company maintained its asset return assumption for 2007 at 8.50%. These offsetting changes will not result in a significant change in pension expense for 2007. Should interest rates rise in 2007, future pension expense and projected benefit obligations could decrease. Conversely, declining interest rates would put upward pressure on future pension expense and projected benefit obligations.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)", which requires employers to recognize the overfunded or underfunded positions of defined benefit postretirement plans, including pension plans, in their balance sheets. Under SFAS No. 158, any actuarial gains and losses, prior service costs and transition assets or obligations that were not recognized under previous accounting standards must be recognized in accumulated other comprehensive income under stockholders' equity, net of tax, until they are amortized as a component of net periodic benefit cost. SFAS No. 158 does not change how net periodic pension and postretirement costs are accounted for and reported in the income statement. The Company adopted the provisions of SFAS No. 158 effective December 31, 2006.

In accordance with SFAS No. 71, the Company has established a regulatory asset for the portion of the total amounts otherwise chargeable to accumulated other comprehensive income that are expected to be recovered through rates in future periods. The changes in actuarial losses and prior service credits pertaining to the regulatory asset will be recognized as an adjustment to the regulatory asset account as these amounts are recognized as components of net periodic pension costs each year. See **Note 9—Pension and Other Postretirement Benefits** for plan assumptions and further discussion of the impact of adopting SFAS No. 158.

Management believes that regulation and the effects of regulatory accounting have the most significant impact on the financial statements. When Southwest files rate cases, capital assets, costs, and gas purchasing practices are subject to review, and disallowances can occur. Regulatory disallowances in the past have not been frequent but have on occasion been significant to the operating results of the Company.

Certifications

The SEC requires the Company to file certifications of its Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") regarding reporting accuracy, disclosure controls and procedures, and internal control over financial reporting as exhibits to the Company's periodic filings. The CEO and CFO certifications for the period ended December 31, 2006 were included as exhibits to the 2006 Annual Report on Form 10-K which was filed with the SEC. The Company is also required to file an annual CEO certification regarding corporate governance listing standards compliance with the New York Stock Exchange ("NYSE"). The most recent annual CEO certification, dated May 10, 2006, was filed with the NYSE in May 2006.

Forward-Looking Statements

This annual report contains statements which constitute "forward-looking statements" within the meaning of the Securities Litigation Reform Act of 1995 ("Reform Act"). All statements other than statements of historical fact included or incorporated by reference in this annual report are forward-looking statements, including, without limitation, statements regarding the Company's plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions. The words "may," "will," "should," "could," "expect," "plan," "anticipate," "believe," "estimate," "predict," "continue," and similar words and expressions are generally used and intended to identify forward-looking statements. In particular, statements regarding customer growth, estimated construction expenditures, the sources and amounts of financing, customer mix and revenue patterns, efficiencies resulting from new technology, construction services contribution, ability to receive more effective rate designs, the expected results of the projected impact in 2007 due to changes in the margin tracker mechanism, sufficiency of working

capital and ability to raise funds and receive external financing, and statements regarding future gas prices, future PGA balances, the effects of recent accounting pronouncements, and the timing and results of future rate approvals and guidelines are forward-looking statements. All forward-looking statements are intended to be subject to the safe harbor protection provided by the Reform Act.

A number of important factors affecting the business and financial results of the Company could cause actual results to differ materially from those stated in the forward-looking statements. These factors include, but are not limited to, the impact of weather variations on customer usage, customer growth rates, changes in natural gas prices, our ability to recover costs through our PGA mechanism, the effects of regulation/deregulation, the timing and amount of rate relief, changes in rate design, changes in gas procurement practices, changes in capital requirements and funding, the impact of conditions in the capital markets on financing costs, changes in construction expenditures and financing, renewal of franchises, easements and rights-of-way, changes in operations and maintenance expenses, effects of accounting changes, future liability claims, changes in pipeline capacity for the transportation of gas and related costs, acquisitions and management's plans related thereto, competition, and our ability to raise capital in external financings. In addition, the Company can provide no assurance that its discussions regarding certain trends relating to its financing, operations and maintenance expenses will continue in future periods. For additional information on the risks associated with the Company's business, see **Item 1A. Risk Factors** in the Company's Annual Report on Form 10-K for the year ended December 31, 2006.

All forward-looking statements in this annual report are made as of the date hereof, based on information available to the Company as of the date hereof, and the Company assumes no obligation to update or revise any of its forward-looking statements even if experience or future changes show that the indicated results or events will not be realized. **We caution you not to unduly rely on any forward-looking statement(s).**

Common Stock Price and Dividend Information

	2006		2005		Dividends Declared	
	High	Low	High	Low	2006	2005
First quarter	$29.04	$26.09	$26.13	$23.66	$0.205	$0.205
Second quarter	31.43	26.46	26.35	23.53	0.205	0.205
Third quarter	34.19	30.70	28.07	25.00	0.205	0.205
Fourth quarter	39.37	32.80	27.86	25.12	0.205	0.205
					$0.820	$0.820

The principal market on which the common stock of the Company is traded is the New York Stock Exchange. At February 15, 2007, there were 23,306 holders of record of common stock, and the market price of the common stock was $38.80.

The Company has a common stock dividend policy which states that common stock dividends will be paid at a prudent level that is within the normal dividend payout range for its respective businesses, and that the dividend will be established at a level considered sustainable in order to minimize business risk and maintain a strong capital structure throughout all economic cycles. The quarterly common stock dividend was 20.5 cents per share throughout 2006. The dividend of 20.5 cents per share has been paid quarterly since September 1994. In February 2007, the Board of Directors increased the quarterly dividend payout to 21.5 cents per share, effective with the June 2007 payment.

Consolidated Balance Sheets

(Thousands of dollars, except par value)	December 31, 2006	2005
ASSETS		
Utility plant:		
Gas plant	$ 3,763,310	$ 3,516,587
Less: accumulated depreciation	(1,175,600)	(1,083,900)
Acquisition adjustments, net	1,992	2,173
Construction work in progress	78,402	54,287
Net utility plant (Note 2)	2,668,104	2,489,147
Other property and investments	136,242	118,094
Current assets:		
Cash and cash equivalents	18,786	29,603
Accounts receivable, net of allowances (Note 3)	225,928	198,081
Accrued utility revenue	73,300	68,400
Deferred purchased gas costs (Note 4)	77,007	109,415
Prepaids and other current assets (Note 4)	106,603	137,161
Total current assets	501,624	542,660
Deferred charges and other assets (Note 4)	178,995	78,525
Total assets	$ 3,484,965	$ 3,228,426
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $1 par (authorized–45,000,000 shares; issued and outstanding–41,770,291 and 39,328,291 shares) (Note 10)	$ 43,400	$ 40,958
Additional paid-in capital	698,258	628,248
Accumulated other comprehensive income (loss), net (Note 9)	(13,666)	(41,645)
Retained earnings	173,433	123,574
Total equity	901,425	751,135
Subordinated debentures due to Southwest Gas Capital II (Note 5)	100,000	100,000
Long-term debt, less current maturities (Note 6)	1,286,354	1,224,898
Total capitalization	2,287,779	2,076,033
Commitments and contingencies (Note 8)		
Current liabilities:		
Current maturities of long-term debt (Note 6)	27,545	83,215
Short-term debt (Note 7)	—	24,000
Accounts payable	265,739	259,476
Customer deposits	64,151	57,552
Accrued general taxes	45,895	40,526
Accrued interest	21,362	22,472
Deferred income taxes (Note 11)	15,471	68,166
Other current liabilities	55,901	65,546
Total current liabilities	496,064	620,953
Deferred income taxes and other credits:		
Deferred income taxes and investment tax credits (Note 11)	308,493	234,739
Taxes payable	5,951	7,551
Accumulated removal costs (Note 4)	125,000	105,000
Other deferred credits (Note 9)	261,678	184,150
Total deferred income taxes and other credits	701,122	531,440
Total capitalization and liabilities	$ 3,484,965	$ 3,228,426

The accompanying notes are an integral part of these statements.

Consolidated Statements Of Income

Year Ended December 31, (In thousands, except per share amounts)	2006	2005	2004
Operating revenues:			
Gas operating revenues	$1,727,394	$1,455,257	$1,262,052
Construction revenues	297,364	259,026	215,008
Total operating revenues	2,024,758	1,714,283	1,477,060
Operating expenses:			
Net cost of gas sold	1,033,988	828,131	645,766
Operations and maintenance	320,803	314,437	290,800
Depreciation and amortization	168,964	156,253	146,018
Taxes other than income taxes	34,994	39,040	37,669
Construction expenses	256,827	225,774	187,040
Total operating expenses	1,815,576	1,563,635	1,307,293
Operating income	209,182	150,648	169,767
Other income and (expenses):			
Net interest deductions	(87,253)	(82,604)	(78,782)
Net interest deductions on subordinated debentures (Note 5)	(7,724)	(7,723)	(7,724)
Other income (deductions)	14,152	8,114	3,751
Total other income and (expenses)	(80,825)	(82,213)	(82,755)
Income before income taxes	128,357	68,435	87,012
Income tax expense (Note 11)	44,497	24,612	30,237
Net income	$ 83,860	$ 43,823	$ 56,775
Basic earnings per share (Note 13)	$ 2.07	$ 1.15	$ 1.61
Diluted earnings per share (Note 13)	$ 2.05	$ 1.14	$ 1.60
Average number of common shares outstanding	40,566	38,132	35,204
Average shares outstanding (assuming dilution)	40,975	38,467	35,488

The accompanying notes are an integral part of these statements.

Consolidated Statements Of Cash Flows

Year Ended December 31, (Thousands of dollars)	2006	2005	2004
CASH FLOW FROM OPERATING ACTIVITIES:			
Net income	$ 83,860	$ 43,823	$ 56,775
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	168,964	156,253	146,018
Deferred income taxes	3,909	(5,514)	38,001
Changes in current assets and liabilities:			
Accounts receivable, net of allowances	(27,847)	(20,216)	(49,307)
Accrued utility revenue	(4,900)	982	(1,500)
Deferred purchased gas costs	32,408	(25,865)	(72,925)
Accounts payable	6,263	92,021	55,758
Accrued taxes	3,198	5,716	3,027
Other current assets and liabilities	24,156	(23,000)	(25,406)
Other	(8,657)	13,424	1,050
Net cash provided by operating activities	281,354	237,624	151,491
CASH FLOW FROM INVESTING ACTIVITIES:			
Construction expenditures and property additions	(345,325)	(294,369)	(302,688)
Other	33,199	1,985	6,106
Net cash used in investing activities	(312,126)	(292,384)	(296,582)
CASH FLOW FROM FINANCING ACTIVITIES:			
Issuance of common stock, net	72,452	64,136	58,687
Dividends paid	(33,500)	(31,228)	(28,836)
Issuance of long-term debt, net	92,400	145,256	147,135
Retirement of long-term debt	(84,397)	(31,442)	(83,437)
Temporary changes in long-term debt	(3,000)	—	—
Change in short-term debt	(24,000)	(76,000)	48,000
Net cash provided by financing activities	19,955	70,722	141,549
Change in cash and cash equivalents	(10,817)	15,962	(3,542)
Cash at beginning of period	29,603	13,641	17,183
Cash at end of period	$ 18,786	$ 29,603	$ 13,641
Supplemental information:			
Interest paid, net of amounts capitalized	$ 92,533	$ 86,465	$ 80,433
Income taxes paid (received), net	$ 39,682	$ 5,977	$ (12,640)

The accompanying notes are an integral part of these statements.

Consolidated Statements Of Stockholders' Equity And Comprehensive Income

(In thousands, except per share amounts)	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total	Comprehensive Income (Loss)
DECEMBER 31, 2003	34,232	$35,862	$510,521	$ —	$ 84,084	$630,467	
Common stock issuances	2,562	2,562	56,125			58,687	
Net income					56,775	56,775	$ 56,775
Additional minimum pension liability adjustment, net of $6.5 million of tax (Note 9)				(10,892)		(10,892)	(10,892)
Dividends declared Common: $0.82 per share					(29,361)	(29,361)	
2004 Comprehensive Income							$ 45,883
DECEMBER 31, 2004	36,794	38,424	566,646	(10,892)	111,498	705,676	
Common stock issuances	2,534	2,534	61,602			64,136	
Net income					43,823	43,823	$ 43,823
Additional minimum pension liability adjustment, net of $19 million of tax (Note 9)				(30,753)		(30,753)	(30,753)
Dividends declared Common: $0.82 per share					(31,747)	(31,747)	
2005 Comprehensive Income							$ 13,070
DECEMBER 31, 2005	39,328	40,958	628,248	(41,645)	123,574	751,135	
Common stock issuances	2,442	2,442	70,010			72,452	
Net income					83,860	83,860	$ 83,860
Additional minimum pension liability adjustment, net of $20.3 million of tax (Note 9)				33,047		33,047	33,047
Net adjustment to adopt SFAS No. 158, net of $3.1 million of tax (Note 9)				(5,068)		(5,068)	
Dividends declared Common: $0.82 per share					(34,001)	(34,001)	
2006 Comprehensive Income							$116,907
DECEMBER 31, 2006	41,770*	$43,400	$698,258	$(13,666)	$173,433	$901,425	

* At December 31, 2006, 1.3 million common shares were registered and available for issuance under provisions of the Employee Investment Plan and the Dividend Reinvestment and Stock Purchase Plan. In addition, 1 million common shares are registered for issuance upon the exercise of options granted under the Stock Incentive Plan (see Note 10). During 2006, approximately 947,000 shares were issued in at-the-market offerings through the Equity Shelf Program with gross proceeds of $28.3 million, agent commissions of $283,000, and net proceeds of $28 million.

The accompanying notes are an integral part of these statements.

Notes to Consolidated Financial Statements

Note 1 Summary of Significant Accounting Policies

Nature of Operations. Southwest Gas Corporation (the "Company") is composed of two segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services. Southwest is engaged in the business of purchasing, distributing and transporting natural gas to customers in portions of Arizona, Nevada, and California. The public utility rates, practices, facilities, and service territories of Southwest are subject to regulatory oversight. Natural gas purchases and the timing of related recoveries can materially impact liquidity. Northern Pipeline Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

Basis of Presentation. The Company follows generally accepted accounting principles ("GAAP") in accounting for all of its businesses. Accounting for the natural gas utility operations conforms with GAAP as applied to regulated companies and as prescribed by federal agencies and the commissions of the various states in which the utility operates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Consolidation. The accompanying financial statements are presented on a consolidated basis and include the accounts of Southwest Gas Corporation and all subsidiaries, except for Southwest Gas Capital II (see Note 5). All significant intercompany balances and transactions have been eliminated with the exception of transactions between Southwest and NPL in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation."

Net Utility Plant. Net utility plant includes gas plant at original cost, less the accumulated provision for depreciation and amortization, plus the unamortized balance of acquisition adjustments. Original cost includes contracted services, material, payroll and related costs such as taxes and benefits, general and administrative expenses, and an allowance for funds used during construction, less contributions in aid of construction.

Deferred Purchased Gas Costs. The various regulatory commissions have established procedures to enable Southwest to adjust its billing rates for changes in the cost of natural gas purchased. The difference between the current cost of gas purchased and the cost of gas recovered in billed rates is deferred. Generally, these deferred amounts are recovered or refunded within one year.

Income Taxes. The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period that includes the enactment date.

For regulatory and financial reporting purposes, investment tax credits ("ITC") related to gas utility operations are deferred and amortized over the life of related fixed assets.

Cash and Cash Equivalents. For purposes of reporting consolidated cash flows, cash and cash equivalents include cash on hand and financial instruments with a purchased maturity of three months or less.

Accumulated Removal Costs. In accordance with approved regulatory practices, the depreciation expense for Southwest includes a component to recover removal costs associated with utility plant retirements. In accordance with the Securities and Exchange Commission's ("SEC") position on presentation of these amounts, management has reclassified $125 million and $105 million, as of December 31, 2006 and 2005, respectively, of estimated removal costs from accumulated depreciation to accumulated removal costs within the liabilities section of the balance sheet.

Gas Operating Revenues. Revenues are recorded when customers are billed. Customer billings are based on monthly meter reads and are calculated in accordance with applicable tariffs and state and local laws, regulations, and agreements. An estimate of the amount of natural gas distributed, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period is also recognized as accrued utility revenue.

The Company acts as an agent for state and local taxing authorities in the collection and remission of a variety of taxes, including franchise fees, sales and use taxes, and surcharges. These taxes are not included in gas operating revenues, except for certain franchise fees in California operating jurisdictions which are not significant.

Construction Revenues. The majority of the NPL contracts are performed under unit price contracts. Generally, these contracts state prices per unit of installation. Typical installations are accomplished in two weeks or less. Revenues are recorded as installations are completed. Long-term fixed-price contracts use the percentage-of-completion method of accounting and, therefore, take into account the cost, estimated earnings, and revenue to date on contracts not yet completed. The amount of revenue recognized is based on costs expended to date relative to anticipated final contract costs. Revisions in estimates of costs and earnings during the course of the work are reflected in the accounting period in which the facts requiring revision become known. If a loss on a contract becomes known or is anticipated, the entire amount of the estimated ultimate loss is recognized at that time in the financial statements.

Note 1 Summary of Significant Accounting Policies (Continued)

Depreciation and Amortization. Utility plant depreciation is computed on the straight-line remaining life method at composite rates considered sufficient to amortize costs over estimated service lives, including components which compensate for salvage value, removal costs, and retirements, as approved by the appropriate regulatory agency. When plant is retired from service, the original cost of plant, including cost of removal, less salvage, is charged to the accumulated provision for depreciation. Costs related to refunding utility debt and debt issuance expenses are deferred and amortized over the weighted-average lives of the new issues. Other regulatory assets, including acquisition adjustments, are amortized when appropriate, over time periods authorized by regulators. Nonutility and construction services-related property and equipment are depreciated on a straight-line method based on the estimated useful lives of the related assets.

Allowance for Funds Used During Construction ("AFUDC"). AFUDC represents the cost of both debt and equity funds used to finance utility construction. AFUDC is capitalized as part of the cost of utility plant. The Company capitalized $2.8 million in 2006, $2 million in 2005, and $808,000 in 2004 of AFUDC related to natural gas utility operations. The debt portion of AFUDC is reported in the consolidated statements of income as an offset to net interest deductions and the equity portion is reported as other income. The debt portion of AFUDC was $1.4 million, $1.1 million and $691,000 for 2006, 2005 and 2004, respectively. Utility plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into operation, and general rate relief is requested and granted.

Earnings Per Share. Basic earnings per share ("EPS") are calculated by dividing net income by the weighted-average number of shares outstanding during the period. Diluted EPS includes the effect of additional weighted-average common stock equivalents (stock options and performance shares). Unless otherwise noted, the term "Earnings Per Share" refers to Basic EPS. A reconciliation of the shares used in the Basic and Diluted EPS calculations is shown in the following table. Net income was the same for Basic and Diluted EPS calculations.

	2006	2005	2004
(In thousands)			
Average basic shares	40,566	38,132	35,204
Effect of dilutive securities:			
Stock options	195	146	111
Performance shares	214	189	173
Average diluted shares	40,975	38,467	35,488

Derivatives. In managing its gas supply portfolios, Southwest uses fixed-price and variable-rate arrangements which qualify as derivative instruments as defined under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133). However, such contracts qualify for the normal purchases and normal sales exception under SFAS No. 133 or have no significant market value. The Company does not currently utilize other stand-alone derivative financial instruments for speculative purposes or for hedging.

Recently Issued Accounting Pronouncements. In February 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140." SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies several other related issues. The provisions of SFAS No. 155 are effective for the Company for all financial instruments acquired or issued after January 1, 2007. The adoption of the standard is not expected to have a material impact on the financial position or results of operations of the Company.

In March 2006, the FASB issued SFAS No. 156, "Accounting for Servicing of Financial Assets—an amendment of FASB Statement No. 140." SFAS No. 156 addresses the recognition and measurement of separately recognized servicing assets and liabilities and provides an approach to simplify efforts to obtain hedge-like (offset) accounting. The provisions of SFAS No. 156 are effective for the Company for the recognition and initial measurement of servicing assets and liabilities acquired or issued after January 1, 2007. The adoption of the standard is not expected to have a material impact on the financial position or results of operations of the Company.

In June 2006, the FASB issued Financial Interpretation ("FIN") No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109." FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes," and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN No. 48 is effective for the Company beginning January 1, 2007. The adoption of the standard is not expected to have a material impact on the financial position or results of operations of the Company.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective for the Company beginning January 1, 2008. The Company is evaluating what impact, if any, this standard might have on its financial position or results of operations.

Stock-Based Compensation. At December 31, 2006, the Company had two stock-based compensation plans which are described more fully in **Note 10—Stock-Based Compensation**. Prior to January 1, 2006, these plans were

Note 1 Summary of Significant Accounting Policies (Continued)

accounted for in accordance with APB Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations. Effective January 1, 2006, the Company adopted SFAS No. 123 (revised 2004) "Share-Based Payment", using the modified prospective transition method. Accordingly, financial information for prior periods has not been restated. The adoption of SFAS No. 123 (revised 2004) did not have a material impact on the Company's financial position, results of operations, or cash flows. Under the modified prospective transition method, expense is recognized for any new awards granted after the effective date and for the unvested portion of awards granted prior to the effective date. Total stock-based compensation expense recognized in the consolidated statements of income for the year ended December 31, 2006 was $3.3 million (net of related tax benefits of $1.6 million). The pro forma effects of recognizing the estimated fair value of stock-based compensation for periods prior to the adoption of SFAS No. 123 (revised 2004) are presented below (thousands of dollars, except per share amounts):

	2005	2004
Net income, as reported	$43,823	$56,775
Add: Stock-based employee compensation expense included in reported net income, net of related tax benefits	2,469	1,825
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax benefits	(2,620)	(1,958)
Pro forma net income	$43,672	$56,642
Earnings per share:		
Basic—as reported	$ 1.15	$ 1.61
Basic—pro forma	1.15	1.61
Diluted—as reported	1.14	1.60
Diluted—pro forma	1.14	1.60

Note 2 Utility Plant

Net utility plant as of December 31, 2006 and 2005 was as follows (thousands of dollars):

December 31,	2006	2005
Gas plant:		
Storage	$ 17,545	$ 17,357
Transmission	243,989	239,872
Distribution	3,153,399	2,917,959
General	219,527	213,906
Other	128,850	127,493
	3,763,310	3,516,587
Less: accumulated depreciation	(1,175,600)	(1,083,900)
Acquisition adjustments, net	1,992	2,173
Construction work in progress	78,402	54,287
Net utility plant	$ 2,668,104	$ 2,489,147

Depreciation and amortization expense on gas plant was $145 million in 2006, $137 million in 2005, and $128 million in 2004.

Note 2 Utility Plant (Continued)

Operating Leases and Rentals. Southwest leases a portion of its corporate headquarters office complex in Las Vegas, and its administrative offices in Phoenix. The leases provide for current terms which expire in 2017 and 2009, respectively, with optional renewal terms available at the expiration dates. The rental payments for the corporate headquarters office complex are $2 million in each of the years 2007 through 2011 and $12.2 million cumulatively thereafter. The rental payments for the Phoenix administrative offices are $1.5 million for each of the years 2007 and 2008, and $1 million in 2009 when the lease expires. In addition to the above, the Company leases certain office and construction equipment. The majority of these leases are short-term. These leases are accounted for as operating leases, and for the gas segment are treated as such for regulatory purposes. Rentals included in operating expenses for all operating leases were $19.2 million in 2006, $19 million in 2005, and $20.3 million in 2004. These amounts include NPL lease expenses of approximately $11.5 million in 2006, $11.5 million in 2005, and $9.8 million in 2004 for various short-term operating leases of equipment and temporary office sites.

The following is a schedule of future minimum lease payments for significant non-cancelable operating leases (with initial or remaining terms in excess of one year) as of December 31, 2006 (thousands of dollars):

Year Ending December 31,	
2007	$ 5,378
2008	4,868
2009	4,010
2010	2,568
2011	2,433
Thereafter	12,890
Total minimum lease payments	$32,147

Note 3 Receivables and Related Allowances

Business activity with respect to gas utility operations is conducted with customers located within the three-state region of Arizona, Nevada, and California. At December 31, 2006, the gas utility customer accounts receivable balance was $182 million. Approximately 54 percent of the gas utility customers were in Arizona, 36 percent in Nevada, and 10 percent in California. Although the Company seeks to minimize its credit risk related to utility operations by requiring security deposits from new customers, imposing late fees, and actively pursuing collection on overdue accounts, some accounts are ultimately not collected. Provisions for uncollectible accounts are recorded monthly, as needed, and are included in the ratemaking process as a cost of service. Activity in the allowance for uncollectibles is summarized as follows (thousands of dollars):

	Allowance for Uncollectibles
Balance, December 31, 2003	$ 2,246
Additions charged to expense	2,586
Accounts written off, less recoveries	(2,860)
Balance, December 31, 2004	1,972
Additions charged to expense	3,787
Accounts written off, less recoveries	(3,458)
Balance, December 31, 2005	2,301
Additions charged to expense	5,805
Accounts written off, less recoveries	(5,085)
Balance, December 31, 2006	$ 3,021

Note 4 Regulatory Assets and Liabilities

Natural gas operations are subject to the regulation of the Arizona Corporation Commission ("ACC"), the Public Utilities Commission of Nevada ("PUCN"), the California Public Utilities Commission ("CPUC"), and the Federal Energy Regulatory Commission ("FERC"). Southwest accounting policies conform to generally accepted accounting principles applicable to rate-regulated enterprises, principally SFAS No. 71, and reflect the effects of the ratemaking process. SFAS No. 71 allows for the deferral as regulatory assets, costs that otherwise would be expensed if it is probable future recovery from customers will occur. If rate recovery is no longer probable, due to competition or the actions of regulators, Southwest is required to write-off the related regulatory asset. Regulatory liabilities are recorded if it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process.

Note 4 Regulatory Assets and Liabilities (Continued)

The following table represents existing regulatory assets and liabilities (thousands of dollars):

December 31,	2006	2005
Regulatory assets:		
Accrued pension and other postretirement benefit costs * (Note 9)	$ 101,402	$ —
Deferred purchased gas costs	77,007	109,415
Accrued purchased gas costs **	40,500	75,300
SFAS No. 109—income taxes, net *	1,846	2,447
Unamortized premium on reacquired debt *	17,676	18,386
Other	30,099	28,236
	268,530	233,784
Regulatory liabilities:		
Accumulated removal costs	(125,000)	(105,000)
Other ***	(1,111)	(821)
Net regulatory assets (liabilities)	$ 142,419	$ 127,963

* Included in Deferred charges and other assets on the Consolidated Balance Sheet.
** Included in Prepaids and other current assets on the Consolidated Balance Sheet.
*** Included in Other deferred credits on the Consolidated Balance Sheet.

Other regulatory assets include deferred costs associated with rate cases, regulatory studies, margin and interest-tracking accounts, and state mandated public purpose programs (including low income and conservation programs), as well as amounts associated with accrued absence time and deferred post-retirement benefits other than pensions.

Note 5 Preferred Trust Securities and Subordinated Debentures

In June 2003, the Company created Southwest Gas Capital II ("Trust II"), a wholly owned subsidiary, as a financing trust for the sole purpose of issuing preferred trust securities for the benefit of the Company. In August 2003, Trust II publicly issued $100 million of 7.70% Preferred Trust Securities ("Preferred Trust Securities"). In connection with the Trust II issuance of the Preferred Trust Securities and the related purchase by the Company for $3.1 million of all of the Trust II common securities ("Common Securities"), the Company issued $103.1 million principal amount of its 7.70% Junior Subordinated Debentures, due 2043 ("Subordinated Debentures") to Trust II. The sole assets of Trust II are and will be the Subordinated Debentures. The interest and other payment dates on the Subordinated Debentures correspond to the distribution and other payment dates on the Preferred Trust Securities and Common Securities. Under certain circumstances, the Subordinated Debentures may be distributed to the holders of the Preferred Trust Securities and holders of the Common Securities in liquidation of Trust II. The Subordinated Debentures are redeemable at the option of the Company after August 2008 at a redemption price of $25 per Subordinated Debenture plus accrued and unpaid interest. In the event that the Subordinated Debentures are repaid, the Preferred Trust Securities and the Common Securities will be redeemed on a pro rata basis at $25 (par value) per Preferred Trust Security and Common Security plus accumulated and unpaid distributions. Company obligations under the Subordinated Debentures, the Trust Agreement (the agreement under which Trust II was formed), the guarantee of payment of certain distributions, redemption payments and liquidation payments with respect to the Preferred Trust Securities to the extent Trust II has funds available therefore and the indenture governing the Subordinated Debentures, including the Company agreement pursuant to such indenture to pay all fees and expenses of Trust II, other than with respect to the Preferred Trust Securities and Common Securities, taken together, constitute a full and unconditional guarantee on a subordinated basis by the Company of payments due on the Preferred Trust Securities. As of December 31, 2006, 4.1 million Preferred Trust Securities were outstanding.

The Company has the right to defer payments of interest on the Subordinated Debentures by extending the interest payment period at any time for up to 20 consecutive quarters

Note 5 Preferred Trust Securities and Subordinated Debentures (Continued)

(each, an "Extension Period"). If interest payments are so deferred, distributions to Preferred Trust Securities holders will also be deferred. During such Extension Period, distributions will continue to accrue with interest thereon (to the extent permitted by applicable law) at an annual rate of 7.70% per annum compounded quarterly. There could be multiple Extension Periods of varying lengths throughout the term of the Subordinated Debentures. If the Company exercises the right to extend an interest payment period, the Company shall not during such Extension Period (i) declare or pay dividends on, or make a distribution with respect to, or redeem, purchase or acquire or make a liquidation payment with respect to, any of its capital stock, or (ii) make any payment of interest, principal, or premium, if any, on or repay, repurchase, or redeem any debt securities issued by the Company that rank equal with or junior to the Subordinated Debentures; provided, however, that restriction (i) above does not apply to any stock dividends paid by the Company where the dividend stock is the same as that on which the dividend is being paid. The Company has no present intention of exercising its right to extend the interest payment period on the Subordinated Debentures.

Although the Company owns 100 percent of the common voting securities of Trust II, under Interpretation No. 46 "Consolidation of Variable Interest Entities—an Interpretation of ARB No. 51", the Company is not considered the primary beneficiary of this trust and therefore Trust II is not consolidated. As a result, the $103.1 million Subordinated Debentures are shown on the balance sheet of the Company, net of the $3.1 million Common Securities, as Subordinated debentures due to Southwest Gas Capital II. Payments and amortizations associated with the Subordinated Debentures are classified on the consolidated statements of income as Net interest deductions on subordinated debentures.

Note 6 Long-Term Debt

December 31,	2006		2005	
	Carrying Amount	Market Value	Carrying Amount	Market Value
(Thousands of dollars)				
Debentures:				
7½% Series, due 2006	$ —	$ —	$ 75,000	$ 76,155
Notes, 8.375%, due 2011	200,000	221,200	200,000	225,720
Notes, 7.625%, due 2012	200,000	217,600	200,000	222,040
8% Series, due 2026	75,000	88,748	75,000	90,525
Medium-term notes, 6.89% series, due 2007	17,500	17,654	17,500	17,971
Medium-term notes, 6.27% series, due 2008	25,000	25,263	25,000	25,600
Medium-term notes, 7.59% series, due 2017	25,000	28,155	25,000	28,573
Medium-term notes, 7.78% series, due 2022	25,000	28,645	25,000	29,088
Medium-term notes, 7.92% series, due 2027	25,000	29,398	25,000	30,000
Medium-term notes, 6.76% series, due 2027	7,500	7,832	7,500	7,976
Unamortized discount	(4,021)	—	(4,657)	—
	595,979		670,343	
Revolving credit facility and commercial paper	147,000	147,000	150,000	150,000
Industrial development revenue bonds:				
Variable-rate bonds:				
Tax-exempt Series A, due 2028	50,000	50,000	50,000	50,000
2003 Series A, due 2038	50,000	50,000	50,000	50,000
2003 Series B, due 2038	50,000	50,000	50,000	50,000
Fixed-rate bonds:				
6.10% 1999 Series A, due 2038	12,410	13,093	12,410	13,068
5.95% 1999 Series C, due 2038	14,320	15,136	14,320	15,057
5.55% 1999 Series D, due 2038	8,270	8,696	8,270	8,593
5.45% 2003 Series C, due 2038	30,000	30,705	30,000	30,264
5.25% 2003 Series D, due 2038	20,000	20,836	20,000	20,400
5.80% 2003 Series E, due 2038	15,000	15,629	15,000	15,218
5.25% 2004 Series A, due 2034	65,000	67,210	65,000	65,878
5.00% 2004 Series B, due 2033	75,000	76,688	75,000	75,000
4.85% 2005 Series A, due 2035 net of $24.6 million held in trust in 2005	100,000	101,050	75,366	73,030
4.75% 2006 Series A, due 2036	56,000	56,213	—	—
Unamortized discount	(4,697)	—	(4,159)	—
	541,303		461,207	
Other	29,617	—	26,563	—
	1,313,899		1,308,113	
Less: current maturities	(27,545)		(83,215)	
Long-term debt, less current maturities	$1,286,354		$1,224,898	

Note 6 Long-Term Debt (Continued)

In April 2006, the Company amended its $300 million credit facility. The facility was originally scheduled to expire in April 2010 and was extended to April 2011. The Company will continue to use $150 million of the $300 million as long-term debt and the remaining $150 million for working capital purposes. Interest rates for the facility are calculated at either the London Interbank Offering Rate plus an applicable margin, or the greater of the prime rate or one-half of one percent plus the Federal Funds rate. The applicable margin, unused commitment fee, and utilization fee associated with the amended credit facility are lower than those of the previous facility. At December 31, 2006, no borrowings were outstanding on the short-term portion of the credit facility and $147 million was outstanding on the long-term portion.

In September 2006, the Company issued $56 million in Clark County, Nevada 4.75% industrial development revenue bonds ("IDRBs") Series 2006A pursuant to a financing agreement and indenture. The IDRBs were issued at a discount of 0.625% and are due September 1, 2036. The proceeds from the IDRBs were used by Southwest to expand and upgrade facilities in Clark County, Nevada.

The Company's Revolving Credit Facility, letters of credit, and certain bond insurance policies contain financial covenants, the most restrictive of which require a maximum leverage ratio of 70 percent (debt to capitalization as defined) and a minimum net worth calculation of $475 million adjusted for equity issuances after May 10, 2002. If the Company was not in compliance with these covenants, an event of default would occur, which if not cured could cause the amounts outstanding to become due and payable. This would also trigger cross-default provisions in substantially all other outstanding indebtedness of the Company. At December 31, 2006, the Company was in compliance with the applicable covenants.

The effective interest rates on the 2003 Series A and B variable-rate IDRBs were 5.14 percent and 4.09 percent, respectively, at December 31, 2006 and 4.64 percent and 3.84 percent, respectively, at December 31, 2005. The effective interest rates on the tax-exempt Series A variable-rate IDRBs were 5.03 percent and 4.55 percent at December 31, 2006 and 2005, respectively.

The fair value of the revolving credit facility and the variable-rate IDRBs approximates carrying value. Market values for the debentures and fixed-rate IDRBs were determined based on dealer quotes using trading records for December 31, 2006 and 2005, as applicable, and other secondary sources which are customarily consulted for data of this kind.

Estimated maturities of long-term debt for the next five years are $27.5 million, $34.1 million, $6.6 million, $1.4 million, and $347 million, respectively.

The $7.5 million medium-term notes, 6.76% series, due 2027 contain a put feature at the discretion of the bondholder on one date only in 2007. If the bondholder does not exercise the put on that date, the notes mature in 2027. If the bondholder exercises the put, the maturities of long-term debt for 2007 will total $35 million.

Note 7 Short-Term Debt

As discussed in Note 6, Southwest has a $300 million five-year credit facility, effective April 2006, of which $150 million has been designated by management for working capital purposes (and related outstanding amounts are designated as short-term debt). No short-term borrowings were outstanding on the credit facility at December 31, 2006. Short-term borrowings on the credit facility were $24 million at December 31, 2005. The weighted-average interest rate on these borrowings was 5.08 percent at December 31, 2005.

Note 8 Commitments and Contingencies

Legal and Regulatory Proceedings. The Company maintains liability insurance for various risks associated with the operation of its natural gas pipelines and facilities. In May 2005, a leaking natural gas line was involved in a fire that severely injured an individual. By December 2005, the Company had recorded a total liability related to this incident equal to the Company's maximum self-insured retention level for the policy year August 2004 to July 2005 of $11 million. In the fourth quarter of 2006, the case was settled. The amount of the settlement that exceeded $11 million was covered by insurance. The Company's current insurance contracts limit the self-insured retention to $1 million per incident plus payment of the first $5 million in aggregate claims above $1 million.

The Company is a defendant in miscellaneous legal proceedings. The Company is also a party to various regulatory proceedings. The ultimate dispositions of these proceedings are not presently determinable; however, it is the opinion of management that no litigation or regulatory proceeding to which the Company is subject will have a material adverse impact on its financial position or results of operations.

Note 9 Pension and Other Postretirement Benefits

Southwest has a noncontributory qualified retirement plan with defined benefits covering substantially all employees and a separate unfunded supplemental retirement plan ("SERP") which is limited to officers. Southwest also provides postretirement benefits other than pensions ("PBOP") to its qualified retirees for health care, dental, and life insurance benefits.

In September 2006, the FASB issued SFAS No. 158, which requires employers to recognize the overfunded or underfunded positions of defined benefit postretirement plans, including pension plans, in their balance sheets. Under SFAS No. 158, any actuarial gains and losses, prior service costs and transition assets or obligations that were not recognized under previous accounting standards must be recognized in accumulated other comprehensive income under stockholders' equity, net of tax, until they are amortized as a component of net periodic benefit cost. SFAS No. 158 does not change how net periodic pension and postretirement costs are accounted for and reported in the income statement. The Company adopted the provisions of SFAS No. 158 effective December 31, 2006.

In accordance with SFAS No. 71, the Company has established a regulatory asset for the portion of the total amounts otherwise chargeable to accumulated other comprehensive income that are expected to be recovered through rates in future periods. The changes in actuarial gains and losses, prior service costs and transition assets or obligations pertaining to the regulatory asset will be recognized as an adjustment to the regulatory asset account as these amounts are recognized as components of net periodic pension costs each year. The following table discloses the incremental effect of applying the provisions of SFAS No. 158 (and SFAS No. 71) to individual line items in the balance sheet as of December 31, 2006.

(Thousands of dollars)	Before Application of SFAS No. 158 *	SFAS No. 158 Adjustments	SFAS No. 71 Regulatory Adjustments	Adjusted Balance **
Assets				
Deferred charges and other assets	$ 101,712	$ —	$77,283	$ 178,995
Total assets	3,407,682	—	77,283	3,484,965
Capitalization and Liabilities				
Accumulated other comprehensive income (loss), net	(8,598)	(52,983)	47,915	(13,666)
Total equity	906,493	(52,983)	47,915	901,425
Total capitalization	2,292,847	(52,983)	47,915	2,287,779
Current liabilities:				
Deferred income taxes	16,383	(912)	—	15,471
Other current liabilities	53,501	2,400	—	55,901
Total current liabilities	494,576	1,488	—	496,064
Deferred income taxes and other credits:				
Deferred income taxes and investment tax credits	310,686	(31,561)	29,368	308,493
Other deferred credits	178,622	83,056	—	261,678
Total deferred income taxes and other credits	620,259	51,495	29,368	701,122
Total capitalization and liabilities	$3,407,682	$ —	$77,283	$3,484,965

* Balances before application of SFAS No. 158 include the effects of 2006 plan experience and changes in actuarial assumptions on the additional minimum liability, coupled with the regulatory impacts of SFAS No. 71.

** At December 31, 2006, the combined net funded status of the three plans reflected a liability of $155 million. Of this amount, approximately $101 million was offset with a regulatory asset.

The table below discloses net amounts recognized in accumulated other comprehensive income as a result of adopting the provisions of SFAS No. 158 (as impacted by SFAS No. 71) as of December 31, 2006. Tax amounts are calculated using a 38 percent rate.

(Thousands of dollars)	Total	Qualified Retirement Plan	SERP	PBOP
Adjustments to adopt SFAS No. 158:				
Net actuarial loss, net of $44.9 million of tax	$(73,323)	$(62,464)	$(8,045)	$(2,814)
Net transition obligation, net of $2 million of tax	(3,225)	—	—	(3,225)
Prior service credit, net of $9,000 of tax	14	14	—	—
Reversal of additional minimum pension liability, net of $14.4 million of tax	23,551	16,432	7,119	—
Estimated amounts recoverable through rates, net of $29.4 million of tax	47,915	41,876	—	6,039
Total amounts recognized in accumulated other comprehensive income	$ (5,068)	$ (4,142)	$ (926)	$ —

Note 9 Pension and Other Postretirement Benefits (Continued)

Investment objectives and strategies for the qualified retirement plan are developed and approved by the Pension Plan Investment Committee of the Board of Directors of the Company. They are designed to preserve capital, maintain minimum liquidity required for retirement plan operations and effectively manage pension assets.

A target portfolio of investments in the qualified retirement plan is developed by the Pension Plan Investment Committee and is reevaluated periodically. Rate of return assumptions are determined by evaluating performance expectations of the target portfolio. Projected benefit obligations are estimated using actuarial assumptions and Company benefit policy. A target mix of assets is then determined based on acceptable risk versus estimated returns in order to fund the benefit obligation. The current percentage ranges of the target portfolio are:

Type of Investment	Percentage Range
Equity securities	58 to 70
Debt securities	32 to 38
Other	up to 5

The Company's pension costs for these plans are affected by the amount of cash contributions to the plans, the return on plan assets, discount rates, and by employee demographics, including age, compensation, and length of service. Changes made to the provisions of the plans may also impact current and future pension costs. Actuarial formulas are used in the determination of pension costs and are affected by actual plan experience and assumptions about future experience. Key actuarial assumptions include the expected return on plan assets, the discount rate used in determining the projected benefit obligation and pension costs, and the assumed rate of increase in employee compensation. Relatively small changes in these assumptions, particularly the discount rate, may significantly affect pension costs and plan obligations for the qualified retirement plan.

SFAS No. 87 *Employer's Accounting for Pensions* states that the assumed discount rate should reflect the rate at which the pension benefits could be effectively settled. In making this estimate, in addition to rates implicit in current prices of annuity contracts that could be used to settle the liabilities, employers may look to rates of return on high-quality fixed-income investments currently available and expected to be available during the period to maturity of the pension benefits. In determining the discount rate, the Company matches the plan's projected cash flows to a spot-rate yield curve based on highly rated corporate bonds. The resulting rate is then rounded to the nearest 25 basis points.

Due to an increase in market interest rates for high-quality fixed-income investments, the Company raised the discount rate to 6.00% at December 31, 2006 from 5.75% at December 31, 2005. The weighted-average rate of compensation increase was raised to 3.75% from 3.30%. The Company maintained its asset return assumption for 2007 at 8.50%. These offsetting changes will not result in a significant change in pension expense for 2007.

Note 9 Pension and Other Postretirement Benefits (Continued)

The following tables set forth the retirement plan, SERP, and PBOP funded status and amounts recognized on the Consolidated Balance Sheets and Statements of Income.

	2006		
(Thousands of dollars)	Qualified Retirement Plan	SERP	PBOP
Change in benefit obligations			
Benefit obligation for service rendered to date at beginning of year (PBO/PBO/APBO)	$ 473,418	$ 34,123	$ 37,553
Service cost	16,284	211	854
Interest cost	26,805	1,893	2,118
Actuarial loss (gain)	(4,806)	(207)	(297)
Benefits paid	(15,898)	(2,363)	(1,121)
Benefit obligation at end of year (PBO/PBO/APBO)	495,803	33,657	39,107
Change in plan assets			
Market value of plan assets at beginning of year	338,618	—	20,979
Actual return on plan assets	42,733	—	2,742
Employer contributions	23,253	2,363	1,107
Benefits paid	(15,898)	(2,363)	—
Market value of plan assets at end of year	388,706	—	24,828
Funded status at year end	$(107,097)	$(33,657)	$(14,279)
Weighted-average assumptions (benefit obligation)			
Discount rate	6.00%	6.00%	6.00%
Weighted-average rate of compensation increase	3.75%	3.75%	3.75%
Asset Allocation			
Equity securities	63%		77%
Debt securities	32%		16%
Other	5%		7%
Total	100%	N/A	100%

Note 9 Pension and Other Postretirement Benefits (Continued)

(Thousands of dollars)	2005 Qualified Retirement Plan	2005 SERP	2005 PBOP
Change in benefit obligations			
Benefit obligation for service rendered to date at beginning of year (PBO/PBO/APBO)	$ 428,116	$ 31,385	$ 35,988
Service cost	15,787	223	837
Interest cost	25,327	1,811	2,115
Actuarial loss (gain)	17,842	2,963	103
Benefits paid	(13,654)	(2,259)	(1,490)
Benefit obligation at end of year (PBO/PBO/APBO)	473,418	34,123	37,553
Change in plan assets			
Market value of plan assets at beginning of year	318,664	—	18,750
Actual return on plan assets	15,988	—	1,102
Employer contributions	17,620	2,259	1,127
Benefits paid	(13,654)	(2,259)	—
Market value of plan assets at end of year	338,618	—	20,979
Funded status	(134,800)	(34,123)	(16,574)
Unrecognized net actuarial loss (gain)	123,028	14,428	5,954
Unrecognized transition obligation (2012)	—	—	6,069
Unrecognized prior service cost	(34)	9	—
Prepaid (accrued) benefit cost	$ (11,806)	$(19,686)	$ (4,551)
Accrued benefit liability	$ (66,082)	$(32,580)	$ (4,551)
Additional minimum pension liability adjustment	54,276	12,894	—
	$ (11,806)	$(19,686)	$ (4,551)
Weighted-average assumptions (benefit obligation)			
Discount rate	5.75%	5.75%	5.75%
Weighted-average rate of compensation increase	3.30%	3.30%	3.30%
Asset Allocation			
Equity securities	61%		71%
Debt securities	30%		15%
Other	9%		14%
Total	100%	N/A	100%

Estimated funding for the plans above during calendar year 2007 is approximately $24 million. The accumulated benefit obligation for the retirement plan was $422 million and $405 million, and for the SERP was $32.2 million and $32.6 million at December 31, 2006 and 2005, respectively.

Pension benefits expected to be paid for each of the next five years beginning with 2007 are the following: $16.8 million, $18 million, $19.2 million, $20.6 million, and $22.2 million. Pension benefits expected to be paid during 2012 to 2016 total $138 million. Retiree welfare benefits expected to be paid for each of the next five years beginning with 2007 are the following: $1.4 million, $1.5 million, $1.6 million, $1.7 million, and $1.8 million. Retiree welfare benefits expected to be paid during 2012 to 2016 total $10.5 million. SERP benefits expected to be paid for each of the next five years beginning with 2007 are the following: $2.4 million, $2.5 million, $2.5 million, $2.5 million, and $2.5 million. SERP benefits expected to be paid during 2012 to 2016 total $12.6 million. No assurance can be made that actual funding and benefits paid will match our estimates.

For PBOP measurement purposes, the per capita cost of covered health care benefits is assumed to increase five percent annually. The Company makes fixed contributions for health care benefits of employees who retire after 1988, but pays up to 100 percent of covered health care costs for employees who retired prior to 1989. The assumed annual rate of increase noted above applies to the benefit obligations of pre-1989 retirees only.

Note 9 Pension and Other Postretirement Benefits (Continued)

Components of net periodic benefit cost:

	Qualified Retirement Plan			SERP			PBOP		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
(Thousands of dollars)									
Service cost	$ 16,284	$ 15,787	$ 13,790	$ 211	$ 223	$ 211	$ 854	$ 837	$ 722
Interest cost	26,805	25,327	23,659	1,893	1,811	1,745	2,118	2,115	2,180
Expected return on plan assets	(30,608)	(29,553)	(28,067)	—	—	—	(1,817)	(1,675)	(1,426)
Amortization of prior service costs (credits)	(11)	(11)	54	9	116	140	—	—	—
Amortization of transition obligation	—	—	—	—	—	—	867	867	867
Amortization of net loss	5,352	2,453	—	1,244	912	639	168	136	213
Net periodic benefit cost	$ 17,822	$ 14,003	$ 9,436	$3,357	$3,062	$2,735	$ 2,190	$ 2,280	$ 2,556
Weighted-average assumptions (net benefit cost)									
Discount rate	5.75%	6.00%	6.50%	5.75%	6.00%	6.50%	5.75%	6.00%	6.50%
Expected return on plan assets	8.50%	8.75%	8.75%	8.50%	8.75%	8.75%	8.50%	8.75%	8.75%
Weighted-average rate of compensation increase	3.30%	4.00%	4.25%	3.30%	4.00%	4.25%	3.30%	4.00%	4.25%

The estimated net loss that will be amortized from accumulated other comprehensive income or regulatory assets into net periodic benefit cost over the next year is $5 million for the qualified retirement plan and $1.1 million for the SERP. The estimated transition obligation for the PBOP that will be amortized from regulatory assets into net periodic benefit cost over the next year is $870,000. The estimated prior service costs (credits) for the qualified retirement plan and SERP and the estimated net loss for the PBOP that will be amortized over the next year are not significant.

The Employees' Investment Plan provides for purchases of various mutual fund investments and Company common stock by eligible Southwest employees through deductions of a percentage of base compensation, subject to IRS limitations. Southwest matches up to one-half of amounts deferred. The maximum matching contribution is three percent of an employee's annual compensation. The cost of the plan was $3.6 million in 2006, $3.5 million in 2005, and $3.5 million in 2004. NPL has a separate plan, the cost and liability for which are not significant.

Southwest has a deferred compensation plan for all officers and members of the Board of Directors. The plan provides the opportunity to defer up to 100 percent of annual cash compensation. Southwest matches one-half of amounts deferred by officers. The maximum matching contribution is three percent of an officer's annual base salary. Upon retirement, payments of compensation deferred, plus interest, are made in equal monthly installments over 10, 15, or 20 years, as elected by the participant. Directors have an additional option to receive such payments over a five-year period. Deferred compensation earns interest at a rate determined each January. The interest rate equals 150 percent of Moody's Seasoned Corporate Bond Rate Index.

Note 10 Stock-Based Compensation

At December 31, 2006, the Company had two stock-based compensation plans: a stock option plan and a performance share stock plan. Prior to January 1, 2006, these plans were accounted for in accordance with APB Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations. Effective January 1, 2006, the Company adopted SFAS No. 123 (revised 2004) "Share-Based Payment", using the modified prospective transition method. Accordingly, financial information for prior periods has not been restated. The adoption of SFAS No. 123 (revised 2004) did not have a material impact on the Company's financial condition, results of operations, or cash flows. Under the modified prospective transition method, expense is recognized for any new awards granted after the effective date and for the unvested portion of awards granted prior to the effective date.

Under the option plan, the Company may grant options to purchase shares of common stock to key employees and outside directors. The option grants in 2006 consumed the remaining options that could be issued under the option plan and no future grants are anticipated. Each option has an exercise price equal to the market price of Company common stock on the date of grant and a maximum term of ten years. The options vest 40 percent at the end of year one and 30 percent at the end of years two and three. The grant date fair value of the options was estimated using the Black-Scholes option pricing model in 2006 and 2005 and the extended binomial option pricing model in 2004. The following assumptions were used in the valuation calculation:

	2006	2005	2004
Dividend yield	2.48 to 2.82%	3.14 to 3.28%	3.50%
Risk-free interest rate range	4.91 to 5.06%	3.88 to 4.09%	1.66 to 3.23%
Expected volatility range	15%	18%	13 to 20%
Expected life	6 years	6 years	1 to 3 years

The following tables summarize Company stock option plan activity and related information (thousands of options):

	2006		2005		2004	
	Number of options	Weighted-average exercise price	Number of options	Weighted-average exercise price	Number of options	Weighted-average exercise price
Outstanding at the beginning of the year	1,475	$23.70	1,646	$22.46	1,502	$21.83
Granted during the year	252	32.60	347	26.00	403	23.36
Exercised during the year	(749)	23.30	(510)	21.28	(254)	20.21
Forfeited during the year	(6)	26.81	(8)	22.41	(5)	21.83
Expired during the year	(15)	28.09	—	—	—	—
Outstanding at year end	957	$26.26	1,475	$23.70	1,646	$22.46
Exercisable at year end	413	$23.31	813	$23.06	1,010	$22.36

Note 10 Stock-Based Compensation (Continued)

The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option. The aggregate intrinsic value of outstanding options was $11.6 million, $4.3 million, and $5.3 million at December 31, 2006, December 31, 2005, and December 31, 2004, respectively. The aggregate intrinsic value of exercisable options was $6.2 million, $3 million, and $3.6 million at December 31, 2006, December 31, 2005, and December 31, 2004, respectively. The aggregate intrinsic value of exercised options was $11.3 million, $2.6 million, and $1.3 million during 2006, 2005, and 2004, respectively. The market value of Southwest Gas stock was $38.37, $26.40, and $25.40 at December 31, 2006, December 31, 2005, and December 31, 2004, respectively.

The weighted-average remaining contractual life for outstanding options was 7.7 years for 2006. The weighted-average remaining contractual life for exercisable options was 6.4 years for 2006. The weighted-average grant-date fair value of options granted was $5.92 for 2006, $4.18 for 2005, and $1.65 for 2004. The following table summarizes information about stock options outstanding at December 31, 2006 (thousands of options):

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Number outstanding	Weighted-average remaining contractual life	Weighted-average exercise price	Number exercisable	Weighted-average exercise price
$15.00 to $19.13	26	2.7 Years	$18.13	26	$18.13
$20.49 to $26.10	664	7.4 Years	$24.12	368	$23.36
$28.75 to $33.07	267	9.0 Years	$32.38	19	$29.14

As of December 31, 2006, there was $1.5 million of total unrecognized compensation cost related to nonvested stock options. That cost is expected to be recognized over a period of 3 years. The total fair value of options vested was $1 million, $609,000, and $917,000 during 2006, 2005, and 2004, respectively. The Company received $17.5 million in cash from the exercise of options during 2006 and a corresponding tax benefit of $2.6 million which was recorded in additional paid-in capital. The following table summarizes the status of the Company's nonvested options as of December 31, 2006 (thousands of options):

	Number of options	Weighted-average grant date fair value
Nonvested at the beginning of the year	662	$3.00
Granted	252	$5.92
Vested	(364)	$2.80
Forfeited	(6)	$4.15
Nonvested at December 31, 2006	544	$4.47

In addition to the option plan, the Company may issue performance shares to encourage key employees to remain in its employment to achieve short-term and long-term performance goals. Plan participants are eligible to receive a cash bonus (i.e., short-term incentive) and performance shares (i.e., long-term incentive). The performance shares vest three years after grant (and are subject to a final adjustment as determined by the Board of Directors) and are then issued as common stock. The following table summarizes the activity of this plan (thousands of shares):

Year Ended December 31,	2006	2005	2004
Nonvested performance shares at beginning of year	357	316	381
Performance shares granted (including dividends)	95	143	156
Performance shares forfeited	—	(6)	—
Shares vested and issued*	(133)	(96)	(221)
Nonvested performance shares at end of year	319	357	316
Average grant date fair value of awards granted this year	$26.97	$24.71	$22.70

* Includes shares converted for taxes and retiree payouts.

Note 11 Income Taxes

Income tax expense (benefit) consists of the following (thousands of dollars):

Year Ended December 31,	2006	2005	2004
Current:			
Federal	$29,916	$ 553	$ (225)
State	4,830	2,218	(1,186)
	34,746	2,771	(1,411)
Deferred:			
Federal	9,385	21,301	28,607
State	366	540	3,041
	9,751	21,841	31,648
Total income tax expense	$44,497	$24,612	$30,237

Deferred income tax expense (benefit) consists of the following significant components (thousands of dollars):

Year Ended December 31,	2006	2005	2004
Deferred federal and state:			
Property-related items	$ 28,372	$ (3,143)	$ (3,165)
Purchased gas cost adjustments	(22,188)	28,094	34,923
Employee benefits	(3,223)	2,232	240
Injuries and damages reserves	4,543	(4,072)	190
All other deferred	3,115	(402)	328
Total deferred federal and state	10,619	22,709	32,516
Deferred ITC, net	(868)	(868)	(868)
Total deferred income tax expense	$ 9,751	$21,841	$31,648

The consolidated effective income tax rate for the period ended December 31, 2006 and the two prior periods differ from the federal statutory income tax rate. The sources of these differences and the effect of each are summarized as follows:

Year Ended December 31,	2006	2005	2004
Federal statutory income tax rate	35.0%	35.0%	35.0%
Net state taxes	2.5	2.7	2.8
Property-related items	0.6	1.1	0.8
Effect of closed tax years and resolved issues	(1.3)	—	(1.8)
Tax credits	(0.7)	(1.3)	(1.0)
Corporate owned life insurance	(0.9)	(1.6)	(0.7)
All other differences	(0.5)	0.1	(0.3)
Consolidated effective income tax rate	34.7%	36.0%	34.8%

Note 11 Income Taxes (Continued)

Deferred tax assets and liabilities consist of the following (thousands of dollars):

December 31,	2006	2005
Deferred tax assets:		
Deferred income taxes for future amortization of ITC	$ 6,427	$ 6,964
Employee benefits	36,542	50,468
Alternative minimum tax	36,820	28,903
Net operating losses & credits	—	37,976
Other	4,549	10,510
Valuation allowance	—	—
	84,338	134,821
Deferred tax liabilities:		
Property-related items, including accelerated depreciation	330,308	337,234
Regulatory balancing accounts	46,207	68,395
Property-related items previously flowed through	8,272	9,411
Unamortized ITC	10,330	11,198
Debt-related costs	5,681	6,292
Other	7,504	5,196
	408,302	437,726
Net deferred tax liabilities	$323,964	$302,905
Current	$ 15,471	$ 68,166
Noncurrent	308,493	234,739
Net deferred tax liabilities	$323,964	$302,905

Note 12 Segment Information

Company operating segments are determined based on the nature of their activities. The natural gas operations segment is engaged in the business of purchasing, transporting, and distributing natural gas. Revenues are generated from the sale and transportation of natural gas. The construction services segment is engaged in the business of providing utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

The accounting policies of the reported segments are the same as those described within **Note 1—Summary of Significant Accounting Policies**. NPL accounts for the services provided to Southwest at contractual (market) prices. At December 31, 2006 and 2005, accounts receivable for these services totaled $9.2 million and $8.2 million, respectively, which were not eliminated during consolidation.

The financial information pertaining to the natural gas operations and construction services segments for each of the three years in the period ended December 31, 2006 is as follows (thousands of dollars):

2006	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,727,394	$216,753		$1,944,147
Intersegment sales	—	80,611		80,611
Total	$1,727,394	$297,364		$2,024,758
Interest expense	$ 93,291	$ 1,686		$ 94,977
Depreciation and amortization	$ 146,654	$ 22,310		$ 168,964
Income tax expense	$ 36,240	$ 8,257		$ 44,497
Segment income	$ 71,473	$ 12,387		$ 83,860
Segment assets	$3,352,074	$136,654	$(3,763)	$3,484,965
Capital expenditures	$ 305,914	$ 39,411		$ 345,325

2005	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,455,257	$187,249		$1,642,506
Intersegment sales	—	71,777		71,777
Total	$1,455,257	$259,026		$1,714,283
Interest expense	$ 89,318	$ 1,009		$ 90,327
Depreciation and amortization	$ 137,981	$ 18,272		$ 156,253
Income tax expense	$ 17,767	$ 6,845		$ 24,612
Segment income	$ 33,670	$ 10,153		$ 43,823
Segment assets	$3,103,804	$128,181	$(3,559)	$3,228,426
Capital expenditures	$ 258,547	$ 35,822		$ 294,369

2004	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,262,052	$153,392		$1,415,444
Intersegment sales	—	61,616		61,616
Total	$1,262,052	$215,008		$1,477,060
Interest expense	$ 85,861	$ 645		$ 86,506
Depreciation and amortization	$ 130,515	$ 15,503		$ 146,018
Income tax expense	$ 24,698	$ 5,539		$ 30,237
Segment income	$ 48,354	$ 8,421		$ 56,775
Segment assets	$2,843,199	$ 99,120	$(4,203)	$2,938,116
Capital expenditures	$ 274,748	$ 27,940		$ 302,688

(a) Construction services segment assets include deferred tax assets of $3 million and income taxes payable of $758,000 in 2006, which were netted against gas operations segment deferred tax liabilities and income taxes receivable, net during consolidation and deferred tax assets of $3.6 million and $4.2 million in 2005 and 2004, respectively, which were netted against gas operations segment deferred tax liabilities during consolidation.

Note 13 Quarterly Financial Data (Unaudited)

(Thousands of dollars, except per share amounts)	Quarter Ended March 31	June 30	September 30	December 31
2006				
Operating revenues	$676,941	$430,902	$351,800	$565,115
Operating income (loss)	89,325	25,236	3,197	91,424
Net income (loss)	44,180	3,709	(10,736)	46,707
Basic earnings (loss) per common share*	1.12	0.09	(0.26)	1.12
Diluted earnings (loss) per common share*	1.11	0.09	(0.26)	1.11
2005				
Operating revenues	$542,880	$361,130	$313,278	$496,995
Operating income (loss)	72,849	14,935	(5,459)	68,323
Net income (loss)	32,829	(2,817)	(16,444)	30,255
Basic earnings (loss) per common share*	0.88	(0.07)	(0.43)	0.77
Diluted earnings (loss) per common share*	0.88	(0.07)	(0.43)	0.76
2004				
Operating revenues	$473,400	$278,697	$264,467	$460,496
Operating income (loss)	85,802	5,954	(9,017)	87,028
Net income (loss)	41,044	(8,362)	(16,353)	40,446
Basic earnings (loss) per common share*	1.19	(0.24)	(0.46)	1.12
Diluted earnings (loss) per common share*	1.18	(0.24)	(0.46)	1.11

* The sum of quarterly earnings (loss) per average common share may not equal the annual earnings (loss) per share due to the ongoing change in the weighted-average number of common shares outstanding.

The demand for natural gas is seasonal, and it is the opinion of management that comparisons of earnings for the interim periods do not reliably reflect overall trends and changes in the operations of the Company. Also, the timing of general rate relief can have a significant impact on earnings for interim periods. See Management's Discussion and Analysis for additional discussion of operating results.

Management's Report on Internal Control Over Financial Reporting

Company management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined by Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Company management, including the principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of internal control over financial reporting based on the *"Internal Control–Integrated Framework"* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based upon the Company's evaluation under such framework, Company management concluded that the internal control over financial reporting was effective as of December 31, 2006. Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

February 28, 2007

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Southwest Gas Corporation

We have completed integrated audits of Southwest Gas Corporation's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of cash flows and of stockholders' equity and comprehensive income present fairly, in all material respects, the financial position of Southwest Gas Corporation and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 and Note 9 to the consolidated financial statements, the Company changed the manner in which it accounts for share-based compensation and defined benefit postretirement plans in 2006.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PRICEWATERHOUSECOOPERS LLP

Los Angeles, California
February 28, 2007

Shareholder Information

Stock Listing Information
Southwest Gas Corporation's common stock is listed on the New York Stock Exchange under the ticker symbol "SWX." Quotes may be obtained in daily financial newspapers or some local newspapers where it is listed under "SoWestGas."

Annual Meeting
The Annual Meeting of Shareholders will be held on May 3, 2007 at 10:00 a.m. at the Palms Casino Resort, 4321 West Flamingo Road, Las Vegas, Nevada.

Dividend Reinvestment and Stock Purchase Plan
The Southwest Gas Corporation Dividend Reinvestment and Stock Purchase Plan (DRSPP) provides its shareholders, natural gas customers, employees and residents of Arizona, California and Nevada with a simple and convenient method of purchasing the Company's common stock and investing cash dividends in additional shares without payment of any brokerage commission.

The DRSPP features include:
Initial investments of $100, up to $100,000 annually
Automatic investing
No commissions on purchases
Safekeeping for common stock certificates

For more information contact:
Shareholder Services, Southwest Gas Corporation, P. O. Box 98511, Las Vegas, NV 89193-8511 or call (800) 331-1119.

Dividends
Dividends on common stock are declared quarterly by the Board of Directors. As a general rule, they are payable on the first day of March, June, September and December.

Investor Relations
Southwest Gas Corporation is committed to providing relevant and complete investment information to shareholders, individual investors and members of the investment community. Additional copies of the Company's 2006 Annual Report on Form 10-K, without exhibits, as filed with the Securities and Exchange Commission may be obtained upon request free of charge. Additional financial information may be obtained by contacting Kenneth J. Kenny, Investor Relations, Southwest Gas Corporation, P. O. Box 98510, Las Vegas, NV 89193-8510 or by calling (702) 876-7237.

Southwest Gas Corporation information is also available on the Internet at www.swgas.com. For non-financial information, please call (702) 876-7011.

Transfer Agent
Shareholder Services
Southwest Gas Corporation
P. O. Box 98511
Las Vegas, NV 89193-8511

Registrar
Southwest Gas Corporation
P. O. Box 98510
Las Vegas, NV 89193-8510

Auditors
PricewaterhouseCoopers LLP
350 S. Grand Avenue
Los Angeles, CA 90071

Board of Directors and Officers

Directors

George C. Biehl
Las Vegas, Nevada
Executive Vice President/Chief Financial Officer and Corporate Secretary
Southwest Gas Corporation

Thomas E. Chestnut
Tucson, Arizona
Owner, President and Chief Executive Officer
Chestnut Construction Company

Stephen C. Comer
Las Vegas, Nevada
Retired Partner
Deloitte & Touche

Richard M. Gardner
Scottsdale, Arizona
Retired Partner
Deloitte & Touche

LeRoy C. Hanneman, Jr.
Phoenix, Arizona
Chairman and Chief Executive Officer
Element Homes, LLC
Chairman of the Board of Directors
Southwest Gas Corporation

James J. Kropid
Las Vegas, Nevada
President
James J. Kropid Investments

Michael O. Maffie
Las Vegas, Nevada
Retired Chief Executive Officer
Southwest Gas Corporation

Anne L. Mariucci
Phoenix, Arizona
Private Investor

Michael J. Melarkey
Reno, Nevada
Partner
Avansino, Melarkey, Knobel & Mulligan

Jeffrey W. Shaw
Las Vegas, Nevada
Chief Executive Officer
Southwest Gas Corporation

Carolyn M. Sparks
Las Vegas, Nevada
President
International Insurance Services, Ltd.

Terrence L. Wright
Las Vegas, Nevada
Owner/Chairman of the Board
Nevada Title Company

Officers

Jeffrey W. Shaw
Chief Executive Officer

James P. Kane
President

George C. Biehl
Executive Vice President/Chief Financial Officer and Corporate Secretary

John P. Hester
Senior Vice President/Regulatory Affairs and Energy Resources

Edward A. Janov
Senior Vice President/Finance

Christina A. Palacios
Senior Vice President/
Central Arizona Division

Thomas R. Sheets
Senior Vice President/Legal Affairs and General Counsel

Dudley J. Sondeno
Senior Vice President/Chief Knowledge and Technology Officer

Roy R. Centrella
Vice President/Controller/Chief Accounting Officer

Garold L. Clark
Vice President/
Southern Arizona Division

Fred W. Cover
Vice President/Human Resources

Luis F. Frisby
Vice President/
Southern California Division

Kenneth J. Kenny
Vice President/Treasurer

Roger C. Montgomery
Vice President/Pricing

William N. Moody
Vice President/Gas Resources

Dennis Redmond
Vice President/
Northern Nevada Division

Anita M. Romero
Vice President/
Southern Nevada Division

Robert J. Weaver
Vice President/Information Services

James F. Wunderlin
Vice President/Engineering

Southwest Gas Corporation
5241 Spring Mountain Road
Las Vegas, Nevada 89150

Volume I

Current Tariff Sheets

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SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

Ninety-Third Revised A.C.C. Sheet No. 11
Canceling Ninety-Second Revised A.C.C. Sheet No. 11

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate
G-5 – Single-Family Residential Gas Service				
Basic Service Charge per Month	$ 9.70			$ 9.70
Commodity Charge per Therm:				
Summer (May–October):				
First 15 Therms	$ .54200	$ .01263	$ .95372	$ 1.50835
Over 15 Therms	.50100	.01263	.95372	1.46735
Winter (November–April):				
First 35 Therms	$ .54200	$ .01263	$ .95372	$ 1.50835
Over 35 Therms	.50100	.01263	.95372	1.46735
G-6 – Multi-Family Residential Gas Service				
Basic Service Charge per Month	$ 8.70			$ 8.70
Commodity Charge per Therm:				
Summer (May–October):				
First 7 Therms	$ .54200	$ .01263	$ .95372	$ 1.50835
Over 7 Therms	.50100	.01263	.95372	1.46735
Winter (November–April):				
First 18 Therms	$ .54200	$ .01263	$ .95372	$ 1.50835
Over 18 Therms	.50100	.01263	.95372	1.46735
G-10 – Single-Family Low Income Residential Gas Service				
Basic Service Charge per Month	$ 7.00			$ 7.00
Commodity Charge per Therm:				
Summer (May–October):				
First 15 Therms	$ .54200	$ .00322	$ .84372	$ 1.38894
Over 15 Therms	.50100	.00322	.84372	1.34794
Winter (November–April):				
First 35 Therms	$ .26421	$ .00322	$ .84372	$ 1.11115
Next 115 Therms	.23141	.00322	.84372	1.07835
Over 150 Therms	.50100	.00322	.84372	1.34794
G-11 – Multi-Family Low Income Residential Gas Service				
Basic Service Charge per Month	$ 7.00			$ 7.00
Commodity Charge per Therm:				
Summer (May–October):				
First 7 Therms	$ .54200	$ .00322	$ .84372	$ 1.38894
Over 7 Therms	.50100	.00322	.84372	1.34794
Winter (November–April):				
First 18 Therms	$ .26421	$ .00322	$ .84372	$ 1.11115
Next 132 Therms	.23141	.00322	.84372	1.07835
Over 150 Therms	.50100	.00322	.84372	1.34794
G-15 – Special Residential Gas Service for Air Conditioning				
Basic Service Charge per Month	$ 9.70			$ 9.70
Commodity Charge per Therm:				
Summer (May–October):				
First 15 Therms	$ .54200	$ .00322	$ .95372	$ 1.49894
Over 15 Therms	.28200	.00322	.95372	1.23894
Winter (November–April):				
First 35 Therms	$ .54200	$ .00322	$ .95372	$ 1.49894
Over 35 Therms	.50100	.00322	.95372	1.45794

Issued On July 24, 2007
Docket No. G-00000C-98-0568

Issued by
John P. Hester
Senior Vice President

Effective July 31, 2007
Decision No. 62994

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

Ninety-Sixth Revised A.C.C. Sheet No. 12
Canceling Ninety-Fifth Revised A.C.C. Sheet No. 12

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/
(Continued)

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate
G-20 – Master-Metered Mobile Home Park Gas Service				
Basic Service Charge per Month	$ 60.00			$ 60.00
Commodity Charge per Therm:				
All Usage	$ .38400	$ .01263	$ .95372	$ 1.35035
G-25 – General Gas Service				
Basic Service Charge per Month:				
Small	$ 25.00			$ 25.00
Medium	33.00			33.00
Large	145.00			145.00
Transportation Eligible	720.00			720.00
Commodity Charge per Therm:				
Small, All Usage	$ .56217	$ .00322	$ .95372	$ 1.51911
Medium, All Usage	.39349	.00322	.95372	1.35043
Large, All Usage	.27211	.00322	.95372	1.22905
Transportation Eligible	.08953	.00322	.95372	1.04647
Demand Charge per Month– Transportation Eligible:				
Demand Charge 5/	$ .06234			$ 0.06234
G-30 – Optional Gas Service				
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 27.			
Commodity Charge per Therm:				
All Usage	As specified on A.C.C. Sheet No. 28.			
G-40 – Air-Conditioning Gas Service				
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 32.			
Commodity Charge per Therm:				
All Usage	$ .09900	$ .00322	$ .95372	$ 1.05594
G-45 – Street Lighting Gas Service				
Commodity Charge per Therm of Rated Capacity:				
All Usage	$ .54600	$ .00322	$ .95372	$ 1.50294
G-55 – Gas Service for Compression on Customer's Premises 6/				
Basic Service Charge per Month:				
Small	$ 25.00			$ 25.00
Large	190.00			190.00
Residential	9.70			9.70
Commodity Charge per Therm:				
All Usage	$ .17000	$ .00322	$ .95372	$ 1.12694
G-60 – Electric Generation Gas Service				
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 40.			
Commodity Charge per Therm:				
All Usage	$ .11400	$ .00322	$ .95372	$ 1.07094
G-75 – Small Essential Agricultural User Gas Service				
Basic Service Charge per Month	$ 90.00			$ 90.00
Commodity Charge per Therm:				
All Usage	$ .22300	$ .00322	$ .95372	$ 1.17994

Issued On July 24, 2007
Docket No. G-00000C-98-0568

Issued by
John P. Hester
Senior Vice President

Effective July 31, 2007
Decision No. 62994

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

Thirtieth Revised A.C.C. Sheet No. 13
Canceling Twenty-Ninth Revised A.C.C. Sheet No. 13

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/
(Continued)

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate
G-80 – Natural Gas Engine 7/ Gas Service				
Basic Service Charge per Month:				
Off-Peak Season (October–March)	$ 0.00			$ 0.00
Peak Season (April–September)	$ 95.00			$ 95.00
Commodity Charge per Therm:				
All Usage	$ .17700	$ .00322	$ .73057	$ 0.91079

1/ All charges are subject to adjustment for any applicable taxes or governmental impositions.

2/ Customers taking transportation service will pay the Basic Service Charge, the Commodity Charge per Therm less the Monthly Gas Cost, and Demand Charge, if applicable, of the Currently Effective Tariff Rate for each meter included in the transportation service agreement, plus an amount of $.00806 per therm for distribution shrinkage as defined in Rule No. 1 of this Arizona Gas Tariff. The shrinkage charge shall be updated annually effective May 1. For customers converting from sales service, an additional amount equal to the currently effective Gas Cost Balancing Account Adjustment will be assessed for a period of 12 months.

3/ (a) For Schedule Nos. G-5, G-6 and G-20, the Rate Adjustment includes $.00941 per therm to recover LIRA program costs. This charge shall be updated annually effective May 1.

(b) For all rate schedules except for Schedule Nos. G-30 and B-1, the Rate Adjustment includes $0.00176 per therm to fund DSM Program costs. This charge shall be updated annually effective the first billing cycle in April.

(c) For all rate schedules, except for Schedule Nos. G-30 and B-1, the Rate Adjustment includes $.00074 per therm for the Gas Research Fund. This charge shall be updated annually effective May 1.

(d) For all rate schedules, the Rate Adjustment includes $.00072 per therm for the Department of Transportation (DOT) Safety Program costs. This charge shall be updated annually effective May 1 and will expire on February 28, 2009.

4/ Except for Schedule Nos. G-10, G-11, G-30 and G-80, the Monthly Gas Cost includes $.11000 per therm to reduce the unrecovered balance in the Gas Cost Balancing Account.

5/ The total monthly demand charge is equal to the unit rate shown multiplied by the customer's billing determinant.

6/ The charges for Schedule No. G-55 are subject to adjustment for applicable state and federal taxes on fuel used in motor vehicles.

7/ The gas cost for this rate schedule shall be updated seasonally, April 1 and October 1 of each year.

Issued On April 23, 2007
Docket No. G-01551A-01-0060/ G-01551A-04-0876

Issued by
John P. Hester
Senior Vice President

Effective May 1, 2007
Decision No. 63598/68649

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION

I. TITLE ASSIGNMENT SERVICE

A. APPLICABILITY

This Title Assignment Service provision shall apply only to natural gas transportation customers with Title Assignment Operating Agreements executed with the Utility prior to April 1, 1993, in conjunction with an executed service agreement pursuant to Schedule No. T-1, Transportation of Customer-Secured Natural Gas. It specifies the procedures to be utilized by the Utility in providing upstream pipeline firm transportation service to eligible Title Assignment transportation customers and recovering associated costs from such customers. This Title Assignment Service provision is closed to new customers.

B. CHARACTER OF SERVICE

1. The Utility will provide eligible transportation customers access to the Utility's upstream pipeline firm transportation capacity and service subject to the provisions and limitations set forth in this provision, Schedule No. T-1 and Rule No. 7 of this Arizona Gas Tariff. Upstream pipeline firm transportation service under this provision is available on a recallable basis only.

2. Title Assignment Service shall be recalled by the Utility only to protect service to Priority 1 and 2 customers pursuant to the provisions of Schedule No. T-1 and Rule No. 7 of this Arizona Gas Tariff, and in force majeure conditions which may occur from time to time on the upstream pipeline system.

C. TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

D. TERM

1. The minimum term for transportation customers electing service under this provision is 24 months.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

I. TITLE ASSIGNMENT SERVICE (Continued)

D. TERM *(Continued)*

2. The minimum requirement for notice of termination of Title Assignment Service shall be by written notice from the customer at least 24 months prior to the start of any calendar month.

E. RATES FOR TITLE ASSIGNMENT SERVICE

1. Title Assignment customers shall elect a Daily Contract Demand Quantity (DCDQ), not to exceed the maximum daily quantity specified in their respective transportation service agreement.

2. Title Assignment customers shall pay the Utility monthly the sum of the following charges for service under this provision:

a. Reservation Charge: A monthly demand charge equal to the customer's DCDQ multiplied by the currently effective interstate pipeline(s) reservation charges for firm transportation, including applicable surcharges.

b. Volume Charge: A rate per therm for all quantities transported by the Utility on behalf of the customer on the upstream pipeline(s) during the month, which includes the currently effective usage charges for firm upstream pipeline transportation service plus any applicable surcharges.

3. The customer's maximum daily entitlement for Title Assignment Service pursuant to this provision shall be equal to the DCDQ elected by the customer.

4. In the event that Title Assignment Service is recalled by the Utility, the customer shall receive a Reservation Charge credit to their regular monthly bill based on the pro rata portion of the capacity recalled to such customer's total DCDQ.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

I. TITLE ASSIGNMENT SERVICE (Continued)

F. CHANGES IN RATES

The Utility will revise rates for Title Assignment Service as necessary to reflect Federal Energy Regulatory Commission (FERC) authorized changes in upstream pipeline transportation rates and billing determinants. Any refunds received from upstream pipelines will be allocated on the basis of the customer's Title Assignment volumes billed during the refund period.

G. ACCOUNTING FOR TITLE ASSIGNMENT REVENUES

All revenues received by the Utility in providing service under this provision shall be credited to Account No. 191, Unrecovered Purchased Gas Costs.

II. CAPACITY RELEASE SERVICE

A. APPLICABILITY

The purpose of this Capacity Release Service provision is to govern the release of interstate pipeline capacity in excess of the requirements of the Utility's Title Assignment and Priority 1 and 2 customers. The Utility shall identify and offer for release any available interstate pipeline capacity reserved to serve such customers for the purpose of minimizing the overall cost of upstream interstate pipeline capacity.

1. Capacity released pursuant to this provision shall be made available on a non-discriminatory basis. As a condition precedent to obtaining released capacity under this provision, on-system transportation customers of the Utility must execute a transportation service agreement pursuant to Schedule No. T-1, Transportation of Customer-Secured Gas, and must comply with all applicable terms and conditions contained in this Arizona Gas Tariff.

2. In order to acquire any of the Utility's firm interstate pipeline capacity released under this provision, acquiring shippers must demonstrate to the Utility that they have met the creditworthiness and other requirements of the applicable interstate pipeline(s) and such other credit standards that the Utility may deem appropriate.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE (Continued)

A. APPLICABILITY (Continued)

3. Capacity release pursuant to this provision is subject to all FERC rules and regulations and the specific terms and conditions governing capacity release on the interstate pipeline system(s).

B. RATES AND BIDDING PROCEDURES

1. The Utility shall identify excess interstate pipeline capacity available for release on a monthly basis and from time-to-time more frequently thereafter as necessary to pre-arrange the release of any remaining available capacity. The Utility reserves the right to not release capacity if market conditions so warrant, or if the Utility is seeking to reduce its billing determinant or contract demand on the upstream interstate pipeline(s).

2. The Utility shall determine the minimum acceptable bid price for released capacity. The minimum acceptable bid represents the floor price for the Utility's consideration of any particular bid. The minimum acceptable bid shall be the greater of a., b. or c. below:

a. The Utility's best determination of the current market value for such released capacity, based on a comparison of the price of completed bids of a like nature and term posted to the applicable interstate pipeline's electronic bulletin board.

b. When an interruptible transportation crediting mechanism exists on the upstream interstate pipeline and, therefore, interruptible transportation credits could be earned if such capacity was not released, a bid price equal to the current market rate for interruptible transportation service.

c. If the Utility is able to determine the cost allocation methodology that will be utilized by the upstream pipeline to develop future interstate pipeline charges, the Utility reserves the right to adjust the minimum acceptable bid price to protect the interests of its Priority 1 and Priority 2 gas sales customers.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE *(Continued)*

B. RATES AND BIDDING PROCEDURES *(Continued)*

3. The release of interstate pipeline capacity for a term of more than one month shall be accomplished according to the following procedures.

a. The Utility shall offer to prearrange the release of interstate pipeline capacity at rates greater than or equal to the minimum acceptable bid for the release period being considered. All bids below the minimum acceptable bid floor shall be rejected. Bids for prearranged capacity release shall be accepted based on the highest price offered. If more than one bid is received at the same price, bids shall be accepted based on the longest term offered. Bids of an identical price and term shall be accepted on a pro rata basis up to the amount of capacity available for release.

b. Successful prearranged bids shall then be submitted to the applicable interstate pipeline for posting on its electronic bulletin board.

(1) Unless the bid price is equal to the interstate pipeline's full "as-billed" rate, other eligible parties will be allowed by the pipeline to submit bids higher than that of the prearranged shipper. If prearranged bids are outbid by another party, the prearranged bidder shall have the right of first refusal to match the higher bid and thereby acquire the released capacity.

(2) If the higher bid is not matched, the award shall be made to the higher bidder(s) pursuant to the established bid evaluation and (or) "tie breaker" procedures of the interstate pipeline.

c. Any remaining capacity available for release shall then be posted for open bidding to the applicable interstate pipeline electronic bulletin board at the minimum acceptable bid price determined according to Section B.2 above.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE *(Continued)*

B. RATES AND BIDDING PROCEDURES *(Continued)*

4. The Utility reserves the right to prearrange from time-to-time the release of excess capacity for a term of one month or less. Capacity released for a term of one month or less shall be subject to all FERC and interstate pipeline rules and regulations governing such releases, and shall be at rates greater than or equal to the minimum acceptable bid.

C. BILLING

Billing for released capacity shall be made by the interstate pipeline directly to acquiring customers and shippers. Shippers acquiring released capacity shall be billed by the pipeline at the accepted bid price plus applicable usage charges and surcharges. The Utility will receive credit from the interstate pipeline for the payment of reservation charges and reservation surcharges due from the acquiring shipper.

D. RECALL OF RELEASED CAPACITY

Capacity released by the Utility shall be recallable over the term of the release under the following conditions:

1. Force majeure situations occurring on the upstream pipeline system; or

2. To protect service to Priority 1 and Priority 2 customers; or

3. When the Utility's core demand for upstream pipeline capacity is greater than the Utility's current billing determinant or contract demand on the applicable interstate pipeline(s); or

4. If the acquiring shipper fails to remit payment for services rendered to the interstate pipeline when such amounts are due.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE (Continued)

E. ACCOUNTING FOR CAPACITY RELEASE CREDITS

All capacity release credits received by the Utility shall be credited to Account No. 191, Unrecovered Purchased Gas Costs.

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7

Original A.C.C. Sheet No. 98–103
Canceling _____ A.C.C. Sheet No. _____

HELD FOR FUTURE USE

Issued On August 29, 1997
Docket No. U-1551-96-596

Issued by
Edward S. Zub
Senior Vice President

Effective September 1, 1997
Decision No. 60352

Volume I

Proposed Tariff Sheets

SOUTHWEST GAS CORPORATION
PROPOSED ARIZONA TARIFF REVISIONS

DESCRIPTION	PROPOSED CHANGE
Table of Contents	Reflect proposed changes to Special Supplementary Tariff Provisions.
Statement of Rates	Change rates to reflect Southwest's proposed rate design changes and revenue requirement. Include footnote on Sheet No. 13 describing rate adjustments for Revenue Decoupling Adjustment Provision.
Special Supplementary Tariff	Eliminate Title Assignment Service. Implement new tariff provisions for the Company's proposed Weather Normalization Adjustment Provision and Revenue Decoupling Adjustment Provision.

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SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

PROPOSED TARIFF SHEET

A.C.C. Sheet No. 11
Canceling _____ A.C.C. Sheet No. _____

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES [1/ 2/]

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate	
G-5 – Single-Family Residential Gas Service					
Basic Service Charge per Month	$ 12.80			$ 12.80	I
Commodity Charge per Therm:					
Summer (May–October):					
First 15 Therms	$ .88069	$ .01263	$ .59733	$ 1.49065	I
Over 15 Therms	.00000	.01263	1.47802	1.49065	I
Winter (November–April):					
First 35 Therms	$ .88069	$ .01263	$ .59733	$ 1.49065	I
Over 35 Therms	.00000	.01263	1.47802	1.49065	I
G-6 – Multi-Family Residential Gas Service					
Basic Service Charge per Month	$ 8.70			$ 8.70	I
Commodity Charge per Therm:					
Summer (May–October):					
First 7 Therms	$ .88069	$ .01263	$ .59733	$ 1.49065	I
Over 7 Therms	.00000	.01263	1.47802	1.49065	I
Winter (November–April):					
First 18 Therms	$ .88069	$ .01263	$ .59733	$ 1.49065	I
Over 18 Therms	.00000	.01263	1.47802	1.49065	I
G-10 – Single-Family Low Income Residential Gas Service					
Basic Service Charge per Month	$ 7.50			$ 7.50	I
Commodity Charge per Therm:					
Summer (May–October):					
First 15 Therms	$ .88069	$ .00322	$ .48733	$ 1.37124	I
Over 15 Therms	.00000	.00322	1.36802	1.37124	I
Winter (November–April):					
First 35 Therms	$ .60644	$ .00322	$ .48733	$ 1.09699	I
Next 115 Therms	(.27425)	.00322	1.36802	1.09699	I
Over 150 Therms	.00000	.00322	1.36802	1.37124	I
G-11 – Multi-Family Low Income Residential Gas Service					
Basic Service Charge per Month	$ 7.50			$ 7.50	I
Commodity Charge per Therm:					
Summer (May–October):					
First 7 Therms	$ .88069	$ .00322	$ .48733	$ 1.37124	I
Over 7 Therms	.00000	.00322	1.36802	1.37124	I
Winter (November–April):					
First 18 Therms	$ .60644	$ .00322	$ .48733	$ 1.09699	I
Next 132 Therms	(.27425)	.00322	1.36802	1.09699	I
Over 150 Therms	.00000	.00322	1.36802	1.37124	I
G-15 – Special Residential Gas Service for Air Conditioning					
Basic Service Charge per Month	$ 12.80			$ 12.80	I
Commodity Charge per Therm:					
Summer (May–October):					
First 15 Therms	$ .88069	$ .00322	$ .59733	$ 1.48124	I
Over 15 Therms	.00000	.00322	1.47802	1.48124	I
Winter (November–April):					
First 35 Therms	$ .88069	$ .00322	$ .59733	$ 1.48124	I
Over 35 Therms	.00000	.00322	1.47802	1.48124	I

Issued On August 31, 2007
Docket No. _____

Issued by
John P. Hester
Senior Vice President

Effective _____
Decision No. _____

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

PROPOSED TARIFF SHEET

A.C.C. Sheet No. 12
Canceling _____ A.C.C. Sheet No. _____

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/
(Continued)

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate	
G-20 – Master-Metered Mobile Home Park Gas Service					
Basic Service Charge per Month	$ 60.00			$ 60.00	
Commodity Charge per Therm:					
All Usage	$ .41531	$ .01263	$ .92426	$ 1.35220	I
G-25 – General Gas Service					
Basic Service Charge per Month:					
Small	$ 25.00			$ 25.00	I
Medium	43.50			43.50	I
Large	160.00			160.00	I
Transportation Eligible	950.00			950.00	I
Commodity Charge per Therm:					
Small, All Usage	$ .75852	$ .00322	$ .92426	$ 1.68600	I
Medium, All Usage	.40988	.00322	.92426	1.33736	I
Large, All Usage	.28843	.00322	.92426	1.21591	I
Transportation Eligible	.09902	.00322	.92426	1.02650	I
Demand Charge per Month– Transportation Eligible:					
Demand Charge 5/	$ .064142			$ 0.064142	I
G-30 – Optional Gas Service					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 27.				
Commodity Charge per Therm:					
All Usage	As specified on A.C.C. Sheet No. 28.				
G-40 – Air-Conditioning Gas Service					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 32.				
Commodity Charge per Therm:					
All Usage	$ .09513	$ .00322	$ .92426	$ 1.02261	I
G-45 – Street Lighting Gas Service					
Commodity Charge per Therm of Rated Capacity:					
All Usage	$ .69899	$ .00322	$ .92426	$ 1.62647	I
G-55 – Gas Service for Compression on Customer's Premises 6/					
Basic Service Charge per Month:					
Small	$ 25.00			$ 25.00	I
Large	250.00			250.00	I
Residential	12.80			12.80	I
Commodity Charge per Therm:					
All Usage	$ .17535	$ .00322	$ .92426	$ 1.10283	I
G-60 – Electric Generation Gas Service					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 40.				
Commodity Charge per Therm:					
All Usage	$ .12363	$ .00322	$ .92426	$ 1.05111	I
G-75 – Small Essential Agricultural User Gas Service					
Basic Service Charge per Month	$120.00			$120.00	I
Commodity Charge per Therm:					
All Usage	$ .23335	$ .00322	$ .92426	$ 1.16083	I

Issued On August 31, 2007
Docket No. _____

Issued by
John P. Hester
Senior Vice President

Effective _____
Decision No. _____

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/
(Continued)

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate	
G-80 – Natural Gas Engine 7/ Gas Service					
Basic Service Charge per Month:					
Off-Peak Season (October–March)	$ 0.00			$ 0.00	
Peak Season (April–September)	$125.00			$125.00	I
Commodity Charge per Therm:					
All Usage	$ .18746	$ .00322	$ .73057	$ 0.92125	I

1/ All charges are subject to adjustment for any applicable taxes or governmental impositions.

2/ Customers taking transportation service will pay the Basic Service Charge, the Commodity Charge per Therm less the Monthly Gas Cost, and Demand Charge, if applicable, of the Currently Effective Tariff Rate for each meter included in the transportation service agreement, plus an amount of $.00806 per therm for distribution shrinkage as defined in Rule No. 1 of this Arizona Gas Tariff. The shrinkage charge shall be updated annually effective May 1. For customers converting from sales service, an additional amount equal to the currently effective Gas Cost Balancing Account Adjustment will be assessed for a period of 12 months.

3/ (a) For Schedule Nos. G-5, G-6 and G-20, the Rate Adjustment includes $.00941 per therm to recover LIRA program costs. This charge shall be updated annually effective May 1.

(b) For all rate schedules except for Schedule Nos. G-30 and B-1, the Rate Adjustment includes $0.00176 per therm to fund DSM Program costs. This charge shall be updated annually effective the first billing cycle in April.

(c) For all rate schedules, except for Schedule Nos. G-30 and B-1, the Rate Adjustment includes $.00074 per therm for the Gas Research Fund. This charge shall be updated annually effective May 1.

(d) For all rate schedules, the Rate Adjustment includes $.00072 per therm for the Department of Transportation (DOT) Safety Program costs. This charge shall be updated annually effective May 1 and will expire on February 28, 2009.

(e) For rate Schedule Nos. G-5, G-6, G-10, G-11, G-25(S), G-25(M), and G-25(L), the Rate Adjustment includes an amount to recover/return RDAP under- or over-collections. The Rate Adjustment includes the following amounts: G-5 $.00000, G-6 $.00000, G-10 $.00000, G-11 $.00000, G-25(S) $.00000, G-25(M) $.00000, and G-25(L) $.00000. N N

4/ Except for Schedule Nos. G-10, G-11, G-30 and G-80, the Monthly Gas Cost includes $.11000 per therm to reduce the unrecovered balance in the Gas Cost Balancing Account.

5/ The total monthly demand charge is equal to the unit rate shown multiplied by the customer's billing determinant.

6/ The charges for Schedule No. G-55 are subject to adjustment for applicable state and federal taxes on fuel used in motor vehicles.

7/ The gas cost for this rate schedule shall be updated seasonally, April 1 and October 1 of each year.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY RELEASE SERVICE PROVISION

T

D/L

A. APPLICABILITY

The purpose of this Capacity Release Service provision is to govern the release of interstate pipeline capacity in excess of the requirements of the Utility's Title Assignment and Priority 1 and 2 customers. The Utility shall identify and offer for release any available interstate pipeline capacity reserved to serve such customers for the purpose of minimizing the overall cost of upstream interstate pipeline capacity.

1. Capacity released pursuant to this provision shall be made available on a non-discriminatory basis. As a condition precedent to obtaining released capacity under this provision, on-system transportation customers of the Utility must execute a transportation service agreement pursuant to Schedule No. T-1, Transportation of Customer-Secured Gas, and must comply with all applicable terms and conditions contained in this Arizona Gas Tariff.

2. In order to acquire any of the Utility's firm interstate pipeline capacity released under this provision, acquiring shippers must demonstrate to the Utility that they have met the creditworthiness and other requirements of the applicable interstate pipeline(s) and such other credit standards that the Utility may deem appropriate.

3. Capacity release pursuant to this provision is subject to all FERC rules and regulations and the specific terms and conditions governing capacity release on the interstate pipeline system(s).

B. RATES AND BIDDING PROCEDURES

1. The Utility shall identify excess interstate pipeline capacity available for release on a monthly basis and from time-to-time more frequently thereafter as necessary to pre-arrange the release of any remaining available capacity. The Utility reserves the right to not release capacity if market conditions so warrant, or if the Utility is seeking to reduce its billing determinant or contract demand on the upstream interstate pipeline(s).

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SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY RELEASE SERVICE PROVISION
(Continued)

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B. RATES AND BIDDING PROCEDURES *(Continued)*

D/L

2. The Utility shall determine the minimum acceptable bid price for released capacity. The minimum acceptable bid represents the floor price for the Utility's consideration of any particular bid. The minimum acceptable bid shall be the greater of a., b., or c. below:

   a. The Utility's best determination of the current market value for such released capacity, based on a comparison of the price of completed bids of a like nature and term posted to the applicable interstate pipeline's electronic bulletin board.

   b. When an interruptible transportation crediting mechanism exists on the upstream interstate pipeline and, therefore, interruptible transportation credits could be earned if such capacity was not released, a bid price equal to the current market rate for interruptible transportation service.

   c. If the Utility is able to determine the cost allocation methodology that will be utilized by the upstream pipeline to develop future interstate pipeline charges, the Utility reserves the right to adjust the minimum acceptable bid price to protect the interests of its Priority 1 and Priority 2 gas sales customers.

3. The release of interstate pipeline capacity for a term of more than one month shall be accomplished according to the following procedures.

   a. The Utility shall offer to prearrange the release of interstate pipeline capacity at rates greater than or equal to the minimum acceptable bid for the release period being considered. All bids below the minimum acceptable bid floor shall be rejected. Bids for prearranged capacity release shall be accepted based on the highest price offered. If more than one bid is received at the same price, bids shall be accepted based on the longest term offered. Bids of an identical price and term shall be accepted on a pro rata basis up to the amount of capacity available for release.

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SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY RELEASE SERVICE PROVISION T
(Continued)

B. RATES AND BIDDING PROCEDURES *(Continued)* D/L

b. Successful prearranged bids shall then be submitted to the applicable interstate pipeline for posting on its electronic bulletin board.

(1) Unless the bid price is equal to the interstate pipeline's full "as-billed" rate, other eligible parties will be allowed by the pipeline to submit bids higher than that of the prearranged shipper. If prearranged bids are outbid by another party, the prearranged bidder shall have the right of first refusal to match the higher bid and thereby acquire the released capacity.

(2) If the higher bid is not matched, the award shall be made to the higher bidder(s) pursuant to the established bid evaluation and (or) "tie breaker" procedures of the interstate pipeline.

c. Any remaining capacity available for release shall then be posted for open bidding to the applicable interstate pipeline electronic bulletin board at the minimum acceptable bid price determined according to Section B.2 above.

4. The Utility reserves the right to prearrange from time-to-time the release of excess capacity for a term of one month or less. Capacity released for a term of one month or less shall be subject to all FERC and interstate pipeline rules and regulations governing such releases, and shall be at rates greater than or equal to the minimum acceptable bid.

C. BILLING

Billing for released capacity shall be made by the interstate pipeline directly to acquiring customers and shippers. Shippers acquiring released capacity shall be billed by the pipeline at the accepted bid price plus applicable usage charges and surcharges. The Utility will receive credit from the interstate pipeline for the payment of reservation charges and reservation surcharges due from the acquiring shipper. L

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY RELEASE SERVICE PROVISION
(Continued)

T

D. RECALL OF RELEASED CAPACITY

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Capacity released by the Utility shall be recallable over the term of the release under the following conditions:

1. Force majeure situations occurring on the upstream pipeline system; or
2. To protect service to Priority 1 and Priority 2 customers; or
3. When the Utility's core demand for upstream pipeline capacity is greater than the Utility's current billing determinant or contract demand on the applicable interstate pipeline(s); or
4. If the acquiring shipper fails to remit payment for services rendered to the interstate pipeline when such amounts are due.

E. ACCOUNTING FOR CAPACITY RELEASE CREDITS

All capacity release credits received by the Utility shall be credited to Account No. 191, Unrecovered Purchased Gas Costs.

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SPECIAL SUPPLEMENTARY TARIFF
REVENUE DECOUPLING ADJUSTMENT PROVISION

APPLICABILITY

The Revenue Decoupling Adjustment Provision (RDAP) applies to residential Rate Schedule Nos. G-5, G-6, G-10 and G-11 and to General Service Schedule Nos. G-25(S), G-25(M) and G-25(L) included in this Arizona Gas Tariff. The RDAP specifies the accounting procedures and rate setting adjustments necessary to assure the Utility neither over-recovers, nor under-recovers, the margins-per-customer authorized in its most recent general rate case proceeding.

TEST PERIOD

The Test Period shall be the first full 12-month period following the implementation of the most recently authorized general rates, and each 12-month period thereafter.

RATE ADJUSTMENT

The Rate Adjustment applicable to each schedule subject to this provision shall be revised annually to reflect the difference between the margin-per-customer authorized in the utility's last general rate case and the margin billed pursuant to the Utility's Weather Normalization Adjustment Provision during the Test Period. The Rate Adjustment revisions will be accomplished by increasing or decreasing the Revenue Decoupling Adjustment Provision Balancing Account (RDAPBA) Adjustment. The RDAPBA Adjustment will be calculated by dividing the RDAPBA at the end of the Test Period by the volume of natural gas expected to be delivered to customers over the following 12-month period for each customer class included in the RDAP.

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SPECIAL SUPPLEMENTARY TARIFF
REVENUE DECOUPLING ADJUSTMENT PROVISION
(Continued)

REVENUE DECOUPLING ADJUSTMENT PROVISION BALANCING ACCOUNT

The Utility shall maintain accounting records that accumulate the difference between authorized and actual billed margin. Entries shall be recorded to the RDAPBA each month as follows:

1. A debit or credit entry equal to difference between authorized margin and actual billed margin for each rate schedule subject to this provision. Authorized margin is the product of the monthly margin-per-customer authorized in the Utility's last general rate case, as stated below and the actual number of customers during the month.

Average Margin per Customer per Month

	G-5	G-6	G-15	G-25(S)	G-25(M)	G-25(L)
January	$ 39.77	$ 22.07	$ 42.00	$ 73.41	$ 205.14	$ 895.49
February	39.25	21.94	41.90	67.29	192.91	859.48
March	37.52	21.47	40.47	53.70	174.57	824.22
April	31.36	19.99	35.57	40.39	140.00	694.07
May	23.38	14.11	24.08	36.09	120.32	593.59
June	21.32	13.82	23.36	32.11	107.38	527.83
July	20.33	13.62	23.47	31.26	100.66	486.63
August	19.98	13.52	22.95	31.30	98.38	478.09
September	20.44	13.62	23.65	31.52	103.48	498.95
October	21.06	13.76	23.69	32.24	108.79	535.04
November	27.47	18.91	33.49	36.21	135.30	682.07
December	37.68	21.70	40.83	56.93	187.13	881.07

2. A debit or credit entry equal to the therms billed during the month under the schedules subject to this provision, multiplied by the applicable RDAPBA Adjustment.

TIMING AND MANNER OF FILING

The Utility shall file its RDAP Rate Adjustment revisions annually with the Commission in accordance with all statutory and regulatory requirements.

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SPECIAL SUPPLEMENTARY TARIFF
WEATHER NORMALIZATION ADJUSTMENT PROVISION

APPLICABILITY

The Weather Normalization Adjustment Provision (WNAP) applies to the heat-sensitive portion of residential Rate Schedule Nos. G-5, G-6, G-10, and G-11, and General Service Schedule Nos. G-25(S), G-25(M), and G-25(L). The WNAP specifies the procedures used to adjust the monthly bill for each customer served under these rate schedules to account for variations in non-gas revenues which are due to differences between the actual temperatures and normal temperatures for the days in the customer's billing cycle. The WNAP will apply to bills during the winter season months of November through April.

WNAP PROCESS

A "WNAP Volume Adjustment" will be calculated for each customer for each winter billing cycle to reflect the difference between the customer's actual use and usage assuming normal weather. The WNAP Volume Adjustment will then be used to calculate a "WNAP Dollar Adjustment" which will be added to each customer's non-gas revenue calculated on actual metered volumes. The process is set forth below.

WNAP CYCLE HEATING DEGREE DAY (HDD) VARIANCE

HDDs will be calculated for each billing cycle and for each operating district of the Company's Arizona service area. Normal HDDs are calculated as the ten-year average HDDs for each day during the winter season months. Actual HDDs are calculated as the number of degrees Fahrenheit that any winter season day's average of high and low temperature is below 65 degrees. The degree day calculation formulas are as follows:

Normal Cycle HDD	=	Ten-year average HDDs for each day in the billing cycle
Actual Cycle HDD	=	The number of degrees that any day's average temperature is less than 65 degrees Fahrenheit for each day in the billing cycle
Cycle HDD Variance	=	The sum of Normal Cycle HDDs for each day in the billing cycle less the sum of Actual Cycle HDDs for each day in the billing cycle

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SPECIAL SUPPLEMENTARY TARIFF
WEATHER NORMALIZATION ADJUSTMENT PROVISION
(Continued)

NON-TEMPERATURE SENSITIVE BASE LOAD VOLUME PER DAY

A Base Load Volume will be calculated for each customer to estimate the customer's monthly non-temperature sensitive usage. The Base Load Volume per Day will be calculated by determining the customer's lowest average daily use for the summer, May through October billing periods. Average daily use is the customer's total monthly use divided by the number of days in the billing cycle. For new customers, Base Load Volume per Day will be estimated based upon the average Base Load Volume for other customers in the operating district. If necessary, Company personnel will adjust customers' Base Load Volume per Day to reflect a more representative amount.

CYCLE USAGE PER HDD

A cycle usage per HDD will be calculated for each customer. Cycle Usage per HDD will be calculated by subtracting the customer's Base Load Volume (Base Load Volume = Base Load Volume per Day multiplied by the number of days in billing cycle) from actual usage and provided the difference is greater than zero, dividing the difference by the Actual Cycle HDDs. If the actual usage is less than the customer's Base Load Volume no weather adjustment will be made to the customer's bill.

WNAP VOLUME ADJUSTMENT

A WNAP Volume Adjustment will be calculated for each customer. The WNAP Volume Adjustment will be calculated by multiplying the customer's Cycle Usage per HDD by the Cycle HDD Variance.

WNAP DOLLAR ADJUSTMENT

A WNAP Dollar Adjustment will be calculated for each customer. The WNAP Dollar Adjustment will be calculated by multiplying the WNAP Volume Adjustment by Southwest's non-gas delivery charge rates including the affect of any "blocks" in Southwest's rate design. The WNAP Dollar Adjustment will be added to the customer's non-gas revenue calculated on actual metered volumes for billing purposes.

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SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

PROPOSED TARIFF SHEET

A.C.C. Sheet No. 99-103
Canceling _____
A.C.C. Sheet No. _____

HELD FOR FUTURE USE

D/N

Issued On August 31, 2007
Docket No. _____

Issued by
John P. Hester
Senior Vice President

Effective _____ T
Decision No. _____

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-____

2007
ARIZONA
GENERAL RATE CASE

Volume II
SUPPORTING SCHEDULES

August 31, 2007

SOUTHWEST GAS CORPORATION
ARIZONA
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ARIZONA
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Volume II

Supporting Schedules

A

SOUTHWEST GAS CORPORATION
ARIZONA
INCREASE IN GROSS REVENUE REQUIREMENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Reference	Original Cost	Reconstruction Cost New Depreciated	50% Original Cost 50% RCND Fair Value	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Adjusted Rate Base	B-1	$ 1,094,790,046	$ 1,843,481,069	$ 1,469,135,558	1
2	Adjusted Operating Income	C-1	$ 73,180,098	$ 73,180,098	$ 73,180,098	2
3	Current Rate of Return		6.68%	3.97%	4.98%	3
4	Required Operating Income		$ 103,457,659	$ 103,457,659	$ 103,457,659	4
5	Required Rate of Return	D-1	9.45%	5.61%	7.04%	5
6	Operating Income Deficiency (Ln 4 - Ln 2)				$ 30,277,561	6
7	Gross Revenue Conversion Factor	C-3			1.6586	7
8	Increase in Gross Revenue Requirements				$ 50,219,828	8

SCHEDULE A-1
Sheet 1 of 3

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF THE OVERALL RESULTS OF OPERATIONS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Recorded at 04/30/07	Adjustments	Adjusted Amounts	Deficiency	Adjusted for Deficiency	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	Operating Revenue	$ 996,389,570	$ (597,154,892)	$ 399,234,678	$ 50,219,828	$ 449,454,506	1
2	Gas Cost	593,424,664	(593,424,664)	0	0	0	2
3	Operating Margin	$ 402,964,907	$ (3,730,229)	$ 399,234,678	$ 50,219,828	$ 449,454,506	3
	Operating Expenses						
4	Other Gas Supply	$ 685,079	$ 16,522	$ 701,601	$ 0	$ 701,601	4
5	Distribution	87,644,582	1,883,873	89,528,455	0	89,528,455	5
6	Customer Accounts	37,800,950	929,959	38,730,909	150,107	38,881,016	6
7	Customer Service & Information	1,320,355	(193,559)	1,126,796	0	1,126,796	7
8	Sales	230,155	(230,155)	0	0	0	8
	Administrative and General						
9	Direct	4,018,714	(9,175)	4,009,539	0	4,009,539	9
10	System Allocable	49,951,482	2,985,674	52,937,155	0	52,937,155	10
	Depreciation and Amortization						
11	Direct	77,709,373	3,246,873	80,956,247	0	80,956,247	11
12	System Allocable	6,721,772	(74,834)	6,646,938	0	6,646,938	12
13	Regulatory Amortizations	2,234,576	(1,950,048)	284,528	0	284,528	13
14	Taxes Other Than Income	28,912,193	4,212,687	33,124,880	0	33,124,880	14
15	Interest on Customer Deposits	1,856,153	59,161	1,915,314	0	1,915,314	15
16	Income Taxes	21,941,766	(5,849,548)	16,092,218	19,792,160	35,884,378	16
17	Total Operating Expenses	$ 321,027,150	$ 5,027,430	$ 326,054,580	$ 19,942,267	$ 345,996,847	17
18	Net Operating Income	$ 81,937,757	$ (8,757,659)	$ 73,180,098	$ 30,277,561	$ 103,457,659	18
	Rate Base						
	Gas Plant in Service						
19	Direct	$ 1,956,244,952	$ 2,976,115	$ 1,959,221,067		$ 1,959,221,067	19
20	System Allocable	93,253,492	1,373,330	94,626,822		94,626,822	20
21	Total Gross Plant	$ 2,049,498,445	$ 4,349,445	$ 2,053,847,890		$ 2,053,847,890	21
	Accumulated Provision for Depreciation and Amortization						
22	Direct	$ 692,096,947	$ 0	$ 692,096,947		$ 692,096,947	22
23	System Allocable	60,178,616	0	60,178,616		60,178,616	23
24	Total Accumulated Provision for Depreciation and Amortization	$ 752,275,563	$ 0	$ 752,275,563		$ 752,275,563	24
25	Net Plant in Service	$ 1,297,222,881	$ 4,349,445	$ 1,301,572,326		$ 1,301,572,326	25
	Other Rate Base Items						
26	Working Capital	$ 5,681,932	$ 0	$ 5,681,932		$ 5,681,932	26
27	Customer Advances	(37,910,017)	0	(37,910,017)		(37,910,017)	27
28	Customer Deposits	(31,921,898)	0	(31,921,898)		(31,921,898)	28
29	Deferred Taxes	(142,632,297)	0	(142,632,297)		(142,632,297)	29
30	Total Other Rate Base Items	$ (206,782,280)	$ 0	$ (206,782,280)		$ (206,782,280)	30
31	Total Rate Base	$ 1,090,440,601	$ 4,349,445	$ 1,094,790,046		$ 1,094,790,046	31
32	Rate of Return	7.51%		6.68%		9.45%	32

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SPREAD OF REVENUE INCREASE BY CUSTOMER CLASS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Increase/(Decrease) [1] Dollars	Increase/(Decrease) [1] Percent	Line No.
	(a)	(b)	(e)	(f)	
	Sales Service				
1	Residential Gas Service	G-5	$ 39,934,556	15.84%	1
2	Multi-Family Residential Gas Service	G-6	(172,559)	-2.60%	2
3	Low Income Residential Gas Service	G-10	628,374	9.31%	3
4	Low Income Multi-Family Residential	G-11	(21,515)	-4.48%	4
5	Special Residential Gas Service	G-15	(29,730)	-42.30%	5
6	Master Metered Mobile Home Park Gas Service	G-20	69,634	7.16%	6
	General Gas Service	G-25			
7	Small		985,825	12.53%	7
8	Medium		2,781,036	11.44%	8
9	Large		3,717,967	7.01%	9
10	Transporation Eligible		1,732,413	8.62%	10
11	Optional Gas Service	G-30	0	0.00%	11
12	Air Conditioning Gas Service	G-40	6,712	5.43%	12
13	Street Lighting Gas Service	G-45	15,649	28.02%	13
	Gas Service for Compression on Customer's Premises	G-55			
14	Small		950	2.60%	14
15	Large		28,302	6.99%	15
16	Residential		4,358	17.10%	16
17	Electric Generation Gas Service	G-60	148,774	5.88%	17
18	Small Essential Agriculture User Gas Service	G-75	175,508	5.65%	18
19	Natural Gas Engine Gas Service	G-80	214,392	8.38%	19
20	Total Sales and Full Margin Transportation		$ 50,220,646	13.06%	20
21	Special Contract Service	B-1	0	0.00%	21
22	Other Operating Revenue		0	0.00%	22
23	Total Arizona Revenue		$ 50,220,646	12.58%	23

[1] Schedule H-1, Sheet 1.

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF RESULTS OF OPERATIONS

Line No.	Description	Prior Years Year Ending 2005 [1]	Prior Years Year Ending 2006 [1]	Test Year Actual 4/30/07 [2]	Test Year Adjusted 4/30/07 [2]	Projected Year Present Rates 4/30/08 [3]	Projected Year Proposed Rates 4/30/08 [3]	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Operating Revenues	$ 748,627,816	$ 895,549,006	$ 402,964,907	$ 399,234,678	$ 406,994,556	$ 453,949,051	1
2	Operating Expenses and Taxes	708,138,708	827,185,527	321,027,150	326,054,580	334,116,215	352,676,952	2
3	Net Operating Income	$ 40,489,108	$ 68,363,479	$ 81,937,757	$ 73,180,098	$ 72,878,341	$ 101,272,100	3
4	Other Income and Deductions	0	0	0	0	0	0	4
5	Interest Expense	45,778,673	47,089,555	47,844,172	48,035,008	48,035,008	48,035,008	5
6	Net Income	$ (5,289,565)	$ 21,273,925	$ 34,093,585	$ 25,145,090	$ 24,843,333	$ 53,237,092	6

[1] Supporting Schedule E-2.
[2] Supporting Schedule C-1.
[3] Supporting Schedule F-1.
NOTE: Operating revenue and expenses reflected on a margin basis in columns (d), (e), (f), and (g).

SCHEDULE A-2
Sheet 1 of 2

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
SUMMARY RESULTS OF OPERATIONS [1]

Line No.	Description	Prior Years Year Ended 2005	Prior Years Year Ended 2006	Test Year 12 Months Ended 4/30/2007	Line No.
	(a)	(b)	(c)	(d)	
1	Gross Revenues	$ 1,444,439,794	$ 1,714,338,144	$ 1,819,838,987	1
2	Revenue Deductions & Operating Expenses	1,331,337,384	1,564,262,733	1,663,045,445	2
3	Operating Income	$ 113,102,410	$ 150,075,411	$ 156,793,542	3
4	Other Income and (Deductions)	20,022,734	27,086,512	23,197,938	4
5	Income Before Interest Deductions	$ 133,125,144	$ 177,161,923	$ 179,991,480	5
6	Interest Expense	$ 90,348,303	$ 94,658,870	$ 94,386,778	6
7	Allowance for Debt Funds Used During Construction	1,046,495	1,356,704	1,340,971	7
8	Net Interest Expense	$ 89,301,808	$ 93,302,166	$ 93,045,807	8
9	Net Income	$ 43,823,336	$ 83,859,757	$ 86,945,673	9
10	Preferred and Preference Dividend Requirements	-	-	-	10
11	Net Income Applicable to Common Stock	$ 43,823,336	$ 83,859,757	$ 86,945,673	11
12	Weighted Average Shares of Common Stock Outstanding	38,131,533	40,565,773	42,015,865	
13	Earnings per Common Share	$ 1.15	$ 2.07	$ 2.07	13
14	Dividends paid per Common Share	$ 0.82	$ 0.82	$ 0.86	14
15	Dividend Pay-out Ratio	71%	40%	42%	15
16	Return on Average Invested Capital	5.81%	9.82%	9.22%	16
17	Return on Year End Invested Capital	5.53%	9.16%	8.96%	17
18	Return on Average Common Equity	5.81%	9.82%	9.22%	18
19	Return on year End Common Equity	5.53%	9.16%	8.96%	19
20	Times Bond Interest Earned- Before Income Taxes	1.75	2.41	2.54	20
21	Times Total Interest and Preferred Dividend Earned - After Income Taxes	1.49	1.90	1.93	21

[1] In this proceeding, the Company is requesting rate relief for the Arizona rate jurisdiction of its system only. Projections for the total Company's financial position are not compiled or available.

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
SUMMARY OF CAPITAL STRUCTURE [1]

Line No.	Description	Prior Years: Year Ended 2005	Prior Years: Year Ended 2006	Test Year Ended 4/30/07	Projected Year 4/30/08 [2]	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Net Capital Amounts					
1	Short-Term Debt	$ 24,000,000	-	-	-	1
2	Long-Term Debt	1,281,549,896	1,284,281,898	1,191,537,443	1,232,254,958	2
3	Total Debt	$ 1,305,549,896	1,284,281,898	1,191,537,443	1,232,254,958	3
4	Preferred Equity	$ 100,000,000	100,000,000	100,000,000	100,000,000	4
5	Common Equity	792,779,873	915,091,067	970,385,472	1,063,024,645	5
6	Total Capital	$ 2,198,329,769	2,299,372,965	2,261,922,915	2,395,279,603	6
	Capitalization Ratios					
7	Short-Term Debt	1.09%	0.00%	0.00%	0.00%	7
8	Long-Term Debt	58.30%	55.85%	52.68%	51.45%	8
9	Total Debt					9
10	Preferred Equity	4.55%	4.35%	4.42%	4.17%	10
11	Common Equity	36.06%	39.80%	42.90%	44.38%	11
12	Total	100.00%	100.00%	100.00%	100.00%	12
	Weighted Cost of Capital					
13	Short-Term Debt	0.08%	0.00%	0.00%	0.00%	13
14	Long-Term Debt	4.01%	3.81%	3.63%	3.54%	14
15	Preferred Equity	0.37%	0.36%	0.36%	0.34%	15
16	Common Equity	3.97%	3.78%	4.83%	4.99%	16
17	Total Weighted Cost of Capital	8.43%	7.95%	8.82%	8.88%	17

[1] Based on the equity method of accounting
[2] Estimated

SCHEDULE A-3
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
CONSTRUCTION EXPENDITURES, PLANT PLACED IN SERVICE, AND GROSS PLANT
FOR THE YEARS ENDED DECEMBER 31, 2005 AND 2006,
THE TEST YEAR ENDED APRIL 30, 2007
AND PROJECTED YEARS ENDING APRIL 30, 2008, 2009 AND 2010

Line No.	Description	Actual Year Ended 2005	Actual Year Ended 2006	Actual Test Year Ended 4/30/07	Projected Year Ending 4/30/08	Projected Year Ending 4/30/09	Projected Year Ending 4/30/10	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Construction Expenditures							
1	Arizona Direct	$ 138,867,871	$ 160,629,695	$ 186,420,582	$ 152,957,589	$ 127,213,460	$ 110,084,317	1
2	System Allocable [1]	4,895,032	4,439,341	5,276,742	12,249,310	12,976,995	10,829,825	2
3	Total Construction Expenditures	$ 143,762,903	$ 165,069,036	$ 191,697,324	$ 165,206,899	$ 140,190,455	$ 120,914,142	3
	Net Plant Placed in Service							
4	Arizona Direct	$ 104,459,744	$ 138,976,231	$ 174,818,211	$ 135,957,589	$ 110,213,460	$ 93,084,317	4
5	System Allocable [1]	3,290,925	2,359,381	1,960,813	5,244,359	5,656,956	4,439,511	5
6	Total Net Plant Placed in Service	$ 107,750,669	$ 141,335,612	$ 176,779,024	$ 141,201,948	$ 115,870,416	$ 97,523,828	6
	Gross Utility Plant in Service							
7	Arizona Direct	$ 1,743,005,275	$ 1,881,981,506	$ 1,956,244,952	$ 2,092,202,541	$ 2,202,416,001	$ 2,295,500,318	7
8	System Allocable [1]	89,522,472	91,881,853	93,253,492	98,497,851	104,154,807	108,594,318	8
9	Total Gross Utility Plant in Service	$ 1,832,527,747	$ 1,973,863,359	$ 2,049,498,444	$ 2,190,700,392	$ 2,306,570,808	$ 2,404,094,636	9

[1] Allocation based on the 4-Factor (56.70%), Sch C-1, Sh 17

SCHEDULE A-4
Sheet 1 of 1

Volume II

Supporting Schedules

B

SOUTHWEST GAS CORPORATION
ARIZONA
ADJUSTED ORIGINAL COST AND RCND RATE BASE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Schedule Reference	Adjusted Original Cost Rate Base	Adjusted RCND	Fair Value [1]	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Gas Plant in Service	B-2 & B-3	$ 2,053,847,890	$ 3,224,193,614	$ 2,639,020,752	1
2	Accumulated Depreciation and Amortization	B-2 & B-3	752,275,563	1,173,930,265	963,102,914	2
3	Net Gas Plant in Service		$ 1,301,572,326	$ 2,050,263,349	$ 1,675,917,838	3
	Additions					
4	Working Capital	B-5	$ 5,681,932	$ 5,681,932	$ 5,681,932	4
5	Total Additions		$ 5,681,932	$ 5,681,932	$ 5,681,932	5
	Deductions					
6	Customer Advances for Construction	B-6	$ (37,910,017)	$ (37,910,017)	$ (37,910,017)	6
7	Customer Deposits	B-6	(31,921,898)	(31,921,898)	(31,921,898)	7
8	Deferred Income Taxes	B-6	(142,632,297)	(142,632,297)	(142,632,297)	8
9	Total Deductions		$ (212,464,212)	$ (212,464,212)	$ (212,464,212)	9
10	Total Rate Base		$ 1,094,790,046	$ 1,843,481,069	$ 1,469,135,558	10

[1] 50/50 weighting of Original Cost and Reconstructed Cost.

SOUTHWEST GAS CORPORATION
ARIZONA
RECORDED RATE BASE, AS ADJUSTED
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Recorded at 04/30/07 (b)	Adjustments (c)	Adjusted at 04/30/07 (d)	Line No.
	Rate Base				
	Gas Plant in Service				
1	Direct	$ 1,956,244,952	$ 2,976,115	$ 1,959,221,067	1
2	System Allocable	93,253,492	1,373,330	94,626,822	2
3	Total Gross Plant	$ 2,049,498,445	$ 4,349,445	$ 2,053,847,890	3
	Accumulated Provision for Depreciation and Amortization				
4	Direct	$ 692,096,947	$ 0	$ 692,096,947	4
5	System Allocable	60,178,616	0	60,178,616	5
6	Total Accumulated Provision for Depreciation and Amortization	$ 752,275,563	$ 0	$ 752,275,563	6
7	Net Plant in Service [1]	$ 1,297,222,881	$ 4,349,445	$ 1,301,572,326	7
	Other Rate Base Items				
8	Working Capital [2]	$ 5,681,932	$ 0	$ 5,681,932	8
9	Customer Advances [3]	(37,910,017)	0	(37,910,017)	9
10	Customer Deposits [3]	(31,921,898)	0	(31,921,898)	10
11	Deferred Taxes [3]	(142,632,297)	0	(142,632,297)	11
12	Total Other Rate Base Items	$ (206,782,280)	$ 0	$ (206,782,280)	12
13	Total Rate Base	$ 1,090,440,601	$ 4,349,445	$ 1,094,790,046	13

[1] Supporting Workpaper B-2
[2] Supporitng Schedule B-5
[3] Supporitng Schedule B-6

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY COST OF GAS PLANT
AT APRIL 30, 2007

Line No.	Description	Account Number	Balance at 04/30/07	Adjustments	Adjusted Balance	Allocation Of System Allocable Amounts [1]	Test Year Balance As Allocated at 04/30/07	Line No.
	(a)	(b)	(c) WP B-2	(d) WP B-2	(e) WP B-2	(f)	(g)	
	Direct Gas Plant in Service							
1	Intangible Plant		$ 3,877,710	$ 0	$ 3,877,710	$ 64,301,246	$ 68,178,956	1
2	Distribution Plant		1,857,071,868	2,705,995	1,859,777,863	0	1,859,777,863	2
3	General Plant		95,295,374	270,120	95,565,494	30,325,576	125,891,071	3
4	Total Gas Plant in Service	101	$ 1,956,244,952	$ 2,976,115	$ 1,959,221,067	$ 94,626,822	$ 2,053,847,890	4
	Accumulated Provision for Depreciation and Amortization							
5	Intangible Plant		$ 2,614,115	$ 0	$ 2,614,115	$ 45,888,295	$ 48,502,410	5
6	Distribution Plant		677,637,884	0	677,637,884	0	677,637,884	6
7	General Plant		11,844,949	0	11,844,949	14,290,321	26,135,269	7
8	Total Accumulated Depreciation and Amortization	108 & 111	$ 692,096,947	$ 0	$ 692,096,947	$ 60,178,616	$ 752,275,563	8
9	Total Net Gas Plant In Service		$ 1,264,148,005	$ 2,976,115	$ 1,267,124,120	$ 34,448,206	$ 1,301,572,326	9
	System Allocable Gas Plant in Service							
10	Intangible Plant		$ 111,710,077	$ 1,696,000	$ 113,406,077			10
11	General Plant		52,758,163	726,099	53,484,262			11
12	Total System Allocable Gas Plant	101	$ 164,468,240	$ 2,422,099	$ 166,890,339			12
	Accumulated Provision For Depreciation and Amortization							
13	Intangible Plant		$ 80,931,738	$ 0	$ 80,931,738			13
14	General Plant		25,203,388	0	25,203,388			14
15	Total System Allocable Accumulated Depreciation and Amortization	108 & 111	$ 106,135,125	$ 0	$ 106,135,125			15
16	System Allocable Net Gas Plant In Service		$ 58,333,115	$ 2,422,099	$ 60,755,214			16

[1] Allocated based on the 4-Factor. Supporting Schedule C-1, Sh 17

SCHEDULE B-2
Sheet 1 of 3

SOUTHWEST GAS CORPORATION
ARIZONA
COMPLETED CONSTRUCTION NOT CLASSIFIED
ADJUSTMENT NO. 17

Line No.	Description (a)	Account Number (b)		Completed Cost of Plant [1] (c)	Line No.
	Distribution Plant				
1	Land and Land Rights	374.0	$	733,126	1
2	Mains	376.0		1,530,064	2
3	Regulator Station	378.0		325,675	3
4	Industrial Measuring & Regulating Station	385.0		117,130	4
5	Total Distribution Plant		$	2,705,995	5
	General Plant				
6	Structures and Improvements	390.1	$	27,443	6
7	Office Furniture and Equipment	391.0		215,492	7
8	Transportation Equipment	392.1		27,184	8
9	Total General Plant		$	270,120	9
10	Total Arizona		$	2,976,115	10

Explanation
To record direct Arizona non-revenue producing plant completed but not yet classified to plant-in-service accounts.

[1] Supporting Workpapers B-2, Adj. 17

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
COMPLETED CONSTRUCTION NOT CLASSIFIED
ADJUSTMENT NO. 17

Line No.	Description (a)	Account Number (b)	Completed Cost of Plant [1] (c)	Line No.
	Intangible Plant			
1	Miscellaneous Intangible [1]	303.0	$ 1,696,000	1
2	Total Intangible Plant		$ 1,696,000	2
	General Plant [2]			
3	Structures and Improvements	390.1	$ 265,254	3
4	Office Furniture & Equipment	391.0	28,258	4
5	Computer Equipment	391.1	432,587	5
6	Total General Plant		$ 726,099	6
7	Total System Allocable		$ 2,422,099	7
8	Arizona 4-Factor [3]		56.70%	8
9	Amount Allocated to Arizona		$ 1,373,330	9

Explanation
To record System Allocable plant completed but not yet classified to plant-in-service accounts and adjust Miscellaneous Intangible consistent with prior Commission decisions.

[1] Adjustment to Miscellaneous Intangible Plant detailed on WP B-2, Adj. 17
[2] Supporting Workpapers B-2, Adj. 17
[3] Supporting Schedule C-1, Sh 17

SOUTHWEST GAS CORPORATION
ARIZONA
RCND GAS PLANT IN SERVICE
AT APRIL 30, 2007

Line No.	Description	Reference	Balance at 04/30/07	Adjustments [1]	Adjusted Balance	Allocation Of System Allocable Amounts [2]	Test Year Balance As Allocated at 04/30/07	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Gas Plant in Service							
1	Intangible Plant	B-2, Sh 1	$ 3,877,710	$ 0	$ 3,877,710	$ 64,301,246	$ 68,178,956	1
2	Distribution Plant	B-4	2,993,874,268	2,705,995	2,996,580,263	0	2,996,580,263	2
3	General Plant	B-4	121,281,531	270,120	121,551,651	37,882,745	159,434,396	3
4	Total Gas Plant in Service		$ 3,119,033,509	$ 2,976,115	$ 3,122,009,624	$ 102,183,990	$ 3,224,193,614	4
	Accumulated Provision for Depreciation and Amortization							
5	Intangible Plant	B-2, Sh 1	$ 2,614,115	$ 0	$ 2,614,115	$ 45,888,295	$ 48,502,410	5
6	Distribution Plant	[3]	1,092,452,403	0	1,092,452,403	0	1,092,452,403	6
7	General Plant	[3]	15,074,955	0	15,074,955	17,900,496	32,975,451	7
8	Total Accumulated Depreciation and Amortization		$ 1,110,141,473	$ 0	$ 1,110,141,473	$ 63,788,792	$ 1,173,930,265	8
9	Total Net Gas Plant In Service		$ 2,008,892,036	$ 2,976,115	$ 2,011,868,151	$ 38,395,198	$ 2,050,263,349	9
	System Allocable Gas Plant in Service							
10	Intangible Plant	B-2, Sh 1	$ 111,710,077	$ 1,696,000	$ 113,406,077			10
11	General Plant	B-4	66,086,502	726,099	66,812,601			11
12	Total System Allocable Gas Plant		$ 177,796,579	$ 2,422,099	$ 180,218,678			12
	Accumulated Provision For Depreciation and Amortization							
13	Intangible Plant	B-2, Sh 1	$ 80,931,738	$ 0	$ 80,931,738			13
14	General Plant	[3]	31,570,540	0	31,570,540			14
15	Total System Allocable Accumulated Depreciation and Amortization		$ 112,502,278	$ 0	$ 112,502,278			15
16	System Allocable Net Gas Plant In Service		$ 65,294,301	$ 2,422,099	$ 67,716,400			16

[1] Adjustments are calculated in Schedule B-2, and are identical to the adjustments presented in Schedule B-3.
[2] Amounts are allocated to Arizona using the 4-Factor of 56.70% as calculated in Sch C-1, Sh 17.
[3] RCND accumulated provision for depreciation and amortization reflected as a percent of RCND gas plant in the same ratio as adjusted accumulated provision for depreciation and amortization as a percent of adjusted gas plant.

SCHEDULE B-3
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 374.1 & 374.2 - Land and Land Rights

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	1	1.00	$ 0	1
2	1931	0	1	1.00	0	2
3	1932	0	1	1.00	0	3
4	1933	0	1	1.00	0	4
5	1934	0	1	1.00	0	5
6	1935	0	1	1.00	0	6
7	1936	0	1	1.00	0	7
8	1937	0	1	1.00	0	8
9	1938	0	1	1.00	0	9
10	1939	0	1	1.00	0	10
11	1940	112	1	1.00	112	11
12	1941	14	1	1.00	14	12
13	1942	0	1	1.00	0	13
14	1943	160	1	1.00	160	14
15	1944	0	1	1.00	0	15
16	1945	2	1	1.00	2	16
17	1946	0	1	1.00	0	17
18	1947	0	1	1.00	0	18
19	1948	952	1	1.00	952	19
20	1949	139	1	1.00	139	20
21	1950	101	1	1.00	101	21
22	1951	667	1	1.00	667	22
23	1952	183	1	1.00	183	23
24	1953	124	1	1.00	124	24
25	1954	104	1	1.00	104	25
26	1955	121	1	1.00	121	26
27	1956	116	1	1.00	116	27
28	1957	138	1	1.00	138	28
29	1958	9,892	1	1.00	9,892	29
30	1959	75	1	1.00	75	30
31	1960	164	1	1.00	164	31
32	1961	178	1	1.00	178	32
33	1962	896	1	1.00	896	33
34	1963	2,944	1	1.00	2,944	34
35	1964	2,322	1	1.00	2,322	35
36	1965	849	1	1.00	849	36
37	1966	1,145	1	1.00	1,145	37
38	1967	664	1	1.00	664	38
39	1968	896	1	1.00	896	39
40	1969	4,059	1	1.00	4,059	40
41	1970	20,184	1	1.00	20,184	41
42	1971	18,376	1	1.00	18,376	42
43	1972	11,259	1	1.00	11,259	43
44	1973	16,606	1	1.00	16,606	44
45	1974	29,634	1	1.00	29,634	45
46	1975	8,619	1	1.00	8,619	46
47	1976	15,469	1	1.00	15,469	47
48	1977	13,306	1	1.00	13,306	48
49	1978	12,233	1	1.00	12,233	49
50	1979	5,998	1	1.00	5,998	50
51	1980	3,835	1	1.00	3,835	51
52	1981	69,501	1	1.00	69,501	52
53	1982	21,828	1	1.00	21,828	53
54	1983	13,467	1	1.00	13,467	54
55	1984	5,304	1	1.00	5,304	55
56	1985	387,575	1	1.00	387,575	56
57	1986	20,552	1	1.00	20,552	57
58	1987	8,770	1	1.00	8,770	58
59	1988	3,206	1	1.00	3,206	59
60	1989	3,127	1	1.00	3,127	60
61	1990	0	1	1.00	0	61
62	1991	0	1	1.00	0	62
63	1992	0	1	1.00	0	63
64	1993	4,750	1	1.00	4,750	64
65	1994	6,025	1	1.00	6,025	65
66	1995	0	1	1.00	0	66
67	1996	0	1	1.00	0	67
68	1997	130,099	1	1.00	130,099	68
69	1998	1,767	1	1.00	1,767	69
70	1999	0	1	1.00	0	70
71	2000	39,620	1	1.00	39,620	71
72	2001	15,864	1	1.00	15,864	72
73	2002	36,423	1	1.00	36,423	73
74	2003	12,148	1	1.00	12,148	74
75	2004	104,102	1	1.00	104,102	75
76	2005	78,132	1	1.00	78,132	76
77	2006	270,953	1	1.00	270,953	77
78	2007	0	1	1.00	0	78
79	Total	$ 1,415,749			$ 1,415,749	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 375 - Structures and Improvements

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	19	19.42	$ 0	1
2	1931	0	17	21.71	0	2
3	1932	0	16	23.06	0	3
4	1933	0	17	21.71	0	4
5	1934	0	19	19.42	0	5
6	1935	0	18	20.50	0	6
7	1936	0	19	19.42	0	7
8	1937	196	20	18.45	3,616	8
9	1938	94	20	18.45	1,734	9
10	1939	1,659	20	18.45	30,609	10
11	1940	373	20	18.45	6,882	11
12	1941	2,797	22	16.77	46,906	12
13	1942	0	23	16.04	0	13
14	1943	0	23	16.04	0	14
15	1944	0	24	15.38	0	15
16	1945	5,437	24	15.38	83,621	16
17	1946	2,032	27	13.67	27,777	17
18	1947	895	32	11.53	10,319	18
19	1948	4,989	36	10.25	51,137	19
20	1949	6,441	37	9.97	64,217	20
21	1950	8,724	39	9.46	82,529	21
22	1951	21,212	42	8.79	186,453	22
23	1952	1,568	44	8.39	13,156	23
24	1953	4,318	44	8.39	36,228	24
25	1954	2,625	46	8.02	21,053	25
26	1955	959	48	7.69	7,375	26
27	1956	4,816	52	7.10	34,194	27
28	1957	0	55	6.71	0	28
29	1958	0	57	6.47	0	29
30	1959	0	58	6.36	0	30
31	1960	0	59	6.25	0	31
32	1961	0	58	6.36	0	32
33	1962	0	59	6.25	0	33
34	1963	0	60	6.15	0	34
35	1964	0	61	6.05	0	35
36	1965	394	64	5.77	2,273	36
37	1966	0	65	5.68	0	37
38	1967	0	67	5.51	0	38
39	1968	0	71	5.20	0	39
40	1969	0	75	4.92	0	40
41	1970	0	79	4.67	0	41
42	1971	0	87	4.24	0	42
43	1972	0	93	3.97	0	43
44	1973	23,733	100	3.69	87,575	44
45	1974	8,122	118	3.13	25,422	45
46	1975	0	133	2.77	0	46
47	1976	0	138	2.67	0	47
48	1977	437	148	2.49	1,088	48
49	1978	674	161	2.29	1,543	49
50	1979	0	177	2.08	0	50
51	1980	0	194	1.90	0	51
52	1981	0	204	1.81	0	52
53	1982	0	207	1.78	0	53
54	1983	0	215	1.72	0	54
55	1984	0	224	1.65	0	55
56	1985	0	226	1.63	0	56
57	1986	0	231	1.60	0	57
58	1987	0	232	1.59	0	58
59	1988	0	233	1.58	0	59
60	1989	0	232	1.59	0	60
61	1990	2,068	237	1.56	3,227	61
62	1991	2,033	233	1.58	3,212	62
63	1992	0	238	1.55	0	63
64	1993	0	250	1.48	0	64
65	1994	0	261	1.41	0	65
66	1995	3,960	265	1.39	5,504	66
67	1996	0	176	2.10	0	67
68	1997	0	282	1.31	0	68
69	1998	0	285	1.29	0	69
70	1999	0	287	1.29	0	70
71	2000	0	295	1.25	0	71
72	2001	0	303	1.22	0	72
73	2002	0	310	1.19	0	73
74	2003	0	320	1.15	0	74
75	2004	0	342	1.08	0	75
76	2005	0	355	1.04	0	76
77	2006	0	364	1.01	0	77
78	2007	0	369	1.00	0	78
79	Total	$ 110,556			$ 837,650	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 376 - Mains - Steel

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 110,287	19	29.21	$ 3,221,483	1
2	1931	2,569	18	30.83	79,202	2
3	1932	0	18	30.83	0	3
4	1933	0	17	32.65	0	4
5	1934	2,743	18	30.83	84,567	5
6	1935	8,484	19	29.21	247,818	6
7	1936	25	18	30.83	771	7
8	1937	18,672	20	27.75	518,148	8
9	1938	21,117	20	27.75	585,997	9
10	1939	255	20	27.75	7,076	10
11	1940	248	20	27.75	6,882	11
12	1941	50,081	20	27.75	1,389,748	12
13	1942	28,746	21	26.43	759,757	13
14	1943	36,902	21	26.43	975,320	14
15	1944	19,749	21	26.43	521,966	15
16	1945	74,752	22	25.23	1,885,993	16
17	1946	1,842	24	23.13	42,605	17
18	1947	340,177	27	20.56	6,994,039	18
19	1948	892,864	31	17.90	15,982,266	19
20	1949	593,535	33	16.82	9,983,259	20
21	1950	887,648	35	15.86	14,078,097	21
22	1951	775,075	37	15.00	11,626,125	22
23	1952	785,337	39	14.23	11,175,346	23
24	1953	572,737	41	13.54	7,754,859	24
25	1954	714,888	44	12.61	9,014,738	25
26	1955	2,960,952	46	12.07	35,738,691	26
27	1956	1,298,571	48	11.56	15,011,481	27
28	1957	1,337,661	52	10.67	14,272,843	28
29	1958	2,201,021	54	10.28	22,626,496	29
30	1959	2,323,128	57	9.74	22,627,267	30
31	1960	2,013,690	58	9.57	19,271,013	31
32	1961	2,066,692	61	9.10	18,806,897	32
33	1962	2,012,622	63	8.81	17,731,200	33
34	1963	1,636,906	64	8.67	14,191,975	34
35	1964	2,076,922	66	8.41	17,466,914	35
36	1965	2,042,130	68	8.16	16,663,781	36
37	1966	1,740,646	69	8.04	13,994,794	37
38	1967	1,154,873	73	7.60	8,777,035	38
39	1968	805,513	75	7.40	5,960,796	39
40	1969	1,645,787	80	6.94	11,421,762	40
41	1970	1,038,468	84	6.61	6,864,273	41
42	1971	2,068,456	90	6.17	12,762,374	42
43	1972	3,400,169	96	5.78	19,652,977	43
44	1973	2,689,968	100	5.55	14,929,322	44
45	1974	3,010,081	117	4.74	14,267,784	45
46	1975	1,357,176	133	4.17	5,659,424	46
47	1976	706,819	142	3.91	2,763,662	47
48	1977	1,255,176	155	3.58	4,493,530	48
49	1978	1,332,530	171	3.25	4,330,723	49
50	1979	1,174,106	187	2.97	3,487,095	50
51	1980	1,585,387	200	2.78	4,407,376	51
52	1981	3,146,219	219	2.53	7,959,934	52
53	1982	1,678,376	239	2.32	3,893,832	53
54	1983	2,498,554	246	2.26	5,646,732	54
55	1984	3,647,489	251	2.21	8,060,951	55
56	1985	2,176,976	245	2.27	4,941,736	56
57	1986	2,955,225	233	2.38	7,033,436	57
58	1987	3,391,604	241	2.30	7,800,689	58
59	1988	2,383,093	258	2.15	5,123,650	59
60	1989	3,717,875	270	2.06	7,658,823	60
61	1990	3,308,320	276	2.01	6,649,723	61
62	1991	4,659,996	283	1.96	9,133,592	62
63	1992	5,778,074	286	1.94	11,209,464	63
64	1993	5,226,581	294	1.89	9,878,238	64
65	1994	6,761,555	315	1.76	11,900,337	65
66	1995	8,725,101	317	1.75	15,268,927	66
67	1996	7,138,415	319	1.74	12,420,842	67
68	1997	7,144,441	327	1.70	12,145,550	68
69	1998	7,074,377	330	1.68	11,884,953	69
70	1999	7,096,919	341	1.63	11,567,978	70
71	2000	9,767,186	356	1.56	15,236,810	71
72	2001	12,970,719	362	1.53	19,845,200	72
73	2002	14,391,437	367	1.51	21,731,070	73
74	2003	13,625,719	385	1.44	19,621,035	74
75	2004	24,561,057	470	1.18	28,982,047	75
76	2005	27,276,025	568	0.98	26,730,505	76
77	2006	23,737,792	580	0.96	22,788,280	77
78	2007	13,791,193	555	1.00	13,791,193	78
79	Total	$ 281,504,501			$ 784,023,074	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 376 - Mains - Plastic

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	0	0.00	$ 0	1
2	1931	0	0	0.00	0	2
3	1932	0	0	0.00	0	3
4	1933	0	0	0.00	0	4
5	1934	0	0	0.00	0	5
6	1935	0	0	0.00	0	6
7	1936	0	0	0.00	0	7
8	1937	0	0	0.00	0	8
9	1938	0	0	0.00	0	9
10	1939	0	0	0.00	0	10
11	1940	0	0	0.00	0	11
12	1941	0	0	0.00	0	12
13	1942	0	0	0.00	0	13
14	1943	0	0	0.00	0	14
15	1944	0	0	0.00	0	15
16	1945	0	0	0.00	0	16
17	1946	0	0	0.00	0	17
18	1947	0	0	0.00	0	18
19	1948	0	0	0.00	0	19
20	1949	0	0	0.00	0	20
21	1950	0	0	0.00	0	21
22	1951	0	0	0.00	0	22
23	1952	0	0	0.00	0	23
24	1953	0	0	0.00	0	24
25	1954	0	0	0.00	0	25
26	1955	0	0	0.00	0	26
27	1956	0	0	0.00	0	27
28	1957	0	0	0.00	0	28
29	1958	0	0	0.00	0	29
30	1959	0	0	0.00	0	30
31	1960	0	0	0.00	0	31
32	1961	0	0	0.00	0	32
33	1962	748,193	71	5.99	4,481,676	33
34	1963	428,972	72	5.90	2,530,935	34
35	1964	475,983	73	5.82	2,770,221	35
36	1965	307,898	74	5.74	1,767,335	36
37	1966	905,696	76	5.59	5,062,841	37
38	1967	1,064,717	79	5.38	5,728,177	38
39	1968	627,957	81	5.25	3,296,774	39
40	1969	1,230,749	84	5.06	6,227,590	40
41	1970	665,960	87	4.89	3,256,544	41
42	1971	1,443,059	92	4.62	6,666,933	42
43	1972	2,050,016	96	4.43	9,081,571	43
44	1973	1,941,493	100	4.25	8,251,345	44
45	1974	2,050,661	112	3.79	7,772,005	45
46	1975	1,578,398	130	3.27	5,161,361	46
47	1976	536,310	137	3.10	1,662,561	47
48	1977	1,089,575	147	2.89	3,148,872	48
49	1978	592,055	158	2.69	1,592,628	49
50	1979	2,381,840	174	2.44	5,811,690	50
51	1980	3,284,873	193	2.20	7,226,721	51
52	1981	4,119,248	209	2.03	8,362,073	52
53	1982	2,666,401	224	1.90	5,066,162	53
54	1983	4,331,689	232	1.83	7,926,991	54
55	1984	6,449,088	236	1.80	11,608,358	55
56	1985	5,345,843	235	1.81	9,675,976	56
57	1986	16,844,922	238	1.79	30,152,410	57
58	1987	18,046,412	245	1.73	31,220,293	58
59	1988	20,871,124	256	1.66	34,646,066	59
60	1989	16,391,542	273	1.56	25,570,806	60
61	1990	21,710,416	281	1.51	32,782,728	61
62	1991	6,734,079	288	1.48	9,966,437	62
63	1992	9,637,063	290	1.47	14,166,483	63
64	1993	22,121,139	297	1.43	31,633,229	64
65	1994	26,500,967	302	1.41	37,366,363	65
66	1995	33,530,317	305	1.39	46,607,141	66
67	1996	32,013,365	313	1.36	43,538,176	67
68	1997	28,045,133	319	1.33	37,300,027	68
69	1998	31,758,246	324	1.31	41,603,302	69
70	1999	41,479,609	329	1.29	53,508,696	70
71	2000	42,957,950	336	1.26	54,127,017	71
72	2001	44,929,064	344	1.24	55,712,039	72
73	2002	48,155,194	350	1.21	58,267,785	73
74	2003	39,882,777	356	1.19	47,460,505	74
75	2004	48,178,101	368	1.15	55,404,816	75
76	2005	35,969,957	391	1.09	39,207,253	76
77	2006	44,084,470	411	1.03	45,407,004	77
78	2007	25,612,217	425	1.00	25,612,217	78
79	Total	$ 701,770,738			$ 985,398,133	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 378 - Measuring and Regulating Equipment - Gen.

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	24	20.58	$ 0	1
2	1931	0	24	20.58	0	2
3	1932	0	23	21.48	0	3
4	1933	0	22	22.45	0	4
5	1934	0	22	22.45	0	5
6	1935	0	22	22.45	0	6
7	1936	9	22	22.45	204	7
8	1937	0	24	20.58	0	8
9	1938	0	24	20.58	0	9
10	1939	0	24	20.58	0	10
11	1940	0	26	19.00	0	11
12	1941	0	26	19.00	0	12
13	1942	0	26	19.00	0	13
14	1943	0	26	19.00	0	14
15	1944	0	26	19.00	0	15
16	1945	0	26	19.00	0	16
17	1946	257	29	17.03	4,383	17
18	1947	0	34	14.53	0	18
19	1948	0	37	13.35	0	19
20	1949	0	39	12.67	0	20
21	1950	0	40	12.35	0	21
22	1951	0	44	11.23	0	22
23	1952	0	45	10.98	0	23
24	1953	0	46	10.74	0	24
25	1954	0	47	10.51	0	25
26	1955	0	49	10.08	0	26
27	1956	1,909	54	9.15	17,467	27
28	1957	862	57	8.67	7,474	28
29	1958	4,597	60	8.23	37,833	29
30	1959	9,479	62	7.97	75,548	30
31	1960	990	64	7.72	7,643	31
32	1961	2,924	64	7.72	22,573	32
33	1962	2,126	66	7.48	15,902	33
34	1963	1,761	67	7.37	12,979	34
35	1964	3,436	68	7.26	24,945	35
36	1965	10,337	68	7.26	75,047	36
37	1966	18,044	70	7.06	127,391	37
38	1967	1,213	72	6.86	8,321	38
39	1968	6,213	73	6.77	42,062	39
40	1969	9,130	76	6.50	59,345	40
41	1970	6,758	83	5.95	40,210	41
42	1971	26,432	90	5.49	145,112	42
43	1972	121,838	97	5.09	620,155	43
44	1973	7,125	100	4.94	35,198	44
45	1974	25,965	116	4.26	110,611	45
46	1975	8,724	135	3.66	31,930	46
47	1976	5,089	148	3.34	16,997	47
48	1977	51,116	158	3.13	159,993	48
49	1978	48,042	173	2.86	137,400	49
50	1979	19,178	187	2.64	50,630	50
51	1980	38,905	203	2.43	94,539	51
52	1981	14,510	224	2.21	32,067	52
53	1982	111,363	246	2.01	223,840	53
54	1983	195,817	246	2.01	393,592	54
55	1984	223,722	248	1.99	445,207	55
56	1985	36,610	243	2.03	74,318	56
57	1986	245,515	243	2.03	498,395	57
58	1987	85,410	250	1.98	169,112	58
59	1988	159,597	267	1.85	295,254	59
60	1989	82,821	278	1.78	147,421	60
61	1990	167,420	276	1.79	299,682	61
62	1991	138,093	279	1.77	244,425	62
63	1992	681,920	288	1.72	1,172,902	63
64	1993	746,297	298	1.66	1,238,853	64
65	1994	1,155,389	310	1.59	1,837,069	65
66	1995	1,541,035	313	1.58	2,434,835	66
67	1996	1,310,502	323	1.53	2,005,068	67
68	1997	768,309	332	1.49	1,144,780	68
69	1998	2,070,724	335	1.47	3,043,964	69
70	1999	4,464,002	342	1.44	6,428,163	70
71	2000	999,272	352	1.40	1,398,981	71
72	2001	2,013,010	358	1.38	2,777,954	72
73	2002	3,115,187	363	1.36	4,236,654	73
74	2003	1,848,155	365	1.35	2,495,009	74
75	2004	2,731,884	422	1.17	3,196,304	75
76	2005	2,108,698	480	1.03	2,171,959	76
77	2006	2,029,761	494	1.00	2,029,761	77
78	2007	2,950,936	494	1.00	2,950,936	78
79	Total	$ 32,428,418			$ 45,368,397	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 380 - Services - Steel

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 7,968	16	26.88	$ 214,180	1
2	1931	0	15	28.67	0	2
3	1932	89	15	28.67	2,552	3
4	1933	0	14	30.71	0	4
5	1934	18	15	28.67	516	5
6	1935	0	15	28.67	0	6
7	1936	27	16	26.88	726	7
8	1937	0	17	25.29	0	8
9	1938	57	17	25.29	1,442	9
10	1939	2,685	17	25.29	67,904	10
11	1940	90	18	23.89	2,150	11
12	1941	5,351	18	23.89	127,835	12
13	1942	13,586	19	22.63	307,451	13
14	1943	854	19	22.63	19,326	14
15	1944	18,288	19	22.63	413,857	15
16	1945	41,233	19	22.63	933,103	16
17	1946	95,483	22	19.55	1,866,693	17
18	1947	160,197	25	17.20	2,755,388	18
19	1948	273,184	28	15.36	4,196,106	19
20	1949	174,401	30	14.33	2,499,166	20
21	1950	360,219	32	13.44	4,841,343	21
22	1951	460,792	33	13.03	6,004,120	22
23	1952	536,295	35	12.29	6,591,066	23
24	1953	431,133	37	11.62	5,009,765	24
25	1954	407,929	39	11.03	4,499,457	25
26	1955	1,057,831	41	10.49	11,096,647	26
27	1956	640,051	45	9.56	6,118,888	27
28	1957	689,534	48	8.96	6,178,225	28
29	1958	700,970	50	8.60	6,028,342	29
30	1959	347,311	53	8.11	2,816,692	30
31	1960	34,061	54	7.96	271,126	31
32	1961	50,735	58	7.41	375,946	32
33	1962	30,786	60	7.17	220,736	33
34	1963	32,890	60	7.17	235,821	34
35	1964	8,473	63	6.83	57,871	35
36	1965	50,907	64	6.72	342,095	36
37	1966	27,286	66	6.52	177,905	37
38	1967	19,573	69	6.23	121,940	38
39	1968	6,249	72	5.97	37,307	39
40	1969	1,610	77	5.58	8,984	40
41	1970	8,413	84	5.12	43,075	41
42	1971	17,239	90	4.78	82,402	42
43	1972	54,231	95	4.53	245,666	43
44	1973	45,257	100	4.30	194,605	44
45	1974	85,242	113	3.81	324,772	45
46	1975	17,598	129	3.33	58,601	46
47	1976	25,345	138	3.12	79,076	47
48	1977	21,208	149	2.89	61,291	48
49	1978	3,548	161	2.67	9,473	49
50	1979	141,078	176	2.44	344,230	50
51	1980	272,137	192	2.24	609,587	51
52	1981	270,738	208	2.07	560,428	52
53	1982	28,363	226	1.90	53,890	53
54	1983	466,371	232	1.85	862,786	54
55	1984	233,187	237	1.81	422,068	55
56	1985	42,502	234	1.84	78,204	56
57	1986	31,816	233	1.85	58,860	57
58	1987	14,688	241	1.78	26,145	58
59	1988	26,998	246	1.75	47,247	59
60	1989	15,753	251	1.71	26,938	60
61	1990	141,536	262	1.64	232,119	61
62	1991	122,859	272	1.58	194,117	62
63	1992	274,772	278	1.55	425,897	63
64	1993	1,189,070	285	1.51	1,795,496	64
65	1994	572,577	293	1.47	841,688	65
66	1995	850,702	292	1.47	1,250,532	66
67	1996	483,798	296	1.45	701,507	67
68	1997	580,186	301	1.43	829,666	68
69	1998	686,681	306	1.41	968,220	69
70	1999	425,847	313	1.37	583,410	70
71	2000	403,721	323	1.33	536,949	71
72	2001	411,556	331	1.30	535,023	72
73	2002	432,844	338	1.27	549,712	73
74	2003	389,176	347	1.24	482,578	74
75	2004	464,438	382	1.13	524,815	75
76	2005	268,769	426	1.01	271,457	76
77	2006	466,936	436	0.99	462,267	77
78	2007	144,339	430	1.00	144,339	78
79	Total	$ 16,819,665			$ 89,961,807	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 380 - Services - Plastic

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	0	0.00	$ 0	1
2	1931	0	0	0.00	0	2
3	1932	0	0	0.00	0	3
4	1933	0	0	0.00	0	4
5	1934	0	0	0.00	0	5
6	1935	0	0	0.00	0	6
7	1936	0	0	0.00	0	7
8	1937	0	0	0.00	0	8
9	1938	0	0	0.00	0	9
10	1939	0	0	0.00	0	10
11	1940	0	0	0.00	0	11
12	1941	0	0	0.00	0	12
13	1942	0	0	0.00	0	13
14	1943	0	0	0.00	0	14
15	1944	0	0	0.00	0	15
16	1945	0	0	0.00	0	16
17	1946	0	0	0.00	0	17
18	1947	0	0	0.00	0	18
19	1948	0	0	0.00	0	19
20	1949	0	0	0.00	0	20
21	1950	0	0	0.00	0	21
22	1951	0	0	0.00	0	22
23	1952	0	0	0.00	0	23
24	1953	10,524	45	8.58	90,296	24
25	1954	20,492	46	8.39	171,928	25
26	1955	89,224	47	8.21	732,529	26
27	1956	67,961	49	7.88	535,533	27
28	1957	142,579	52	7.42	1,057,936	28
29	1958	180,891	54	7.15	1,293,371	29
30	1959	429,116	56	6.89	2,956,609	30
31	1960	167,121	57	6.77	1,131,409	31
32	1961	213,075	59	6.54	1,393,511	32
33	1962	379,364	61	6.33	2,401,374	33
34	1963	401,788	62	6.23	2,503,139	34
35	1964	343,634	64	6.03	2,072,113	35
36	1965	371,547	65	5.94	2,206,989	36
37	1966	288,639	68	5.68	1,639,470	37
38	1967	324,970	71	5.44	1,767,837	38
39	1968	218,855	74	5.22	1,142,423	39
40	1969	3,871	78	4.95	19,161	40
41	1970	62,485	84	4.60	287,431	41
42	1971	115,755	89	4.34	502,377	42
43	1972	321,912	95	4.06	1,306,963	43
44	1973	191,634	100	3.86	739,707	44
45	1974	805,654	111	3.48	2,803,676	45
46	1975	201,283	127	3.04	611,900	46
47	1976	199,709	134	2.88	575,162	47
48	1977	283,669	144	2.68	760,233	48
49	1978	137,791	155	2.49	343,100	49
50	1979	1,215,235	170	2.27	2,758,583	50
51	1980	1,632,379	184	2.10	3,427,996	51
52	1981	1,930,226	197	1.96	3,783,243	52
53	1982	2,481,893	218	1.77	4,392,951	53
54	1983	17,999,839	227	1.70	30,599,726	54
55	1984	20,143,737	230	1.68	33,841,478	55
56	1985	12,910,774	226	1.71	22,077,424	56
57	1986	20,755,210	230	1.68	34,868,753	57
58	1987	18,437,590	236	1.64	30,237,648	58
59	1988	18,135,471	240	1.61	29,198,108	59
60	1989	12,999,818	247	1.56	20,279,716	60
61	1990	16,593,624	256	1.51	25,056,372	61
62	1991	7,709,642	265	1.46	11,256,077	62
63	1992	12,845,145	269	1.43	18,368,557	63
64	1993	15,838,556	277	1.39	22,015,593	64
65	1994	22,614,705	281	1.37	30,982,146	65
66	1995	25,690,373	279	1.38	35,452,715	66
67	1996	30,339,320	287	1.34	40,654,689	67
68	1997	26,934,376	292	1.32	35,553,376	68
69	1998	27,410,423	297	1.30	35,633,550	69
70	1999	33,943,021	304	1.27	43,107,637	70
71	2000	30,039,853	312	1.24	37,249,418	71
72	2001	31,512,238	323	1.20	37,814,686	72
73	2002	31,740,729	333	1.16	36,819,246	73
74	2003	30,777,545	339	1.14	35,086,401	74
75	2004	30,761,193	348	1.11	34,144,924	75
76	2005	28,751,552	364	1.06	30,476,645	76
77	2006	38,644,406	377	1.02	39,417,294	77
78	2007	11,683,913	386	1.00	11,683,913	78
79	Total	$ 588,446,329			$ 807,285,042	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 381 - Meters, Regulators, and Installations

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 66,335	27	7.67	$ 508,789	1
2	1931	4,694	26	7.96	37,364	2
3	1932	2,225	25	8.28	18,423	3
4	1933	1,940	25	8.28	16,063	4
5	1934	11,552	25	8.28	95,651	5
6	1935	14,275	25	8.28	118,197	6
7	1936	17,283	25	8.28	143,103	7
8	1937	35,418	26	7.96	281,927	8
9	1938	20,040	26	7.96	159,518	9
10	1939	14,175	26	7.96	112,833	10
11	1940	20,448	26	7.96	162,766	11
12	1941	32,988	26	7.96	262,584	12
13	1942	26,062	26	7.96	207,454	13
14	1943	17,148	26	7.96	136,498	14
15	1944	15,493	26	7.96	123,324	15
16	1945	18,994	26	7.96	151,192	16
17	1946	49,872	33	6.27	312,697	17
18	1947	130,316	41	5.05	658,096	18
19	1948	208,674	42	4.93	1,028,763	19
20	1949	188,559	45	4.60	867,371	20
21	1950	160,885	48	4.31	693,414	21
22	1951	206,128	55	3.76	775,041	22
23	1952	196,035	55	3.76	737,092	23
24	1953	240,519	55	3.76	904,351	24
25	1954	147,460	55	3.76	554,450	25
26	1955	550,773	56	3.70	2,037,860	26
27	1956	257,251	63	3.29	846,356	27
28	1957	151,675	66	3.14	476,260	28
29	1958	535,560	71	2.92	1,563,835	29
30	1959	187,001	71	2.92	546,043	30
31	1960	743,022	71	2.92	2,169,624	31
32	1961	288,444	73	2.84	819,181	32
33	1962	535,657	79	2.62	1,403,421	33
34	1963	483,084	79	2.62	1,265,680	34
35	1964	112,953	79	2.62	295,937	35
36	1965	313,021	79	2.62	820,115	36
37	1966	146,307	86	2.41	352,600	37
38	1967	90,075	88	2.35	211,676	38
39	1968	106,468	88	2.35	250,200	39
40	1969	122,731	89	2.33	285,963	40
41	1970	248,264	94	2.20	546,181	41
42	1971	463,749	100	2.07	959,960	42
43	1972	680,916	100	2.07	1,409,496	43
44	1973	714,375	100	2.07	1,478,756	44
45	1974	849,428	111	1.86	1,579,936	45
46	1975	320,571	128	1.62	519,325	46
47	1976	378,527	131	1.58	598,073	47
48	1977	454,756	136	1.52	691,229	48
49	1978	210,584	139	1.49	313,770	49
50	1979	825,508	143	1.45	1,196,987	50
51	1980	1,444,227	149	1.39	2,007,476	51
52	1981	1,311,743	158	1.31	1,718,383	52
53	1982	1,434,834	158	1.31	1,879,633	53
54	1983	3,944,172	146	1.42	5,600,724	54
55	1984	2,763,584	147	1.41	3,896,653	55
56	1985	3,596,759	158	1.31	4,711,754	56
57	1986	1,759,158	166	1.25	2,198,948	57
58	1987	1,909,784	165	1.25	2,387,230	58
59	1988	3,943,060	170	1.22	4,810,533	59
60	1989	4,217,411	177	1.17	4,934,371	60
61	1990	3,392,259	185	1.12	3,799,330	61
62	1991	4,270,504	190	1.09	4,654,849	62
63	1992	2,596,384	192	1.08	2,804,095	63
64	1993	307,772	191	1.08	332,394	64
65	1994	8,240,560	189	1.10	9,064,616	65
66	1995	6,217,363	190	1.09	6,776,926	66
67	1996	5,994,503	192	1.08	6,474,063	67
68	1997	5,877,396	196	1.06	6,230,040	68
69	1998	6,495,044	196	1.06	6,884,747	69
70	1999	10,060,249	193	1.07	10,764,466	70
71	2000	8,828,259	202	1.02	9,004,824	71
72	2001	10,103,988	209	0.99	10,002,948	72
73	2002	11,723,077	203	1.02	11,957,539	73
74	2003	13,152,999	191	1.08	14,205,239	74
75	2004	17,175,222	183	1.13	19,408,001	75
76	2005	16,109,089	186	1.11	17,881,089	76
77	2006	38,344,542	197	1.05	40,261,769	77
78	2007	19,831,069	207	1.00	19,831,069	78
79	Total	$ 226,663,229			$ 266,189,134	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 385 - Measuring and Regulating Equipment - Ind.

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	24	20.58	$ 0	1
2	1931	0	24	20.58	0	2
3	1932	0	23	21.48	0	3
4	1933	0	22	22.45	0	4
5	1934	0	22	22.45	0	5
6	1935	0	22	22.45	0	6
7	1936	0	22	22.45	0	7
8	1937	0	24	20.58	0	8
9	1938	0	24	20.58	0	9
10	1939	0	24	20.58	0	10
11	1940	0	26	19.00	0	11
12	1941	0	26	19.00	0	12
13	1942	0	26	19.00	0	13
14	1943	0	26	19.00	0	14
15	1944	0	26	19.00	0	15
16	1945	0	26	19.00	0	16
17	1946	0	29	17.03	0	17
18	1947	0	34	14.53	0	18
19	1948	0	37	13.35	0	19
20	1949	0	39	12.67	0	20
21	1950	0	40	12.35	0	21
22	1951	0	44	11.23	0	22
23	1952	0	45	10.98	0	23
24	1953	0	46	10.74	0	24
25	1954	0	47	10.51	0	25
26	1955	0	49	10.08	0	26
27	1956	0	54	9.15	0	27
28	1957	0	57	8.67	0	28
29	1958	0	60	8.23	0	29
30	1959	0	62	7.97	0	30
31	1960	0	64	7.72	0	31
32	1961	0	64	7.72	0	32
33	1962	0	66	7.48	0	33
34	1963	0	67	7.37	0	34
35	1964	0	68	7.26	0	35
36	1965	0	68	7.26	0	36
37	1966	0	70	7.06	0	37
38	1967	0	72	6.86	0	38
39	1968	59,173	73	6.77	400,601	39
40	1969	0	76	6.50	0	40
41	1970	0	83	5.95	0	41
42	1971	0	90	5.49	0	42
43	1972	21,891	97	5.09	111,425	43
44	1973	32,288	100	4.94	159,503	44
45	1974	103,218	116	4.26	439,709	45
46	1975	76,790	135	3.66	281,051	46
47	1976	45,302	148	3.34	151,309	47
48	1977	16,356	158	3.13	51,194	48
49	1978	17,162	173	2.86	49,083	49
50	1979	31,941	187	2.64	84,324	50
51	1980	125,610	203	2.43	305,232	51
52	1981	102,045	224	2.21	225,519	52
53	1982	140,659	246	2.01	282,725	53
54	1983	172,078	246	2.01	345,877	54
55	1984	365,456	248	1.99	727,257	55
56	1985	62,688	243	2.03	127,257	56
57	1986	156,319	243	2.03	317,328	57
58	1987	14,460	250	1.98	28,631	58
59	1988	164,131	267	1.85	303,642	59
60	1989	90,436	278	1.78	160,976	60
61	1990	52,403	276	1.79	93,801	61
62	1991	61,230	279	1.77	108,377	62
63	1992	35,239	288	1.72	60,611	63
64	1993	141,754	298	1.66	235,312	64
65	1994	246,541	310	1.59	392,000	65
66	1995	329,429	313	1.58	520,498	66
67	1996	486,187	323	1.53	743,866	67
68	1997	622,531	332	1.49	927,571	68
69	1998	686,294	335	1.47	1,008,852	69
70	1999	521,190	342	1.44	750,514	70
71	2000	202,831	352	1.40	283,963	71
72	2001	314,785	358	1.38	434,403	72
73	2002	362,293	363	1.36	492,718	73
74	2003	416,339	365	1.35	562,058	74
75	2004	333,516	422	1.17	390,214	75
76	2005	381,770	480	1.03	393,223	76
77	2006	350,639	494	1.00	350,639	77
78	2007	106,977	494	1.00	106,977	78
79	Total	$ 7,449,951			$ 12,408,240	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 387 - Other Distribution Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	24	20.58	$ 0	1
2	1931	0	24	20.58	0	2
3	1932	0	23	21.48	0	3
4	1933	0	22	22.45	0	4
5	1934	0	22	22.45	0	5
6	1935	0	22	22.45	0	6
7	1936	0	22	22.45	0	7
8	1937	0	24	20.58	0	8
9	1938	0	24	20.58	0	9
10	1939	0	24	20.58	0	10
11	1940	0	26	19.00	0	11
12	1941	0	26	19.00	0	12
13	1942	0	26	19.00	0	13
14	1943	0	26	19.00	0	14
15	1944	0	26	19.00	0	15
16	1945	0	26	19.00	0	16
17	1946	0	29	17.03	0	17
18	1947	0	34	14.53	0	18
19	1948	0	37	13.35	0	19
20	1949	0	39	12.67	0	20
21	1950	0	40	12.35	0	21
22	1951	0	44	11.23	0	22
23	1952	0	45	10.98	0	23
24	1953	0	46	10.74	0	24
25	1954	0	47	10.51	0	25
26	1955	0	49	10.08	0	26
27	1956	0	54	9.15	0	27
28	1957	0	57	8.67	0	28
29	1958	0	60	8.23	0	29
30	1959	0	62	7.97	0	30
31	1960	0	64	7.72	0	31
32	1961	0	64	7.72	0	32
33	1962	0	66	7.48	0	33
34	1963	0	67	7.37	0	34
35	1964	0	68	7.26	0	35
36	1965	0	68	7.26	0	36
37	1966	0	70	7.06	0	37
38	1967	0	72	6.86	0	38
39	1968	0	73	6.77	0	39
40	1969	0	76	6.50	0	40
41	1970	0	83	5.95	0	41
42	1971	0	90	5.49	0	42
43	1972	0	97	5.09	0	43
44	1973	0	100	4.94	0	44
45	1974	0	116	4.26	0	45
46	1975	2,618	135	3.66	9,582	46
47	1976	0	148	3.34	0	47
48	1977	0	158	3.13	0	48
49	1978	0	173	2.86	0	49
50	1979	35,268	187	2.64	93,108	50
51	1980	34,199	203	2.43	83,104	51
52	1981	88,691	224	2.21	196,007	52
53	1982	254,179	246	2.01	510,900	53
54	1983	0	246	2.01	0	54
55	1984	12,674	248	1.99	25,221	55
56	1985	45	243	2.03	91	56
57	1986	29,911	243	2.03	60,719	57
58	1987	1,134	250	1.98	2,245	58
59	1988	0	267	1.85	0	59
60	1989	0	278	1.78	0	60
61	1990	0	276	1.79	0	61
62	1991	193	279	1.77	342	62
63	1992	541	288	1.72	931	63
64	1993	0	298	1.66	0	64
65	1994	0	310	1.59	0	65
66	1995	245	313	1.58	387	66
67	1996	0	323	1.53	0	67
68	1997	2,006	332	1.49	2,989	68
69	1998	0	335	1.47	0	69
70	1999	0	342	1.44	0	70
71	2000	0	352	1.40	0	71
72	2001	1,026	358	1.38	1,416	72
73	2002	0	363	1.36	0	73
74	2003	0	365	1.35	0	74
75	2004	0	422	1.17	0	75
76	2005	0	480	1.03	0	76
77	2006	0	494	1.00	0	77
78	2007	0	494	1.00	0	78
79	Total	$ 462,730			$ 987,042	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 389 - Land and Land Rights

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	1	1.00	$ 0	1
2	1931	0	1	1.00	0	2
3	1932	0	1	1.00	0	3
4	1933	0	1	1.00	0	4
5	1934	0	1	1.00	0	5
6	1935	0	1	1.00	0	6
7	1936	0	1	1.00	0	7
8	1937	0	1	1.00	0	8
9	1938	0	1	1.00	0	9
10	1939	0	1	1.00	0	10
11	1940	0	1	1.00	0	11
12	1941	0	1	1.00	0	12
13	1942	0	1	1.00	0	13
14	1943	0	1	1.00	0	14
15	1944	0	1	1.00	0	15
16	1945	0	1	1.00	0	16
17	1946	0	1	1.00	0	17
18	1947	0	1	1.00	0	18
19	1948	0	1	1.00	0	19
20	1949	0	1	1.00	0	20
21	1950	0	1	1.00	0	21
22	1951	0	1	1.00	0	22
23	1952	0	1	1.00	0	23
24	1953	0	1	1.00	0	24
25	1954	0	1	1.00	0	25
26	1955	0	1	1.00	0	26
27	1956	0	1	1.00	0	27
28	1957	0	1	1.00	0	28
29	1958	0	1	1.00	0	29
30	1959	0	1	1.00	0	30
31	1960	0	1	1.00	0	31
32	1961	0	1	1.00	0	32
33	1962	0	1	1.00	0	33
34	1963	0	1	1.00	0	34
35	1964	0	1	1.00	0	35
36	1965	0	1	1.00	0	36
37	1966	0	1	1.00	0	37
38	1967	0	1	1.00	0	38
39	1968	0	1	1.00	0	39
40	1969	0	1	1.00	0	40
41	1970	27,505	1	1.00	27,505	41
42	1971	0	1	1.00	0	42
43	1972	0	1	1.00	0	43
44	1973	0	1	1.00	0	44
45	1974	0	1	1.00	0	45
46	1975	0	1	1.00	0	46
47	1976	0	1	1.00	0	47
48	1977	0	1	1.00	0	48
49	1978	0	1	1.00	0	49
50	1979	0	1	1.00	0	50
51	1980	573,337	1	1.00	573,337	51
52	1981	0	1	1.00	0	52
53	1982	0	1	1.00	0	53
54	1983	0	1	1.00	0	54
55	1984	792,870	1	1.00	792,870	55
56	1985	895,545	1	1.00	895,545	56
57	1986	355,216	1	1.00	355,216	57
58	1987	0	1	1.00	0	58
59	1988	7,000	1	1.00	7,000	59
60	1989	3,091,144	1	1.00	3,091,144	60
61	1990	0	1	1.00	0	61
62	1991	0	1	1.00	0	62
63	1992	0	1	1.00	0	63
64	1993	0	1	1.00	0	64
65	1994	0	1	1.00	0	65
66	1995	0	1	1.00	0	66
67	1996	0	1	1.00	0	67
68	1997	209,928	1	1.00	209,928	68
69	1998	0	1	1.00	0	69
70	1999	502,044	1	1.00	502,044	70
71	2000	0	1	1.00	0	71
72	2001	0	1	1.00	0	72
73	2002	0	1	1.00	0	73
74	2003	0	1	1.00	0	74
75	2004	0	1	1.00	0	75
76	2005	0	1	1.00	0	76
77	2006	0	1	1.00	0	77
78	2007	1,963,827	1	1.00	1,963,827	78
79	Total	$ 8,418,416			$ 8,418,416	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 390.1 - Structures and Improvements

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	19	19.42	$ 0	1
2	1931	0	17	21.71	0	2
3	1932	0	16	23.06	0	3
4	1933	0	17	21.71	0	4
5	1934	0	19	19.42	0	5
6	1935	0	18	20.50	0	6
7	1936	0	19	19.42	0	7
8	1937	0	20	18.45	0	8
9	1938	0	20	18.45	0	9
10	1939	0	20	18.45	0	10
11	1940	0	20	18.45	0	11
12	1941	0	22	16.77	0	12
13	1942	0	23	16.04	0	13
14	1943	0	23	16.04	0	14
15	1944	0	24	15.38	0	15
16	1945	0	24	15.38	0	16
17	1946	0	27	13.67	0	17
18	1947	0	32	11.53	0	18
19	1948	0	36	10.25	0	19
20	1949	0	37	9.97	0	20
21	1950	0	39	9.46	0	21
22	1951	0	42	8.79	0	22
23	1952	0	44	8.39	0	23
24	1953	0	44	8.39	0	24
25	1954	0	46	8.02	0	25
26	1955	0	48	7.69	0	26
27	1956	0	52	7.10	0	27
28	1957	0	55	6.71	0	28
29	1958	0	57	6.47	0	29
30	1959	0	58	6.36	0	30
31	1960	0	59	6.25	0	31
32	1961	0	58	6.36	0	32
33	1962	0	59	6.25	0	33
34	1963	0	60	6.15	0	34
35	1964	0	61	6.05	0	35
36	1965	0	64	5.77	0	36
37	1966	0	65	5.68	0	37
38	1967	0	67	5.51	0	38
39	1968	0	71	5.20	0	39
40	1969	0	75	4.92	0	40
41	1970	0	79	4.67	0	41
42	1971	0	87	4.24	0	42
43	1972	15,408	93	3.97	61,170	43
44	1973	2,858	100	3.69	10,546	44
45	1974	5,984	118	3.13	18,730	45
46	1975	28,410	133	2.77	78,696	46
47	1976	0	138	2.67	0	47
48	1977	333,672	148	2.49	830,843	48
49	1978	2,837	161	2.29	6,497	49
50	1979	0	177	2.08	0	50
51	1980	5,244,133	194	1.90	9,963,853	51
52	1981	38,653	204	1.81	69,962	52
53	1982	0	207	1.78	0	53
54	1983	0	215	1.72	0	54
55	1984	2,441,523	224	1.65	4,028,513	55
56	1985	1,687,626	226	1.63	2,750,830	56
57	1986	1,023,067	231	1.60	1,636,907	57
58	1987	67,606	232	1.59	107,494	58
59	1988	5,267,716	233	1.58	8,322,991	59
60	1989	3,221,887	232	1.59	5,122,800	60
61	1990	168,754	237	1.56	263,256	61
62	1991	838,588	233	1.58	1,324,969	62
63	1992	193,045	238	1.55	299,220	63
64	1993	98,925	250	1.48	146,409	64
65	1994	255,760	261	1.41	360,622	65
66	1995	481,215	265	1.39	668,889	66
67	1996	189,940	176	2.10	398,874	67
68	1997	353,457	282	1.31	463,029	68
69	1998	478,732	285	1.29	617,564	69
70	1999	1,090,608	287	1.29	1,406,884	70
71	2000	779,977	295	1.25	974,971	71
72	2001	177,401	303	1.22	216,429	72
73	2002	336,702	310	1.19	400,675	73
74	2003	262,206	320	1.15	301,537	74
75	2004	452,406	342	1.08	488,598	75
76	2005	72,343	355	1.04	75,237	76
77	2006	139,383	364	1.01	140,777	77
78	2007	314,145	369	1.00	314,145	78
79	Total	$ 26,064,967			$ 41,871,917	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 390.2 - Leasehold Structures and Improvements

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	19	19.42	$ 0	1
2	1931	0	17	21.71	0	2
3	1932	0	16	23.06	0	3
4	1933	0	17	21.71	0	4
5	1934	0	19	19.42	0	5
6	1935	0	18	20.50	0	6
7	1936	0	19	19.42	0	7
8	1937	0	20	18.45	0	8
9	1938	0	20	18.45	0	9
10	1939	0	20	18.45	0	10
11	1940	0	20	18.45	0	11
12	1941	0	22	16.77	0	12
13	1942	0	23	16.04	0	13
14	1943	0	23	16.04	0	14
15	1944	0	24	15.38	0	15
16	1945	0	24	15.38	0	16
17	1946	0	27	13.67	0	17
18	1947	0	32	11.53	0	18
19	1948	0	36	10.25	0	19
20	1949	0	37	9.97	0	20
21	1950	0	39	9.46	0	21
22	1951	0	42	8.79	0	22
23	1952	0	44	8.39	0	23
24	1953	0	44	8.39	0	24
25	1954	0	46	8.02	0	25
26	1955	0	48	7.69	0	26
27	1956	0	52	7.10	0	27
28	1957	0	55	6.71	0	28
29	1958	0	57	6.47	0	29
30	1959	0	58	6.36	0	30
31	1960	0	59	6.25	0	31
32	1961	0	58	6.36	0	32
33	1962	0	59	6.25	0	33
34	1963	0	60	6.15	0	34
35	1964	0	61	6.05	0	35
36	1965	0	64	5.77	0	36
37	1966	0	65	5.68	0	37
38	1967	0	67	5.51	0	38
39	1968	0	71	5.20	0	39
40	1969	0	75	4.92	0	40
41	1970	0	79	4.67	0	41
42	1971	0	87	4.24	0	42
43	1972	0	93	3.97	0	43
44	1973	0	100	3.69	0	44
45	1974	0	118	3.13	0	45
46	1975	0	133	2.77	0	46
47	1976	0	138	2.67	0	47
48	1977	0	148	2.49	0	48
49	1978	0	161	2.29	0	49
50	1979	19,087	177	2.08	39,701	50
51	1980	7,025	194	1.90	13,348	51
52	1981	0	204	1.81	0	52
53	1982	0	207	1.78	0	53
54	1983	0	215	1.72	0	54
55	1984	68,562	224	1.65	113,127	55
56	1985	27,722	226	1.63	45,187	56
57	1986	30,477	231	1.60	48,763	57
58	1987	0	232	1.59	0	58
59	1988	87,786	233	1.58	138,702	59
60	1989	119,619	232	1.59	190,194	60
61	1990	0	237	1.56	0	61
62	1991	0	233	1.58	0	62
63	1992	0	238	1.55	0	63
64	1993	89,014	250	1.48	131,741	64
65	1994	10,978	261	1.41	15,479	65
66	1995	0	265	1.39	0	66
67	1996	6,416	176	2.10	13,474	67
68	1997	9,418	282	1.31	12,338	68
69	1998	121,696	285	1.29	156,988	69
70	1999	55,047	287	1.29	71,011	70
71	2000	14,670	295	1.25	18,338	71
72	2001	235,573	303	1.22	287,399	72
73	2002	60,614	310	1.19	72,131	73
74	2003	5,638	320	1.15	6,484	74
75	2004	10,805	342	1.08	11,669	75
76	2005	2,005	355	1.04	2,085	76
77	2006	4,067	364	1.01	4,108	77
78	2007	0	369	1.00	0	78
79	Total	$ 986,219			$ 1,392,267	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 391 - Office Furniture and Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	2,051	60	5.17	10,604	36
37	1966	3,149	62	5.00	15,745	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	1,554	74	4.19	6,511	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	0	123	2.52	0	46
47	1976	0	130	2.38	0	47
48	1977	3,374	141	2.20	7,423	48
49	1978	0	151	2.05	0	49
50	1979	0	164	1.89	0	50
51	1980	244,314	178	1.74	425,106	51
52	1981	1,097	186	1.67	1,832	52
53	1982	0	203	1.53	0	53
54	1983	9,167	209	1.48	13,567	54
55	1984	49,377	212	1.46	72,090	55
56	1985	1,031,674	211	1.47	1,516,561	56
57	1986	365,471	218	1.42	518,969	57
58	1987	52,450	226	1.37	71,857	58
59	1988	515,269	219	1.42	731,682	59
60	1989	114,045	213	1.46	166,506	60
61	1990	6,328	228	1.36	8,606	61
62	1991	14,321	242	1.28	18,331	62
63	1992	29,616	249	1.24	36,724	63
64	1993	29,863	260	1.19	35,537	64
65	1994	69,698	257	1.21	84,335	65
66	1995	93,459	246	1.26	117,758	66
67	1996	48,437	250	1.24	60,062	67
68	1997	92,529	251	1.24	114,736	68
69	1998	82,590	254	1.22	100,760	69
70	1999	461,041	261	1.19	548,639	70
71	2000	660,913	268	1.16	766,659	71
72	2001	42,515	280	1.11	47,192	72
73	2002	532,749	289	1.07	570,041	73
74	2003	25,848	293	1.06	27,399	74
75	2004	192,535	298	1.04	200,236	75
76	2005	8,828	303	1.02	9,005	76
77	2006	94,985	305	1.02	96,885	77
78	2007	560,912	310	1.00	560,912	78
79	Total	$ 5,440,159			$ 6,962,270	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 391.1 - Computer Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	0	60	5.17	0	36
37	1966	0	62	5.00	0	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	0	74	4.19	0	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	0	123	2.52	0	46
47	1976	0	130	2.38	0	47
48	1977	0	141	2.20	0	48
49	1978	0	151	2.05	0	49
50	1979	0	164	1.89	0	50
51	1980	0	178	1.74	0	51
52	1981	0	186	1.67	0	52
53	1982	0	203	1.53	0	53
54	1983	0	209	1.48	0	54
55	1984	0	212	1.46	0	55
56	1985	0	211	1.47	0	56
57	1986	0	218	1.42	0	57
58	1987	0	226	1.37	0	58
59	1988	0	219	1.42	0	59
60	1989	0	213	1.46	0	60
61	1990	0	228	1.36	0	61
62	1991	0	242	1.28	0	62
63	1992	0	249	1.24	0	63
64	1993	18,529	260	1.19	22,050	64
65	1994	15,506	257	1.21	18,762	65
66	1995	37,950	246	1.26	47,817	66
67	1996	7,201	250	1.24	8,929	67
68	1997	26,325	251	1.24	32,643	68
69	1998	16,218	254	1.22	19,786	69
70	1999	33,827	261	1.19	40,254	70
71	2000	126,939	268	1.16	147,249	71
72	2001	385,839	280	1.11	428,281	72
73	2002	187,887	289	1.07	201,039	73
74	2003	933,310	293	1.06	989,309	74
75	2004	869,595	298	1.04	904,379	75
76	2005	3,109,193	303	1.02	3,171,377	76
77	2006	2,278,230	305	1.02	2,323,795	77
78	2007	516,819	310	1.00	516,819	78
79	Total	$ 8,563,368			$ 8,872,489	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 392.1 - Transportation Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	3,530	197	2.35	8,296	50
51	1980	24,702	222	2.09	51,627	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	1,020	269	1.72	1,754	54
55	1984	4,311	273	1.70	7,329	55
56	1985	19,935	276	1.68	33,491	56
57	1986	15,181	280	1.65	25,049	57
58	1987	26,797	286	1.62	43,411	58
59	1988	18,237	295	1.57	28,632	59
60	1989	10,678	281	1.65	17,619	60
61	1990	21,628	298	1.55	33,523	61
62	1991	15,983	320	1.45	23,175	62
63	1992	46,577	316	1.47	68,468	63
64	1993	81,449	324	1.43	116,472	64
65	1994	99,120	331	1.40	138,768	65
66	1995	690,587	333	1.39	959,916	66
67	1996	56,193	336	1.38	77,546	67
68	1997	415,661	351	1.32	548,673	68
69	1998	1,695,088	380	1.22	2,068,007	69
70	1999	1,427,295	385	1.20	1,712,754	70
71	2000	3,067,572	389	1.19	3,650,411	71
72	2001	5,426,548	390	1.19	6,457,592	72
73	2002	3,974,869	395	1.17	4,650,597	73
74	2003	1,229,586	401	1.15	1,414,024	74
75	2004	2,855,228	414	1.12	3,197,855	75
76	2005	3,033,617	439	1.05	3,185,298	76
77	2006	4,950,008	457	1.01	4,999,508	77
78	2007	1,914,959	463	1.00	1,914,959	78
79	Total	$ 31,126,359			$ 35,434,754	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 393 - Stores Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	31,662	222	2.09	66,174	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	2,855	269	1.72	4,911	54
55	1984	0	273	1.70	0	55
56	1985	62,611	276	1.68	105,186	56
57	1986	30,615	280	1.65	50,515	57
58	1987	17,738	286	1.62	28,736	58
59	1988	36,482	295	1.57	57,277	59
60	1989	1,293	281	1.65	2,133	60
61	1990	0	298	1.55	0	61
62	1991	0	320	1.45	0	62
63	1992	0	316	1.47	0	63
64	1993	9,251	324	1.43	13,229	64
65	1994	52,958	331	1.40	74,141	65
66	1995	0	333	1.39	0	66
67	1996	0	336	1.38	0	67
68	1997	41,958	351	1.32	55,385	68
69	1998	5,158	380	1.22	6,293	69
70	1999	50,326	385	1.20	60,391	70
71	2000	19,100	389	1.19	22,729	71
72	2001	4,375	390	1.19	5,206	72
73	2002	73,301	395	1.17	85,762	73
74	2003	0	401	1.15	0	74
75	2004	26,256	414	1.12	29,407	75
76	2005	64,821	439	1.05	68,062	76
77	2006	11,760	457	1.01	11,878	77
78	2007	0	463	1.00	0	78
79	Total	$ 542,520			$ 747,415	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 394 - Tools, Shop and Garage Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	55,189	222	2.09	115,345	51
52	1981	23,738	246	1.88	44,627	52
53	1982	34,866	263	1.76	61,364	53
54	1983	2,424	269	1.72	4,169	54
55	1984	22,791	273	1.70	38,745	55
56	1985	17,010	276	1.68	28,577	56
57	1986	269,928	280	1.65	445,381	57
58	1987	30,450	286	1.62	49,329	58
59	1988	77,470	295	1.57	121,628	59
60	1989	226,378	281	1.65	373,524	60
61	1990	17,527	298	1.55	27,167	61
62	1991	25,031	320	1.45	36,295	62
63	1992	71,553	316	1.47	105,183	63
64	1993	87,860	324	1.43	125,640	64
65	1994	71,131	331	1.40	99,583	65
66	1995	342,679	333	1.39	476,324	66
67	1996	46,697	336	1.38	64,442	67
68	1997	79,347	351	1.32	104,738	68
69	1998	489,352	380	1.22	597,009	69
70	1999	269,676	385	1.20	323,611	70
71	2000	358,741	389	1.19	426,902	71
72	2001	242,895	390	1.19	289,045	72
73	2002	380,357	395	1.17	445,018	73
74	2003	134,426	401	1.15	154,590	74
75	2004	504,361	414	1.12	564,884	75
76	2005	662,868	439	1.05	696,011	76
77	2006	496,552	457	1.01	501,518	77
78	2007	183,727	463	1.00	183,727	78
79	Total	$ 5,225,024			$ 6,504,376	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 395 - Laboratory Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	0	60	5.17	0	36
37	1966	0	62	5.00	0	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	0	74	4.19	0	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	0	123	2.52	0	46
47	1976	0	130	2.38	0	47
48	1977	0	141	2.20	0	48
49	1978	0	151	2.05	0	49
50	1979	0	164	1.89	0	50
51	1980	0	178	1.74	0	51
52	1981	0	186	1.67	0	52
53	1982	0	203	1.53	0	53
54	1983	0	209	1.48	0	54
55	1984	0	212	1.46	0	55
56	1985	0	211	1.47	0	56
57	1986	0	218	1.42	0	57
58	1987	0	226	1.37	0	58
59	1988	0	219	1.42	0	59
60	1989	0	213	1.46	0	60
61	1990	2,960	228	1.36	4,026	61
62	1991	0	242	1.28	0	62
63	1992	0	249	1.24	0	63
64	1993	1,176	260	1.19	1,399	64
65	1994	35,045	257	1.21	42,404	65
66	1995	11,623	246	1.26	14,645	66
67	1996	10,818	250	1.24	13,414	67
68	1997	0	251	1.24	0	68
69	1998	3,633	254	1.22	4,432	69
70	1999	145,052	261	1.19	172,612	70
71	2000	0	268	1.16	0	71
72	2001	0	280	1.11	0	72
73	2002	59,897	289	1.07	64,090	73
74	2003	1,553	293	1.06	1,646	74
75	2004	4,842	298	1.04	5,036	75
76	2005	0	303	1.02	0	76
77	2006	2,466	305	1.02	2,515	77
78	2007	0	310	1.00	0	78
79	Total	$ 279,065			$ 326,219	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 396 - Power Operated Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	8,127	197	2.35	19,098	50
51	1980	2,846	222	2.09	5,948	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	842	269	1.72	1,448	54
55	1984	65,772	273	1.70	111,812	55
56	1985	3,072	276	1.68	5,161	56
57	1986	32,514	280	1.65	53,648	57
58	1987	10,232	286	1.62	16,576	58
59	1988	10,046	295	1.57	15,772	59
60	1989	28,315	281	1.65	46,720	60
61	1990	0	298	1.55	0	61
62	1991	81,471	320	1.45	118,133	62
63	1992	9,053	316	1.47	13,308	63
64	1993	52,469	324	1.43	75,031	64
65	1994	908,327	331	1.40	1,271,658	65
66	1995	106,996	333	1.39	148,724	66
67	1996	99,210	336	1.38	136,910	67
68	1997	25,800	351	1.32	34,056	68
69	1998	286,456	380	1.22	349,476	69
70	1999	160,970	385	1.20	193,164	70
71	2000	194,797	389	1.19	231,808	71
72	2001	298,640	390	1.19	355,382	72
73	2002	145,971	395	1.17	170,786	73
74	2003	91,305	401	1.15	105,001	74
75	2004	291,462	414	1.12	326,437	75
76	2005	455,586	439	1.05	478,365	76
77	2006	542,423	457	1.01	547,847	77
78	2007	396,593	463	1.00	396,593	78
79	Total	$ 4,309,295			$ 5,228,862	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 397.1 - Communication Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	15	23.33	$ 0	1
2	1931	0	15	23.33	0	2
3	1932	0	15	23.33	0	3
4	1933	0	15	23.33	0	4
5	1934	0	15	23.33	0	5
6	1935	0	15	23.33	0	6
7	1936	0	15	23.33	0	7
8	1937	0	17	20.59	0	8
9	1938	0	17	20.59	0	9
10	1939	0	17	20.59	0	10
11	1940	0	17	20.59	0	11
12	1941	0	18	19.44	0	12
13	1942	0	19	18.42	0	13
14	1943	0	19	18.42	0	14
15	1944	0	19	18.42	0	15
16	1945	0	19	18.42	0	16
17	1946	0	21	16.67	0	17
18	1947	0	24	14.58	0	18
19	1948	0	26	13.46	0	19
20	1949	0	28	12.50	0	20
21	1950	0	30	11.67	0	21
22	1951	0	31	11.29	0	22
23	1952	0	33	10.61	0	23
24	1953	0	34	10.29	0	24
25	1954	0	36	9.72	0	25
26	1955	0	37	9.46	0	26
27	1956	0	39	8.97	0	27
28	1957	0	41	8.54	0	28
29	1958	0	42	8.33	0	29
30	1959	0	45	7.78	0	30
31	1960	0	46	7.61	0	31
32	1961	0	49	7.14	0	32
33	1962	0	51	6.86	0	33
34	1963	0	52	6.73	0	34
35	1964	0	54	6.48	0	35
36	1965	0	57	6.14	0	36
37	1966	0	58	6.03	0	37
38	1967	0	62	5.65	0	38
39	1968	0	64	5.47	0	39
40	1969	0	69	5.07	0	40
41	1970	1,328	78	4.49	5,963	41
42	1971	0	88	3.98	0	42
43	1972	0	95	3.68	0	43
44	1973	3,598	100	3.50	12,593	44
45	1974	0	109	3.21	0	45
46	1975	0	122	2.87	0	46
47	1976	0	131	2.67	0	47
48	1977	0	142	2.46	0	48
49	1978	0	151	2.32	0	49
50	1979	0	160	2.19	0	50
51	1980	0	170	2.06	0	51
52	1981	0	185	1.89	0	52
53	1982	0	206	1.70	0	53
54	1983	6,506	218	1.61	10,475	54
55	1984	0	220	1.59	0	55
56	1985	267,138	214	1.64	438,106	56
57	1986	50,148	215	1.63	81,741	57
58	1987	62,216	216	1.62	100,790	58
59	1988	21,920	215	1.63	35,730	59
60	1989	39,104	214	1.64	64,131	60
61	1990	0	220	1.59	0	61
62	1991	2,143	225	1.56	3,343	62
63	1992	7,069	232	1.51	10,674	63
64	1993	36,691	236	1.48	54,303	64
65	1994	246,135	239	1.46	359,357	65
66	1995	104,819	247	1.42	148,843	66
67	1996	28,698	254	1.38	39,603	67
68	1997	250,043	257	1.36	340,058	68
69	1998	204,183	265	1.32	269,522	69
70	1999	490,884	275	1.27	623,423	70
71	2000	115,485	285	1.23	142,047	71
72	2001	10,168	299	1.17	11,897	72
73	2002	0	309	1.13	0	73
74	2003	32,490	318	1.10	35,739	74
75	2004	79,112	327	1.07	84,650	75
76	2005	25,766	337	1.04	26,797	76
77	2006	57,712	345	1.01	58,289	77
78	2007	514,903	350	1.00	514,903	78
79	Total	$ 2,658,259			$ 3,472,977	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 397.2 - Telemetering Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	15	23.33	$ 0	1
2	1931	0	15	23.33	0	2
3	1932	0	15	23.33	0	3
4	1933	0	15	23.33	0	4
5	1934	0	15	23.33	0	5
6	1935	0	15	23.33	0	6
7	1936	0	15	23.33	0	7
8	1937	0	17	20.59	0	8
9	1938	0	17	20.59	0	9
10	1939	0	17	20.59	0	10
11	1940	0	17	20.59	0	11
12	1941	0	18	19.44	0	12
13	1942	0	19	18.42	0	13
14	1943	0	19	18.42	0	14
15	1944	0	19	18.42	0	15
16	1945	0	19	18.42	0	16
17	1946	0	21	16.67	0	17
18	1947	0	24	14.58	0	18
19	1948	0	26	13.46	0	19
20	1949	0	28	12.50	0	20
21	1950	0	30	11.67	0	21
22	1951	0	31	11.29	0	22
23	1952	0	33	10.61	0	23
24	1953	0	34	10.29	0	24
25	1954	0	36	9.72	0	25
26	1955	0	37	9.46	0	26
27	1956	0	39	8.97	0	27
28	1957	0	41	8.54	0	28
29	1958	0	42	8.33	0	29
30	1959	0	45	7.78	0	30
31	1960	0	46	7.61	0	31
32	1961	0	49	7.14	0	32
33	1962	0	51	6.86	0	33
34	1963	0	52	6.73	0	34
35	1964	0	54	6.48	0	35
36	1965	0	57	6.14	0	36
37	1966	0	58	6.03	0	37
38	1967	0	62	5.65	0	38
39	1968	0	64	5.47	0	39
40	1969	0	69	5.07	0	40
41	1970	0	78	4.49	0	41
42	1971	0	88	3.98	0	42
43	1972	0	95	3.68	0	43
44	1973	0	100	3.50	0	44
45	1974	0	109	3.21	0	45
46	1975	0	122	2.87	0	46
47	1976	0	131	2.67	0	47
48	1977	0	142	2.46	0	48
49	1978	0	151	2.32	0	49
50	1979	0	160	2.19	0	50
51	1980	0	170	2.06	0	51
52	1981	0	185	1.89	0	52
53	1982	0	206	1.70	0	53
54	1983	0	218	1.61	0	54
55	1984	0	220	1.59	0	55
56	1985	0	214	1.64	0	56
57	1986	0	215	1.63	0	57
58	1987	0	216	1.62	0	58
59	1988	19,285	215	1.63	31,435	59
60	1989	0	214	1.64	0	60
61	1990	0	220	1.59	0	61
62	1991	0	225	1.56	0	62
63	1992	5,275	232	1.51	7,965	63
64	1993	3,280	236	1.48	4,854	64
65	1994	27,121	239	1.46	39,597	65
66	1995	130,115	247	1.42	184,763	66
67	1996	16,779	254	1.38	23,155	67
68	1997	0	257	1.36	0	68
69	1998	0	265	1.32	0	69
70	1999	9,867	275	1.27	12,531	70
71	2000	36,919	285	1.23	45,410	71
72	2001	0	299	1.17	0	72
73	2002	0	309	1.13	0	73
74	2003	0	318	1.10	0	74
75	2004	5,834	327	1.07	6,242	75
76	2005	534,901	337	1.04	556,297	76
77	2006	0	345	1.01	0	77
78	2007	0	350	1.00	0	78
79	Total	$ 789,376			$ 912,249	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 398 - Miscellaneous Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	15	23.33	$ 0	1
2	1931	0	15	23.33	0	2
3	1932	0	15	23.33	0	3
4	1933	0	15	23.33	0	4
5	1934	0	15	23.33	0	5
6	1935	0	15	23.33	0	6
7	1936	0	15	23.33	0	7
8	1937	0	17	20.59	0	8
9	1938	0	17	20.59	0	9
10	1939	0	17	20.59	0	10
11	1940	0	17	20.59	0	11
12	1941	0	18	19.44	0	12
13	1942	0	19	18.42	0	13
14	1943	0	19	18.42	0	14
15	1944	0	19	18.42	0	15
16	1945	0	19	18.42	0	16
17	1946	0	21	16.67	0	17
18	1947	0	24	14.58	0	18
19	1948	0	26	13.46	0	19
20	1949	0	28	12.50	0	20
21	1950	0	30	11.67	0	21
22	1951	0	31	11.29	0	22
23	1952	0	33	10.61	0	23
24	1953	0	34	10.29	0	24
25	1954	0	36	9.72	0	25
26	1955	0	37	9.46	0	26
27	1956	0	39	8.97	0	27
28	1957	0	41	8.54	0	28
29	1958	0	42	8.33	0	29
30	1959	0	45	7.78	0	30
31	1960	0	46	7.61	0	31
32	1961	0	49	7.14	0	32
33	1962	0	51	6.86	0	33
34	1963	0	52	6.73	0	34
35	1964	0	54	6.48	0	35
36	1965	0	57	6.14	0	36
37	1966	0	58	6.03	0	37
38	1967	0	62	5.65	0	38
39	1968	0	64	5.47	0	39
40	1969	0	69	5.07	0	40
41	1970	0	78	4.49	0	41
42	1971	0	88	3.98	0	42
43	1972	0	95	3.68	0	43
44	1973	0	100	3.50	0	44
45	1974	1,816	109	3.21	5,829	45
46	1975	0	122	2.87	0	46
47	1976	0	131	2.67	0	47
48	1977	4,754	142	2.46	11,695	48
49	1978	0	151	2.32	0	49
50	1979	3,438	160	2.19	7,529	50
51	1980	32,264	170	2.06	66,464	51
52	1981	5,188	185	1.89	9,805	52
53	1982	0	206	1.70	0	53
54	1983	0	218	1.61	0	54
55	1984	1,062	220	1.59	1,689	55
56	1985	5,617	214	1.64	9,212	56
57	1986	37,656	215	1.63	61,379	57
58	1987	7,287	216	1.62	11,805	58
59	1988	3,370	215	1.63	5,493	59
60	1989	3,341	214	1.64	5,479	60
61	1990	13,839	220	1.59	22,004	61
62	1991	5,291	225	1.56	8,254	62
63	1992	0	232	1.51	0	63
64	1993	17,590	236	1.48	26,033	64
65	1994	24,420	239	1.46	35,653	65
66	1995	12,023	247	1.42	17,073	66
67	1996	9,106	254	1.38	12,566	67
68	1997	8,397	257	1.36	11,420	68
69	1998	15,676	265	1.32	20,692	69
70	1999	21,553	275	1.27	27,372	70
71	2000	345,507	285	1.23	424,974	71
72	2001	39,231	299	1.17	45,900	72
73	2002	59,479	309	1.13	67,211	73
74	2003	11,761	318	1.10	12,937	74
75	2004	29,579	327	1.07	31,650	75
76	2005	92,304	337	1.04	95,996	76
77	2006	40,749	345	1.01	41,156	77
78	2007	40,050	350	1.00	40,050	78
79	Total	$ 892,348			$ 1,137,320	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 389 - Land and Land Rights

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	1	1.00	$ 0	1
2	1931	0	1	1.00	0	2
3	1932	0	1	1.00	0	3
4	1933	0	1	1.00	0	4
5	1934	0	1	1.00	0	5
6	1935	0	1	1.00	0	6
7	1936	0	1	1.00	0	7
8	1937	0	1	1.00	0	8
9	1938	0	1	1.00	0	9
10	1939	0	1	1.00	0	10
11	1940	0	1	1.00	0	11
12	1941	0	1	1.00	0	12
13	1942	0	1	1.00	0	13
14	1943	0	1	1.00	0	14
15	1944	0	1	1.00	0	15
16	1945	0	1	1.00	0	16
17	1946	0	1	1.00	0	17
18	1947	0	1	1.00	0	18
19	1948	0	1	1.00	0	19
20	1949	0	1	1.00	0	20
21	1950	0	1	1.00	0	21
22	1951	0	1	1.00	0	22
23	1952	0	1	1.00	0	23
24	1953	0	1	1.00	0	24
25	1954	0	1	1.00	0	25
26	1955	0	1	1.00	0	26
27	1956	0	1	1.00	0	27
28	1957	0	1	1.00	0	28
29	1958	0	1	1.00	0	29
30	1959	0	1	1.00	0	30
31	1960	0	1	1.00	0	31
32	1961	0	1	1.00	0	32
33	1962	0	1	1.00	0	33
34	1963	0	1	1.00	0	34
35	1964	0	1	1.00	0	35
36	1965	0	1	1.00	0	36
37	1966	0	1	1.00	0	37
38	1967	0	1	1.00	0	38
39	1968	0	1	1.00	0	39
40	1969	0	1	1.00	0	40
41	1970	0	1	1.00	0	41
42	1971	0	1	1.00	0	42
43	1972	0	1	1.00	0	43
44	1973	0	1	1.00	0	44
45	1974	0	1	1.00	0	45
46	1975	0	1	1.00	0	46
47	1976	0	1	1.00	0	47
48	1977	0	1	1.00	0	48
49	1978	0	1	1.00	0	49
50	1979	0	1	1.00	0	50
51	1980	0	1	1.00	0	51
52	1981	0	1	1.00	0	52
53	1982	0	1	1.00	0	53
54	1983	0	1	1.00	0	54
55	1984	0	1	1.00	0	55
56	1985	0	1	1.00	0	56
57	1986	0	1	1.00	0	57
58	1987	0	1	1.00	0	58
59	1988	0	1	1.00	0	59
60	1989	248,909	1	1.00	248,909	60
61	1990	0	1	1.00	0	61
62	1991	0	1	1.00	0	62
63	1992	0	1	1.00	0	63
64	1993	142,398	1	1.00	142,398	64
65	1994	0	1	1.00	0	65
66	1995	0	1	1.00	0	66
67	1996	0	1	1.00	0	67
68	1997	0	1	1.00	0	68
69	1998	0	1	1.00	0	69
70	1999	0	1	1.00	0	70
71	2000	0	1	1.00	0	71
72	2001	0	1	1.00	0	72
73	2002	0	1	1.00	0	73
74	2003	0	1	1.00	0	74
75	2004	0	1	1.00	0	75
76	2005	0	1	1.00	0	76
77	2006	0	1	1.00	0	77
78	2007	0	1	1.00	0	78
79	Total	$ 391,307			$ 391,307	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 390 - General Plant Structures

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	19	19.42	$ 0	1
2	1931	0	17	21.71	0	2
3	1932	0	16	23.06	0	3
4	1933	0	17	21.71	0	4
5	1934	0	19	19.42	0	5
6	1935	0	18	20.50	0	6
7	1936	0	19	19.42	0	7
8	1937	0	20	18.45	0	8
9	1938	0	20	18.45	0	9
10	1939	0	20	18.45	0	10
11	1940	0	20	18.45	0	11
12	1941	0	22	16.77	0	12
13	1942	0	23	16.04	0	13
14	1943	0	23	16.04	0	14
15	1944	0	24	15.38	0	15
16	1945	0	24	15.38	0	16
17	1946	0	27	13.67	0	17
18	1947	0	32	11.53	0	18
19	1948	0	36	10.25	0	19
20	1949	0	37	9.97	0	20
21	1950	0	39	9.46	0	21
22	1951	0	42	8.79	0	22
23	1952	0	44	8.39	0	23
24	1953	0	44	8.39	0	24
25	1954	0	46	8.02	0	25
26	1955	0	48	7.69	0	26
27	1956	0	52	7.10	0	27
28	1957	0	55	6.71	0	28
29	1958	0	57	6.47	0	29
30	1959	0	58	6.36	0	30
31	1960	0	59	6.25	0	31
32	1961	0	58	6.36	0	32
33	1962	0	59	6.25	0	33
34	1963	0	60	6.15	0	34
35	1964	0	61	6.05	0	35
36	1965	0	64	5.77	0	36
37	1966	0	65	5.68	0	37
38	1967	0	67	5.51	0	38
39	1968	0	71	5.20	0	39
40	1969	0	75	4.92	0	40
41	1970	0	79	4.67	0	41
42	1971	0	87	4.24	0	42
43	1972	0	93	3.97	0	43
44	1973	0	100	3.69	0	44
45	1974	0	118	3.13	0	45
46	1975	0	133	2.77	0	46
47	1976	0	138	2.67	0	47
48	1977	0	148	2.49	0	48
49	1978	0	161	2.29	0	49
50	1979	0	177	2.08	0	50
51	1980	0	194	1.90	0	51
52	1981	0	204	1.81	0	52
53	1982	2,627	207	1.78	4,676	53
54	1983	115,704	215	1.72	199,011	54
55	1984	428,836	224	1.65	707,579	55
56	1985	116,407	226	1.63	189,743	56
57	1986	31,084	231	1.60	49,734	57
58	1987	581,609	232	1.59	924,758	58
59	1988	1,012,423	233	1.58	1,599,628	59
60	1989	10,112,249	232	1.59	16,078,476	60
61	1990	66,563	237	1.56	103,838	61
62	1991	59,392	233	1.58	93,839	62
63	1992	15,661	238	1.55	24,275	63
64	1993	225,214	250	1.48	333,317	64
65	1994	43,645	261	1.41	61,539	65
66	1995	32,181	265	1.39	44,732	66
67	1996	78,025	176	2.10	163,853	67
68	1997	50,000	282	1.31	65,500	68
69	1998	257,451	285	1.29	332,112	69
70	1999	127,886	287	1.29	164,973	70
71	2000	364,071	295	1.25	455,089	71
72	2001	133,508	303	1.22	162,880	72
73	2002	69,752	310	1.19	83,005	73
74	2003	190,103	320	1.15	218,618	74
75	2004	757,550	342	1.08	818,154	75
76	2005	2,466,847	355	1.04	2,565,521	76
77	2006	259,307	364	1.01	261,900	77
78	2007	330,840	369	1.00	330,840	78
79	Total	$ 17,928,935			$ 26,037,590	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 391 - Office Furniture and Equipment

Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	0	60	5.17	0	36
37	1966	0	62	5.00	0	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	0	74	4.19	0	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	1,110	123	2.52	2,797	46
47	1976	0	130	2.38	0	47
48	1977	1,109	141	2.20	2,440	48
49	1978	0	151	2.05	0	49
50	1979	21,369	164	1.89	40,387	50
51	1980	3,560	178	1.74	6,194	51
52	1981	42,149	186	1.67	70,389	52
53	1982	111,131	203	1.53	170,030	53
54	1983	9,269	209	1.48	13,718	54
55	1984	239,609	212	1.46	349,829	55
56	1985	226,356	211	1.47	332,743	56
57	1986	109,935	218	1.42	156,108	57
58	1987	139,348	226	1.37	190,907	58
59	1988	32,514	219	1.42	46,170	59
60	1989	94,482	213	1.46	137,944	60
61	1990	52,047	228	1.36	70,784	61
62	1991	94,774	242	1.28	121,311	62
63	1992	60,430	249	1.24	74,933	63
64	1993	793,678	260	1.19	944,477	64
65	1994	180,094	257	1.21	217,914	65
66	1995	273,368	246	1.26	344,444	66
67	1996	32,878	250	1.24	40,769	67
68	1997	317,421	251	1.24	393,602	68
69	1998	530,680	254	1.22	647,430	69
70	1999	187,692	261	1.19	223,353	70
71	2000	157,430	268	1.16	182,619	71
72	2001	254,358	280	1.11	282,337	72
73	2002	792,328	289	1.07	847,791	73
74	2003	417,820	293	1.06	442,889	74
75	2004	223,117	298	1.04	232,042	75
76	2005	149,523	303	1.02	152,513	76
77	2006	1,385,103	305	1.02	1,412,805	77
78	2007	2,478,907	310	1.00	2,478,907	78
79	Total	$ 9,413,589			$ 10,630,576	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 391.1 - Computer Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	0	60	5.17	0	36
37	1966	0	62	5.00	0	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	0	74	4.19	0	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	0	123	2.52	0	46
47	1976	0	130	2.38	0	47
48	1977	0	141	2.20	0	48
49	1978	0	151	2.05	0	49
50	1979	0	164	1.89	0	50
51	1980	0	178	1.74	0	51
52	1981	0	186	1.67	0	52
53	1982	0	203	1.53	0	53
54	1983	0	209	1.48	0	54
55	1984	0	212	1.46	0	55
56	1985	0	211	1.47	0	56
57	1986	0	218	1.42	0	57
58	1987	15,509	226	1.37	21,247	58
59	1988	20,788	219	1.42	29,519	59
60	1989	0	213	1.46	0	60
61	1990	13,289	228	1.36	18,073	61
62	1991	0	242	1.28	0	62
63	1992	4,711	249	1.24	5,842	63
64	1993	142,408	260	1.19	169,466	64
65	1994	8,266	257	1.21	10,002	65
66	1995	1,557,156	246	1.26	1,962,017	66
67	1996	970,663	250	1.24	1,203,622	67
68	1997	656,937	251	1.24	814,602	68
69	1998	238,253	254	1.22	290,669	69
70	1999	1,704,416	261	1.19	2,028,255	70
71	2000	420,553	268	1.16	487,841	71
72	2001	926,702	280	1.11	1,028,639	72
73	2002	1,669,071	289	1.07	1,785,906	73
74	2003	991,003	293	1.06	1,050,463	74
75	2004	496,647	298	1.04	516,513	75
76	2005	1,942,958	303	1.02	1,981,817	76
77	2006	2,424,573	305	1.02	2,473,064	77
78	2007	154,932	310	1.00	154,932	78
79	Total	14,358,835			$ 16,032,489	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 392.11 - Transportation Equip. - Light Vehicles

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	0	222	2.09	0	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	0	269	1.72	0	54
55	1984	0	273	1.70	0	55
56	1985	0	276	1.68	0	56
57	1986	0	280	1.65	0	57
58	1987	0	286	1.62	0	58
59	1988	0	295	1.57	0	59
60	1989	0	281	1.65	0	60
61	1990	0	298	1.55	0	61
62	1991	0	320	1.45	0	62
63	1992	0	316	1.47	0	63
64	1993	0	324	1.43	0	64
65	1994	0	331	1.40	0	65
66	1995	76,379	333	1.39	106,167	66
67	1996	37,111	336	1.38	51,213	67
68	1997	60,586	351	1.32	79,974	68
69	1998	134,635	380	1.22	164,255	69
70	1999	97,475	385	1.20	116,970	70
71	2000	176,541	389	1.19	210,084	71
72	2001	477,300	390	1.19	567,987	72
73	2002	177,063	395	1.17	207,164	73
74	2003	317,824	401	1.15	365,498	74
75	2004	701,089	414	1.12	785,220	75
76	2005	520,369	439	1.05	546,387	76
77	2006	548,895	457	1.01	554,384	77
78	2007	170,559	463	1.00	170,559	78
79	Total	$ 3,495,826			$ 3,925,862	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 392.12 - Transportation Equip - Heavy Vehicles

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	0	222	2.09	0	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	0	269	1.72	0	54
55	1984	0	273	1.70	0	55
56	1985	0	276	1.68	0	56
57	1986	0	280	1.65	0	57
58	1987	0	286	1.62	0	58
59	1988	0	295	1.57	0	59
60	1989	0	281	1.65	0	60
61	1990	0	298	1.55	0	61
62	1991	0	320	1.45	0	62
63	1992	0	316	1.47	0	63
64	1993	0	324	1.43	0	64
65	1994	0	331	1.40	0	65
66	1995	0	333	1.39	0	66
67	1996	0	336	1.38	0	67
68	1997	0	351	1.32	0	68
69	1998	0	380	1.22	0	69
70	1999	0	385	1.20	0	70
71	2000	37,640	389	1.19	44,792	71
72	2001	48,663	390	1.19	57,909	72
73	2002	0	395	1.17	0	73
74	2003	0	401	1.15	0	74
75	2004	0	414	1.12	0	75
76	2005	0	439	1.05	0	76
77	2006	0	457	1.01	0	77
78	2007	0	463	1.00	0	78
79	Total	$ 86,303			$ 102,701	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 393 - Stores Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	0	222	2.09	0	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	0	269	1.72	0	54
55	1984	0	273	1.70	0	55
56	1985	9,972	276	1.68	16,753	56
57	1986	0	280	1.65	0	57
58	1987	0	286	1.62	0	58
59	1988	5,765	295	1.57	9,051	59
60	1989	0	281	1.65	0	60
61	1990	0	298	1.55	0	61
62	1991	0	320	1.45	0	62
63	1992	0	316	1.47	0	63
64	1993	4,370	324	1.43	6,249	64
65	1994	0	331	1.40	0	65
66	1995	0	333	1.39	0	66
67	1996	0	336	1.38	0	67
68	1997	0	351	1.32	0	68
69	1998	0	380	1.22	0	69
70	1999	0	385	1.20	0	70
71	2000	0	389	1.19	0	71
72	2001	0	390	1.19	0	72
73	2002	3,999	395	1.17	4,679	73
74	2003	0	401	1.15	0	74
75	2004	0	414	1.12	0	75
76	2005	0	439	1.05	0	76
77	2006	0	457	1.01	0	77
78	2007	0	463	1.00	0	78
79	Total	$ 24,106			$ 36,732	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 394 - Tools, Shop, and Garage Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	0	222	2.09	0	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	0	269	1.72	0	54
55	1984	0	273	1.70	0	55
56	1985	0	276	1.68	0	56
57	1986	0	280	1.65	0	57
58	1987	3,127	286	1.62	5,066	58
59	1988	0	295	1.57	0	59
60	1989	1,667	281	1.65	2,751	60
61	1990	0	298	1.55	0	61
62	1991	0	320	1.45	0	62
63	1992	18,955	316	1.47	27,864	63
64	1993	10,828	324	1.43	15,484	64
65	1994	21,272	331	1.40	29,781	65
66	1995	6,222	333	1.39	8,649	66
67	1996	7,203	336	1.38	9,940	67
68	1997	0	351	1.32	0	68
69	1998	0	380	1.22	0	69
70	1999	21,393	385	1.20	25,672	70
71	2000	16,336	389	1.19	19,440	71
72	2001	36,762	390	1.19	43,747	72
73	2002	3,117	395	1.17	3,647	73
74	2003	19,712	401	1.15	22,669	74
75	2004	33,759	414	1.12	37,810	75
76	2005	26,730	439	1.05	28,067	76
77	2006	5,013	457	1.01	5,063	77
78	2007	0	463	1.00	0	78
79	Total	$ 232,096			$ 285,650	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 395 - Laboratory Equipment

Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	0	60	5.17	0	36
37	1966	0	62	5.00	0	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	0	74	4.19	0	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	0	123	2.52	0	46
47	1976	0	130	2.38	0	47
48	1977	0	141	2.20	0	48
49	1978	0	151	2.05	0	49
50	1979	0	164	1.89	0	50
51	1980	0	178	1.74	0	51
52	1981	0	186	1.67	0	52
53	1982	0	203	1.53	0	53
54	1983	15,956	209	1.48	23,615	54
55	1984	0	212	1.46	0	55
56	1985	0	211	1.47	0	56
57	1986	0	218	1.42	0	57
58	1987	2,948	226	1.37	4,039	58
59	1988	0	219	1.42	0	59
60	1989	53,551	213	1.46	78,184	60
61	1990	11,519	228	1.36	15,666	61
62	1991	51,141	242	1.28	65,460	62
63	1992	1,364	249	1.24	1,691	63
64	1993	16,254	260	1.19	19,342	64
65	1994	2,387	257	1.21	2,888	65
66	1995	6,021	246	1.26	7,586	66
67	1996	2,723	250	1.24	3,377	67
68	1997	0	251	1.24	0	68
69	1998	0	254	1.22	0	69
70	1999	0	261	1.19	0	70
71	2000	0	268	1.16	0	71
72	2001	0	280	1.11	0	72
73	2002	46,969	289	1.07	50,257	73
74	2003	0	293	1.06	0	74
75	2004	15,738	298	1.04	16,368	75
76	2005	44,639	303	1.02	45,532	76
77	2006	0	305	1.02	0	77
78	2007	9,868	310	1.00	9,868	78
79	Total	$ 281,078			$ 343,873	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 397 - Communication Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	15	23.33	$ 0	1
2	1931	0	15	23.33	0	2
3	1932	0	15	23.33	0	3
4	1933	0	15	23.33	0	4
5	1934	0	15	23.33	0	5
6	1935	0	15	23.33	0	6
7	1936	0	15	23.33	0	7
8	1937	0	17	20.59	0	8
9	1938	0	17	20.59	0	9
10	1939	0	17	20.59	0	10
11	1940	0	17	20.59	0	11
12	1941	0	18	19.44	0	12
13	1942	0	19	18.42	0	13
14	1943	0	19	18.42	0	14
15	1944	0	19	18.42	0	15
16	1945	0	19	18.42	0	16
17	1946	0	21	16.67	0	17
18	1947	0	24	14.58	0	18
19	1948	0	26	13.46	0	19
20	1949	0	28	12.50	0	20
21	1950	0	30	11.67	0	21
22	1951	0	31	11.29	0	22
23	1952	0	33	10.61	0	23
24	1953	0	34	10.29	0	24
25	1954	0	36	9.72	0	25
26	1955	0	37	9.46	0	26
27	1956	0	39	8.97	0	27
28	1957	0	41	8.54	0	28
29	1958	0	42	8.33	0	29
30	1959	0	45	7.78	0	30
31	1960	0	46	7.61	0	31
32	1961	0	49	7.14	0	32
33	1962	0	51	6.86	0	33
34	1963	0	52	6.73	0	34
35	1964	0	54	6.48	0	35
36	1965	0	57	6.14	0	36
37	1966	0	58	6.03	0	37
38	1967	0	62	5.65	0	38
39	1968	0	64	5.47	0	39
40	1969	0	69	5.07	0	40
41	1970	0	78	4.49	0	41
42	1971	0	88	3.98	0	42
43	1972	0	95	3.68	0	43
44	1973	0	100	3.50	0	44
45	1974	0	109	3.21	0	45
46	1975	0	122	2.87	0	46
47	1976	0	131	2.67	0	47
48	1977	0	142	2.46	0	48
49	1978	0	151	2.32	0	49
50	1979	0	160	2.19	0	50
51	1980	0	170	2.06	0	51
52	1981	0	185	1.89	0	52
53	1982	0	206	1.70	0	53
54	1983	0	218	1.61	0	54
55	1984	0	220	1.59	0	55
56	1985	2,036	214	1.64	3,339	56
57	1986	0	215	1.63	0	57
58	1987	0	216	1.62	0	58
59	1988	108,194	215	1.63	176,356	59
60	1989	0	214	1.64	0	60
61	1990	0	220	1.59	0	61
62	1991	0	225	1.56	0	62
63	1992	0	232	1.51	0	63
64	1993	10,150	236	1.48	15,022	64
65	1994	503,169	239	1.46	734,627	65
66	1995	107,946	247	1.42	153,283	66
67	1996	1,840,500	254	1.38	2,539,890	67
68	1997	230,627	257	1.36	313,653	68
69	1998	502,642	265	1.32	663,487	69
70	1999	61,658	275	1.27	78,306	70
71	2000	450,007	285	1.23	553,509	71
72	2001	113,486	299	1.17	132,779	72
73	2002	594,260	309	1.13	671,514	73
74	2003	287,842	318	1.10	316,626	74
75	2004	57,462	327	1.07	61,484	75
76	2005	439,560	337	1.04	457,142	76
77	2006	41,782	345	1.01	42,200	77
78	2007	312,512	350	1.00	312,512	78
79	Total	$ 5,663,833			$ 7,225,729	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 398 - Miscellaneous Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	15	23.33	$ 0	1
2	1931	0	15	23.33	0	2
3	1932	0	15	23.33	0	3
4	1933	0	15	23.33	0	4
5	1934	0	15	23.33	0	5
6	1935	0	15	23.33	0	6
7	1936	0	15	23.33	0	7
8	1937	0	17	20.59	0	8
9	1938	0	17	20.59	0	9
10	1939	0	17	20.59	0	10
11	1940	0	17	20.59	0	11
12	1941	0	18	19.44	0	12
13	1942	0	19	18.42	0	13
14	1943	0	19	18.42	0	14
15	1944	0	19	18.42	0	15
16	1945	0	19	18.42	0	16
17	1946	0	21	16.67	0	17
18	1947	0	24	14.58	0	18
19	1948	0	26	13.46	0	19
20	1949	0	28	12.50	0	20
21	1950	0	30	11.67	0	21
22	1951	0	31	11.29	0	22
23	1952	0	33	10.61	0	23
24	1953	0	34	10.29	0	24
25	1954	0	36	9.72	0	25
26	1955	0	37	9.46	0	26
27	1956	0	39	8.97	0	27
28	1957	0	41	8.54	0	28
29	1958	0	42	8.33	0	29
30	1959	0	45	7.78	0	30
31	1960	0	46	7.61	0	31
32	1961	0	49	7.14	0	32
33	1962	0	51	6.86	0	33
34	1963	0	52	6.73	0	34
35	1964	0	54	6.48	0	35
36	1965	0	57	6.14	0	36
37	1966	0	58	6.03	0	37
38	1967	0	62	5.65	0	38
39	1968	0	64	5.47	0	39
40	1969	0	69	5.07	0	40
41	1970	0	78	4.49	0	41
42	1971	0	88	3.98	0	42
43	1972	0	95	3.68	0	43
44	1973	0	100	3.50	0	44
45	1974	0	109	3.21	0	45
46	1975	0	122	2.87	0	46
47	1976	0	131	2.67	0	47
48	1977	0	142	2.46	0	48
49	1978	0	151	2.32	0	49
50	1979	2,094	160	2.19	4,586	50
51	1980	14,327	170	2.06	29,514	51
52	1981	0	185	1.89	0	52
53	1982	6,931	206	1.70	11,783	53
54	1983	28,541	218	1.61	45,951	54
55	1984	0	220	1.59	0	55
56	1985	13,167	214	1.64	21,594	56
57	1986	2,224	215	1.63	3,625	57
58	1987	32,389	216	1.62	52,470	58
59	1988	17,166	215	1.63	27,981	59
60	1989	6,073	214	1.64	9,960	60
61	1990	5,679	220	1.59	9,030	61
62	1991	0	225	1.56	0	62
63	1992	0	232	1.51	0	63
64	1993	5,876	236	1.48	8,696	64
65	1994	4,570	239	1.46	6,672	65
66	1995	9,222	247	1.42	13,095	66
67	1996	21,868	254	1.38	30,178	67
68	1997	0	257	1.36	0	68
69	1998	16,533	265	1.32	21,824	69
70	1999	78,187	275	1.27	99,297	70
71	2000	21,260	285	1.23	26,150	71
72	2001	59,053	299	1.17	69,092	72
73	2002	130,344	309	1.13	147,289	73
74	2003	235,306	318	1.10	258,837	74
75	2004	33,110	327	1.07	35,428	75
76	2005	40,768	337	1.04	42,399	76
77	2006	97,566	345	1.01	98,542	77
78	2007	0	350	1.00	0	78
79	Total	$ 882,254			$ 1,073,993	79

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF WORKING CAPITAL ALLOWANCE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Reference		Balance	Line No.
	(a)	(b)		(c)	
1	Cash Working Capital	B-5, Sh 2	$	(10,379,937)	1
2	Materials and Supplies	B-5, Sh 3		12,389,898	2
3	Prepayments	B-5, Sh 4		3,671,971	3
4	Total Working Capital		$	5,681,932	4
				B-1, Sh 1	

SOUTHWEST GAS CORPORATION
ARIZONA
LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description [1] (a)	Cost (b)	Lag Days (c)	Dollar Days (d)	Line No.
1	Cost of Gas [2]	$ 540,064,385	42.30	22,842,405,297	1
2	Labor Cost	117,038,570	12.33	1,443,650,156	2
3	Provision for Uncollected Accounts	2,977,729	120.00	357,327,523	3
4	Other O & M Expenses	54,826,860	8.40	460,689,209	4
5	Total O & M Expenses	$ 714,907,545	35.12	25,104,072,186	5
6	Interest	48,035,008	84.65	4,066,302,142	6
7	Taxes Other Than Income Taxes	33,124,880	185.34	6,139,365,177	7
8	Income Taxes-Current	21,699,571	37.00	802,884,115	8
9	Total Operating Expenses	$ 817,767,003	44.16	36,112,623,619	9
10	Number of Days in Test Period	365			10
11	Average Daily Operating Expense	$ 2,240,458			11
12	Lag in Receipt of Revenue		39.53		12
13	Net Difference Revenue-Expense Lag	(4.63)			13
14	Cash Working Capital	$ (10,379,937)			14
		B-5, Sh 1			

[1] Supporting Workpapers B-5.
[2] Gas costs adjusted for present volumes and rates to synchronize with gas cost adjustment.

SOUTHWEST GAS CORPORATION
ARIZONA
MATERIALS AND SUPPLIES
FOR THE THIRTEEN MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number [1] 154	155	163	System Allocable	Total Materials and Supplies	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	April 2006	$ 10,597,125	$ 32,492	$ 279,910	$ (15,105)	$ 10,894,422	1
2	May	11,983,908	33,770	271,892	(15,266)	12,274,304	2
3	June	11,689,534	34,098	182,004	(15,364)	11,890,271	3
4	July	11,770,954	36,340	170,741	(15,553)	11,962,482	4
5	August	11,445,271	39,575	292,884	(15,638)	11,762,092	5
6	September	11,495,118	36,003	546,932	(15,730)	12,062,323	6
7	October	12,297,156	37,707	712,071	(15,751)	13,031,182	7
8	November	12,188,899	34,120	828,671	(13,992)	13,037,698	8
9	December	11,943,342	32,556	1,063,757	(14,070)	13,025,585	9
10	January 2007	11,734,137	33,185	914,604	(15,954)	12,665,971	10
11	February	10,991,050	34,695	1,082,310	(16,071)	12,091,985	11
12	March	12,320,228	32,740	1,363,463	(16,207)	13,700,223	12
13	April	11,644,649	32,332	1,009,492	(16,343)	12,670,131	13
14	Thirteen Month Total	$ 152,101,370	$ 449,613	$ 8,718,730	$ (201,044)	$ 161,068,668	14
15	Thirteen Month Average	$ 11,700,105	$ 34,586	$ 670,672	$ (15,465)	$ 12,389,898	15

B-5, Sh 1

Note:
System Allocable includes common inventory accounts for 154, 155 and 163 after 4-Factor allocation on Supporting Schedule C-1, Sh 17 of 56.70%.

[1] Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
PREPAYMENTS
FOR THE THIRTEEN MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Balance [1] (b)	4-Factor [2] (c)	Allocation (d)	Line No.
1	April 2006	$ 5,367,019			1
2	May	4,571,452			2
3	June	3,756,402			3
4	July	5,219,958			4
5	August	9,299,535			5
6	September	8,623,454			6
7	October	7,836,438			7
8	November	6,430,014			8
9	December	9,144,710			9
10	January 2007	8,343,687			10
11	February	7,723,320			11
12	March	6,044,664			12
13	April	5,600,962			13
14	Thirteen Month Total	$ 87,961,615			14
15	13 Month Average	$ 6,766,278			15
16	Deferred Taxes	(290,138)			16
17	Net of Deferred Tax	$ 6,476,140	56.70%	$ 3,671,971	17
				B-5, Sh 1	

[1] Eligible Prepayments - Account 165. Supporting Workpapers B-5
[2] Supporting Schedule C-1, Sh 17

SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMER ADVANCES FOR CONSTRUCTION
FOR THE THIRTEEN MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Balance [1] (b)	Line No.
1	April 2006	$ 25,965,152	1
2	May	27,771,678	2
3	June	30,949,084	3
4	July	32,596,096	4
5	August	35,041,274	5
6	September	36,572,843	6
7	October	38,058,790	7
8	November	38,732,669	8
9	December	41,078,966	9
10	January 2007	43,365,612	10
11	February	45,355,426	11
12	March	48,147,845	12
13	April	49,194,789	13
14	Thirteen Month Total	$ 492,830,224	14
15	Thirteen Month Average	$ 37,910,017	15
		B-1, Sh 1	

[1] Source: Company Records, Account 252

SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMER DEPOSITS
FOR THE THIRTEEN MONTHS ENDED APRIL 30, 2007

Line No.	Description	Balance [1]	Line No.
	(a)	(b)	
1	April 2006	$ 29,940,533	1
2	May	30,244,307	2
3	June	30,534,168	3
4	July	30,907,667	4
5	August	31,068,422	5
6	September	31,294,649	6
7	October	31,925,334	7
8	November	32,387,660	8
9	December	32,677,847	9
10	January 2007	32,866,855	10
11	February	33,171,595	11
12	March	33,562,862	12
13	April	34,402,771	13
14	Thirteen Month Total	$ 414,984,669	14
15	Thirteen Month Average	$ 31,921,898	15
		B-1, Sh 1	

[1] Source: Company Records, Account 235
(excludes 235.0 1330)

SOUTHWEST GAS CORPORATION
DEFERRED TAXES
AT APRIL 30, 2007

Line No.	Description [1] (a)	Arizona (b)	System Allocable Allocation (c)	Recorded Deferred Tax (d)	Line No.
1	Account 282\Deferred Tax Liability	$ 154,353,059	$ 9,156,387	$ 163,509,446	1
2	Account 190\Deferred Tax Asset	0	(20,877,149)	(20,877,149)	2
3	Total	$ 154,353,059	$ (11,720,762)	$ 142,632,297	3
				B-1, Sh 1	

Deferred Tax Detail
Arizona

	Description	Federal	State	Total Recorded	
4	Account 282\Deferred Tax Liability	$ 138,065,125	$ 16,287,934	$ 154,353,059	4
5	Account 190\Deferred Tax Asset	0	0	0	5
6	Total	$ 138,065,125	$ 16,287,934	$ 154,353,059	6

System Allocable

	Description [1]	Recorded	
7	Account 282\Deferred Tax Liability	$ 16,148,831	7
8	4-Factor [2]	56.70%	8
9	Arizona Allocation	$ 9,156,387	9
10	Account 190\Deferred Tax Asset	$ (36,820,369)	10
11	4-Factor [2]	56.70%	11
12	Arizona Allocation	$ (20,877,149)	12
		Ln 2, Col (c)	

[1] Source: Company Records
[2] Supporting Schedule C-1, Sh 17

SCHEDULE B-6
Sheet 3 of 3

Volume II

Supporting Schedules

C

SOUTHWEST GAS CORPORATION
ARIZONA
ADJUSTED TEST YEAR INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Reference Sch C-1, Sheet	Recorded at 04/30/07	Adjustments	Adjusted at 04/30/07	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Revenues	2	$ 996,389,570	$ (597,154,892)	$ 399,234,678	1
2	Gas Cost	C-2, Adj 2	593,424,664	(593,424,664)	0	2
3	Total Margin		$ 402,964,907	$ (3,730,229)	$ 399,234,678	3
	Expenses					
4	Other Gas Supply	3	$ 685,079	$ 16,522	$ 701,601	4
5	Distribution	3	87,644,582	1,883,873	89,528,455	5
6	Customer Accounts	3	37,800,950	929,959	38,730,909	6
7	Customer Information	4	1,320,355	(193,559)	1,126,796	7
8	Sales	4	230,155	(230,155)	0	8
	Administrative & General					
9	Direct	9, 10, 13	4,018,714	(9,175)	4,009,539	9
10	System Allocable	9, 12, 13	49,951,482	2,985,673	52,937,155	10
	Depreciation & Amortization					
11	Direct	14, Ln 1 + 2	77,709,373	3,246,873	80,956,247	11
12	System Allocable	14, Ln 10	6,721,772	(74,834)	6,646,938	12
13	Regulatory Amortizations	14, Ln 3 + 4	2,234,576	(1,950,048)	284,528	13
14	Other Taxes	15	28,912,193	4,212,687	33,124,880	14
15	Interest On Customer Deposits	C-2, Adj 16	1,856,153	59,161	1,915,314	15
16	Income Taxes	16	21,941,766	(5,849,548)	16,092,218	16
17	Total Expenses		$ 321,027,150	$ 5,027,429	$ 326,054,579	17
18	Net Income		$ 81,937,757	$ (8,757,658)	$ 73,180,099	18

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
ADJUSTED SALES AND REVENUES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Recorded At 4/30/2007	Adjustment No. 1	Test Period Balance As Adjusted	Line No.
	(a)	(b)	(c)	(d)	
1	Sales Quantity (therms)	699,988,330	(35,386,981)	664,601,349	1
2	Revenue	$ 996,389,570	$(597,154,892)	$ 399,234,678	2
3	Total Revenue Adjustment		$(597,154,892)		3

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description (a)	Account Number (b)	Recorded at 04/30/07 (c)	Adjustments (d)	Adjusted at 04/30/07 (e)	Line No.
	Gas Supply Expenses					
1	Natural Gas Transmission Line Purchases	803	$ 497,594,745	$ (497,594,745)	$ 0	1
2	Purchased Gas Cost Adjustments	805.1	35,473,742	(35,473,742)	0	2
3	Gas Used for Compressor Station Fuel	810	0	0	0	3
4	Other Gas Supply Expenses	813	685,079	16,522	701,601	4
5	Total Other Gas Supply Expenses		$ 533,753,566	$ (533,051,965)	$ 701,601	5
	Transmission Expenses					
6	Trans. and Compression of Gas by Others	858	$ 60,356,176	$ (60,356,176)	$ 0	6
	Distribution Expenses					
7	Operation Supervision and Engineering	870	$ 10,284,450	$ 164,824	$ 10,449,274	7
8	Distribution Load Dispatching	871	365,012	6,776	371,788	8
9	Mains and Services Expenses	874	11,538,999	160,370	11,699,369	9
10	Measuring and Regulating Expenses - General	875	2,508,768	48,137	2,556,906	10
11	Meter and House Regulator Expenses	878	7,953,431	179,386	8,132,818	11
12	Customer Installation Expenses	879	9,368,426	209,595	9,578,022	12
13	Other Expenses	880	11,077,820	1,252	11,079,072	13
14	Rents	881	2,250,258	0	2,250,258	14
15	Maintenance Supervision and Engineering	885	3,063,149	72,731	3,135,880	15
16	Maintenance of Structures and Improvements	886	106,729	698	107,427	16
17	Maintenance of Mains	887	14,780,019	763,708	15,543,726	17
18	Maintenance of Meas. and Reg. Sta. Equip.	889	2,003,667	38,126	2,041,794	18
19	Maintenance of Services	892	9,932,954	199,704	10,132,658	19
20	Maintenance of Meters and House Regulators	893	2,029,799	33,418	2,063,217	20
21	Maintenance of Other Equipment	894	381,100	5,147	386,247	21
22	Total Distribution Expenses		$ 87,644,582	$ 1,883,873	$ 89,528,455	22
	Customer Accounts Expenses					
23	Supervision	901	$ 4,262,958	$ 106,518	$ 4,369,476	23
24	Meter Reading	902	6,927,716	126,770	7,054,485	24
25	Customer Records and Collection Expenses	903	23,221,791	686,168	23,907,959	25
26	Uncollectible Accounts	904	2,977,729	0	2,977,729	26
27	Miscellaneous Customer Accounts Expenses	905	410,756	10,504	421,260	27
28	Total Customer Accounts Expenses		$ 37,800,950	$ 929,959	$ 38,730,909	28

Supporting Schedules C-1, Sh 5-7

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description (a)	Account Number (b)	Recorded at 04/30/07 (c)	Adjustments (d)	Adjusted at 04/30/07 (e)	Line No.
	Customer Service and Informational Expenses					
1	Customer Assistance Expenses	908	$ 1,217,452	$ (137,759)	$ 1,079,693	1
2	Inform. and Instruc. Advertising Expenses	909	35,525	(10,400)	25,125	2
3	Misc. Customer Service and Inform. Expenses	910	67,377	(45,400)	21,977	3
4	Total Customer Service and Informational Expenses		$ 1,320,355	$ (193,559)	$ 1,126,796	4
	Sales Expenses					
5	Supervision	911	$ 0	$ 0	$ 0	5
6	Demonstrating and Selling Expenses	912	0	0	0	6
7	Advertising Expenses	913	230,155	(230,155)	0	7
8	Total Sales Expenses		$ 230,155	$ (230,155)	$ 0	8
9	Total Operation and Maintenance Expenses		$ 721,105,785	$ (591,018,024)	$ 130,087,761	9
	Administrative and General Expenses					
10	Administrative and General Salaries	920	$ 32,197,506	$ 570,687	$ 32,768,193	10
11	Office Supplies and Expenses	921	5,852,900	(5,657)	5,847,243	11
12	Admin. and Gen. Exp. Transferred - Credit	922	(5,306,010)	(93,963)	(5,399,973)	12
13	Outside Services Employed	923	5,826,032	7,789	5,833,821	13
14	Property Insurance	924	205,169	(3,563)	201,606	14
15	Injuries and Damages	925	5,678,766	2,490,088	8,168,854	15
16	Employee Pension and Benefits	926	53,270	0	53,270	16
17	Regulatory Commission Expenses	928	125,693	(33,693)	92,000	17
18	Miscellaneous General Expenses	930	3,704,733	9,716	3,714,448	18
19	Rents	931	2,525,009	4,443	2,529,452	19
20	Maintenance of General Plant	935	3,107,127	30,652	3,137,779	20
21	Total Administrative and General Expenses		$ 53,970,196	$ 2,976,498	$ 56,946,694	21
22	Total Operation, Maintenance and Administrative General Expenses		$ 775,075,980	$ (588,041,525)	$ 187,034,455	22

Supporting Schedules C-1, Sh 8-13

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Recorded at 04/30/07	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Customer Billing Annualization Adj. No. 4	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Leak Survey and Repair Adj. No. 8	Surcharge Adjustment Adj. No. 9	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Gas Supply Expenses												
1	Natural Gas Transmission Line Purchases	803	$ 497,594,745	$ (497,594,745)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2	Purchased Gas Cost Adjustments	805.1	35,473,742	(35,473,742)	0	0	0	0	0	0	0	0	2
3	Gas Used for Compressor Station Fuel	810	0	0	0	0	0	0	0	0	0	0	3
4	Total Gas Supply Expenses		$ 533,068,487	$ (533,068,487)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	4
	Other Gas Costs												
	Other Gas Supply Expenses	813											
5	Labor		$ 395,051	$ 0	$ 16,354	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 411,405	5
6	Labor Loadings		230,046	0	168	0	0	0	0	0	0	230,214	6
7	Materials and Expenses		59,983	0	0	0	0	0	0	0	0	59,983	7
8	Total		$ 685,079	$ 0	$ 16,522	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 701,601	8
	Transmission Expenses												
	Transmission and Compression of Gas	858											
9	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	9
10	Labor Loadings		0	0	0	0	0	0	0	0	0	0	10
11	Materials and Expenses		60,356,176	(60,356,176)	0	0	0	0	0	0	0	0	11
12	Total		$ 60,356,176	$ (60,356,176)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
	Distribution Expenses												
	Operation												
	Operation Supervision and Engineering	870											
13	Labor		$ 5,432,837	$ 0	$ 269,456	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 5,702,293	13
14	Labor Loadings		3,324,229	0	(35,615)	0	0	0	0	0	0	3,288,613	14
15	Materials and Expenses		1,527,384	0	0	0	(13,837)	(55,179)	0	0	0	1,458,368	15
16	Total		$ 10,284,450	$ 0	$ 233,841	$ 0	$ (13,837)	$ (55,179)	$ 0	$ 0	$ 0	$ 10,449,274	16
	Distribution Load Dispatching	871											
17	Labor		$ 157,302	$ 0	$ 6,786	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 164,089	17
18	Labor Loadings		94,460	0	(10)	0	0	0	0	0	0	94,450	18
19	Materials and Expenses		113,250	0	0	0	0	0	0	0	0	113,250	19
20	Total		$ 365,012	$ 0	$ 6,776	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 371,788	20
	Mains and Services Expenses	874											
21	Labor		$ 3,721,975	$ 0	$ 185,450	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,907,425	21
22	Labor Loadings		2,276,795	0	(25,080)	0	0	0	0	0	0	2,251,715	22
23	Materials and Expenses		5,540,228	0	0	0	0	0	0	0	0	5,540,228	23
24	Total		$ 11,538,999	$ 0	$ 160,370	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 11,699,369	24
	Measuring and Regulating Station Expenses	875											
25	Labor		$ 1,123,829	$ 0	$ 55,995	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,179,824	25
26	Labor Loadings		687,366	0	(7,571)	0	0	0	0	0	0	679,795	26
27	Materials and Expenses		697,574	0	0	0	(286)	0	0	0		697,287	27
28	Total		$ 2,508,768	$ 0	$ 48,424	$ 0	$ (286)	$ 0	$ 0	$ 0	$ 0	$ 2,556,906	28
	Meter and House Regulator Expenses	878											
29	Labor		$ 4,168,770	$ 0	$ 207,711	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,376,482	29
30	Labor Loadings		2,571,424	0	(28,325)	0	0	0	0	0	0	2,543,099	30
31	Materials and Expenses		1,213,237	0	0	0	0	0	0	0	0	1,213,237	31
32	Total		$ 7,953,431	$ 0	$ 179,386	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 8,132,818	32
	Customer Installation Expenses	879											
33	Labor		$ 4,871,260	$ 0	$ 242,713	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 5,113,973	33
34	Labor Loadings		3,006,582	0	(33,118)	0	0	0	0	0	0	2,973,464	34
35	Materials and Expenses		1,490,584	0	0	0	0	0	0	0	0	1,490,584	35
36	Total		$ 9,368,426	$ 0	$ 209,595	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 9,578,022	36

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Recorded at 04/30/07	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Customer Billing Annualization Adj. No. 4	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Leak Survey and Repair Adj. No. 8	Surcharge Adjustment Adj. No. 9	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Other Expenses	880											
1	Labor		$ 3,961,678	$ 0	$ 194,282	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,155,960	1
2	Labor Loadings		2,411,926	0	(24,052)	0	0	0	0	0	0	2,387,874	2
3	Materials and Expenses		4,704,216	0	0	0	(168,977)	0	0	0	0	4,535,239	3
4	Total		$ 11,077,820	$ 0	$ 170,230	$ 0	$ (168,977)	$ 0	$ 0	$ 0	$ 0	$ 11,079,072	4
	Rents	881											
5	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
6	Labor Loadings		0	0	0	0	0	0	0	0	0	0	6
7	Materials and Expenses		2,250,258	0	0	0	0	0	0	0	0	2,250,258	7
8	Total		$ 2,250,258	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,250,258	8
	Maintenance												
	Maintenance Supervision and Engineering	885											
9	Labor		$ 1,690,204	$ 0	$ 83,771	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,773,975	9
10	Labor Loadings		1,034,883	0	(11,040)	0	0	0	0	0	0	1,023,843	10
11	Materials and Expenses		338,062	0	0	0	0	0	0	0	0	338,062	11
12	Total		$ 3,063,149	$ 0	$ 72,731	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,135,880	12
	Maintenance of Structures and Improvements	886											
13	Labor		$ 16,168	$ 0	$ 806	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 16,974	13
14	Labor Loadings		9,808	0	(108)	0	0	0	0	0	0	9,700	14
15	Materials and Expenses		80,753	0	0	0	0	0	0	0	0	80,753	15
16	Total		$ 106,729	$ 0	$ 698	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 107,427	16
	Maintenance of Mains	887											
17	Labor		$ 5,132,018	$ 0	$ 255,705	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 5,387,723	17
18	Labor Loadings		3,146,953	0	(34,664)	0	0	0	0	0	0	3,112,289	18
19	Materials and Expenses		6,501,048	0	0	0	0	0	113,670	(143,226)	572,224	7,043,715	19
20	Total		$ 14,780,019	$ 0	$ 221,041	$ 0	$ 0	$ 0	$ 113,670	$ (143,226)	$ 572,224	$ 15,543,726	20
	Maint. of Meas. & Reg. Station Equipment	889											
21	Labor		$ 884,322	$ 0	$ 44,062	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 928,384	21
22	Labor Loadings		538,866	0	(5,936)	0	0	0	0	0	0	532,930	22
23	Materials and Expenses		580,480	0	0	0	0	0	0	0	0	580,480	23
24	Total		$ 2,003,667	$ 0	$ 38,126	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,041,794	24
	Maintenance of Services	892											
25	Labor		$ 3,713,870	$ 0	$ 185,045	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,898,915	25
26	Labor Loadings		2,285,768	0	(25,178)	0	0	0	0	0	0	2,260,590	26
27	Materials and Expenses		3,933,316	0	0	0	0	0	113,670	(73,832)	0	3,973,153	27
28	Total		$ 9,932,954	$ 0	$ 159,866	$ 0	$ 0	$ 0	$ 113,670	$ (73,832)	$ 0	$ 10,132,658	28
	Maintenance of Meters and House Regulators	893											
29	Labor		$ 775,241	$ 0	$ 38,627	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 813,868	29
30	Labor Loadings		472,875	0	(5,209)	0	0	0	0	0	0	467,666	30
31	Materials and Expenses		781,684	0	0	0	0	0	0	0	0	781,684	31
32	Total		$ 2,029,799	$ 0	$ 33,418	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,063,217	32
	Maintenance of Other Equipment	894											
33	Labor		$ 119,238	$ 0	$ 5,941	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 125,180	33
34	Labor Loadings		72,151	0	(795)	0	0	0	0	0	0	71,356	34
35	Materials and Expenses		189,711	0	0	0	0	0	0	0	0	189,711	35
36	Total		$ 381,100	$ 0	$ 5,147	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 386,247	36
	Total Distribution Expenses												
37	Labor		$ 35,768,714	$ 0	$ 1,776,349	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 37,545,063	37
38	Labor Loadings		21,934,085	0	(236,701)	0	0	0	0	0	0	21,697,383	38
39	Materials and Expenses		29,941,784	0	0	0	(183,101)	(55,179)	227,339	(217,058)	572,224	30,286,009	39
40	Total		$ 87,644,582	$ 0	$ 1,539,648	$ 0	$ (183,101)	$ (55,179)	$ 227,339	$ (217,058)	$ 572,224	$ 89,528,455	40

SCHEDULE C-1
Sheet 6 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Recorded at 04/30/07	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Customer Billing Annualization Adj. No. 4	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Leak Survey and Repair Adj. No. 8	Surcharge Adjustment Adj. No. 9	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Customer Accounts Expenses												
	Operation												
	Supervision	901											
1	Labor		$ 2,472,697	$ 0	$ 123,203	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,595,900	1
2	Labor Loadings		1,514,764	0	(16,686)	0	0	0	0	0	0	1,498,079	2
3	Materials and Expenses		275,497	0	0	0	0	0	0	0	0	275,497	3
4	Total		$ 4,262,958	$ 0	$ 106,518	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,369,476	4
	Meter Reading Expenses	902											
5	Labor		$ 2,940,669	$ 0	$ 146,520	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,087,190	5
6	Labor Loadings		1,793,044	0	(19,751)	0	0	0	0	0	0	1,773,293	6
7	Materials and Expenses		2,194,002	0	0	0	0	0	0	0	0	2,194,002	7
8	Total		$ 6,927,716	$ 0	$ 126,770	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 7,054,485	8
	Customer Records and Collections - Division	903											
9	Labor		$ 9,707,531	$ 0	$ 508,848	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 10,216,379	9
10	Labor Loadings		5,903,813	0	(57,725)	0	0	0	0	0	0	5,846,088	10
11	Materials and Expenses		6,969,822	0	0	285,239	(48,126)	0	0	0	0	7,206,935	11
12	Total		$ 22,581,166	$ 0	$ 451,123	$ 285,239	$ (48,126)	$ 0	$ 0	$ 0	$ 0	$ 23,269,402	12
	Customer Records and Collections - Allocation	903											
13	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	13
14	Labor Loadings		0	0	0	0	0	0	0	0	0	0	14
15	Materials and Expenses		640,625	0	0	0	(2,068)	0	0	0	0	638,557	15
16	Total		$ 640,625	$ 0	$ 0	$ 0	$ (2,068)	$ 0	$ 0	$ 0	$ 0	$ 638,557	16
	Uncollectible Accounts Expenses	904											
17	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	17
18	Labor Loadings		0	0	0	0	0	0	0	0	0	0	18
19	Materials and Expenses		2,977,729	0	0	0	0	0	0	0	0	2,977,729	19
20	Total		$ 2,977,729	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,977,729	20
	Miscellaneous Customer Accounts Expenses	905											
21	Labor		$ 243,969	$ 0	$ 12,156	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 256,125	21
22	Labor Loadings		149,992	0	(1,652)	0	0	0	0	0	0	148,340	22
23	Materials and Expenses		16,795	0	0	0	0	0	0	0	0	16,795	23
24	Total		$ 410,756	$ 0	$ 10,504	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 421,260	24
	Total Customer Accounts Expenses												
25	Labor		$ 15,364,865	$ 0	$ 790,727	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 16,155,593	25
26	Labor Loadings		9,361,613	0	(95,813)	0	0	0	0	0	0	9,265,800	26
27	Materials and Expenses		13,074,471	0	0	285,239	(50,194)	0	0	0	0	13,309,516	27
28	Total		$ 37,800,950	$ 0	$ 694,914	$ 285,239	$ (50,194)	$ 0	$ 0	$ 0	$ 0	$ 38,730,909	28

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Sheet 7 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Recorded at 04/30/07	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Customer Billing Annualization Adj. No. 4	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Leak Survey and Repair Adj. No. 8	Surcharge Adjustment Adj. No. 9	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Customer Service and Informational Expenses												
	Operation												
	Customer Assistance Expenses	908											
1	Labor		$ 311,697	$ 0	$ 14,712	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 326,410	1
2	Labor Loadings		189,887	0	(1,400)	0	0	0	0	0	0	188,487	2
3	Materials and Expenses		715,869	0	0	0	(151,072)	0	0	0	0	564,797	3
4	Total		$ 1,217,452	$ 0	$ 13,313	$ 0	$ (151,072)	$ 0	$ 0	$ 0	$ 0	$ 1,079,693	4
	Informational and Instructional Expenses	909											
5	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
6	Labor Loadings		0	0	0	0	0	0	0	0	0	0	6
7	Materials and Expenses		35,525	0	0	0	(10,400)	0	0	0	0	25,125	7
8	Total		$ 35,525	$ 0	$ 0	$ 0	$ (10,400)	$ 0	$ 0	$ 0	$ 0	$ 25,125	8
	Misc. Customer Service & Inform. Expense	910											
9	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	9
10	Labor Loadings		0	0	0	0	0	0	0	0	0	0	10
11	Materials and Expenses		67,377	0	0	0	(45,400)	0	0	0	0	21,977	11
12	Total		$ 67,377	$ 0	$ 0	$ 0	$ (45,400)	$ 0	$ 0	$ 0	$ 0	$ 21,977	12
	Total Customer Service & Info. Expense												
13	Labor		$ 311,697	$ 0	$ 14,712	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 326,410	13
14	Labor Loadings		189,887	0	(1,400)	0	0	0	0	0	0	188,487	14
15	Materials and Expenses		818,771	0	0	0	(206,872)	0	0	0	0	611,899	15
16	Total		$ 1,320,355	$ 0	$ 13,313	$ 0	$ (206,872)	$ 0	$ 0	$ 0	$ 0	$ 1,126,796	16
	Sales Expenses												
	Supervision	911											
17	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	17
18	Labor Loadings		0	0	0	0	0	0	0	0	0	0	18
19	Materials and Expenses		0	0	0	0	0	0	0	0	0	0	19
20	Total		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	20
	Demonstration and Selling Expenses	912											
21	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	21
22	Labor Loadings		0	0	0	0	0	0	0	0	0	0	22
23	Materials and Expenses		0	0	0	0	0	0	0	0	0	0	23
24	Total		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	24
	Advertising Expenses	913											
25	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Labor Loadings		0	0	0	0	0	0	0	0	0	0	26
27	Materials and Expenses		230,155	0	0	0	(230,155)	0	0	0	0	0	27
28	Total		$ 230,155	$ 0	$ 0	$ 0	$ (230,155)	$ 0	$ 0	$ 0	$ 0	$ 0	28
	Total Sales Expenses												
29	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	29
30	Labor Loadings		0	0	0	0	0	0	0	0	0	0	30
31	Materials and Expenses		230,155	0	0	0	(230,155)	0	0	0	0	0	31
32	Total		$ 230,155	$ 0	$ 0	$ 0	$ (230,155)	$ 0	$ 0	$ 0	$ 0	$ 0	32
	Total Rate Jurisdiction												
33	Labor		$ 51,840,327	$ 0	$ 2,598,143	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 54,438,470	33
34	Labor Loadings		31,715,630	0	(333,746)	0	0	0	0	0	0	31,381,884	34
35	Materials and Expenses		637,549,827	(593,424,664)	0	285,239	(670,322)	(55,179)	227,339	(217,058)	572,224	44,267,406	35
36	Total		$ 721,105,785	$ (593,424,664)	$ 2,264,397	$ 285,239	$ (670,322)	$ (55,179)	$ 227,339	$ (217,058)	$ 572,224	$ 130,087,761	36

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF RECORDED ADMINISTRATIVE AND GENERAL EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Total Company	Direct Charges: Total Arizona	Direct Charges: Other Jurisdictions	To Be Allocated	Allocation Factor [1]: 4-Factor	Factor II	Factor III	A&G Allocation	Total Allocation	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f) (c-d-e)	(g)	(h)	(i)	(j)	(k)	(l) (d) + (k)	
	Administrative and General Salaries	920											
1	Labor		$ 39,960,366	$ 0	$ 0	$ 39,960,366	$ 22,657,527	$ 0	$ 0	$ 0	$ 22,657,527	$ 22,657,527	1
2	Labor Loadings		18,893,123	0	0	18,893,123	10,712,401	0	0	0	10,712,401	10,712,401	2
3	Materials and Expense		(2,067,764)	0	0	(2,067,764)	(1,172,422)	0	0	0	(1,172,422)	(1,172,422)	3
4	Total Administrative and General Salaries		$ 56,785,724	$ 0	$ 0	$ 56,785,724	$ 32,197,506	$ 0	$ 0	$ 0	$ 32,197,506	$ 32,197,506	4
5	Office Supplies	921	$ 10,322,576	$ 0	$ 0	$ 10,322,576	$ 5,852,900	$ 0	$ 0	$ 0	$ 5,852,900	$ 5,852,900	5
6	Administrative Expenses Transferred - Credit	922	$ (8,953,780)	$ 0	$ 0	$ (8,953,780)	$ 0	$ 0	$ 0	$ (5,306,010)	$ (5,306,010)	$ (5,306,010)	6
7	Outside Services Employed	923	$ 10,109,664	$ 768,490	$ 421,346	$ 8,919,827	$ 5,057,542	$ 0	$ 0	$ 0	$ 5,057,542	$ 5,826,032	7
8	Property Insurance	924	$ 373,578	$ 0	$ 0	$ 373,578	$ 0	$ 205,169	$ 0	$ 0	$ 205,169	$ 205,169	8
9	Injuries and Damages	925	$ 10,468,287	$ 406,029	$ 762,898	$ 9,299,361	$ 5,272,737	$ 0	$ 0	$ 0	$ 5,272,737	$ 5,678,766	9
10	Employee Pensions and Benefits	926	$ 0	$ 179,818	$ 32,821	$ (212,639)	$ 0	$ 0	$ (126,547)	$ 0	$ (126,547)	$ 53,270	10
11	Regulatory Commission Expenses	928	$ 349,604	$ 125,693	$ 223,911	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 125,693	11
	Miscellaneous General Expenses	930											
12	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	Labor Loadings		0	0	0	0	0	0	0	0	0	0	13
14	Materials and Expense		6,599,734	471,259	425,699	5,702,776	3,233,474	0	0	0	3,233,474	3,704,733	14
15	Total Miscellaneous General Expenses		$ 6,599,734	$ 471,259	$ 425,699	$ 5,702,776	$ 3,233,474	$ 0	$ 0	$ 0	$ 3,233,474	$ 3,704,733	15
16	Rents	931	$ 4,453,278	$ 0	$ 0	$ 4,453,278	$ 2,525,009	$ 0	$ 0	$ 0	$ 2,525,009	$ 2,525,009	16
	Maintenance of General Plant	935											
17	Labor		$ 820,763	$ 569,163	$ 32,834	$ 218,766	$ 124,040	$ 0	$ 0	$ 0	$ 124,040	$ 693,203	17
18	Labor Loadings		496,745	348,660	19,929	128,156	72,665	0	0	0	72,665	421,325	18
19	Materials and Expense		2,995,721	1,149,602	359,351	1,486,767	842,997	0	0	0	842,997	1,992,599	19
20	Total Maintenance of General Plant		$ 4,313,229	$ 2,067,425	$ 412,115	$ 1,833,689	$ 1,039,702	$ 0	$ 0	$ 0	$ 1,039,702	$ 3,107,127	20
	Total Administrative and General Expenses												
21	Labor		$ 40,781,129	$ 569,163	$ 32,834	$ 40,179,132	$ 22,781,568	$ 0	$ 0	$ 0	$ 22,781,568	$ 23,350,731	21
22	Labor Loadings		19,389,868	348,660	19,929	19,021,279	10,785,065	0	0	0	10,785,065	11,133,725	22
23	Materials and Expense		34,650,897	3,100,891	2,226,027	29,323,980	21,612,237	205,169	(126,547)	(5,306,010)	16,384,849	19,485,739	23
24	Total Administrative and General Expenses		$ 94,821,894	$ 4,018,714	$ 2,278,790	$ 88,524,391	$ 55,178,870	$ 205,169	$ (126,547)	$ (5,306,010)	$ 49,951,482	$ 53,970,196	24
				C-1, Sh 1							C-1, Sh 1		

[1] Schedule C-1, Sh 17

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SOUTHWEST GAS CORPORATION
ARIZONA
DIRECT ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL EXPENSE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Labor/Loading Annualization Adj. No. 3	Rate Case Expense Adj. No. 13	Total Adjustments	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Administrative and General Salaries	920				
1	Labor		$ 0	$ 0	$ 0	1
2	Labor Loadings		0	0	0	2
3	Materials and Expenses		0	0	0	3
4	Total Administrative and General Salaries		$ 0	$ 0	$ 0	4
5	Office Supplies and Expense	921	$ 0	$ 0	$ 0	5
6	Administrative Expenses Transferred - Credit	922	$ 0	$ 0	$ 0	6
7	Outside Services Employed	923	$ 0	$ 0	$ 0	7
8	Property Insurance	924	$ 0	$ 0	$ 0	8
9	Injuries and Damages	925	$ 0	$ 0	$ 0	9
10	Employee Pensions and Benefits	926	$ 0	$ 0	$ 0	10
11	Regulatory Commission Expense	928	$ 0	$ (33,693)	$ (33,693)	11
	Miscellaneous General Expense	930				
12	Labor		$ 0	$ 0	$ 0	12
13	Labor Loadings		0	0	0	13
14	Materials and Expenses		0	0	0	14
15	Total Miscellaneous General Expense		$ 0	$ 0	$ 0	15
16	Rents	931	$ 0	$ 0	$ 0	16
	Maintenance of General Plant	935				
17	Labor		$ 28,359	$ 0	$ 28,359	17
18	Labor Loadings		(3,841)	0	(3,841)	18
19	Materials and Expenses		0	0	0	19
20	Total Maintenance of General Plant		$ 24,518	$ 0	$ 24,518	20
	Total Administrative and General					
21	Labor		$ 28,359	$ 0	$ 28,359	21
22	Labor Loadings		(3,841)	0	(3,841)	22
23	Materials and Expenses		0	(33,693)	(33,693)	23
24	Total Administrative and General Expense		$ 24,518	$ (33,693)	$ (9,175)	24
					C-1, Sh 1	

SCHEDULE C-1
Sheet 10 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
SYSTEM ALLOCABLE ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL EXPENSE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Labor/Loading Annualization Adj. No. 3	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Injuries and Damages Adj. No. 10	AGA Dues Adj. No. 11	Paiute/SGTC Annualization Adj. No. 12	Total Adjustments	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Administrative and General Salaries	920									
1	Labor		$ 1,167,758	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,167,758	1
2	Labor Loadings		10,876	0	0	0	0	0	0	10,876	2
3	Materials and Expenses		0	0	(251,850)	0	0	0	79,720	(172,130)	3
4	Total Administrative and General Salaries		$ 1,178,634	0	$ (251,850)	$ 0	$ 0	$ 0	$ 79,720	$ 1,006,503	4
5	Office Supplies and Expense	921	$ 0	(26,128)	$ 0	$ 0	$ 0	$ 0	$ 16,150	$ (9,977)	5
6	Administrative Expenses Transferred - Credit	922	$ (158,561)	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (158,561)	6
7	Outside Services Employed	923	$ 0	0	$ 0	$ 0	$ 0	$ 0	$ 13,738	$ 13,738	7
8	Property Insurance	924	$ 0	0	$ 0	$ 0	$ 0	$ 0	$ (6,487)	$ (6,487)	8
9	Injuries and Damages	925	$ 0	0	$ 0	446,779	$ 3,930,256	$	$ 14,654	$ 4,391,689	9
10	Employee Pensions and Benefits	926	$ 0	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	10
11	Regulatory Commission Expense	928	$ 0	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	11
	Miscellaneous General Expense	930									
12	Labor		$ 0	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	Labor Loadings		0	0	0	0	0	0	0	0	13
14	Materials and Expenses		0	(19,810)	0	0	0	(13,087)	50,032	17,135	14
15	Total Miscellaneous General Expense		$ 0	(19,810)	$ 0	$ 0	$ 0	$ (13,087)	$ 50,032	$ 17,135	15
16	Rents	931	$ 0	0	$ 0	$ 0	$	$ 0	$ 7,836	$ 7,836	16
	Maintenance of General Plant	935									
17	Labor		$ 7,889	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 7,889	17
18	Labor Loadings		74	0	0	0	0	0	0	74	18
19	Materials and Expenses		0	0	0	0	0	0	2,855	2,855	19
20	Total Maintenance of General Plant		$ 7,963	0	$ 0	$ 0	$ 0	$ 0	$ 2,855	$ 10,818	20
	Total Administrative and General										
21	Labor		$ 1,175,647	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,175,647	21
22	Labor Loadings		10,950	0	0	0	0	0	0	10,950	22
23	Materials and Expenses		(158,561)	(45,937)	(251,850)	446,779	3,930,256	(13,087)	178,498	4,086,097	23
24	Total Administrative and General Expense		$ 1,028,035	(45,937)	$ (251,850)	$ 446,779	$ 3,930,256	$ (13,087)	$ 178,498	$ 5,272,694	24
										C-1, Sh 12	

SCHEDULE C-1
Sheet 11 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF ADMINISTRATIVE AND GENERAL EXPENSE ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Total Company	Direct Charges		To Be Allocated [2]	Allocation Factor [3]					Adjustment Total	Line No.
				Arizona [1]	Other Jurisdictions		4-Factor	Factor II	Factor III	A&G Allocation	Total Allocation		
	(a)	(b)	(c) (d)+(e)+(f)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l) (d) + (k)	
	Administrative and General Salaries	920											
1	Labor		$ 1,167,758	$ 0	$ 0	$ 1,167,758	$ 662,119	$ 0	$ 0	$ 0	$ 662,119	$ 662,119	1
2	Labor Loadings		10,876	0	0	10,876	6,167	0	0	0	6,167	6,167	2
3	Materials and Expense		(172,130)	0	0	(172,130)	(97,598)	0	0	0	(97,598)	(97,598)	3
4	Total Administrative and General Salaries		$ 1,006,503	$ 0	$ 0	$ 1,006,503	$ 570,687	$ 0	$ 0	$ 0	$ 570,687	$ 570,687	4
5	Office Supplies	921	$ (9,977)	$ 0	$ 0	$ (9,977)	$ (5,657)	$ 0	$ 0	$ 0	$ (5,657)	$ (5,657)	5
6	Administrative Expenses Transferred - Credit	922	$ (158,561)	$ 0	$ 0	$ (158,561)	$ 0	$ 0	$ 0	$ (93,963)	$ (93,963)	$ (93,963)	6
7	Outside Services Employed	923	$ 13,738	$ 0	$ 0	$ 13,738	$ 7,789	$ 0	$ 0	$ 0	$ 7,789	$ 7,789	7
8	Property Insurance	924	$ (6,487)	$ 0	$ 0	$ (6,487)	$ 0	$ (3,563)	$ 0	$ 0	$ (3,563)	$ (3,563)	8
9	Injuries and Damages	925	$ 4,391,689	$ 0	$ 0	$ 4,391,689	$ 2,490,088	$ 0	$ 0	$ 0	$ 2,490,088	$ 2,490,088	9
10	Employee Pensions and Benefits	926	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	10
11	Regulatory Commission Expenses	928	$ (33,693)	$ (33,693)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (33,693)	11
	Miscellaneous General Expenses	930											
12	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	Labor Loadings		0	0	0	0	0	0	0	0	0	0	13
14	Materials and Expense		17,135	0	0	17,135	9,716	0	0	0	9,716	9,716	14
15	Total Miscellaneous General Expenses		$ 17,135	$ 0	$ 0	$ 17,135	$ 9,716	$ 0	$ 0	$ 0	$ 9,716	$ 9,716	15
16	Rents	931	$ 7,836	$ 0	$ 0	$ 7,836	$ 4,443	$ 0	$ 0	$ 0	$ 4,443	$ 4,443	16
	Maintenance of General Plant	935											
17	Labor		$ 36,248	$ 28,359	$ 0	$ 7,889	$ 4,473	$ 0	$ 0	$ 0	$ 4,473	$ 32,832	17
18	Labor Loadings		(3,767)	(3,841)	0	74	42	0	0	0	42	(3,799)	18
19	Materials and Expenses		2,855	0	0	2,855	1,619	0	0	0	1,619	1,619	19
20	Total Maintenance of General Plant		$ 35,337	$ 24,518	$ 0	$ 10,818	$ 6,134	$ 0	$ 0	$ 0	$ 6,134	$ 30,652	20
	Total Administrative and General Expenses												
21	Labor		$ 1,204,006	$ 28,359	$ 0	$ 1,175,647	$ 666,592	$ 0	$ 0	$ 0	$ 666,592	$ 694,951	21
22	Labor Loadings		7,109	(3,841)	0	10,950	6,208	0	0	0	6,208	2,368	22
23	Materials and Expenses		4,052,404	(33,693)	0	4,086,097	2,410,400	(3,563)	0	(93,963)	2,312,873	2,279,180	23
24	Total Administrative and General Expenses		$ 5,263,519	$ (9,175)	$ 0	$ 5,272,694	$ 3,083,200	$ (3,563)	$ 0	$ (93,963)	$ 2,985,674	$ 2,976,499	24
											C-1, Sh 1		

[1] Schedule C-1, Sheet 10, Column e
[2] Schedule C-1, Sheet 11, Column j

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF ADJUSTED ADMINISTRATIVE AND GENERAL EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Total Company [1]	Direct Charges		To Be Allocated	Allocation Factor [4]					Total	Line No.
				Arizona [2]	Other Jurisdictions [3]		4-Factor	Factor II	Factor III	A&G Allocation	Total Allocation		
	(a)	(b)	(c)	(d)	(e)	(f) (c-d-e)	(g)	(h)	(i)	(j)	(k)	(l) (d) + (k)	
	Administrative and General Salaries	920											
1	Labor		$ 41,128,124	$ 0	$ 0	$ 41,128,124	$ 23,319,646	$ 0	$ 0	$ 0	$ 23,319,646	$ 23,319,646	1
2	Labor Loadings		18,903,999	0	0	18,903,999	10,718,567	0	0	0	10,718,567	10,718,567	2
3	Materials and Expense		(2,239,895)	0	0	(2,239,895)	(1,270,020)	0	0	0	(1,270,020)	(1,270,020)	3
4	Total Administrative and General Salaries		$ 57,792,228	$ 0	$ 0	$ 57,792,228	$ 32,768,193	$ 0	$ 0	$ 0	$ 32,768,193	$ 32,768,193	4
5	Office Supplies	921	$ 10,312,598	$ 0	$ 0	$ 10,312,598	$ 5,847,243	$ 0	$ 0	$ 0	$ 5,847,243	$ 5,847,243	5
6	Administrative Expenses Transferred - Credit	922	$ (9,112,341)	$ 0	$ 0	$ (9,112,341)	$ 0	$ 0	$ 0	$ (5,399,973)	$ (5,399,973)	$ (5,399,973)	6
7	Outside Services Employed	923	$ 10,123,402	$ 768,490	$ 421,346	$ 8,933,565	$ 5,065,331	$ 0	$ 0	$ 0	$ 5,065,331	$ 5,833,821	7
8	Property Insurance	924	$ 367,090	$ 0	$ 0	$ 367,090	$ 0	$ 201,606	$ 0	$ 0	$ 201,606	$ 201,606	8
9	Injuries and Damages	925	$ 14,859,976	$ 406,029	$ 762,898	$ 13,691,049	$ 7,762,825	$ 0	$ 0	$ 0	$ 7,762,825	$ 8,168,854	9
10	Employee Pensions and Benefits	926	$ 0	$ 179,818	$ 32,821	$ (212,639)	$ 0	$ 0	$ (126,547)	$ 0	$ (126,547)	$ 53,270	10
11	Regulatory Commission Expenses	928	$ 315,911	$ 92,000	$ 223,911	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 92,000	11
	Miscellaneous General Expenses	930											
12	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	Labor Loadings		0	0	0	0	0	0	0	0	0	0	13
14	Materials and Expense		6,616,869	471,259	425,699	5,719,911	3,243,190	0	0	0	3,243,190	3,714,448	14
15	Total Miscellaneous General Expenses		$ 6,616,869	$ 471,259	$ 425,699	$ 5,719,911	$ 3,243,190	$ 0	$ 0	$ 0	$ 3,243,190	$ 3,714,448	15
16	Rents	931	$ 4,461,114	$ 0	$ 0	$ 4,461,114	$ 2,529,452	$ 0	$ 0	$ 0	$ 2,529,452	$ 2,529,452	16
	Maintenance of General Plant	935											
17	Labor		$ 857,011	$ 597,522	$ 32,834	$ 226,655	$ 128,513	$ 0	$ 0	$ 0	$ 128,513	$ 726,035	17
18	Labor Loadings		492,978	344,820	19,929	128,230	72,706	0	0	0	72,706	417,526	18
19	Materials and Expense		2,998,576	1,149,602	359,351	1,489,622	844,616	0	0	0	844,616	1,994,218	19
20	Total Maintenance of General Plant		$ 4,348,565	$ 2,091,943	$ 412,115	$ 1,844,507	$ 1,045,836	$ 0	$ 0	$ 0	$ 1,045,836	$ 3,137,779	20
	Total Administrative and General Expenses												
21	Labor		$ 41,985,135	$ 597,522	$ 32,834	$ 41,354,778	$ 23,448,159	$ 0	$ 0	$ 0	$ 23,448,159	$ 24,045,681	21
22	Labor Loadings		19,396,977	344,820	19,929	19,032,229	10,791,274	0	0	0	10,791,274	11,136,093	22
23	Materials and Expense		38,703,301	3,067,198	2,226,027	33,410,077	24,022,636	201,606	(126,547)	(5,399,973)	18,697,722	21,764,919	23
24	Total Administrative and General Expenses		$ 100,085,413	$ 4,009,539	$ 2,278,790	$ 93,797,084	$ 58,262,069	$ 201,606	$ (126,547)	$ (5,399,973)	$ 52,937,155	$ 56,946,694	24
				C-1, Sh 1							C-1, Sh 1		

[1] Schedule C-1, Sheet 9, Column (c) + Schedule C-1, Sheet 12, Column (c)
[2] Schedule C-1, Sheet 9, Column (d) + Schedule C-1, Sheet 12, Column (d)
[3] Schedule C-1, Sheet 9, Column (e) + Schedule C-1, Sheet 12, Column (e)
[4] Schedule C-1, Sheet 17

SCHEDULE C-1
Sheet 13 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Account Number (b)	Recorded at 04/30/07 (c)	Adjustments (d)	Adjusted at 04/30/07 (e)	Line No.
	Arizona					
1	Depreciation [1]	403	$ 77,518,821	$ 3,310,495	$ 80,829,317	1
2	Amortization [1]	404.3	190,552	(63,622)	126,930	2
3	Amortization of Gas Plant Acquisition	406	(52,996)	0	(52,996)	3
4	Regulatory Amortizations [2]	407.3	2,287,572	(1,950,048)	337,524	4
5	Total Depreciation and Amortization Expense		$ 79,943,949	$ 1,296,825	$ 81,240,775	5
	System Allocable					
6	Depreciation [1]	403	$ 4,293,980	$ 186,182	$ 4,480,162	6
7	Amortization [1]	404.3	7,560,997	(318,164)	7,242,833	7
8	Total System Allocable Depreciation and Amortization		$ 11,854,978	$ (131,982)	$ 11,722,995	8
9	Arizona 4-Factor [3]		56.70%	56.70%	56.70%	9
10	Arizona Allocation		$ 6,721,772	$ (74,834)	$ 6,646,938	10
11	Total Depreciation and Amortization (Ln 5 + Ln 10)		$ 86,665,721	$ 1,221,991	$ 87,887,713	11

[1] Supporting Workpapers C-2, Adj. No. 14
[2] Supporting Workpapers C-2, Adj. No. 9
[3] Supporting Schedule C-1, Sheet 17

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF OTHER TAXES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Account Number	Recorded at 04/30/07	Adjustment	Adjusted at 04/30/07	Line No.
	(a)	(b)	(c) [1]	(d) [2]	(e)	
1	Property Tax	408.1	$ 28,899,902	$ 4,212,687	$ 33,112,588	1
2	Miscellaneous	408.1	12,291	0	12,291	2
3	Total Other Taxes		$ 28,912,193	$ 4,212,687	$ 33,124,880	3
				C-1, Sh 1		

[1] Source: Company Records
[2] Supporting Schedule C-2, Adj. 15

SCHEDULE C-1
Sheet 15 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
INCOME TAXES ON OPERATIONS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
AS ADJUSTED

Line No.	Description (a)	Recorded at 04/30/07 (b)	Adjusted at 4/30/07 (c)	After Rate Relief (d)	Line No.
	State Income Tax				
1	Margin	$ 402,964,907	$ 399,234,678	$ 449,454,506	1
2	Expenses	299,085,384	309,962,362	310,112,469	2
3	Taxable Income Before Interest	$ 103,879,523	$ 89,272,317	$ 139,342,038	3
4	Interest Expense (Ln 24)	47,844,172	48,035,008	48,035,008	4
5	State Taxable Income	$ 56,035,351	$ 41,237,308	$ 91,307,030	5
6	Effective State Income Tax Rate [2]	6.9680%	6.9680%	6.9680%	6
7	State Income Tax	$ 3,904,543	$ 2,873,416	$ 6,362,274	7
8	South Georgia Amortization	29,686	29,686	29,686	8
9	Investment Tax Credit	0	0	0	9
10	State Income Tax	$ 3,934,229	$ 2,903,102	$ 6,391,960	10
	Federal Income Tax				
11	Margin	$ 402,964,907	$ 399,234,678	$ 449,454,506	11
12	Expenses	299,085,384	309,962,362	310,112,469	12
13	Taxable Income Before Interest	$ 103,879,523	$ 89,272,317	$ 139,342,038	13
14	Interest Expense (Ln 24)	47,844,172	48,035,008	48,035,008	14
15	Federal Taxable Income	$ 56,035,351	$ 41,237,308	$ 91,307,030	15
16	Federal Income Tax Rate [2]	32.5612%	32.5612%	32.5612%	16
17	Federal Income Tax	$ 18,245,783	$ 13,427,362	$ 29,730,665	17
18	South Georgia Amortization	290,114	290,114	290,114	18
19	Investment Tax Credit	(528,360)	(528,360)	(528,360)	19
20	Federal Income Tax	$ 18,007,537	$ 13,189,116	$ 29,492,419	20
21	Total Federal and State Income Tax	$ 21,941,766	$ 16,092,218	$ 35,884,378	21
	Interest Calculation [1]				
22	Rate Base	$ 1,090,440,601	$ 1,094,790,046	$ 1,094,790,046	22
23	Weighted Cost of Debt	4.39%	4.39%	4.39%	23
24	Interest Expense	$ 47,844,172	$ 48,035,008	$ 48,035,008	24

[1] Supporting Schedule A-1, Sheet 2.
[2] Supporting Schedule C-3, Sheet 2.

SOUTHWEST GAS CORPORATION
COMPUTATION OF FOUR FACTOR ALLOCATION RATE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Arizona (b)	Northern California (d)	Southern California (e)	Northern Nevada (f)	Southern Nevada (g)	Total (h)	Line No.
	Factor I							
1	Direct Operating Expenses	$ 128,081,480	$ 4,645,847	$ 17,949,491	$ 13,762,642	$ 54,937,257	$ 219,376,717	1
2	Percent of Total	58.38%	2.12%	8.18%	6.27%	25.04%	100.00%	2
	Factor II							
3	Average Direct Gross Plant in Service	$ 1,864,610,670	$ 101,980,124	$ 247,575,806	$ 184,517,164	$ 996,926,187	$ 3,395,609,951	3
4	Percent of Total	54.92%	3.00%	7.29%	5.43%	29.36%	100.00%	4
	Factor III							
5	Direct Labor	$ 52,409,490	$ 1,521,078	$ 7,754,523	$ 5,481,942	$ 20,897,037	$ 88,064,070	5
6	Percent of Total	59.51%	1.73%	8.81%	6.22%	23.73%	100.00%	6
	Factor IV							
7	Average Number of Customers	$ 945,005	$ 42,464	$ 131,286	$ 88,459	$ 543,377	$ 1,750,591	7
8	Percent of Total	53.98%	2.43%	7.50%	5.05%	31.04%	100.00%	8
9	Total 4-Factor	226.80%	9.27%	31.78%	22.98%	109.17%	400.00%	9
10	4-Factor	56.70%	2.32%	7.94%	5.74%	27.29%	99.99%	10
	A&G Transfer Rate							
11	A&G Overheads	$ 5,304,411	$ 154,515	$ 675,322	$ 329,935	$ 2,486,783	$ 8,950,966	11
12	Percent of Total	59.26%	1.73%	7.54%	3.69%	27.78%	100.00%	12

SCHEDULE C-1
Sheet 17 of 18

SOUTHWEST GAS CORPORATION
CALCULATION OF THE MODIFIED
MASSACHUSETTS FORMULA
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Arizona (b)	Northern California (c)	Southern California (d)	Northern Nevada (e)	Southern Nevada (f)	Paiute (g)	SGTC (h)	Total (i)	Line No.
1	Total Direct Labor	$ 52,409,490	$ 1,521,078	$ 7,754,523	$ 5,481,942	$ 20,897,037	$ 2,841,146	$ 0	$ 90,905,216	1
2	Percent to Total	57.65%	1.67%	8.53%	6.03%	22.99%	3.13%	0.00%	100.00%	2
3	Margin	$ 402,964,907	$ 15,712,229	$ 46,127,511	$ 38,627,527	$ 173,896,582	$ 29,948,409	$ 461,150	$ 707,738,315	3
4	Percent to Total	56.94%	2.22%	6.52%	5.46%	24.57%	4.23%	0.07%	100.00%	4
5	Gross Plant	$ 1,956,244,952	$ 104,698,050	$ 257,583,088	$ 189,891,399	$ 1,031,916,426	$ 163,574,936	$ 1,794,544	$ 3,705,703,395	5
6	Percent to Total	52.79%	2.83%	6.95%	5.12%	27.85%	4.41%	0.05%	100.00%	6
7	Total (Ln 2 + Ln 4 + Ln 6)	167.38%	6.72%	22.00%	16.61%	75.41%	11.77%	0.11%	300.00%	7
8	Total Modified Mass Formula (Ln 7 / 3)	55.79%	2.24%	7.33%	5.54%	25.14%	3.92%	0.04%	100.00%	8

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Revenue Adj. No. 1	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Customer Billing Annualization Adj. No. 4	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Leak Survey and Repair Adj. No. 8	Surcharge Adjustment Adj. No. 9	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	Operating Revenue	$ (597,154,892)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2	Gas Cost	0	(593,424,664)	0	0	0	0	0	0	0	2
3	Operating Margin	$ (597,154,892)	$ 593,424,664	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	3
	Operating Expenses										
4	Other Gas Supply	$ 0	$ 0	$ 16,522	$ 0	$ 0	$ 0	$ 0	$ 0	0	4
5	Distribution	0	0	1,539,648	0	(183,101)	(55,179)	227,339	(217,058)	572,224	5
6	Customer Accounts	0	0	694,914	285,239	(50,194)	0	0	0	0	6
7	Customer Service & Information	0	0	13,313	0	(206,872)	0	0	0	0	7
8	Sales	0	0	0	0	(230,155)	0	0	0	0	8
	Administrative and General										
9	Direct	0	0	24,518	0	0	0	0	0	0	9
10	System Allocable	0	0	578,837	0	(26,046)	(142,799)	253,323	0	0	10
	Depreciation and Amortization										
11	Direct	0	0	0	0	0	0	0	0	0	11
12	System Allocable	0	0	0	0	0	0	0	0	0	12
13	Regulatory Amortizations	0	0	0	0	0	0	0	0	(1,950,048)	13
14	Taxes Other Than Income	0	0	0	0	0	0	0	0	0	14
15	Interest on Customer Deposits	0	0	0	0	0	0	0	0	0	15
16	Total Operating Expenses	$ 0	$ 0	$ 2,867,752	$ 285,239	$ (696,368)	$ (197,978)	$ 480,662	$ (217,058)	$ (1,377,824)	16
17	Net Operating Income	$ (597,154,892)	$ 593,424,664	$ (2,867,752)	$ (285,239)	$ 696,368	$ 197,978	$ (480,662)	$ 217,058	$ 1,377,824	17
	Rate Base										
	Gas Plant in Service										
18	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	18
19	System Allocable	0	0	0	0	0	0	0	0	0	19
20	Total Gross Plant	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	20
	Accumulated Provision for Depreciation and Amortization										
21	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	21
22	System Allocable	0	0	0	0	0	0	0	0	0	22
23	Total Accumulated Provision for Depreciation and Amortization	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	23
24	Net Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	24
	Other Rate Base Items										
25	Working Capital	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Customer Advances	0	0	0	0	0	0	0	0	0	26
27	Customer Deposits	0	0	0	0	0	0	0	0	0	27
28	Deferred Taxes	0	0	0	0	0	0	0	0	0	28
29	Total Other Rate Base Items	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	29
30	Total Rate Base	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	30

SCHEDULE C-2
Sheet 1 of 2

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Injuries and Damages Adj. No. 10	AGA Dues Adj. No. 11	Paiute Alloc. Annualization Adj. No. 12	Rate Case Expense Adj. No. 13	Annualized Dep. & Amort. Adj. No. 14	Property Tax Annualization Adj. No. 15	Interest on Customer Dep. Adj. No. 16	CCNC Adj. No. 17	Total of Adjustments	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	Operating Revenue	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$	$ 0	$ (597,154,892)	1
2	Gas Cost	0	0	0	0	0	0		0	(593,424,664)	2
3	Operating Margin	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$	$ 0	$ (3,730,229)	3
	Operating Expenses										
4	Other Gas Supply	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 16,522	4
5	Distribution	0	0	0	0	0	0	0	0	1,883,873	5
6	Customer Accounts	0	0	0	0	0	0	0	0	929,959	6
7	Customer Service & Information	0	0	0	0	0	0	0	0	(193,559)	7
8	Sales	0	0	0	0	0	0	0	0	(230,155)	8
	Administrative and General										
9	Direct	0	0	0	(33,693)	0	0	0	0	(9,175)	9
10	System Allocable	2,228,455	(7,420)	101,324						2,985,674	10
	Depreciation and Amortization										
11	Direct	0	0	0	0	3,246,873	0	0	0	3,246,873	11
12	System Allocable	0	0	0	0	(74,834)	0	0	0	(74,834)	12
13	Regulatory Amortizations	0	0	0	0	0	0	0	0	(1,950,048)	13
14	Taxes Other Than Income	0	0	0	0	0	4,212,687	0	0	4,212,687	14
15	Interest on Customer Deposits	0	0	0	0	0	0	59,161	0	59,161	15
16	Total Operating Expenses	$ 2,228,455	$ (7,420)	$ 101,324	$ (33,693)	$ 3,172,039	$ 4,212,687	$ 59,161	$ 0	$ 10,876,978	16
17	Net Operating Income	$ (2,228,455)	$ 7,420	$ (101,324)	$ 33,693	$ (3,172,039)	$ (4,212,687)	$ (59,161)	$ 0	$ (14,607,206)	17
	Rate Base										
	Gas Plant in Service										
18	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,976,115	$ 2,976,115	18
19	System Allocable	0	0	0	0	0	0	0	1,373,330	1,373,330	19
20	Total Gross Plant	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,349,445	$ 4,349,445	20
	Accumulated Provision for Depreciation and Amortization										
21	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	21
22	System Allocable	0	0	0	0	0	0	0	0	0	22
23	Total Accumulated Provision for Depreciation and Amortization	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	23
24	Net Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,349,445	$ 4,349,445	24
	Other Rate Base Items										
25	Working Capital	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Customer Advances	0	0	0	0	0	0	0	0	0	26
27	Customer Deposits	0	0	0	0	0	0	0	0	0	27
28	Deferred Taxes	0	0	0	0	0	0	0	0	0	28
29	Total Other Rate Base Items	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	29
30	Total Rate Base	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,349,445	$ 4,349,445	30

SCHEDULE C-2
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SALES & TRANSPORTATION QUANTITY AND REVENUES
ADJUSTMENT NO.1
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Recorded At 4/30/2007	Adjustment No. 1	Test Period Balance As Adjusted	Line No.
	(a)	(b)	(c)	(d)	
1	Sales Quantity (therms)	699,988,330	(35,386,981)	664,601,349	1
2	Transportation Quantity (therms)	74,237,984	4,271,585	78,509,569	2
3	Total Quantity	774,226,314	(31,115,396)	743,110,918	3
4	Revenue	$ 996,389,570	$(597,154,892)	**$ 399,234,678**	4
5	Total Revenue Adjustment		$(597,154,892)		5

Explanation:
To adjust for changes in number of bills and sales volumes, to annualize revenues at currently effective rates, to reverse unbilled revenues and to remove gas cost ($540,064,385) from the cost of service.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PURCHASED GAS COST
ADJUSTMENT NO. 2
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	FERC Account Number	Amount	Line No.
	(a)	(b)	(c)	
1	Operating Expenses	401	$(593,424,664)	1
	Explanation: To adjust for changes in sales volumes and to adjust the average cost of purchased gas to match the average cost of purchased gas included in currently effective base tariff sales rates.			
	Details			
	Gas Supply Expenses			
2	Natural Gas Wellhead Purchases	800	$ 0	2
3	Present Volume Adjustment	803	(25,155,242)	3
4	Present Rate Adjustment	803	67,624,882	4
5	Proposed Rate Making Adjustment	803	(540,064,385)	5
6	Purchased Gas Cost Adjustments	805.1	(35,473,742)	6
7	Gas Used for Compressor Station Fuel	808.1	0	7
8	Gas Withdrawn from Storage	808.2	0	8
9	Total Gas Supply Expenses		$(533,068,487)	9
	Transmission Expenses			
10	Transmission & Compression of Gas by Others	858	$(60,356,176)	10
11	Total Transmission Expenses		$(60,356,176)	11
12	Adjustment No. 2		$(593,424,664)	12

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
COST OF PURCHASED GAS - ACCOUNT NO. 803
ADJUSTED AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Recorded Total	Volume Adjustment			Rate Adjustment			Adjusted Total	Line No.
			Sales	Seasonal	Optional	Sales	Seasonal	Optional		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	Sales Volumes - Therms	699,988,330	(15,556,599)	(213,516)	(19,616,866)	602,083,024	13,070,981	49,447,344	664,601,349	1
2	Recorded Average Cost of Purchased Gas - Account No. 803	$ 0.71086	$ 0.71086	$ 0.71086	$ 0.71086	$ 0.71086	$ 0.71086	$ 0.71086		2
3	Cost of Purchased Gas [1]					$ 0.81426	$ 0.73057	$ 0.81426		3
4	Change In Average Cost of Purchased Gas					$ 0.10340	$ 0.01971	$ 0.10340		4
5	Cost of Purchased Gas - Account No. 803	$ 497,594,745	$(11,058,587)	$(151,780)	$(13,944,875)	$ 62,254,490	$ 257,610	$ 5,112,782	$ 540,064,385	5

[1] Cost of gas effective May 1, 2007 excluding Account No. 191 surcharge.

SCHEDULE C-2
ADJUSTMENT NO. 2
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
ARIZONA
LABOR AND LABOR LOADING ANNUALIZATION
ADJUSTMENT NO. 3

Line No.	Description (a)	Labor [1] (b)	Loading [1] (c)	Total (d) (b) + (c)	Line No.
	Operations				
1	Account 813	$ 16,354	$ 168	$ 16,522	1
2	Account 870	269,456	(35,615)	233,841	2
3	Account 871	6,786	(10)	6,776	3
4	Account 874	185,450	(25,080)	160,370	4
5	Account 875	55,995	(7,571)	48,424	5
6	Account 878	207,711	(28,325)	179,386	6
7	Account 879	242,713	(33,118)	209,595	7
8	Account 880	194,282	(24,052)	170,230	8
9	Account 901	123,203	(16,686)	106,518	9
10	Account 902	146,520	(19,751)	126,770	10
11	Account 903	508,848	(57,725)	451,123	11
12	Account 905	12,156	(1,652)	10,504	12
13	Account 908	14,712	(1,400)	13,313	13
14	Account 909	0	0	0	14
15	Account 910	0	0	0	15
16	Account 920	662,119	6,167	668,285	16
17	Account 922	(93,096)	(867)	(93,963)	17
18	Account 930	0	0	0	18
19	Total Operating Expense	$ 2,553,210	$ (245,517)	$ 2,307,693	19
	Maintenance				
20	Account 885	$ 83,771	$ (11,040)	$ 72,731	20
21	Account 886	806	(108)	698	21
22	Account 887	255,705	(34,664)	221,041	22
23	Account 889	44,062	(5,936)	38,126	23
24	Account 892	185,045	(25,178)	159,866	24
25	Account 893	38,627	(5,209)	33,418	25
26	Account 894	5,941	(795)	5,147	26
27	Account 935	32,832	(3,799)	29,033	27
28	Total Maintenance Expense	$ 646,788	$ (86,728)	$ 560,059	28
29	Total Operations and Maintenance	$ 3,199,998	$ (332,245)	$ 2,867,752	29
	Functionalization				
30	Other Gas Supply	$ 16,354	$ 168	$ 16,522	30
31	Distribution	1,776,349	(236,701)	1,539,648	31
32	Customer Accounts	790,727	(95,813)	694,914	32
33	Customer Service & Information	14,712	(1,400)	13,313	33
34	Sales	0	0	0	34
35	Administrative and General	601,854	1,501	603,355	35
36	Total	$ 3,199,998	$ (332,245)	$ 2,867,752	36

Explanation
To annualize labor and related loadings as of April 30, 2007, to reflect within-grade increases through April 2008, and a 6.09% compounded labor increase effective June 2007 and June 2008.

[1] Supporting Workpapers C-2, Adj. 3

SOUTHWEST GAS CORPORATION
ARIZONA AND CORPORATE STAFF
INCREMENTAL BILLING COSTS FOR ANNUALIZED CUSTOMERS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
ADJUSTMENT NO. 4

Line No.	Description (a)	Reference (b)	Amount [1] (c)	Line No.
	Bill Print Function			
	Hardware/Software Maintenance Fees & Supplies:	Company Records		
1	Variable Form Usage Fee from IBM		$ 41,110	1
2	Equipment Supplies (toner, developer & fuser)		32,100	2
3	Bill Stock (regular, disconnect & final)		327,070	3
4	Subtotal - Bill Print Function		$ 400,280	4
	Bill Insert Function			
	Hardware/Software Supplies:	Company Records		
5	Supplies (B&H, strapping & tags)		$ 14,353	5
6	Envelopes (mailing & remittance)		472,983	6
7	Subtotal - Bill Insert Function		$ 487,336	7
	Postage			
8	Postage for Bills Only	Company Records	$ 6,280,154	8
9	Subtotal - Postage		$ 6,280,154	9
10	Total Annual Variable Costs Related to Customer Billing	Ln 4 + Ln 7 + Ln 9	$ 7,167,770	10
11	Annual Number of Bills - Total Company	Company Records	21,145,300	11
12	Incremental Cost per Customer Bill	Ln 10 / Ln 11	$ 0.34	12
13	Annual Number of Bills in Test Year - Arizona	Company Records	11,340,054	13
14	Annual Number of Bills in Test Year As Adjusted - Arizona	Company Records	11,502,844	14
15	Increase in Annual Number of Arizona Bills	Ln 14 - Ln 13	162,790	15
16	Adjustment to Recognize Incremental Billing Costs for Annualized Customers	Ln 12 * Ln 15	$ 55,182	16
17	Postage Increase [2]		$ 0.02	17
18	Postage Adjustment	Ln 14 * Ln 17	$ 230,057	18
19	Total Adjustment (Account 903)	Ln 16 + Ln 18	$ 285,239	19

Explanation
To recognize the incremental costs of billing for additional customer bills and postage added to the Test Year based on annualized customer levels.

[1] Supporting Workpapers C-2, Adj. 4

SOUTHWEST GAS CORPORATION
ARIZONA
MISCELLANEOUS ADJUSTMENTS
ADJUSTMENT NO. 5

Line No.	Account Number (a)	Reference (b)	Amount (c)	Paiute & SGTC Allocation [1] 3.96% (d)	Net of Paiute (e) (c) + (d)	Allocation Factor [2] (f)	Total (g) (e) * (f)	Line No.
	Arizona							
1	870	WP C-2, Adj. 5	$ 13,837				$ 13,837	1
2	875	WP C-2, Adj. 5	286				286	2
3	880	WP C-2, Adj. 5	168,977				168,977	3
4	Subtotal Distribution	Ln 1 to Ln 3	$ 183,101				$ 183,101	4
5	903	WP C-2, Adj. 5	$ 48,126				$ 48,126	5
6	Subtotal Customer Accounts	Ln 5	$ 48,126				$ 48,126	6
7	908	WP C-2, Adj. 5	$ 148,422				$ 148,422	7
8	909	WP C-2, Adj. 5	10,400				10,400	8
9	910	WP C-2, Adj. 5	45,400				45,400	9
10	Subtotal Customer Service & Information	Ln 7 to Ln 9	$ 204,222				$ 204,222	10
11	913		$ 230,155				$ 230,155	11
12	Subtotal Sales	Ln 11	$ 230,155				$ 230,155	12
13	Subtotal Arizona	Ln 4 + Ln 6 + Ln 10 + Ln 12	$ 665,604				$ 665,604	13
	System Allocable							
14	903	WP C-2, Adj. 5	$ 3,831	N/A	$ 3,831	53.98%	$ 2,068	14
15	Subtotal Customer Accounts	Ln 14	$ 3,831		$ 3,831		$ 2,068	15
16	908		$ 4,673	N/A	$ 4,673	56.70%	$ 2,650	16
17	Subtotal Customer Service & Information	Ln 16	$ 4,673		$ 4,673		$ 2,650	17
18	921	WP C-2, Adj. 5	$ 27,205	$ 1,078	$ 26,128	56.70%	$ 14,814	18
19	930.2		20,627	817	19,810	56.70%	11,232	19
20	Subtotal Administrative and General	Ln 18 to Ln 19	$ 47,832	$ 1,895	$ 45,937		$ 26,046	20
21	Subtotal System Allocable	Ln 15 + Ln 17 + Ln 20	$ 56,336	$ 1,895	$ 54,441		$ 30,764	21
22	Total Adjustment	Ln 13 + Ln 21					$ 696,368	22

Explanation
To remove various expenditures from the cost of service.

[1] Supporting Schedule C-1, Sh 18.
[2] Allocation factors calculated in C-1, Sh 17. Accounts 813, 921, 930.2, and 935 are allocated using the 4-Factor and ccount 903 is allocated based on Factor IV.

SCHEDULE C-2
ADJUSTMENT NO. 5
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
EMPLOYEE VEHICLE COMPENSATION
ADJUSTMENT NO. 6

Line No.	Description (a)	Reference (b)	Account Number (c)	Amount (d)	Line No.
1	Arizona	Company Records	870	$ 55,179	1
2	System Allocable	Company Records		$ 262,239	2
3	Less: Paiute & SGTC Allocation at 3.96%	C-1, Sh 18		10,389	3
4	Adjustment Before 4-Factor Allocation	Ln 2 - Ln 3		$ 251,850	4
5	Arizona 4-Factor Allocation	C-1, Sh 17		56.70%	5
6	Adjustment Allocated to Arizona	Ln 4 * Ln 5	920	$ 142,799	6
7	Total Adjustment	Ln 1 + Ln 6		$ 197,978	7

Explanation
To remove imputed earnings associated with an employees' personal use of a company vehicle. Includes employees who fall under "Category D" of the Southwest Gas Standard Practice 100.1.

SOUTHWEST GAS CORPORATION
ARIZONA
OUT OF PERIOD EXPENSES
ADJUSTMENT NO. 7

Line No.	Description (a)	Reference (b)	Account Number (c)		Total (d)	Line No.
	Arizona					
1	J/E 335 [1]	Company Records	887	$	113,670	1
2	J/E 335 [1]	Company Records	892		113,670	2
3	Subtotal	Ln 1 + Ln 2		$	227,339	3
	System Allocable					
4	70898270	Company Records	925	$	101,747	4
5	70898393				180,883	5
6	70898275				182,578	6
7	Subtotal	Ln 4 + Ln 5 + Ln 6		$	465,208	7
8	Less: Paiute & SGTC Allocation at 3.96%	C-1, Sh 18			3.96%	8
9	Amount to be Allocated	Ln 7 * Ln 8		$	446,779	9
10	Arizona 4-Factor	C-1, Sh 17			56.70%	10
11	Net System Allocable to Arizona	Ln 9 * Ln 10		$	253,323	11
12	Total Adjustment	Ln 3 + Ln 11		$	480,662	12

[1] To include Arizona expenses charged to Southern Nevada erroneously during the test year (April 2007).
[2] To remove reclassification booked during the test year (May 2006) of three payments made prior to the test year year (April 2006).

SOUTHWEST GAS CORPORATION
ARIZONA
LEAK SURVEY AND REPAIR
ADJUSTMENT NO. 8

Line No.	Description	Account Number	Leak Repair [1]	Accelerated Leak Survey [1]	Total Adjustment	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Maintenance of Mains	887	$ (71,515)	$ (71,712)	$ (143,226)	1
2	Maintenance of Services	892	(20,865)	(52,967)	(73,832)	2
3	Total Adjustment [2]		$ (92,379)	$ (124,679)	$ (217,058)	3

[1] Supporting Workpapers C-2, Adj. 8

SOUTHWEST GAS CORPORATION
ARIZONA
SURCHARGE ADJUSTMENTS
ADJUSTMENT NO. 9

Line No.	Description	Account Number	Amount [1]	Line No.
	(a)	(b)	(c)	
1	Recorded Regulatory Amortization	407.3	$ 2,287,572	1
	Adjustments: [2]			
2	R&D		$ (755,950)	2
3	TRIMP		(551,530)	3
4	Demand Side Management (DSM)		(642,568)	4
5	Total Adjustments (Ln 2 + Ln 3 + Ln 4)		$ (1,950,048)	5
6	Annualized Regulatory Amortization (Ln 1 + Ln 5)	407.3	$ 337,524	6
7	Test Year TRIMP Costs [3]	182.3	$ 920,914	7
8	TRIMP written off [4]	887	(348,690)	8
9	O&M Expense Adjustment [5] (Ln 7 + Ln 8)	887	$ 572,224	9
10	Total Revenue Requirement Impact (Ln 5 + Ln 9)		$ (1,377,824)	10

[1] Source: Company Records
[2] R&D, TRIMP, and DSM costs are recovered through a surcharge. Since the Company is not including the offsetting revenue in revenue at present rates, the expense is being removed with this adjustment.
[3] TRIMP costs were deferred to Account 182.3, and 50% of these costs were recovered through a surcharge per Decision No. 68487.
[4] Disallowed TRIMP costs were written off to Account 887. There is a one month lag between the transaction posting date and the write-off date.
[5] Southwest is requesting to recover its ongoing non-capital related incremental TRIMP costs in base rates, based on test year expenditures, and to discontinue the TRIMP surcharge.

SOUTHWEST GAS CORPORATION
ARIZONA
INJURIES AND DAMAGES
SELF-INSURED RETENTION NORMALIZATION
ADJUSTMENT NO. 10

Line No.	Description [1] (a)	Reference (b)	Allocation Percent (c)	System Allocable (d)	10-Year Total (e)	Total Arizona Accrual (f)	Line No.
	Claims Paid	WP C-2, Adj. 10					
1	< $1,000,000				$ 7,698,138		1
2	At $1,000,000				8,000,000		2
3	$1,000,000 < $10,000,000				16,963,879		3
4	Total Claims Paid				$ 32,662,017		4
5	10 Year Average					$ 3,266,202	5
6	Less FERC Allocation @ 3.96%	C-1, Sh 18	3.96%			(129,342)	6
7	Net System Allocable					$ 3,136,860	7
8	Arizona 4-Factor	C-1, Sh 17	56.70%			$ 1,778,600	8
9	Recorded Amounts [2]			$ 200,000			9
10	Less FERC Allocation @ 3.96%	C-1, Sh 18	3.96%	(7,920)			10
11	Net System Allocable			$ 192,080			11
12	Arizona 4-Factor	C-1, Sh 17	56.70%			$ 108,909	12
13	Arizona Direct [2]		100.00%			(558,765)	13
14	Total Recorded Arizona					$ (449,856)	14
15	Total Adjustment (Ln 8 - Ln 14)					$ 2,228,455	15

[1] Supporting Workpapers C-2, Adj. 10
[2] Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
AMERICAN GAS ASSOCIATION (AGA) DUES
ADJUSTMENT NO. 11

Line No.	Description (a)	Reference (b)	Account Number (c)	Amounts (d)	Line No.
1	2007 AGA Dues	Company Records	930.2	$ 401,975	1
2	Marketing & Lobbying Percentage	WP C-2, Adj. 11		3.39%	2
3	Marketing & Lobbying Amount of Dues	Ln 1 * Ln 2		$ (13,627)	3
4	Less: Paiute & SGTC Allocation at 3.96%	C-1, Sh 18		540	4
5	Adjustment to AGA Dues Before 4-Factor	Ln 3 + Ln 4		$ (13,087)	5
6	Arizona 4-Factor Allocation	C-1, Sh 17		56.70%	6
7	Adjustment to Arizona for Removal of Marketing & Lobbying from AGA Dues	Ln 5 * Ln 6		$ (7,420)	7

Explanation:
To remove from test year expenses that portion of the AGA dues paid by SWG that have been disallowed in prior rate cases.

Note: AGA eliminated promotional expenditures in 2000.

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
ADMINISTRATIVE AND GENERAL EXPENSES
ANNUALIZED PAIUTE ALLOCATION
ADJUSTMENT NO. 12

Line No.	Description	FERC Account Number	12 Months Ended 04/30/07 Net Recorded [1]	Charged to Paiute [2]	Gross Recorded	MMF Allocation Paiute [3]	Paiute Annualized	Reduction to Paiute's A&G Expenses	Amount Allocated to Arizona [4]	Line No.
	(a)	(b)	(c)	(d)	(e) (c) + (d)	(f)	(g)	(h) (d) - (g)	(i)	
1	Administrative and General Salaries	920	$ 56,785,724	$ 2,402,071	$ 59,187,796	3.92%	$ 2,322,351	$ 79,720	$ 45,201	1
2	Office Supplies	921	10,322,576	438,378	10,760,953	3.92%	422,227	16,150	9,157	2
3	Outside Services Employed	923	8,919,827	378,579	9,298,407	3.92%	364,842	13,738	7,789	3
4	Property Insurance	924	373,578	91,630	465,208	21.09%	98,118	(6,487)	(3,563)	4
5	Injuries and Damages	925	9,299,361	395,033	9,694,393	3.92%	380,379	14,654	8,309	5
6	Miscellaneous General Expenses	930.2	4,453,278	233,944	4,687,222	3.92%	183,913	50,032	28,368	6
7	Rents	931	4,453,278	190,026	4,643,304	3.92%	182,189	7,836	4,443	7
8	Maintenance of General Plant	935	1,833,689	77,859	1,911,548	3.92%	75,003	2,855	1,619	8
9	Total		$ 96,441,311	$ 4,207,520	$ 100,648,831		$ 4,029,022	$ 178,498	$ 101,324	9

Explanation:
Consistent with the methodology accepted by the Commission in previous rate cases, this adjustment annualizes the recorded amounts allocated to Paiute Pipeline to reflect Paiute's MMF allocation percentage based on the test year ended April 30, 2007.

Note:
Account 493, Rent from Gas Property, changed by -$63,304 due to annualizing the Paiute rental charge at April 30, 2007. Supporting Workpaper C-2, Adj. 12.

[1] Supporting Schedule C-1, Sh 9
[2] Source: Company Records
[3] Modified Massachusetts Formula as calculated in Sch C-1, Sh 18, Col (g); 21.09% based on insurable property. Supporting Workpaper C-2, Adj. 12.
[4] All accounts except 924 are allocated to Arizona using the 4-Factor. Account 924 uses the Factor II percentage. Supporting Schedule C-1, Sh 17.

SCHEDULE C-2
ADJUSTMENT NO. 12
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
SCHEDULE OF ESTIMATED INCREMENTAL RATE CASE EXPENSE
ADJUSTMENT NO. 13

Line No.	Description (a)	Account Number (b)	Estimated Amounts (c)	Line No.
	2007 Arizona Rate Case			
1	Printing/Copying/Postage/Freight		$ 55,000	1
2	Professional Services		120,000	2
3	Notice/Publication		10,000	3
4	Court Reporting		16,000	4
5	Travel/Transportation		75,000	5
6	Total Arizona Rate Case Expense		$ 276,000	6
7	Amortization Period (In Years) [1]		3	7
8	Annual Arizona Rate Case Expense (Ln 6 / Ln 7)	928	$ 92,000	8
9	Rate Case Expense Recorded in Test Year	928	125,693	9
10	Adjustment to Test Year Expense (Ln 8 - Ln 9)		$ (33,693)	10

Source: Company Records

[1] The Company proposes to amortize its incremental rate case expense over three years, which is the estimated length of its Arizona rate case cycle.

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION AND AMORTIZATION EXPENSE ANNUALIZATION
ADJUSTMENT NO. 14

Line No.	Description	Recorded at 04/30/07	Annualization Adjustment	Adjusted at 04/30/07	Line No.
	(a)	(b)	(c)	(d)	
	Arizona [1]				
1	Depreciation Expense	$ 77,518,821	$ 3,310,495	$ 80,829,317	1
2	Amortization Expense	2,425,128	(63,622)	2,361,506	2
3	Total	$ 79,943,949	$ 3,246,873	$ 83,190,823	3
	System Allocable [1]				
4	Depreciation Expense	$ 4,293,980	$ 186,182	$ 4,480,162	4
5	Amortization Expense	7,560,997	(318,164)	7,242,833	5
6	Total	$ 11,854,978	$ (131,982)	$ 11,722,995	6
7	Arizona 4-Factor [2]	56.70%	56.70%	56.70%	7
8	Amount Allocated to Arizona	$ 6,721,772	(74,834)	6,646,938	8
9	Total (Ln 3 + Ln 8)	$ 86,665,721	$ 3,172,039	$ 89,837,761	9

Explanation:
This adjustment annualizes depreciation and amortization expense as of April 30, 2007.

[1] Supporting Workpapers C-2, Adj. 14
[2] Supporting Schedule C-1, Sh 17

SCHEDULE C-2
ADJUSTMENT NO. 14
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
PROPERTY TAX
ADJUSTMENT NO. 15

Line No.	Description	Reference		Arizona	Line No.
	(a)	(b)		(c)	
1	Adjusted Net Plant in Service	B-2, Sh 1	$	1,267,124,120	1
	Add:				
2	Materials and Supplies	B-5, Sh 3		12,389,898	2
	Less:				
3	Transportation Equipment	[1]		(27,969,828)	3
4	Land Rights	[2]		(1,823,920)	4
5	Estimated Full Cash Value	Ln 1 to Ln 4	$	1,249,720,269	5
6	2008 Assessment Rate			23.00%	6
7	Assessed Value	Ln 5 * Ln 6	$	287,435,662	7
8	Property Tax Rate			11.52%	8
9	Annualized Property Tax Expense	Ln 7 * Ln 8	$	33,112,588	9
10	Recorded Property Tax Expense	C-1, Sh 16		28,899,902	10
11	Total Adjustment	Ln 9 - Ln 10	$	4,212,687	11

Explanation:
To annualize Property Tax Expense to reflect adjusted investment at 04/30/07 based on estimated 2007 property tax rates and the statutory 2008 assessment ratio.

[1] Adjusted balance net of accumulated depreciation. Supporting Workpapers B-2
[2] Balance as recorded at 04/30/07. Supporting Workpapers B-2

SOUTHWEST GAS CORPORATION
ARIZONA
INTEREST ON CUSTOMER DEPOSITS
ADJUSTMENT NO. 16

Line No.	Description	Account Number	Recorded at 04/30/07 [1]	Adjustment	Adjusted at 04/30/07	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Interest Expense	431	$ 1,856,153	$ 59,161	$ 1,915,314	1
	Customer Deposits	235				
2	April 2006				$ 29,940,533	2
3	May				30,244,307	3
4	June				30,534,168	4
5	July				30,907,667	5
6	August				31,068,422	6
7	September				31,294,649	7
8	October				31,925,334	8
9	November				32,387,660	9
10	December				32,677,847	10
11	January 2007				32,866,855	11
12	February				33,171,595	12
13	March				33,562,862	13
14	April				34,402,771	14
15	Thirteen Month Total				$ 414,984,669	15
16	Thirteen Month Average				$ 31,921,898	16
17	Interest Rate				6.00%	17
18	Adjusted Interest Expense				$ 1,915,314	18
					Ln 1	

Explanation:
To synchronize interest on customer deposits with the adjusted average of the thirteen monthly balances of customer deposits used as a rate base reduction.

[1] Supporting Workpapers C-2, Adj. 16

SOUTHWEST GAS CORPORATION
ARIZONA
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR

Line No.	Description (a)	Base Amount (b)	Rate (c)	Amount (d)	Line No.
1	Gross Operating Revenues			$ 1,000.00	1
2	Less: Uncollectibles [1]	$ 1,000.00	0.2989%	2.99	2
3	Subtotal			$ 997.01	3
4	Less: State Income Tax [2]	$ 997.01	6.9680%	69.47	4
5	Subtotal			$ 927.54	5
6	Less: Federal Income Tax [2]	$ 997.01	32.5612%	324.64	6
7	Total			$ 602.90	7
8	Gross Revenue Conversion Factor (Ln 1 / Ln 7)			1.6586	8
				A-1, Sh 1	

[1] Uncollectibles divided by Test Year Recorded Revenue
[2] Supporting Schedule C-3, Sh 2

SOUTHWEST GAS CORPORATION
ARIZONA
COMPUTATION OF STATE AND FEDERAL TAX RATES
AS OF APRIL 30, 2007

Line No.	Description (a)	Rate (b)	Rate (c)	Line No.
1	Current State Income Tax Rate (SIT)		6.9680%	1
2	Current Federal Income Tax Rate (FIT)	35.0000%		2
	Effective Rate = FIT x (1-ESIT)			
3	.35 x (1-.06968)		32.5612%	3
4	Total Effective Rate		39.5292%	4
			C-1, Sh 16	

Volume II

Supporting Schedules

D

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF CAPITAL AT APRIL 30, 2007

Line No.	Description	Capital Ratio	Capital Cost	Weighted Cost of Capital	Line No.
	(a)	(b)	(c)	(d)	
1	Long-Term Debt	51.00%	7.96% [1]	4.06%	1
2	Preferred Equity	4.00%	8.20% [2]	0.33%	2
3	Common Equity	45.00%	11.25% [3]	5.06%	3
4	Total	100.00%		9.45%	4

[1] Reference Schedule D-2, Sheet 1 of 4
[2] Reference Schedule D-3, Sheet 1 of 2
[3] Reference Schedule D-4, Sheet 1 of 1

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
NET CAPITAL AT APRIL 30, 2007

Line No.	Description	Net System Balance at 4/30/2007	Adjustments[1]	Pro Forma Net Capital Amounts	Capital Ratio	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Debt					
	Long-Term Debt:					
1	Debentures	$ 466,044,469	$ -	$ 466,044,469	27.19%	1
2	Medium-Term Notes	124,418,910	-	124,418,910	7.26%	2
3	Term Facilities	53,169,199	-	53,169,199	3.10%	3
4	Clark County IDRB's	470,604,484	(470,604,484)	-	0.00%	4
5	Big Bear IDRB's	49,268,815	(49,268,815)	-	0.00%	5
6	Total Long-Term Debt	$ 1,163,505,877	$ (519,873,299)	$ 643,632,578	37.55%	6
	Equity					
7	Preferred Equity	$ 100,000,000	-	$ 100,000,000	5.83%	7
8	Common Equity	970,385,472	-	970,385,472	56.61%	8
9	Total Equity	$ 1,070,385,472	$ -	$ 1,070,385,472	62.45%	9
10	Total Capital	$ 2,233,891,349	$ (519,873,299)	$ 1,714,018,050	100.00%	10

[1] Adjustments:

Clark County and Big Bear IDRB's are eliminated because those issues are used solely to fund qualified construction expenditures in Clark County, Nevada and San Bernardino County, California.

SCHEDULE D-1
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF DEBT AT APRIL 30, 2007

Line No.	Description	Net Principal Amount Outstanding	Interest Rate	Cost of Debt	Line No.
	(a)	(b)	(c)	(d)	
1	Fixed Rate Debt [1]	$ 590,463,379	8.11%	$ 47,871,327	1
2	Variable Rate Debt [2]	53,169,199	6.27%	3,332,516	2
3	Total Long-Term Debt	$ 643,632,578	7.96%	$ 51,203,843	3

[1] Reference Schedule D-2, Sheet 2 of 4
[2] Reference Schedule D-2, Sheet 3 of 4

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF LONG-TERM FIXED RATE DEBT
AT APRIL 30, 2007

Line No.	Description (a)	Principal Amount Outstanding (b)	Unamortized Debt Expense and Discount (c)	Net Proceeds (d)	Effective Interest Rate (e)	Cost of Debt (f)	Line No.
	Debentures						
1	8.0% Debenture, Due 2026	75,000,000	6,089,371	68,910,629	8.89%	6,126,155	1
2	8.375% Note, Due 2011	200,000,000	1,485,867	198,514,133	8.61%	17,091,670	2
3	7.625% Note, Due 2012	200,000,000	1,380,294	198,619,706	7.79%	15,472,475	3
4	Total Debentures	$ 475,000,000	$ 8,955,531	$ 466,044,469	8.30%	$ 38,690,300	4
	Medium Term Notes						
5	7.59% MTN, Due 2017	$ 25,000,000	$ 147,215	$ 24,852,785	7.68%	$ 1,908,694	5
6	7.78% MTN, Due 2022	25,000,000	175,679	24,824,321	7.86%	1,951,192	6
7	7.92% MTN, Due 2027	25,000,000	204,455	24,795,545	8.00%	1,983,644	7
8	6.89% MTN, Due 2007	17,500,000	7,731	17,492,269	7.00%	1,224,459	8
9	6.76% MTN, Due 2027	7,500,000	3,458	7,496,542	6.88%	515,762	9
10	6.27% MTN, Due 2008	25,000,000	42,553	24,957,447	6.40%	1,597,277	10
11	Total Medium Term Notes	$ 125,000,000	$ 581,090	$ 124,418,910	7.38%	$ 9,181,027	11
12	Total Debentures and MTNs	$ 600,000,000	$ 9,536,621	$ 590,463,379	8.11%	$ 47,871,327	12
					Sch D-2, Sheet 1		
	Tax Exempt Clark County						
15	1999 Series A, Due 2038	12,410,000	588,249	11,821,751	6.56%	775,635	15
16	1999 Series C, Due 2038	14,320,000	802,862	13,517,138	6.49%	877,460	16
17	1999 Series D, Due 2038	8,270,000	463,307	7,806,693	6.07%	473,654	17
18	2003 Series C, Due 2038	30,000,000	1,449,535	28,550,465	5.89%	1,682,012	18
19	2003 Series D, Due 2038	20,000,000	1,805,668	18,194,332	6.09%	1,108,562	19
20	2003 Series E, Due 2038	15,000,000	190,744	14,809,256	5.92%	876,186	20
21	2004 Series A, Due 2034	65,000,000	3,164,929	61,835,071	5.99%	3,706,076	21
22	2004 Series B, Due 2033	75,000,000	5,031,036	69,968,964	5.91%	4,133,791	22
23	2005 Series A, Due 2034	100,000,000	3,609,886	96,390,114	5.34%	5,143,154	23
24	2006 Series B, Due 2033	56,000,000	1,410,826	54,589,174	5.08%	2,774,192	24
25	Total Tax Exempt	$ 396,000,000	$ 18,517,043	$ 377,482,957	5.71%	$ 21,550,723	25
26	Total Fixed-Rate Debt	$ 996,000,000	$ 28,053,664	$ 967,946,336	7.17%	$ 69,422,049	26

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
VARIABLE RATE DEBT COST OF DEBT
AT APRIL 30, 2007

Line No.	Description	Net Proceeds	Interest Rate	Cost of Debt	Line No.
	(a)	(b)	(c)	(d)	
1	Term Facility[1]	$ 53,169,199	6.27%	$ 3,332,516	1
			Sch D-2, Sheet 1		
2	Big Bear 1993 Series A IDRB [2]	$ 49,268,815	5.33%	$ 2,624,876	2
3	Clark Co.2003 Series A & B IDRB [3]	93,121,527	5.18%	$ 4,821,469	3

[1] Based on $150 million designated long-term of the $300 million Bank Facility less $842 thousand of unamortized expense.
[2] The net amount represents $50 million face value less $ $731 thousand of unamortized balances.
[3] The net amount represents $100 million face value less $6.88 million of unamortized balances.

SCHEDULE D-2
Sheet 3 of 4

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF LONG-TERM DEBT
ORIGINAL NET PROCEEDS OF ISSUES OUTSTANDING [1]

Line No.	Description	Origination Date	Maturity Date	Coupon Rate	Offered	Gross Proceeds	Underwriter's Commission and Discounts Amount	Underwriter's Commission and Discounts Percent of Gross Proceeds	Debt and Issuance Expense Amount	Debt and Issuance Expense Percent of Gross Proceeds	Net Proceeds Amount	Net Proceeds Per $100 Unit	Cost of Money [2]	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
	Debentures													
2	8.0% Debenture, Due 2026	08/01/96	08/01/26	8.00%	75,000,000	75,000,000	894,750	1.19%	6,048,405	8.06%	68,056,845	90.74	8.89%	2
3	8.375% Note, Due 2011	02/13/01	02/15/11	8.38%	200,000,000	200,000,000	2,818,000	1.41%	288,784	0.14%	196,893,216	98.45	8.61%	3
4	7.625 Note, Due 2012	05/06/02	05/15/12	7.63%	200,000,000	200,000,000	2,052,000	1.03%	270,042	0.14%	197,677,958	98.84	7.79%	4
5	Total Debentures				$ 475,000,000	$ 475,000,000	$ 5,764,750	1.21%	$ 6,607,231	1.39%	$ 462,628,019	97.40		5
	Medium Term Notes													
6	7.59% MTN, Due 2017	01/17/97	01/17/17	7.59%	$ 25,000,000	$ 25,000,000	$ 187,500	0.75%	$ 33,400	0.13%	$ 24,779,100	99.12	7.68%	6
7	7.78% MTN, Due 2022	02/03/97	02/03/22	7.78%	25,000,000	25,000,000	187,500	0.75%	33,400	0.13%	24,779,100	99.12	7.86%	7
8	7.92% MTN, Due 2027	06/04/97	06/04/27	7.92%	25,000,000	25,000,000	187,500	0.75%	45,761	0.18%	24,766,739	99.07	8.00%	8
9	6.89% MTN, Due 2007	09/23/97	09/24/07	6.89%	17,500,000	17,500,000	102,325	0.58%	40,200	0.23%	17,357,475	99.19	7.00%	9
10	6.76% MTN, Due 2027 [3]	09/23/97	09/24/27	6.76%	7,500,000	7,500,000	46,875	0.63%	17,228	0.23%	7,435,897	99.15	6.88%	10
11	6.27% MTN, Due 2008	09/24/98	09/22/08	6.27%	25,000,000	25,000,000	156,250	0.63%	79,928	0.32%	24,763,822	99.06	6.40%	11
13	Total Medium Term Notes				$ 125,000,000	$ 125,000,000	$ 867,950	0.69%	$ 249,917	0.20%	$ 123,882,133	99.11		13
	Tax Exempt Clark County													
14	1999 Series A, Due 2038 [3]	10/05/99	12/01/38	6.10%	12,410,000	12,410,000	53,920	0.43%	658,490	5.31%	11,697,590	94.26	6.64%	14
15	1999 Series C, Due 2038 [3]	07/19/00	12/01/38	5.95%	14,320,000	14,320,000	38,342	0.27%	936,800	6.54%	13,344,858	93.19	6.45%	15
16	1999 Series D, Due 2038 [3]	09/26/01	12/01/38	5.55%	8,270,000	8,270,000	21,451	0.26%	523,760	6.33%	7,724,789	93.41	6.13%	16
17	2003 Series A, Due 2038	03/25/03	03/01/38	Var	50,000,000	50,000,000	128,076	0.26%	2,820,818	5.64%	47,051,106	94.10	Var	17
18	2003 Series B, Due 2038	03/25/03	03/01/38	Var	50,000,000	50,000,000	128,076	0.26%	2,820,818	5.64%	47,051,106	94.10	Var	18
19	2003 Series C, Due 2038 [3]	03/25/03	03/01/38	5.45%	30,000,000	30,000,000	200,538	0.67%	1,440,962	4.80%	28,358,500	94.53	5.93%	19
20	2003 Series D, Due 2038 [3]	03/25/03	03/01/38	5.25%	20,000,000	20,000,000	133,692	0.67%	1,533,688	7.67%	18,332,620	91.66	3.70%	20
21	2003 Series E, Due 2038 [3]	03/25/03	03/01/38	5.80%	15,000,000	15,000,000	100,269	0.67%	115,735	0.77%	14,783,996	98.56	5.93%	21
22	2004 Series A, Due 2034 [3]	07/16/04	07/01/34	5.25%	65,000,000	65,000,000	1,081,500	1.66%	2,915,229	4.48%	61,003,271	93.85	6.07%	22
23	2004 Series B, Due 2033 [3]	10/16/04	12/01/33	5.00%	75,000,000	75,000,000	956,250	1.28%	5,034,263	6.71%	69,009,487	92.01	5.99%	23
22	2005 Series A, Due 2035 [3]	10/01/05	10/01/35	4.85%	100,000,000	100,000,000	1,350,000	1.35%	2,724,048	2.72%	95,925,952	95.93	5.36%	22
23	2006 Series B, Due 2036 [3]	09/01/06	09/01/36	4.75%	56,000,000	56,000,000	686,000	1.23%	791,438	1.41%	54,522,562	97.36	5.09%	23
24	Total Tax Exempt Clark County				$ 496,000,000	$ 496,000,000	$ 4,878,114	0.98%	$ 22,316,049	4.50%	$ 468,805,837	94.52		24
	Tax Exempt Big Bear													
25	1993 Series A, Due 2028	12/01/93	12/01/28	Var	$ 50,000,000	$ 50,000,000	$ 175,000	0.35%	$ 656,763	1.31%	$ 49,168,237	98.34	Var	25
26	Term Facility [4]	04/20/06	04/19/11	Var	$ 150,000,000	$ 150,000,000	$ -	0.00%	$ 711,178	0.47%	$ 149,288,822	99.53	Var	26
27	Total Debt Capital				$ 1,296,000,000	$ 1,296,000,000	$ 11,685,814	0.90%	$ 30,541,139	2.36%	$ 1,253,773,047	96.74		27

[1] Based on Company records.
[2] Based on the Net Proceeds method.
[3] Effective rate at issuance.
[4] A commercial paper program was initiated in October 2002 and is backed by $50 million of the term facility.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF PREFERRED SECURITIES
AT APRIL 30, 2007

Line No.	Description	Net Proceeds Per Security	Number of Securities	Net Proceeds	Effective Cost	Annual Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	Trust Originated Preferred Securities Liquidation Amount $25[1]	$ 23.52	4,000,000	$ 94,172,446	8.20% Sch D-1, sh 1	$ 7,722,141	1

[1] The 7.70% Trust Originated Preferred Securities were issued in a public offering on August 25, 2003 by Southwest Gas Capital II. Southwest Gas Capital II is a business trust which exists for the sole purpose of issuing Preferred Securities and Common Securities and investing the proceeds thereof in an equivalent amount of 7.70% Subordinated Deferrable Interest Notes due September 15, 2043 of Southwest Gas Corporation. Southwest Gas Corporation owns all of the common securities representing undivided beneficial interests in the assets of the Trust.

SOUTHWEST GAS CORPORATION
COST OF PREFERRED SECURITIES
ORIGINAL NET PROCEEDS OF ISSUES OUTSTANDING AT APRIL 30, 2007

Line No.	Description	Annual Dividend Rate/Share	Total Issued		Underwriter's Commission		Reacquired Debt Expense		Issuance Expense		Net Proceeds		Line No.
			At Par	Gross Proceeds	Amount	Percent of Gross Proceeds	Amount	Percent of Gross Proceeds	Amount	Percent of Gross Proceeds	Amount	Amount Per Share	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
1	Trust Originated Preferred Securities Liquidation Amount $25[1]	7.70%	$ 100,000,000	$ 100,000,000	$ 3,150,000	3.150%	$ 2,221,449	2.221%	$ 547,324	0.547%	$ 94,081,227	$ 23.52	1

[1] The 7.70% Preferred Trust Securities were issued in a public offering on August 25, 2003 by Southwest Gas Capital II. Southwest Gas Capital II is a business trust which exists for the sole purpose of issuing Preferred Securities and Common Securities and investing the proceeds thereof in an equivalent amount of 7.70% junior subordinated debentures due September 15, 2043 of Southwest Gas Corporation. Southwest Gas Corporation owns all of the common securities representing undivided beneficial interests in the assets of the Trust. Southwest Gas Capital II may redeem some or all of the preferred trust securities on or after August 25, 2008, or all of the preferred trust securities at any time upon the occurrence of a special event at a redemption price equal to $25 per preferred trust security plus accumulated and unpaid distributions, if any.

SCHEDULE D-3
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF COMMON EQUITY

Line No.	Description	Line No.
1	A cost of common equity of 11.25 percent is recommended by Southwest Gas Corporation as more fully explained and supported in the direct testimony of Mr. Frank J. Hanley.	1

Volume II

Supporting Schedules

E

SOUTHWEST GAS CORPORATION
COMPARATIVE BALANCE SHEETS

Line No.	Description	Balance at 4/30/07 Arizona	Balance at 4/30/07 Other	Balance at 4/30/07 Total	Balance at 12/31/06 Arizona	Balance at 12/31/06 Other	Balance at 12/31/06 Total	Balance at 12/31/05 Arizona	Balance at 12/31/05 Other	Balance at 12/31/05 Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Assets and Other Debits										
	Utility Plant										
1	Utility Plant (101, 105, 114, 118)	$ 1,955,564,837	$ 1,755,558,061	$ 3,711,122,898	$ 1,881,283,726	$ 1,713,418,973	$ 3,594,702,699	$ 1,742,254,499	$ 1,607,809,819	$ 3,350,064,318	1
2	Construction Work in Progress (107)	11,303,613	38,662,980	49,966,593	30,910,335	43,313,114	74,223,449	28,781,731	24,212,307	52,994,038	2
3	Total Utility Plant	$ 1,966,868,450	$ 1,794,221,041	$ 3,761,089,491	$ 1,912,194,061	$ 1,756,732,087	$ 3,668,926,148	$ 1,771,036,230	$ 1,632,022,126	$ 3,403,058,356	3
4	Less: Accumulated Provision for Depreciation and Amortization (108, 111, 119)	688,698,569	582,306,358	1,271,004,927	674,414,547	560,886,077	1,235,300,624	614,949,046	514,204,471	1,129,153,517	4
5	Net Utility Plant	$ 1,278,169,881	$ 1,211,914,683	$ 2,490,084,564	$ 1,237,779,514	$ 1,195,846,010	$ 2,433,625,524	$ 1,156,087,184	$ 1,117,817,655	$ 2,273,904,839	5
	Other Property and Investments										
6	Northern California Surcharge (120)	$ -	$ 5,547,483	$ 5,547,483	$ -	$ 5,859,991	$ 5,859,991	$ -	$ 6,735,698	$ 6,735,698	6
7	Non-Utility Property (121)	-	80,017	80,017	-	80,017	80,017	-	80,017	80,017	7
8	Non-Utility Accumulated Depreciation (122)	-	-	-	-	-	-	-	-	-	8
9	Investment in Subsidiary and Associated Companies (123, 123.1)	-	135,594,132	135,594,132	-	131,063,571	131,063,571	-	115,110,620	115,110,620	9
10	Other Investments (124)	-	-	-	-	-	-	-	-	-	10
11	Special Funds (125, 128)	-	55,174,633	55,174,633	-	52,868,271	52,868,271	-	50,122,378	50,122,378	11
12	Total Other Property and Investments	$ -	$ 196,396,265	$ 196,396,265	$ -	$ 189,871,850	$ 189,871,850	$ -	$ 172,048,713	$ 172,048,713	12
	Current and Accrued Assets										
13	Cash (131)	$ -	$ (28,267,866)	$ (28,267,866)	$ -	$ (9,643,554)	$ (9,643,554)	$ -	$ (4,853,506)	$ (4,853,506)	13
14	Working Funds (135)	-	1,108,034	1,108,034	-	947,094	947,094	-	725,769	725,769	14
15	Temporary Cash Investments (136)	-	1,980,928	1,980,928	-	8,470,545	8,470,545	-	42,046,806	42,046,806	15
16	Notes and Accounts Receivables Less Accumulated Provision for Uncollectible Accounts (141 - 144)	7,297,701	127,184,206	134,481,907	14,498,307	171,761,870	186,260,177	18,577,422	137,417,311	155,994,733	16
17	Receivables from Associated Companies (145-146)	-	19,921,310	19,921,310	-	23,248,322	23,248,322	-	32,029,585	32,029,585	17
18	Materials and Supplies (151, 154, 155, 163)	12,900,762	9,981,939	22,882,701	13,255,070	10,247,461	23,502,531	11,563,091	10,362,693	21,925,784	18
19	Liquefied Natural Gas Stored (164.1, 164.2)	-	8,951,081	8,951,081	-	14,005,846	14,005,846	-	13,047,683	13,047,683	19
20	Prepayments (165)	-	5,941,216	5,941,216	-	9,658,139	9,658,139	-	9,510,702	9,510,702	20
21	Interest and Dividends Receivable (171)	-	-	-	-	-	-	-	-	-	21
22	Accrued Utility Revenue (173)	-	40,300,000	40,300,000	-	73,300,000	73,300,000	-	68,400,000	68,400,000	22
23	Miscellaneous Current and Accrued Assets (174)	-	(7,293,006)	(7,293,006)	-	3,300,749	3,300,749	-	2,915,682	2,915,682	23
24	Total Current and Accrued Assets	$ 20,198,463	$ 179,807,842	$ 200,006,305	$ 27,753,377	$ 305,296,472	$ 333,049,849	$ 30,140,513	$ 311,602,725	$ 341,743,238	24
	Deferred Debits										
25	Unamortized Debt Discount and Expenses (181)	$ -	$ 18,877,479	$ 18,877,479	$ -	$ 19,334,215	$ 19,334,215	$ -	$ 20,132,394	$ 20,132,394	25
26	Other Regulatory Assets (182)	4,807,329	31,954,790	36,762,119	4,985,215	70,719,430	75,704,645	5,219,715	101,984,008	107,203,723	26
27	Preliminary Survey and Investigation Charges (183)	-	(741,889)	(741,889)	-	(141,888)	(141,888)	-	(330,051)	(330,051)	27
28	Clearing Accounts (184)	(146,740)	280,916	134,176	(98,085)	155,105	57,020	(113,083)	286,332	173,249	28
29	Miscellaneous Deferred Debits (186)	5,515,015	4,973,380	10,488,395	5,781,981	5,255,832	11,037,813	5,748,523	5,348,064	11,096,587	29
30	Research & Development (188)	-	-	-	-	223,939	223,939	-	243,559	243,559	30
31	Loss on Reacquired Debt (189)	-	17,448,187	17,448,187	-	17,676,072	17,676,072	-	18,386,157	18,386,157	31
32	Accumulated Deferred Income Taxes (190)	-	36,820,369	36,820,369	-	36,820,369	36,820,369	-	28,902,829	28,902,829	32
33	Unrecovered Purchased Gas Costs (191)	63,014,918	(20,111,034)	42,903,884	67,851,766	9,154,811	77,006,577	46,447,057	62,967,432	109,414,489	33
34	Total Deferred Debits	$ 73,190,522	$ 89,502,198	$ 162,692,720	$ 78,520,877	$ 159,197,885	$ 237,718,762	$ 57,302,212	$ 237,920,724	$ 295,222,936	34
35	Total Assets and Other Debits	$ 1,371,558,866	$ 1,677,620,988	$ 3,049,179,854	$ 1,344,053,768	$ 1,850,212,217	$ 3,194,265,985	$ 1,243,529,909	$ 1,839,389,817	$ 3,082,919,726	35

NOTE: The Arizona columns above reflect only those amounts separately identified in the Southwest Gas general ledger as pertaining solely to Arizona. Allocations are not included, thus the debits and credits in the Arizona columns do not balance. The financial statements appearing herein are unaudited, and were prepared solely for the purposes of complying with the filing requirements for this general rate case.

SCHEDULE E-1
Sheet 1 of 2

SOUTHWEST GAS CORPORATION
COMPARATIVE BALANCE SHEETS

Line No.	Description	Balance at 4/30/07 Arizona	Balance at 4/30/07 Other	Balance at 4/30/07 Total	Balance at 12/31/06 Arizona	Balance at 12/31/06 Other	Balance at 12/31/06 Total	Balance at 12/31/05 Arizona	Balance at 12/31/05 Other	Balance at 12/31/05 Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Liabilities and Other Credits										
	Proprietary Capital										
1	Common Stock Issued (201)	$ -	$ 43,781,138	$ 43,781,138	$ -	$ 43,400,167	$ 43,400,167	$ -	$ 40,958,167	$ 40,958,167	1
2	Preferred Stock Issued (204)	-	-	-	-	-	-	-	-	-	2
3	Premium on Capital Stock (207)	-	719,685,842	719,685,842	-	708,795,500	708,795,500	-	638,211,780	638,211,780	3
4	Other Paid in Capital (208-211)	-	-	-	-	-	-	-	-	-	4
5	Reacquired Capital Stock (217)	-	-	-	-	-	-	-	-	-	5
6	Capital Stock Expense (214)	-	(10,537,842)	(10,537,842)	-	(10,537,842)	(10,537,842)	-	(9,964,407)	(9,964,407)	6
7	Retained Earnings (216)	-	217,456,334	217,456,334	-	173,433,242	173,433,242	-	123,574,333	123,574,333	7
8	Total Proprietary Capital	$ -	$ 970,385,472	$ 970,385,472	$ -	$ 915,091,067	$ 915,091,067	$ -	$ 792,779,873	$ 792,779,873	8
	Long-Term Debt										
9	Bonds (221, 222)	$ -	$ 1,146,000,000	$ 1,146,000,000	$ -	$ 1,146,000,000	$ 1,146,000,000	$ -	$ 1,165,000,000	$ 1,165,000,000	9
10	Other Long-Term Debt (224, 226)	-	45,537,442	45,537,442	-	138,281,898	138,281,898	-	141,184,296	141,184,296	10
11	Other - Preferred Securities (224.1)	-	100,000,000	100,000,000	-	100,000,000	100,000,000	-	100,000,000	100,000,000	11
12	Total Long-Term Debt	$ -	$ 1,291,537,442	$ 1,291,537,442	$ -	$ 1,384,281,898	$ 1,384,281,898	$ -	$ 1,406,184,296	$ 1,406,184,296	12
	Current and Accured Liabilities										
13	Notes Payable (231)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,000,000	$ 24,000,000	13
14	Accounts Payable (232)	-	95,913,923	95,913,923	-	239,350,227	239,350,227	-	234,527,974	234,527,974	14
15	Payables to Associated Companies (233,234)	-	7,190,228	7,190,228	-	7,644,900	7,644,900	-	8,449,664	8,449,664	15
16	Customer Deposits (235)	34,911,701	32,449,462	67,361,163	32,944,994	31,205,607	64,150,601	29,349,616	28,202,220	57,551,836	16
17	Taxes Accrued (236)	13,259,372	45,344,420	58,603,792	12,379,928	7,155,100	19,535,028	15,188,196	7,386,794	22,574,990	17
18	Interest Accrued (237)	1,050,806	19,145,588	20,196,394	981,687	20,380,198	21,361,885	884,009	21,588,003	22,472,012	18
19	Dividends Declared (238)	-	9,062,521	9,062,521	-	8,562,910	8,562,910	-	8,062,300	8,062,300	19
20	Tax Collections Payable (241)	11,486,764	8,711,728	20,198,492	12,711,816	14,536,249	27,248,065	12,620,095	10,037,720	22,657,815	20
21	Miscellaneous Current and Accrued Liabilities (242)	6,223,324	53,752,965	59,976,289	3,027,404	51,709,315	54,736,719	2,342,302	56,131,024	58,473,326	21
22	Total Current and Accrued Liabilities	$ 66,931,967	$ 271,570,835	$ 338,502,802	$ 62,045,829	$ 380,544,506	$ 442,590,335	$ 60,384,218	$ 398,385,699	$ 458,769,917	22
	Deferred Credits										
23	Customer Advances for Construction (252)	$ 49,277,781	$ 22,242,084	$ 71,519,865	$ 41,078,966	$ 20,741,161	$ 61,820,127	$ 19,563,413	$ 14,268,786	$ 33,832,199	23
24	Other Deferred Credits (253)	26,392	36,940,611	36,967,003	26,392	35,739,640	35,766,032	26,392	34,574,926	34,601,318	24
25	Other Regulatory Liabilities (254)	13,778	7,056,731	7,070,509	15,500	7,256,383	7,271,883	17,222	7,470,217	7,487,439	25
26	Accumulated Deferred Investment Tax Credit (255)	6,251,910	3,789,207	10,041,117	6,428,030	3,902,279	10,330,309	6,956,390	4,241,495	11,197,885	26
27	Accumulated Deferred Income Taxes (282, 283)	202,414,610	118,764,163	321,178,773	178,076,468	157,186,936	335,263,404	175,200,549	148,819,491	324,020,040	27
28	Total Deferred Credits	$ 257,984,471	$ 188,792,796	$ 446,777,267	$ 225,625,356	$ 224,826,399	$ 450,451,755	$ 201,763,966	$ 209,374,915	$ 411,138,881	28
	Other Long-Term Liabilities										
29	Injuries and Damages Reserve (228)	$ -	$ 1,976,871	$ 1,976,871	$ -	$ 1,850,930	$ 1,850,930	$ -	$ 14,046,759	$ 14,046,759	29
30	Provision for Rate Refunds (229)	-	-	-	-	-	-	-	-	-	30
31	Total Other Long-Term Liabilities	$ -	$ 1,976,871	$ 1,976,871	$ -	$ 1,850,930	$ 1,850,930	$ -	$ 14,046,759	$ 14,046,759	31
32	Total Liabilities and Other Credits	$ 324,916,438	$ 2,724,263,416	$ 3,049,179,854	$ 287,671,185	$ 2,906,594,800	$ 3,194,265,985	$ 262,148,184	$ 2,820,771,542	$ 3,082,919,726	32

NOTE: The Arizona columns above reflect only those amounts separately identified in the Southwest Gas general ledger as pertaining solely to Arizona. Allocations are not included, thus the debits and credits in the Arizona columns do not balance. The financial statements appearing herein are unaudited, and were prepared solely for the purposes of complying with the filing requirements for this general rate case.

SCHEDULE E-1
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
ARIZONA
COMPARATIVE INCOME STATEMENTS

Line No.	Description	For the Test Year Ended 4/30/07	For the Year Ended 12/31/06	For the Year Ended 12/31/05	Line No.
	(a)	(b)	(c)	(d)	
1	Operating Revenue	$ 996,389,571	$ 895,549,006	$ 748,627,816	1
2	Operating Expenses and Taxes	914,451,814	827,185,527	708,138,708	2
3	Operating Income	$ 81,937,757	$ 68,363,479	$ 40,489,108	3
4	Other Income and Deductions	0	0	0	4
5	Income Before Interest Deductions	$ 81,937,757	$ 68,363,479	$ 40,489,108	5
6	Net Interest Deductions	47,844,172	47,089,555	45,778,673	6
7	Net Income	$ 34,093,586	$ 21,273,925	$ (5,289,565)	7

SOUTHWEST GAS CORPORATION
STATEMENTS OF INCOME

Line No.	Description	Year Ended 4/30/07	Year Ended 12/31/06	Year Ended 12/31/05	Line No.
	(a)	(b)	(c)	(d)	
	Utility Operating Income				
1	Operating Revenues (400)	$ 1,819,838,987	$ 1,714,338,144	$ 1,444,439,794	1
	Operating Expenses:				
2	Operation Expense (401)	$ 1,384,748,289	$ 1,301,656,495	$ 1,094,523,587	2
3	Maintenance Expense (402)	59,699,065	57,731,331	52,482,297	3
4	Depreciation Expense (403)	135,124,525	131,614,569	123,211,463	4
5	Amortization of Other Limited Term Gas Plant (404.3)	7,814,947	8,241,888	8,213,311	5
6	Amortization of Utility Plant Acquisition Adjustment (406)	154,011	154,011	154,011	6
7	Amortization of Property Losses (407.1)	-	-	-	7
8	Amortization of Regulatory assets (407.3)	2,287,572	1,425,096	1,307,538	8
9	Taxes Other than Income Taxes (408.1)	37,842,709	34,166,679	38,082,464	9
10	Income Taxes - Federal (409.1)	59,947,616	19,186,368	(1,488,394)	10
11	Income Taxes - Other (409.1)	7,045,314	3,395,307	921,895	11
12	Provision for Deferred Income Taxes (410.1)	52,267,390	101,021,935	99,662,898	12
13	Provision for Deferred Income Taxes - Credit (411.1)	(83,018,417)	(93,463,370)	(84,866,110)	13
14	Investment Tax Credit Adjustment - Net (411.4)	(867,576)	(867,576)	(867,576)	14
15	Total Utility Operating Expenses	$ 1,663,045,445	$ 1,564,262,733	$ 1,331,337,384	15
16	Net Utility Operating Income	$ 156,793,542	$ 150,075,411	$ 113,102,410	16
	Other Income and Deductions				
	Other Income:				
17	Non-Utility Operating Income (415-418)	$ -	$ -	$ -	17
18	Equity in Earnings of Subsidiary Companies (418.1)	17,690,170	19,446,160	14,479,596	18
19	Interest and Dividend Income (419)	7,303,140	9,389,622	7,226,036	19
20	Allowance for Equity Funds Used During Construction (419.1)	1,424,293	1,372,036	966,689	20
21	Amortization of Investment Tax Credits (420)	-	-	-	21
22	Miscellaneous Non-Operating Income (421)	91,439	779	295,573	22
23	Total Other Income	$ 26,509,042	$ 30,208,597	$ 22,967,894	23
	Other (Income) Deductions:				
24	Miscellaneous Amortization (425)	$ 26,358	$ 26,358	$ 26,358	24
25	Miscellaneous (Income) Deductions (426)	1,044,907	169,178	1,074,955	25
26	Total (Income) Deductions	$ 1,071,265	$ 195,536	$ 1,101,313	26
	Taxes Applicable to Other Income and Deductions				
27	Taxes Other than Income Taxes (408.2)	$ 4,421	$ 4,421	$ 11,760	27
28	Income Taxes - (409.2)	977,586	1,536,215	2,181,392	28
29	Provision for Deferred Income Taxes (410.2,411.2)	1,257,832	1,385,913	(349,305)	29
30	Investment Tax Credit Adjustment - Net (411.5)	-	-	-	30
31	Total Taxes Applicable to Other Income and Deductions	$ 2,239,839	$ 2,926,549	$ 1,843,847	31
32	Net Other Income and (Deductions)	$ 23,197,938	$ 27,086,512	$ 20,022,734	32
	Interest Charges				
33	Interest on Long-Term Debt (427)	$ 79,350,696	$ 80,043,345	$ 76,055,512	33
34	Amortization of Debt Discount and Expense (428)	3,952,146	3,466,931	3,699,622	34
35	Other Interest Expense (430-431)	11,083,936	11,148,594	10,593,169	35
36	Total Interest Charges	$ 94,386,778	$ 94,658,870	$ 90,348,303	36
37	Allowance for Borrowed Funds Used During Construction (432)	1,340,971	1,356,704	1,046,495	37
38	Net Interest Charges	$ 93,045,807	$ 93,302,166	$ 89,301,808	38
39	Net Income	$ 86,945,673	$ 83,859,757	$ 43,823,336	39

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
COMPARATIVE STATEMENT OF CASH FLOWS

Line No.	Description	Test Year Ended 4/30/07	Year Ended 12/31/06	Year Ended 12/31/05	Line No.
	(a)	(b)	(c)	(d)	
	CASH FLOWS FROM OPERATING ACTIVITIES:				
1	Net Income	$ 87,821,323	$ 83,859,756	$ 43,823,336	1
	Adjustments to reconcile net income to net cash provided by operating activities:				
2	Depreciation and amortization	145,381,056	141,435,564	132,886,324	2
3	Deferred income taxes	(30,177,984)	2,458,247	14,465,375	3
	Changes in current assets and liabilities:				
4	Accounts receivable	18,866,845	(31,320,586)	(7,597,731)	4
5	Accrued utility revenue	(3,400,000)	(4,900,000)	(200,000)	5
6	Unrecovered purchased gas costs	88,264,127	32,407,911	(27,338,920)	6
7	Accounts payable	(46,758,655)	14,230,885	114,196,255	7
8	Accrued taxes	42,498,069	1,550,287	6,284,511	8
9	Other current assets and liabilities	-	-	-	9
10	Other	(12,965,202)	4,032,851	(64,815,617)	10
11	Net cash provided by operating activities	$ 289,529,579	$ 243,754,915	$ 211,703,533	11
	CASH FLOWS FROM INVESTING ACTIVITIES:				
12	Construction expenditures	$ (327,268,841)	$ (300,932,762)	$ (256,350,020)	12
13	Other	31,026,415	31,567,651	7,231,287	13
14	Net cash used in investing activities	$ (296,242,426)	$ (269,365,111)	$ (249,118,733)	14
	CASH FLOWS FROM FINANCING ACTIVITIES:				
15	Issuance of common stock	$ 65,896,688	$ 72,452,285	$ 64,135,240	15
16	Issuance of preferred securities, net	-	-	-	16
17	Retirement of preferred securities	-	-	-	17
18	Dividends paid	(34,012,501)	(33,500,237)	(31,227,582)	18
19	Issuance of long-term debt, net	55,948,400	79,948,400	123,255,748	19
20	Retirement of long-term debt	(139,989,000)	(78,000,000)	(25,000,000)	20
21	Issuance (repayment) of short-term debt	-	(24,000,000)	(76,000,000)	21
22	Net cash provided by (used in) financing activitie	$ (52,156,413)	$ 16,900,448	$ 55,163,406	22
23	Change in cash and temporary cash investments	$ (58,869,260)	$ (8,709,748)	$ 17,748,206	23
24	Cash at beginning of period	69,544,757	26,460,546	8,712,340	24
25	Cash at end of period	$ 10,675,497	$ 17,750,798	$ 26,460,546	25

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY AND PREFERRED SECURITIES

Line No.	Description	Preferred Securities (1)		Common		Additional Paid-In Capital	Retained Earnings	Capital Stock Expense	Line No.
		Shares/Units	Amount	Shares	Amount				
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Balance December 31, 2004	-	$ -	36,794,343	$ 38,424,219	$576,298,008	$111,498,039	$ (9,651,927)	1
2	Net Earnings	-	-	-	-	-	43,823,336	-	2
3	Cash Dividends Declared-Common	-	-	-	-	-	(31,747,042)	-	3
4	Common Stock Issue	-	-	2,533,948	2,533,948	61,913,772	-	(312,480)	4
5	Balance December 31, 2005	-	$ -	39,328,291	$ 40,958,167	$638,211,780	$123,574,333	$ (9,964,407)	5
6	Redemption	-	-					-	6
7	Net Earnings	-	-	-	-	-	83,859,756	-	7
8	Cash Dividends Declared-Common	-	-	-	-	-	(34,000,847)	-	8
9	Common Stock Issue	-	-	2,442,000	2,442,000	70,583,720	-	(573,435)	9
10	Balance December 31, 2006	-	$ -	41,770,291	$ 43,400,167	$708,795,500	$173,433,242	$(10,537,842)	10
11	Net Earnings	-	-	-	-	-	53,132,100	-	11
12	Cash Dividends Declared-Common	-	-	-	-	-	(9,109,008)	-	12
13	Common Stock Issue	-	-	380,971	380,971	10,890,342	-	-	13
14	Balance April 30, 2007	-	$ -	42,151,262	$ 43,781,138	$719,685,842	$217,456,334	$(10,537,842)	14

SCHEDULE E-4
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
DETAIL OF UTILITY PLANT - NET ADDITIONS
FOR THE YEAR ENDED APRIL 30, 2007

Line No.	Description	Account Number	Balance at 30-Apr-07	Net Plant Additions (Deletions)	Balance at 31-Dec-06	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Intangible					
1	Organizational Costs	301	$ 42,653	$ 0	$ 42,653	1
2	Franchise and Consents	302	1,877,392	(10,601)	1,887,993	2
3	Miscellaneous Intangible	303	1,957,665	0	1,957,665	3
4	Total Intangible		$ 3,877,710	$ (10,601)	$ 3,888,311	4
	Distribution					
5	Land and Land Rights	374.1	$ 351,685	$ 0	$ 351,685	5
6	Rights of Way	374.2	1,064,064	0	1,064,064	6
7	Structures	375	110,557	0	110,557	7
8	Mains	376	983,275,239	39,661,687	943,613,552	8
9	Measuring and Regulating Station	378	32,428,418	1,327,647	31,100,771	9
10	Services	380	605,265,994	9,829,741	595,436,253	10
11	Meters	381	226,663,229	18,298,523	208,364,706	11
12	Industrial Measuring and Reg. Station	385	7,449,951	137,686	7,312,265	12
13	Other Equipment	387	462,730	0	462,730	13
14	Total Distribution		$ 1,857,071,867	$ 69,255,284	$ 1,787,816,583	14
	General					
15	Land and Land Rights	389	$ 8,418,416	$ 1,963,827	$ 6,454,589	15
16	Structures & Improvements - General	390.1	26,064,967	314,145	25,750,822	16
17	Structures and Improve. - Leasehold	390.2	986,219	0	986,219	17
18	Office Furniture and Equipment	391	5,440,159	560,913	4,879,246	18
19	Computer Equipment	391.1	8,563,368	516,820	8,046,548	19
20	Transportation Equipment	392.1	31,126,359	704,486	30,421,873	20
21	Stores Equipment	393	542,520	0	542,520	21
22	Tools, Shop, Garage Equipment	394	5,225,024	182,670	5,042,354	22
23	Laboratory Equipment	395	279,065	0	279,065	23
24	Power Operated Equipment	396	4,309,295	203,746	4,105,549	24
25	Communication Equipment - General	397	2,658,259	514,902	2,143,357	25
26	Telemetering Equipment	397.2	789,376	17,205	772,171	26
27	Miscellaneous Equipment	398	892,348	40,049	852,299	27
28	Total General		$ 95,295,375	$ 5,018,763	$ 90,276,612	28
29	Total Plant in Service		$ 1,956,244,952	$ 74,263,446	$ 1,881,981,506	29
30	Construction Work in Progress		14,716,205	(15,874,556)	30,590,761	30
31	Less: Accumulated Depreciation/Amort.		692,030,569	20,111,974	671,918,595	31
32	Total Net Plant		$ 1,278,930,588	$ 38,276,916	$ 1,240,653,672	32

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE PLANT
DETAIL OF UTILITY PLANT - NET ADDITIONS
FOR THE YEAR ENDED APRIL 30, 2007

Line No.	Description	Account Number	Balance at 30-Apr-07	Net Plant Additions (Deletions)	Balance at 31-Dec-06	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Intangible					
1	Organizational Costs	301	$ 61,816	$ 0	$ 61,816	1
2	Miscellaneous Intangible	303	111,648,261	1,375,104	110,273,157	2
3	Total Intangible		$ 111,710,077	$ 1,375,104	$ 110,334,973	3
	General					
4	Land and Land Rights	389	$ 391,307	$ 0	$ 391,307	4
5	Structures and Improvements - Gen	390.1	13,696,291	127,552	13,568,739	5
6	Structure and Improve. - Leasehold	390.2	4,232,645	115,411	4,117,234	6
7	Office Furniture and Equipment	391	9,413,589	410,465	9,003,124	7
8	Computer Equipment	391.1	14,358,835	29,491	14,329,344	8
9	Transportation Equipment - Light	392.11	3,495,826	38,713	3,457,113	9
10	Transportation Equipment - Heavy	392.12	86,303	0	86,303	10
11	Stores Equipment	393	24,106	0	24,106	11
12	Tools, Shop, Garage Equipment	394	232,096	0	232,096	12
13	Laboratory Equipment	395	281,078	9,868	271,210	13
14	Communication Equipment	397.1	5,376,875	305,579	5,071,296	14
15	Telemetering Equipment	397.2	286,958	6,933	280,025	15
16	Miscellaneous Equipment	398	882,254	0	882,254	16
17	Total General		$ 52,758,163	$ 1,044,012	$ 51,714,151	17
18	Total Systems - Plant in Service		$ 164,468,240	$ 2,419,116	$ 162,049,124	18
19	Construction Work in Progress		3,707,879	(1,254,849)	4,962,728	19
20	Less: Accumulated Depreciation/Amort.		106,157,029	1,513,306	104,643,723	20
21	Total Net Plant		$ 62,019,090	$ (349,039)	$ 62,368,129	21

SOUTHWEST GAS CORPORATION
ARIZONA
COMPARATIVE DEPARTMENTAL OPERATING INCOME STATEMENTS

Line No.	Description	For the TestYear Ended 4/30/07	For the Year Ended 12/31/06	For the Year Ended 12/31/05	Line No.
	(a)	(b)	(c)	(d)	
	Revenues				
1	Residential	$ 534,629,012	$ 459,375,848	$ 377,481,564	1
2	Small Commercial	242,901,625	223,648,183	177,615,441	2
3	Large Commercial	62,979,199	55,965,426	35,133,244	3
4	Small Industrial	45,642,205	45,890,749	32,947,420	4
5	Commercial-Compressed Nat. Gas	2,493,836	2,522,813	2,002,307	5
6	Irrigation/Water Pumping	12,830,537	13,109,820	13,103,224	6
7	Industrial-Essential Agriculture	23,610,155	20,104,961	8,084,740	7
8	Procurement Sales	44,370,052	48,895,478	82,336,266	8
9	Other Gas Sales	173,495	160,790	175,973	9
10	Transportation of Gas for Others	11,659,328	10,513,078	9,058,071	10
11	Rent from Gas Property	512,498	517,160	614,217	11
12	Other Gas Revenues	0	0	0	12
13	Miscellaneous Service Revenue	11,749,308	11,227,851	10,002,293	13
14	LIRA Program Recovery	868,933	584,995	(38,475)	14
15	Accrued Unbilled Revenues	1,969,388	3,031,854	111,531	15
16	Total Revenues	$ 996,389,571	$ 895,549,006	$ 748,627,816	16
	Operating Expenses				
17	Other Gas Supply and Gas Cost	$ 594,109,743	$ 525,175,154	$ 425,287,419	17
18	Transmission	0	(0)	12,556	18
19	Distribution	87,644,582	85,228,447	81,675,844	19
20	Customer Accounts	37,800,950	37,261,156	35,037,768	20
21	Customer Service & Information	1,320,355	889,541	674,654	21
22	Sales	230,155	250,732	105,813	22
23	Administrative and General	53,970,196	53,266,327	57,242,109	23
24	Depreciation and Amortization	86,665,721	83,858,314	79,019,889	24
25	Interest on Customer Deposits	1,856,153	1,876,829	1,705,847	25
26	Taxes Other Than Income	28,912,193	25,391,691	30,021,921	26
27	Income Taxes - Federal	18,007,537	11,455,272	(2,245,297)	27
28	Income Taxes - State	3,934,229	2,532,064	(399,817)	28
29	Total Expenses	$ 914,451,814	$ 827,185,527	$ 708,138,708	29
30	Operating Income	$ 81,937,757	$ 68,363,479	$ 40,489,108	30

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
OPERATING STATISTICS
FOR THE TEST YEAR ENDED APRIL 30, 2007

Line No.	Description	Schedule No.	Average Customers	Sales (Therms)	Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Residential Gas Service	G-5	844,801	287,627,196	340	1
2	Multi-Family Residential Gas Service	G-6	30,690	6,507,195	212	2
3	Low Income Residential Gas Service	G-10	25,929	8,687,972	335	3
4	Multi-Family Low Income Residential Gas Service	G-11	2,193	538,091	245	4
5	Special Residential Gas Service for A/C	G-15	108	143,315	1,327	5
6	Special Residential Gas Service for Electric Generation	G-16	0	0	-	6
7	Master Metered Mobile Home Park Gas Service	G-20	164	2,214,306	13,502	7
	General Gas Service	G-25				
8	Small		16,961	5,112,687	301	8
9	Medium		16,047	45,322,582	2,824	9
10	Large		6,977	145,251,712	20,817	10
11	Transportation Eligible		145	81,978,961	565,372	11
12	Optional Gas Service	G-30	1	34,477,100	34,477,100	12
13	Gas Service to Armed Forces	G-35	0	0	-	13
14	Air Conditioning Gas Service	G-40	25	744,265	30,378	14
15	Street Lighting Gas Service	G-45	27	102,289	3,788	15
	Gas Service for Compression on Customer's Premises	G-55				
16	Small		21	177,495	8,452	16
17	Large		24	2,060,152	85,840	17
18	Residential		106	77,361	730	18
19	Cogeneration Gas Service	G-60	21	21,521,946	1,024,855	19
20	Small Essential Agriculture User Gas Service	G-75	87	7,214,684	82,611	20
21	Natural Gas Engine Gas Service	G-80	425	13,070,981	30,725	21
22	Total Gas Sales		944,753	662,830,290	702	22
23	Transportation Service Including Special Contract	T-1/B-1	247	113,414,439	458,549	23
24	Total Arizona		945,001	776,244,729	821	24

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
OPERATING STATISTICS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2006

Line No.	Description	Schedule No.	Average Customers	Sales (Therms)	Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Residential Gas Service	G-5	810,250	257,670,165	318	1
2	Multi-Family Residential Gas Service	G-6	28,272	5,445,774	193	2
3	Low Income Residential Gas Service	G-10	24,343	7,865,249	323	3
4	Multi-Family Low Income Residential Gas Service	G-11	1,983	430,457	217	4
5	Special Residential Gas Service for A/C	G-15	114	142,235	1,248	5
6	Special Residential Gas Service for Electric Generation	G-16	0	0	-	6
7	Master Metered Mobile Home Park Gas Service	G-20	175	2,124,139	12,126	7
	General Gas Service	G-25				
8	Small		14,215	2,718,743	191	8
9	Medium		18,777	44,692,733	2,380	9
10	Large		6,938	146,196,011	21,071	10
11	Transportation Eligible		138	79,244,698	574,931	11
12	Optional Gas Service	G-30	5	73,283,590	14,416,444	12
13	Gas Service to Armed Forces	G-35	6	1,967,601	310,674	13
14	Air Conditioning Gas Service	G-40	27	782,191	29,332	14
15	Street Lighting Gas Service	G-45	26	101,268	3,907	15
	Gas Service for Compression on Customer's Premises	G-55				
16	Small		23	191,705	8,187	16
17	Large		25	2,220,080	90,003	17
18	Residential		105	74,348	711	18
19	Cogeneration Gas Service	G-60	22	18,701,265	866,468	19
20	Small Essential Agriculture User Gas Service	G-75	96	8,778,744	91,445	20
21	Natural Gas Engine Gas Service	G-80	471	13,755,821	29,190	21
22	Total Gas Sales		906,011	666,386,817	736	22
23	Transportation Service Including Special Contract	T-1/B-1	219	71,031,432	324,715	23
24	Total Arizona		906,230	737,418,249	814	24

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
OPERATING STATISTICS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2005

Line No.	Description	Schedule No.	Average Customers	Sales (Therms)	Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Residential Gas Service	G-5	823,164	258,307,113	314	1
2	Multti-Family Residential Gas Service	G-6	29,850	6,289,177	211	2
3	Low Income Residential Gas Service	G-10	26,177	8,995,604	344	3
4	Multi-Family Low Income Residential Gas Service	G-11	3,657	543,874	149	4
5	Special Residential Gas Service for A/C	G-15	126	181,622	1,437	5
6	Special Residential Gas Service for Electric Generation	G-16	0	29	174	6
7	Master Metered Mobile Home Park Gas Service	G-20	181	2,221,960	12,276	7
	General Gas Service	G-25				
8	Small		32,724	46,258,768	1,414	8
9	Medium		6,998	142,391,261	20,347	9
10	Large		115	51,837,818	449,461	10
11	Optional Gas Service	G-30	42	103,976,689	2,475,635	11
12	Gas Service to Armed Forces	G-35	11	3,153,221	286,656	12
13	Air Conditioning Gas Service	G-40	34	760,755	22,709	13
14	Street Lighting Gas Service	G-45	27	100,928	3,797	14
	Gas Service for Compression on Customer's Premises	G-55				
15	Small		23	204,582	8,831	15
16	Large		26	2,283,894	88,695	16
17	Residential		101	69,155	684	17
18	Cogeneration Gas Service	G-60	23	15,355,050	677,429	18
19	Small Essential Agriculture User Gas Service	G-75	99	8,670,397	87,580	19
20	Natural Gas Engine Gas Service	G-80	523	14,021,900	26,836	20
21	Total Gas Sales		923,899	665,623,797	720	21
22	Transportation Service Including Special Contract	T-1/B-1	218	67,162,701	308,204	22
23	Total Arizona		924,117	732,786,498	793	23

732,786,498
0

SOUTHWEST GAS CORPORATION
ARIZONA
TAXES CHARGED TO OPERATIONS
AS RECORDED AT APRIL 30, 2007

Line No.	Description	For the Test Year Ended 4/30/07	For the Year Ended 12/31/06	For the Year Ended 12/31/05	Line No.
	(a)	(b)	(c)	(d)	
	Federal Taxes				
1	Federal Income Tax	$ 18,007,537	$ 11,455,272	$ (2,245,297)	1
	State Taxes				
2	State Income Tax	$ 3,934,229	$ 2,532,064	$ (399,817)	2
	Local Taxes				
3	Property and Miscellaneous	$ 28,912,193	$ 25,391,691	$ 30,021,921	3

SOUTHWEST GAS CORPORATION
NOTES TO FINANCIAL STATEMENTS

1. The Company uses the accrual method of accounting as prescribed by the Uniform System of Accounts.

2. The Company uses the straight line method for calculating depreciation expense. Depreciation rates by major classification can be found in the Workpapers, Schedule C-2.

3. The Allowance for Funds Used During Construction (AFUDC) rate used in 2006 was 8.96% and is estimated to be 8.75% for 2007.

4. Additional information concerning these statements is contained in Southwest's 2006 Annual Report which is included in the instant application.

Volume II

Supporting Schedules

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SOUTHWEST GAS CORPORATION
ARIZONA
PROJECTED INCOME STATEMENTS - PRESENT AND PROPOSED RATES

Line No.	Description	Test Year Ended 4/30/2007	Projected Year Present Rates 4/30/2008	Projected Year Proposed Rates 4/30/2008	Line No.
	(a)	(b)	(c)	(d)	
1	Operating Margin	$ 402,964,907	$ 406,994,556	$ 453,949,051	1
	Operating Expenses				
2	Other Gas Supply Expenses	$ 685,079	$ 701,601	$ 701,601	2
3	Distribution Expenses	87,644,582	89,521,943	89,521,943	3
4	Customer Accounts Expenses	37,800,950	38,730,909	38,730,909	4
5	Customer Service and Info. Expenses	1,320,355	1,126,796	1,126,796	5
6	Sales Expenses	230,155	0	0	6
7	Administrative and General Expenses	53,970,196	57,280,777	57,280,777	7
8	Depreciation and Amortization Expenses	86,665,721	95,152,859	95,152,859	8
9	Taxes Other than Income	21,941,766	34,118,626	34,118,626	9
10	Interest on Customer Deposits	1,856,153	1,915,314	1,915,314	10
11	Federal Income Taxes	18,007,537	12,919,971	28,208,918	11
12	State Income Taxes	3,934,229	2,845,505	6,117,294	12
13	Total Operating Expenses	$ 314,056,723	$ 334,314,300	$ 352,875,036	13
14	Operating Income	$ 88,908,184	$ 72,680,256	$ 101,074,015	14
15	Less: Interest Expense	47,844,172	48,035,008	48,035,008	15
16	Net Income	$ 41,064,012	$ 24,645,248	$ 53,039,007	16
17	Earnings per Share of Average Common Stock Outstanding	N/A	N/A	N/A	17
18	Percent Return on Common Equity	N/A	N/A	N/A	18

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
COMPARATIVE STATEMENT OF CASH FLOWS

Line No.	Description	Test Year[1] Ended 4/30/07	Projected Year[2] At Present Rates Year Ended 12/31/08	Projected Year[2] At Proposed Rates Year Ended 12/31/08	Line No.
	(a)	(b)	(c)	(d)	
	CASH FLOWS FROM OPERATING ACTIVITIES:				
1	Net Income	$ 87,821,323	$ 87,821,323	$ 118,098,884	1
	Adjustments to reconcile net income to net cash provided by operating activities:				
2	Depreciation and amortization	145,381,056	154,381,056	154,381,056	2
3	Deferred income taxes	(30,177,984)	(30,177,984)	(30,177,984)	3
4	Changes in current assets and liabilities:		-	-	4
5	Accounts receivable	18,866,845	18,866,845	18,866,845	5
6	Accrued utility revenue	(3,400,000)	(3,400,000)	(3,400,000)	6
7	Unrecovered purchased gas costs	88,264,127	73,600,000	73,600,000	7
8	Accounts payable	(46,758,655)	(46,758,655)	(46,758,655)	8
9	Accrued taxes	42,498,069	42,498,069	42,498,069	9
10	Other	(12,965,202)	(12,965,202)	(12,965,202)	10
11	Net cash provided by operating activities	$289,529,579	$283,865,452	$314,143,013	11
	CASH FLOWS FROM INVESTING ACTIVITIES:				
12	Construction expenditures	(327,268,841)	(300,000,000)	(300,000,000)	12
13	Other	31,026,415	31,026,415	31,026,415	13
14	Net cash used in investing activities	(296,242,426)	(268,973,585)	(268,973,585)	14
	CASH FLOWS FROM FINANCING ACTIVITIES:				
15	Issuance of common stock	65,896,688	38,000,000	38,000,000	15
16	Issuance of preferred securities, net	-	-	-	16
17	Retirement of preferred securities	-	-	-	17
18	Dividends paid	(34,012,501)	(35,212,501)	(35,212,501)	18
19	Issuance of long-term debt, net	55,948,400	-	-	19
20	Retirement of long-term debt	(139,989,000)	(25,000,000)	(25,000,000)	20
21	Issuance (repayment) of short-term debt	-	-	-	21
22	Net cash provided by (used in) financing activities	(52,156,413)	(22,212,501)	(22,212,501)	22
23	Change in cash and temporary cash investments	(58,869,260)	(7,320,634)	22,956,927	23
24	Cash at beginning of period	69,544,757	10,675,497	3,354,863	24
25	Cash at end of period	$ 10,675,497	$ 3,354,863	$ 26,311,790	25

[1] Supporting Schedule E-3
[2] Recap Schedule A-5

SOUTHWEST GAS CORPORATION
ARIZONA
CONSTRUCTION EXPENDITURES BY PROPERTY CLASSIFICATION
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
AND PROJECTED TWELVE MONTHS ENDING APRIL 30, 2008, 2009, AND 2010

Line No.	Description	Test Year Ended 4/30/2007	Projected Year Ending 4/30/08	Projected Year Ending 4/30/09	Projected Year Ending 4/30/10	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Intangible Plant					
1	Arizona Direct	$ 99,483	$ 310,000	$ 0	$ 0	1
2	System Allocable [1]	1,878,136	4,421,381	4,983,250	4,067,715	2
3	Total Intangible Plant	$ 1,977,619	$ 4,731,381	$ 4,983,250	$ 4,067,715	3
	Distribution Plant					
4	Arizona Direct	$ 174,032,007	$ 145,824,212	$ 126,357,261	$ 109,086,533	4
5	System Allocable [1]	0	0	0	0	5
6	Total Distribution Plant	$ 174,032,007	$ 145,824,212	$ 126,357,261	$ 109,086,533	6
	General Plant					
7	Arizona Direct	$ 12,289,092	$ 6,823,377	$ 856,199	$ 997,784	7
8	System Allocable [1]	3,398,607	7,827,929	7,993,746	6,762,111	8
9	Total General Plant	$ 15,687,699	$ 14,651,306	$ 8,849,945	$ 7,759,895	9
10	Total Arizona Plant Construction	$ 191,697,325	$ 165,206,899	$ 140,190,456	$ 120,914,143	10

[1] Allocation based on the 4-Factor (56.70%). Supporting Schedule C-1, Sh 17

SCHEDULE F-3
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
ASSUMPTIONS USED IN DEVELOPING PROJECTIONS

1. Customer Growth
2. Growth in Consumption and Customer Demand

   Margin related to customer growth and consumption is anticipated to increase by 1% in the year following the test year.

3. Changes in Expense

   Operation and Maintenance Expenses - The actual amounts for the recorded test year ended April 30, 2007, were adjusted to give the annual effect for known and measurable changes occurring during the test year ending April 30, 2007. The operation and maintenance expenses for the projected year ending April 30, 2008, were calculated by taking the adjusted test year and generally increasing the non-labor expenses by 3%.

   Depreciation and Amortization Expenses - The actual amounts for the recorded test year ended April 30, 2007 were adjusted to annualize depreciation expense at the end of the test period plant balances, and to reflect depreciation expense on projected construction expenditures.

4. Construction Requirements, Including Production Reserves and Changes in Plant Capacity

   Additions to gas plant were based upon anticipated construction expenditures.

5. Capital Structures Changes
6. Financing Costs, Interest Rates

   Items 5 and 6 are not applicable. In this proceeding Southwest Gas Corporation is requesting rate relief for only a portion of its three-state system.

Volume II

Supporting Schedules

G

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY
PRESENT RATES
TEST YEAR ENDING APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total Amount	Single Family Residential	Multi-Family Residential	MMMHP	Small Gen. Service	Medium Gen. Service	Large Gen. Service	Trans. Eligible Service
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Rate Base									
1	Direct Net Plant		$1,267,124,121	$ 972,148,655	$ 26,208,345	$ 2,101,465	$ 21,567,888	$ 69,420,649	$ 106,428,942	$ 52,370,004
2	Systems Allocable Net Plant		34,448,206	26,428,964	712,504	57,131	586,347	1,887,279	2,893,391	1,423,738
3	Cash Working Capital	11.2	(10,379,937)	(8,277,078)	(202,429)	(11,552)	(244,332)	(578,417)	(686,594)	(266,389)
4	Materials & Supplies	1.1	12,389,898	9,505,637	256,264	20,548	210,890	678,793	1,040,659	512,072
5	Prepayments	Direct Net Plant	3,671,971	2,817,168	75,949	6,090	62,501	201,173	308,418	151,762
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-	-	-
7	Customer Deposits	8	(31,921,898)	(29,695,451)	(1,113,765)	(5,508)	(564,803)	(542,371)	-	-
8	Customer Advances	8	(37,910,017)	(35,265,919)	(1,322,692)	(6,541)	(670,752)	(644,112)	-	-
9	Deferred Taxes	1.1	(142,632,297)	(109,428,740)	(2,950,111)	(236,549)	(2,427,763)	(7,814,252)	(11,980,045)	(5,894,966)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-	-	-
11	Total Rate Base		$1,094,790,047	$ 828,233,236	$ 21,664,065	$ 1,925,083	$ 18,519,976	$ 62,608,741	$ 98,004,771	$ 48,296,221
	Margin									
12	Net Operating Margin	Direct	$ 381,188,845	$ 258,989,889	$ 7,115,596	$ 972,093	$ 7,867,642	$ 24,310,776	$ 53,003,981	$ 20,088,639
13	Special Contract Margin	Net Op. Marg.	$ 5,784,028	$ 3,929,823	$ 107,970	$ 14,750	$ 119,381	$ 368,883	$ 804,264	$ 304,818
14	Other Revenue	Net Op. Marg.	12,261,805	10,634,757	376,029	11,075	357,561	552,423	230,620	48,605
15	Total Revenue		$ 399,234,678	$ 273,554,469	$ 7,599,595	$ 997,919	$ 8,344,584	$ 25,232,083	$ 54,038,865	$ 20,442,062
	Operating Deductions									
16	O & M		$(130,087,761)	$(103,733,435)	$(2,536,969)	$(144,778)	$(3,062,120)	$(7,249,078)	$(8,604,815)	$(3,338,545)
17	A & G	O & M	(56,946,694)	(45,409,930)	(1,110,574)	(63,378)	(1,340,461)	(3,173,327)	(3,766,809)	(1,461,468)
18	Depreciation Expense		(87,887,713)	(67,428,218)	(1,817,811)	(145,758)	(1,495,948)	(4,815,015)	(7,381,910)	(3,632,383)
19	Interest on Customer Deposits	8	(1,915,314)	(1,781,727)	(66,826)	(330)	(33,888)	(32,542)	-	-
20	Taxes other than Income	1.1	(33,124,880)	(25,413,696)	(685,133)	(54,936)	(563,823)	(1,814,779)	(2,782,242)	(1,369,045)
21	Total Operating Deductions		$(309,962,361)	$(243,767,007)	$(6,217,312)	$(409,180)	$(6,496,241)	$(17,084,742)	$(22,535,776)	$(9,801,442)
	State Income Tax									
22	Taxable Income before Interest Exp.		$ 89,272,317	$ 29,787,462	$ 1,382,283	$ 588,739	$ 1,848,343	$ 8,147,341	$ 31,503,089	$ 10,640,620
23	Interest Expense	1.1	(48,035,008)	(36,852,876)	(993,524)	(79,664)	(817,610)	(2,631,645)	(4,034,581)	(1,985,278)
24	State Taxable Income		$ 41,237,309	$(7,065,414)	$ 388,759	$ 509,075	$ 1,030,733	$ 5,515,696	$ 27,468,508	$ 8,655,342
25	State Income Tax		2,873,416	(492,318)	27,089	35,472	71,821	384,334	1,914,006	603,104
26	South Georgia	1.1	29,686	22,775	614	49	505	1,626	2,493	1,227
27	Total State Income Tax		$ 2,903,102	$(469,543)	$ 27,703	$ 35,522	$ 72,327	$ 385,960	$ 1,916,499	$ 604,331
	Federal Income Tax									
28	Taxable Income before Interest Exp.		$ 89,272,317	$ 29,787,462	$ 1,382,283	$ 588,739	$ 1,848,343	$ 8,147,341	$ 31,503,089	$ 10,640,620
29	Interest Expense		(48,035,008)	(36,852,876)	(993,524)	(79,664)	(817,610)	(2,631,645)	(4,034,581)	(1,985,278)
30	Federal Taxable Income		$ 41,237,309	$(7,065,414)	$ 388,759	$ 509,075	$ 1,030,733	$ 5,515,696	$ 27,468,508	$ 8,655,342
31	Federal Income Tax		$ 13,427,363	$(2,300,584)	$ 126,585	$ 165,761	$ 335,619	$ 1,795,977	$ 8,944,076	$ 2,818,283
32	I T C	1.1	(528,360)	(405,362)	(10,928)	(876)	(8,993)	(28,947)	(44,378)	(21,837)
33	South Georgia	1.1	290,114	222,578	6,001	481	4,938	15,894	24,367	11,990
34	Total Federal Income Tax		$ 13,189,117	$(2,483,368)	$ 121,657	$ 165,366	$ 331,564	$ 1,782,924	$ 8,924,065	$ 2,808,437
35	Regulatory Amortization	Depr. Exp.	-	-	-	-	-	-	-	-
36	Net Income		$ 73,180,099	$ 32,740,373	$ 1,232,923	$ 387,851	$ 1,444,453	$ 5,978,457	$ 20,662,525	$ 7,227,852

SCHEDULE G-1
SHEET 1 OF 2

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY
PRESENT RATES
TEST YEAR ENDING APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total Amount	Air Conditioning	CNG Small	CNG Large	CNG Residential	Electric Generation	Small Ess. Agr.	Natural Gas Engines	Street Lighting
	(a)	(b)	(c)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	Rate Base										
1	Direct Net Plant		$1,267,124,121	$ 206,853	$ 67,356	$ 757,197	$ 105,396	$ 4,647,622	$5,263,618	$ 5,381,166	$ 448,968
2	Systems Allocable Net Plant		34,448,206	5,624	1,831	20,585	2,865	126,351	143,097	146,293	12,206
3	Cash Working Capital	11.2	(10,379,937)	(1,182)	(555)	(5,054)	(929)	(24,562)	(32,177)	(46,535)	(2,151)
4	Materials & Supplies	1.1	12,389,898	2,023	659	7,404	1,031	45,444	51,467	52,617	4,390
5	Prepayments	Direct Net Plant	3,671,971	599	195	2,194	305	13,468	15,253	15,594	1,301
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-	-	-	-
7	Customer Deposits	8	(31,921,898)	-	-	-	-	-	-	-	-
8	Customer Advances	8	(37,910,017)	-	-	-	-	-	-	-	-
9	Deferred Taxes	1.1	(142,632,297)	(23,284)	(7,582)	(85,233)	(11,864)	(523,154)	(592,493)	(605,724)	(50,538)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-	-	-	-
11	Total Rate Base		$1,094,790,047	$ 190,632	$ 61,903	$ 697,093	$ 96,804	$ 4,285,169	$4,848,767	$ 4,943,410	$ 414,177
	Margin										
12	Net Operating Margin	Direct	$ 381,188,845	$ 123,697	$ 36,474	$ 404,946	$ 25,489	$ 2,529,330	$3,104,924	$ 2,559,519	$ 55,850
13	Special Contract Margin	Net Op. Marg.	$ 5,784,028	$ 1,877	$ 553	$ 6,145	$ 387	$ 38,379	$ 47,113	$ 38,837	$ 847
14	Other Revenue	Net Op. Marg.	12,261,805	576	373	919	1,670	6,008	5,770	26,581	8,837
15	Total Revenue		$ 399,234,678	$ 126,150	$ 37,401	$ 412,009	$ 27,545	$ 2,573,718	$3,157,807	$ 2,624,937	$ 65,534
	Operating Deductions										
16	O & M		$(130,087,761)	$(14,820)	$(6,961)	$(63,340)	$(11,646)	$(307,831)	$(403,259)	$(583,210)	$(26,953)
17	A & G	O & M	(56,946,694)	(6,487)	(3,047)	(27,727)	(5,098)	(134,755)	(176,529)	(255,304)	(11,799)
18	Depreciation Expense		(87,887,713)	(14,347)	(4,672)	(52,519)	(7,310)	(322,359)	(365,084)	(373,238)	(31,140)
19	Interest on Customer Deposits	8	(1,915,314)	-	-	-	-	-	-	-	-
20	Taxes other than Income	1.1	(33,124,880)	(5,408)	(1,761)	(19,794)	(2,755)	(121,497)	(137,600)	(140,673)	(11,737)
21	Total Operating Deductions		$(309,962,361)	$(41,062)	$(16,441)	$(163,381)	$(26,810)	$(886,442)	$(1,082,472)	$(1,352,425)	$(81,629)
	State Income Tax										
22	Taxable Income before Interest Exp.		$ 89,272,317	$ 85,088	$ 20,960	$ 248,628	$ 735	$ 1,687,275	$2,075,334	$ 1,272,512	$(16,095)
23	Interest Expense	1.1	(48,035,008)	(7,842)	(2,553)	(28,704)	(3,995)	(176,185)	(199,537)	(203,993)	(17,020)
24	State Taxable Income		$ 41,237,309	$ 77,247	$ 18,407	$ 219,924	$(3,260)	$ 1,511,090	$1,875,798	$ 1,068,520	$(33,114)
25	State Income Tax		2,873,416	5,383	1,283	15,324	(227)	105,293	130,706	74,454	(2,307)
26	South Georgia	1.1	29,686	5	2	18	2	109	123	126	11
27	Total State Income Tax		$ 2,903,102	$ 5,387	$ 1,284	$ 15,342	$(225)	$ 105,402	$ 130,829	$ 74,581	$(2,297)
	Federal Income Tax										
28	Taxable Income before Interest Exp.		$ 89,272,317	$ 85,088	$ 20,960	$ 248,628	$ 735	$ 1,687,275	$2,075,334	$ 1,272,512	$(16,095)
29	Interest Expense		(48,035,008)	(7,842)	(2,553)	(28,704)	(3,995)	(176,185)	(199,537)	(203,993)	(17,020)
30	Federal Taxable Income		$ 41,237,309	$ 77,247	$ 18,407	$ 219,924	$(3,260)	$ 1,511,090	$1,875,798	$ 1,068,520	$(33,114)
31	Federal Income Tax		$ 13,427,363	$ 25,152	$ 5,993	$ 71,610	$(1,061)	$ 492,029	$ 610,782	$ 347,923	$(10,782)
32	I T C	1.1	(528,360)	(86)	(28)	(316)	(44)	(1,938)	(2,195)	(2,244)	(187)
33	South Georgia	1.1	290,114	47	15	173	24	1,064	1,205	1,232	103
34	Total Federal Income Tax		$ 13,189,117	$ 25,114	$ 5,981	$ 71,467	$(1,081)	$ 491,155	$ 609,793	$ 346,911	$(10,867)
35	Regulatory Amortization	Depr. Exp.	-	-	-	-	-	-	-	-	-
36	Net Income		$ 73,180,099	$ 54,587	$ 13,695	$ 161,819	$ 2,041	$ 1,090,718	$1,334,713	$ 851,021	$(2,931)

SCHEDULE G-1
SHEET 2 OF 2

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY
PROPOSED RATES
TEST YEAR ENDING APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total Amount	Single Family Residential	Multi-Family Residential	MMMHP	Small Gen. Service	Medium Gen. Service	Large Gen. Service	Trans. Eligible Service
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Rate Base									
1	Direct Net Plant		$1,267,124,121	$ 972,148,655	$ 26,208,345	$ 2,101,465	$ 21,567,888	$ 69,420,649	$ 106,428,942	$ 52,370,004
2	Systems Allocable Net Plant		34,448,206	26,428,964	712,504	57,131	586,347	1,887,279	2,893,391	1,423,738
3	Cash Working Capital	11.2	(10,379,937)	(8,277,078)	(202,429)	(11,552)	(244,332)	(578,417)	(686,594)	(266,389)
4	Materials & Supplies	1.1	12,389,898	9,505,637	256,264	20,548	210,890	678,793	1,040,659	512,072
5	Prepayments	Direct Net Plant	3,671,971	2,817,168	75,949	6,090	62,501	201,173	308,418	151,762
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-	-	-
7	Customer Deposits	8	(31,921,898)	(29,695,451)	(1,113,765)	(5,508)	(564,803)	(542,371)	-	-
8	Customer Advances	8	(37,910,017)	(35,265,919)	(1,322,692)	(6,541)	(670,752)	(644,112)	-	-
9	Deferred Taxes	1.1	(142,632,297)	(109,428,740)	(2,950,111)	(236,549)	(2,427,763)	(7,814,252)	(11,980,045)	(5,894,966)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-	-	-
11	Total Rate Base		$1,094,790,047	$ 828,233,236	$ 21,664,065	$ 1,925,083	$ 18,519,976	$ 62,608,741	$ 98,004,771	$ 48,296,221
12	Net Operating Margin	Direct	$ 431,409,491	$ 299,523,089	$ 6,921,522	$ 1,041,727	$ 8,853,467	$ 27,091,812	$ 56,721,948	$ 21,821,052
13	Special Contract&Optional&Resale M	Net Op. Marg.	$ 5,784,028	$ 4,015,790	$ 92,799	$ 13,967	$ 118,701	$ 363,228	$ 760,487	$ 292,561
14	Other Revenue	Net Op. Marg.	12,261,805	10,634,757	376,029	11,075	357,561	552,423	230,620	48,605
15	Total Revenue		$ 449,455,324	$ 314,173,635	$ 7,390,350	$ 1,066,769	$ 9,329,729	$ 28,007,463	$ 57,713,055	$ 22,162,218
	Operating Deductions									
16	O & M		$(130,237,868)	$(103,871,820)	$(2,542,160)	$(144,804)	$(3,064,752)	$(7,251,605)	$(8,605,930)	$(3,338,574)
17	A & G	O & M	(56,946,694)	(45,409,930)	(1,110,574)	(63,378)	(1,340,461)	(3,173,327)	(3,766,809)	(1,461,468)
18	Depreciation Expense		(87,887,713)	(67,428,218)	(1,817,811)	(145,758)	(1,495,948)	(4,815,015)	(7,381,910)	(3,632,383)
19	Interest on Customer Deposits	8	(1,915,314)	(1,781,727)	(66,826)	(330)	(33,888)	(32,542)	-	-
20	Taxes other than Income	1.1	(33,124,880)	(25,413,696)	(685,133)	(54,936)	(563,823)	(1,814,779)	(2,782,242)	(1,369,045)
21	Total Operating Deductions		$(310,112,468)	$(243,905,392)	$(6,222,502)	$(409,205)	$(6,498,873)	$(17,087,269)	$(22,536,891)	$(9,801,471)
	State Income Tax									
22	Taxable Income before Interest Exp.		$ 139,342,856	$ 70,268,244	$ 1,167,848	$ 657,564	$ 2,830,856	$ 10,920,194	$ 35,176,164	$ 12,360,747
23	Interest Expense	1.1	(48,035,008)	(36,852,876)	(993,524)	(79,664)	(817,610)	(2,631,645)	(4,034,581)	(1,985,278)
24	State Taxable Income		$ 91,307,848	$ 33,415,368	$ 174,324	$ 577,900	$ 2,013,246	$ 8,288,548	$ 31,141,583	$ 10,375,469
25	State Income Tax		$ 6,362,331	$ 2,328,383	$ 12,147	$ 40,268	$ 140,283	$ 577,546	$ 2,169,946	$ 722,963
26	South Georgia	1.1	29,686	22,775	614	49	505	1,626	2,493	1,227
27	Total State Income Tax		$ 6,392,017	$ 2,351,158	$ 12,761	$ 40,317	$ 140,788	$ 579,172	$ 2,172,439	$ 724,190
	Federal Income Tax									
28	Taxable Income before Interest Exp.		$ 139,342,856	$ 70,268,244	$ 1,167,848	$ 657,564	$ 2,830,856	$ 10,920,194	$ 35,176,164	$ 12,360,747
29	Interest Expense		(48,035,008)	(36,852,876)	(993,524)	(79,664)	(817,610)	(2,631,645)	(4,034,581)	(1,985,278)
30	Net Taxable Income		$ 91,307,848	$ 33,415,368	$ 174,324	$ 577,900	$ 2,013,246	$ 8,288,548	$ 31,141,583	$ 10,375,469
31	Federal Income Tax		$ 29,730,931	$ 10,880,445	$ 56,762	$ 188,171	$ 655,537	$ 2,698,851	$ 10,140,073	$ 3,378,377
32	I T C	1.1	(528,360)	(405,362)	(10,928)	(876)	(8,993)	(28,947)	(44,378)	(21,837)
33	South Georgia	1.1	290,114	222,578	6,001	481	4,938	15,894	24,367	11,990
34	Total Federal Income Tax		$ 29,492,685	$ 10,697,660	$ 51,834	$ 187,776	$ 651,482	$ 2,685,798	$ 10,120,062	$ 3,368,531
35	Regulatory Amortization	Depr. Exp.	-	-	-	-	-	-	-	-
36	Net Income		$ 103,458,154	$ 57,219,425	$ 1,103,253	$ 429,470	$ 2,038,586	$ 7,655,223	$ 22,883,663	$ 8,268,027
37	Rate of Return on Rate Base		9.45%	6.91%	5.09%	22.31%	11.01%	12.23%	23.35%	17.12%

SCHEDULE G-2
SHEET 1 OF 2

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY
PROPOSED RATES
TEST YEAR ENDING APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total Amount	Air Conditioning	CNG Small	CNG Large	CNG Residential	Electric Generation	Small Ess. Agr.	Natural Gas Engines	Street Lighting
	(a)	(b)	(c)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	Rate Base										
1	Direct Net Plant		$1,267,124,121	$ 206,853	$ 67,356	$ 757,197	$ 105,396	$ 4,647,622	$5,263,618	$ 5,381,166	$ 448,968
2	Systems Allocable Net Plant		34,448,206	5,624	1,831	20,585	2,865	126,351	143,097	146,293	12,206
3	Cash Working Capital	11.2	(10,379,937)	(1,182)	(555)	(5,054)	(929)	(24,562)	(32,177)	(46,535)	(2,151)
4	Materials & Supplies	1.1	12,389,898	2,023	659	7,404	1,031	45,444	51,467	52,617	4,390
5	Prepayments	Direct Net Plant	3,671,971	599	195	2,194	305	13,468	15,253	15,594	1,301
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-	-	-	-
7	Customer Deposits	8	(31,921,898)	-	-	-	-	-	-	-	-
8	Customer Advances	8	(37,910,017)	-	-	-	-	-	-	-	-
9	Deferred Taxes	1.1	(142,632,297)	(23,284)	(7,582)	(85,233)	(11,864)	(523,154)	(592,493)	(605,724)	(50,538)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-	-	-	-
11	Total Rate Base		$1,094,790,047	$ 190,632	$ 61,903	$ 697,093	$ 96,804	$ 4,285,169	$4,848,767	$ 4,943,410	$ 414,177
12	Net Operating Margin	Direct	$ 431,409,491	$ 130,409	$ 37,424	$ 433,248	$ 29,847	$ 2,678,104	$3,280,432	$ 2,773,911	$ 71,499
13	Special Contract&Optional&Resale M	Net Op. Marg.	$ 5,784,028	$ 1,748	$ 502	$ 5,809	$ 400	$ 35,906	$ 43,982	$ 37,191	$ 959
14	Other Revenue	Net Op. Marg.	12,261,805	576	373	919	1,670	6,008	5,770	26,581	8,837
15	Total Revenue		$ 449,455,324	$ 132,734	$ 38,299	$ 439,975	$ 31,917	$ 2,720,019	$3,330,183	$ 2,837,683	$ 81,294
	Operating Deductions										
16	O & M		$(130,237,868)	$(14,824)	$(6,964)	$(63,344)	$(11,663)	$(307,835)	$(403,274)	$(583,277)	$(27,042)
17	A & G	O & M	(56,946,694)	(6,487)	(3,047)	(27,727)	(5,098)	(134,755)	(176,529)	(255,304)	(11,799)
18	Depreciation Expense		(87,887,713)	(14,347)	(4,672)	(52,519)	(7,310)	(322,359)	(365,084)	(373,238)	(31,140)
19	Interest on Customer Deposits	8	(1,915,314)	-	-	-	-	-	-	-	-
20	Taxes other than Income	1.1	(33,124,880)	(5,408)	(1,761)	(19,794)	(2,755)	(121,497)	(137,600)	(140,673)	(11,737)
21	Total Operating Deductions		$(310,112,468)	$(41,066)	$(16,444)	$(163,385)	$(26,826)	$(886,446)	##########	$(1,352,491)	$(81,718)
	State Income Tax										
22	Taxable Income before Interest Exp.		$ 139,342,856	$ 91,668	$ 21,855	$ 276,591	$ 5,090	$ 1,833,573	$2,247,695	$ 1,485,191	$(423)
23	Interest Expense	1.1	(48,035,008)	(7,842)	(2,553)	(28,704)	(3,995)	(176,185)	(199,537)	(203,993)	(17,020)
24	State Taxable Income		$ 91,307,848	$ 83,826	$ 19,302	$ 247,886	$ 1,095	$ 1,657,388	$2,048,158	$ 1,281,198	$(17,443)
25	State Income Tax		$ 6,362,331	$ 5,841	$ 1,345	$ 17,273	$ 76	$ 115,487	$ 142,716	$ 89,274	$(1,215)
26	South Georgia	1.1	29,686	5	2	18	2	109	123	126	11
27	Total State Income Tax		$ 6,392,017	$ 5,846	$ 1,347	$ 17,290	$ 79	$ 115,596	$ 142,839	$ 89,400	$(1,205)
	Federal Income Tax										
28	Taxable Income before Interest Exp.		$ 139,342,856	$ 91,668	$ 21,855	$ 276,591	$ 5,090	$ 1,833,573	$2,247,695	$ 1,485,191	$(423)
29	Interest Expense		(48,035,008)	(7,842)	(2,553)	(28,704)	(3,995)	(176,185)	(199,537)	(203,993)	(17,020)
30	Net Taxable Income		$ 91,307,848	$ 83,826	$ 19,302	$ 247,886	$ 1,095	$ 1,657,388	$2,048,158	$ 1,281,198	$(17,443)
31	Federal Income Tax		$ 29,730,931	$ 27,295	$ 6,285	$ 80,715	$ 356	$ 539,665	$ 666,905	$ 417,174	$(5,680)
32	I T C	1.1	(528,360)	(86)	(28)	(316)	(44)	(1,938)	(2,195)	(2,244)	(187)
33	South Georgia	1.1	290,114	47	15	173	24	1,064	1,205	1,232	103
34	Total Federal Income Tax		$ 29,492,685	$ 27,256	$ 6,272	$ 80,572	$ 337	$ 538,791	$ 665,915	$ 416,162	$(5,764)
35	Regulatory Amortization	Depr. Exp.	-	-	-	-	-	-	-	-	-
36	Net Income		$ 103,458,154	$ 58,566	$ 14,236	$ 178,728	$ 4,675	$ 1,179,186	$1,438,941	$ 979,629	$ 6,546
37	Rate of Return on Rate Base		9.45%	30.72%	23.00%	25.64%	4.83%	27.52%	29.68%	19.82%	1.58%

SCHEDULE G-2
SHEET 2 OF 2

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 7,937	$ 24,717	$ 70
2	302	Franchise & Consent	1.1	1,213,609	225,820	703,280	1,992
3	303	Misc. Intangible	1.1	7,333	1,364	4,249	12
4		Total Intangible		$ 1,263,595	$ 235,121	$ 732,247	$ 2,074
5		Allocation Percentage	Intang. Plant	100.00%	18.61%	57.95%	0.16%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 640,871	$ -	$ -
7	374	Rights of Way	1.0	739,109	436,641	-	-
8	375	Structures	1.0	46,534	27,491	-	-
9	376	Mains - Demand	1.0	353,902,646	209,074,046	-	-
10	376	Mains - Customer	5.0	275,401,498	-	253,894,761	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	9,842,586	11,952,612	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	264,625,607	-
15	381	Meters	6.0	196,168,747	-	154,571,050	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	1,940,005
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(57,587)	-	-
19		Total Distribution		$ 1,182,139,980	$ 219,964,047	$ 685,044,030	$ 1,940,005
20		Allocation Percentage	Dist. Plant	100.00%	18.61%	57.95%	0.16%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 15,578,113	$ 48,515,625	$ 137,393
22		Total Net Plant-Direct		$ 1,267,124,121	$ 235,777,281	$ 734,291,902	$ 2,079,472
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 3,426,149	$ 10,670,210	$ 30,217
24	389-398	General Plant	1.1	$ 16,035,255	$ 2,983,724	$ 9,292,348	$ 26,315
25		Total Systems Allocable		34,448,206	6,409,873	19,962,558	56,533
26		Total Net Plant		$ 1,301,572,327	$ 242,187,153	$ 754,254,460	$ 2,136,005
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(1,000,782)	(7,227,188)	(49,108)
28		Materials & Supplies	1.1	12,389,898	2,305,422	7,179,882	20,333
29		Prepayments	1.1	3,671,971	683,254	2,127,888	6,026
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	(29,695,451)	-
32		Customer Advances	8.0	(37,910,017)	-	(35,265,919)	-
33		Deferred Taxes	1.1	(142,632,297)	(26,539,985)	(82,654,681)	(234,073)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	217,635,062	608,718,991	1,879,183

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(h)	(i)	(j)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 149	$ 732	$ 2
2	302	Franchise & Consent	1.1	1,213,609	4,226	20,829	47
3	303	Misc. Intangible	1.1	7,333	26	126	0
4		Total Intangible		$ 1,263,595	$ 4,400	$ 21,687	$ 49
5		Allocation Percentage	Intang. Plant	100.00%	0.35%	1.72%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 11,992	$ -	$ -
7	374	Rights of Way	1.0	739,109	8,171	-	-
8	375	Structures	1.0	46,534	514	-	-
9	376	Mains - Demand	1.0	353,902,646	3,912,258	-	-
10	376	Mains - Customer	5.0	275,401,498	-	9,522,640	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	184,177	448,298	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	4,911,024	-
15	381	Meters	6.0	196,168,747	-	5,406,606	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	45,988
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(1,078)	-	-
19		Total Distribution		$ 1,182,139,980	$ 4,116,035	$ 20,288,568	$ 45,988
20		Allocation Percentage	Dist. Plant	100.00%	0.35%	1.72%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 291,502	$ 1,436,860	$ 3,257
22		Total Net Plant-Direct		$ 1,267,124,121	$ 4,411,937	$ 21,747,115	$ 49,294
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 64,111	$ 316,014	$ 716
24	389-398	General Plant	1.1	$ 16,035,255	$ 55,832	$ 275,206	$ 624
25		Total Systems Allocable		34,448,206	119,944	591,220	1,340
26		Total Net Plant		$ 1,301,572,327	$ 4,531,880	$ 22,338,335	$ 50,634
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(18,727)	(182,538)	(1,164)
28		Materials & Supplies	1.1	12,389,898	43,140	212,643	482
29		Prepayments	1.1	3,671,971	12,785	63,020	143
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	(1,113,765)	-
32		Customer Advances	8.0	(37,910,017)	-	(1,322,692)	-
33		Deferred Taxes	1.1	(142,632,297)	(496,624)	(2,447,938)	(5,549)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	4,072,454	17,547,064	44,546

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(k)	(l)	(m)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 56	$ 14	$ 1
2	302	Franchise & Consent	1.1	1,213,609	1,589	409	15
3	303	Misc. Intangible	1.1	7,333	10	2	0
4		Total Intangible		$ 1,263,595	$ 1,655	$ 425	$ 15
5		Allocation Percentage	Intang. Plant	100.00%	0.13%	0.03%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 4,510	$ -	$ -
7	374	Rights of Way	1.0	739,109	3,073	-	-
8	375	Structures	1.0	46,534	193	-	-
9	376	Mains - Demand	1.0	353,902,646	1,471,361	-	-
10	376	Mains - Customer	5.0	275,401,498	-	47,093	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	69,267	2,217	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	256,978	-
15	381	Meters	6.0	196,168,747	-	91,750	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	14,485
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(405)	-	-
19		Total Distribution		$ 1,182,139,980	$ 1,548,000	$ 398,038	$ 14,485
20		Allocation Percentage	Dist. Plant	100.00%	0.13%	0.03%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 109,631	$ 28,190	$ 1,026
22		Total Net Plant-Direct		$ 1,267,124,121	$ 1,659,285	$ 426,653	$ 15,527
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 24,112	$ 6,200	$ 226
24	389-398	General Plant	1.1	$ 16,035,255	$ 20,998	$ 5,399	$ 196
25		Total Systems Allocable		34,448,206	45,110	11,599	422
26		Total Net Plant		$ 1,301,572,327	$ 1,704,395	$ 438,252	$ 15,949
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(7,043)	(4,142)	(367)
28		Materials & Supplies	1.1	12,389,898	16,224	4,172	152
29		Prepayments	1.1	3,671,971	4,808	1,236	45
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	(5,508)	-
32		Customer Advances	8.0	(37,910,017)	-	(6,541)	-
33		Deferred Taxes	1.1	(142,632,297)	(186,775)	(48,026)	(1,748)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	1,531,609	379,443	14,031

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(n)	(o)	(p)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 155	$ 570	$ 1
2	302	Franchise & Consent	1.1	1,213,609	4,416	16,207	34
3	303	Misc. Intangible	1.1	7,333	27	98	0
4		Total Intangible		$ 1,263,595	$ 4,598	$ 16,875	$ 35
5		Allocation Percentage	Intang. Plant	100.00%	0.36%	1.34%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 12,533	$ -	$ -
7	374	Rights of Way	1.0	739,109	8,539	-	-
8	375	Structures	1.0	46,534	538	-	-
9	376	Mains - Demand	1.0	353,902,646	4,088,669	-	-
10	376	Mains - Customer	5.0	275,401,498	-	4,829,040	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	192,482	227,337	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	6,034,177	-
15	381	Meters	6.0	196,168,747	-	4,696,472	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	32,701
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(1,126)	-	-
19		Total Distribution		$ 1,182,139,980	$ 4,301,635	$ 15,787,025	$ 32,701
20		Allocation Percentage	Dist. Plant	100.00%	0.36%	1.34%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 304,647	$ 1,118,056	$ 2,316
22		Total Net Plant-Direct		$ 1,267,124,121	$ 4,610,880	$ 16,921,956	$ 35,052
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 67,002	$ 245,898	$ 509
24	389-398	General Plant	1.1	$ 16,035,255	$ 58,350	$ 214,145	$ 444
25		Total Systems Allocable		34,448,206	125,352	460,043	953
26		Total Net Plant		$ 1,301,572,327	$ 4,736,232	$ 17,381,998	$ 36,005
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(19,571)	(223,933)	(828)
28		Materials & Supplies	1.1	12,389,898	45,085	165,462	343
29		Prepayments	1.1	3,671,971	13,362	49,038	102
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	(564,803)	-
32		Customer Advances	8.0	(37,910,017)	-	(670,752)	-
33		Deferred Taxes	1.1	(142,632,297)	(519,018)	(1,904,800)	(3,946)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	4,256,089	14,232,211	31,676

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 846	$ 1,480	$ 11
2	302	Franchise & Consent	1.1	1,213,609	24,086	42,099	304
3	303	Misc. Intangible	1.1	7,333	146	254	2
4		Total Intangible		$ 1,263,595	$ 25,078	$ 43,833	$ 317
5		Allocation Percentage	Intang. Plant	100.00%	1.98%	3.47%	0.03%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 68,354	$ -	$ -
7	374	Rights of Way	1.0	739,109	46,571	-	-
8	375	Structures	1.0	46,534	2,932	-	-
9	376	Mains - Demand	1.0	353,902,646	22,299,503	-	-
10	376	Mains - Customer	5.0	275,401,498	-	4,637,247	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	1,049,794	218,308	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	24,094,138	-
15	381	Meters	6.0	196,168,747	-	12,057,454	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	296,549
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(6,142)	-	-
19		Total Distribution		$ 1,182,139,980	$ 23,461,013	$ 41,007,147	$ 296,549
20		Allocation Percentage	Dist. Plant	100.00%	1.98%	3.47%	0.03%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 1,661,537	$ 2,904,174	$ 21,002
22		Total Net Plant-Direct		$ 1,267,124,121	$ 25,147,627	$ 43,955,154	$ 317,867
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 365,428	$ 638,725	$ 4,619
24	389-398	General Plant	1.1	$ 16,035,255	$ 318,239	$ 556,246	$ 4,023
25		Total Systems Allocable		34,448,206	683,667	1,194,971	8,642
26		Total Net Plant		$ 1,301,572,327	$ 25,831,294	$ 45,150,124	$ 326,509
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(106,742)	(464,169)	(7,507)
28		Materials & Supplies	1.1	12,389,898	245,893	429,792	3,108
29		Prepayments	1.1	3,671,971	72,875	127,377	921
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	(542,371)	-
32		Customer Advances	8.0	(37,910,017)	-	(644,112)	-
33		Deferred Taxes	1.1	(142,632,297)	(2,830,712)	(4,947,759)	(35,780)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	23,212,607	39,108,882	287,251

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 2,312	$ 1,235	$ 35
2	302	Franchise & Consent	1.1	1,213,609	65,793	35,143	998
3	303	Misc. Intangible	1.1	7,333	398	212	6
4		Total Intangible		$ 1,263,595	$ 68,503	$ 36,591	$ 1,039
5		Allocation Percentage	Intang. Plant	100.00%	5.42%	2.90%	0.08%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 186,719	$ -	$ -
7	374	Rights of Way	1.0	739,109	127,217	-	-
8	375	Structures	1.0	46,534	8,010	-	-
9	376	Mains - Demand	1.0	353,902,646	60,914,264	-	-
10	376	Mains - Customer	5.0	275,401,498	-	2,046,189	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	2,867,663	96,329	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	18,170,806	-
15	381	Meters	6.0	196,168,747	-	13,918,572	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	971,921
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(16,778)	-	-
19		Total Distribution		$ 1,182,139,980	$ 64,087,094	$ 34,231,895	$ 971,921
20		Allocation Percentage	Dist. Plant	100.00%	5.42%	2.90%	0.08%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 4,538,723	$ 2,424,343	$ 68,833
22		Total Net Plant-Direct		$ 1,267,124,121	$ 68,694,320	$ 36,692,829	$ 1,041,792
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 998,217	$ 533,194	$ 15,139
24	389-398	General Plant	1.1	$ 16,035,255	$ 869,316	$ 464,342	$ 13,184
25		Total Systems Allocable		34,448,206	1,867,533	997,536	28,322
26		Total Net Plant		$ 1,301,572,327	$ 70,561,853	$ 37,690,365	$ 1,070,115
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(291,581)	(370,411)	(24,603)
28		Materials & Supplies	1.1	12,389,898	671,691	358,781	10,187
29		Prepayments	1.1	3,671,971	199,068	106,331	3,019
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(7,732,493)	(4,130,284)	(117,268)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	63,408,538	33,654,783	941,450

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 1,589	$ 150	$ 23
2	302	Franchise & Consent	1.1	1,213,609	45,224	4,269	665
3	303	Misc. Intangible	1.1	7,333	273	26	4
4		Total Intangible		$ 1,263,595	$ 47,087	$ 4,445	$ 693
5		Allocation Percentage	Intang. Plant	100.00%	3.73%	0.35%	0.05%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 128,344	$ -	$ -
7	374	Rights of Way	1.0	739,109	87,444	-	-
8	375	Structures	1.0	46,534	5,505	-	-
9	376	Mains - Demand	1.0	353,902,646	41,870,334	-	-
10	376	Mains - Customer	5.0	275,401,498	-	53,171	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	1,971,131	2,503	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	1,099,282	-
15	381	Meters	6.0	196,168,747	-	3,003,206	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	648,237
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(11,533)	-	-
19		Total Distribution		$ 1,182,139,980	$ 44,051,226	$ 4,158,161	$ 648,237
20		Allocation Percentage	Dist. Plant	100.00%	3.73%	0.35%	0.05%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 3,119,760	$ 294,486	$ 45,909
22		Total Net Plant-Direct		$ 1,267,124,121	$ 47,218,073	$ 4,457,092	$ 694,839
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 686,140	$ 64,767	$ 10,097
24	389-398	General Plant	1.1	$ 16,035,255	$ 597,537	$ 56,404	$ 8,793
25		Total Systems Allocable		34,448,206	1,283,677	121,171	18,890
26		Total Net Plant		$ 1,301,572,327	$ 48,501,749	$ 4,578,263	$ 713,729
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(200,422)	(49,557)	(16,409)
28		Materials & Supplies	1.1	12,389,898	461,697	43,581	6,794
29		Prepayments	1.1	3,671,971	136,832	12,916	2,014
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(5,315,045)	(501,707)	(78,214)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	43,584,811	4,083,496	627,914

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air-Conditioning Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 6	$ 1	$ 0
2	302	Franchise & Consent	1.1	1,213,609	162	28	7
3	303	Misc. Intangible	1.1	7,333	1	0	0
4		Total Intangible		$ 1,263,595	$ 169	$ 29	$ 8
5		Allocation Percentage	Intang. Plant	100.00%	0.01%	0.00%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 461	$ -	$ -
7	374	Rights of Way	1.0	739,109	314	-	-
8	375	Structures	1.0	46,534	20	-	-
9	376	Mains - Demand	1.0	353,902,646	150,362	-	-
10	376	Mains - Customer	5.0	275,401,498	-	7,609	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	7,079	358	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	11,030	-
15	381	Meters	6.0	196,168,747	-	8,505	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	7,283
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(41)	-	-
19		Total Distribution		$ 1,182,139,980	$ 158,194	$ 27,502	$ 7,283
20		Allocation Percentage	Dist. Plant	100.00%	0.01%	0.00%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 11,203	$ 1,948	$ 516
22		Total Net Plant-Direct		$ 1,267,124,121	$ 169,567	$ 29,479	$ 7,807
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 2,464	$ 428	$ 113
24	389-398	General Plant	1.1	$ 16,035,255	$ 2,146	$ 373	$ 99
25		Total Systems Allocable		34,448,206	4,610	801	212
26		Total Net Plant		$ 1,301,572,327	$ 174,177	$ 30,281	$ 8,019
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(720)	(278)	(184)
28		Materials & Supplies	1.1	12,389,898	1,658	288	76
29		Prepayments	1.1	3,671,971	491	85	23
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(19,087)	(3,318)	(879)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	156,519	27,058	7,055

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 1	$ 1	$ 0
2	302	Franchise & Consent	1.1	1,213,609	42	22	1
3	303	Misc. Intangible	1.1	7,333	0	0	0
4		Total Intangible		$ 1,263,595	$ 43	$ 23	$ 1
5		Allocation Percentage	Intang. Plant	100.00%	0.00%	0.00%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 118	$ -	$ -
7	374	Rights of Way	1.0	739,109	80	-	-
8	375	Structures	1.0	46,534	5	-	-
9	376	Mains - Demand	1.0	353,902,646	38,508	-	-
10	376	Mains - Customer	5.0	275,401,498	-	6,030	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	1,813	284	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	10,847	-
15	381	Meters	6.0	196,168,747	-	4,008	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	1,156
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(11)	-	-
19		Total Distribution		$ 1,182,139,980	$ 40,513	$ 21,169	$ 1,156
20		Allocation Percentage	Dist. Plant	100.00%	0.00%	0.00%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 2,869	$ 1,499	$ 82
22		Total Net Plant-Direct		$ 1,267,124,121	$ 43,426	$ 22,690	$ 1,239
		Systems Allocable Plant					
23	301-303	Intanglble Plant	1.1	$ 18,412,951	$ 631	$ 330	$ 18
24	389-398	General Plant	1.1	$ 16,035,255	$ 550	$ 287	$ 16
25		Total Systems Allocable		34,448,206	1,181	617	34
26		Total Net Plant		$ 1,301,572,327	$ 44,607	$ 23,307	$ 1,273
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(184)	(342)	(29)
28		Materials & Supplies	1.1	12,389,898	425	222	12
29		Prepayments	1.1	3,671,971	126	66	4
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(4,888)	(2,554)	(139)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	40,085	20,699	1,120

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 17	$ 8	$ 0
2	302	Franchise & Consent	1.1	1,213,609	487	224	14
3	303	Misc. Intangible	1.1	7,333	3	1	0
4		Total Intangible		$ 1,263,595	$ 508	$ 233	$ 14
5		Allocation Percentage	Intang. Plant	100.00%	0.04%	0.02%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 1,383	$ -	$ -
7	374	Rights of Way	1.0	739,109	943	-	-
8	375	Structures	1.0	46,534	59	-	-
9	376	Mains - Demand	1.0	353,902,646	451,326	-	-
10	376	Mains - Customer	5.0	275,401,498	-	6,892	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	21,247	324	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	88,292	-
15	381	Meters	6.0	196,168,747	-	122,653	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	13,418
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(124)	-	-
19		Total Distribution		$ 1,182,139,980	$ 474,834	$ 218,161	$ 13,418
20		Allocation Percentage	Dist. Plant	100.00%	0.04%	0.02%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 33,628	$ 15,450	$ 950
22		Total Net Plant-Direct		$ 1,267,124,121	$ 508,969	$ 233,845	$ 14,383
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 7,396	$ 3,398	$ 209
24	389-398	General Plant	1.1	$ 16,035,255	$ 6,441	$ 2,959	$ 182
25		Total Systems Allocable		34,448,206	13,837	6,357	391
26		Total Net Plant		$ 1,301,572,327	$ 522,806	$ 240,202	$ 14,774
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(2,160)	(2,554)	(340)
28		Materials & Supplies	1.1	12,389,898	4,977	2,287	141
29		Prepayments	1.1	3,671,971	1,475	678	42
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(57,292)	(26,322)	(1,619)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	469,806	214,290	12,998

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 1	$ 3	$ 0
2	302	Franchise & Consent	1.1	1,213,609	19	81	1
3	303	Misc. Intangible	1.1	7,333	0	0	0
4		Total Intangible		$ 1,263,595	$ 20	$ 84	$ 1
5		Allocation Percentage	Intang. Plant	100.00%	0.00%	0.01%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 55	$ -	$ -
7	374	Rights of Way	1.0	739,109	37	-	-
8	375	Structures	1.0	46,534	2	-	-
9	376	Mains - Demand	1.0	353,902,646	17,869	-	-
10	376	Mains - Customer	5.0	275,401,498	-	30,438	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	841	1,433	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	31,691	-
15	381	Meters	6.0	196,168,747	-	15,462	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	504
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(5)	-	-
19		Total Distribution		$ 1,182,139,980	$ 18,800	$ 79,023	$ 504
20		Allocation Percentage	Dist. Plant	100.00%	0.00%	0.01%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 1,331	$ 5,597	$ 36
22		Total Net Plant-Direct		$ 1,267,124,121	$ 20,151	$ 84,704	$ 540
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 293	$ 1,231	$ 8
24	389-398	General Plant	1.1	$ 16,035,255	$ 255	$ 1,072	$ 7
25		Total Systems Allocable		34,448,206	548	2,303	15
26		Total Net Plant		$ 1,301,572,327	$ 20,699	$ 87,007	$ 555
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(86)	(831)	(13)
28		Materials & Supplies	1.1	12,389,898	197	828	5
29		Prepayments	1.1	3,671,971	58	245	2
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(2,268)	(9,535)	(61)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	18,601	77,715	488

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 143	$ 8	$ 5
2	302	Franchise & Consent	1.1	1,213,609	4,075	232	144
3	303	Misc. Intangible	1.1	7,333	25	1	1
4		Total Intangible		$ 1,263,595	$ 4,243	$ 242	$ 150
5		Allocation Percentage	Intang. Plant	100.00%	0.34%	0.02%	0.01%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 11,565	$ -	$ -
7	374	Rights of Way	1.0	739,109	7,880	-	-
8	375	Structures	1.0	46,534	496	-	-
9	376	Mains - Demand	1.0	353,902,646	3,772,977	-	-
10	376	Mains - Customer	5.0	275,401,498	-	6,030	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	177,621	284	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	49,890	-
15	381	Meters	6.0	196,168,747	-	170,032	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	140,177
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(1,039)	-	-
19		Total Distribution		$ 1,182,139,980	$ 3,969,499	$ 226,236	$ 140,177
20		Allocation Percentage	Dist. Plant	100.00%	0.34%	0.02%	0.01%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 281,125	$ 16,022	$ 9,928
22		Total Net Plant-Direct		$ 1,267,124,121	$ 4,254,867	$ 242,501	$ 150,254
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 61,829	$ 3,524	$ 2,183
24	389-398	General Plant	1.1	$ 16,035,255	$ 53,845	$ 3,069	$ 1,901
25		Total Systems Allocable		34,448,206	115,673	6,593	4,085
26		Total Net Plant		$ 1,301,572,327	$ 4,370,540	$ 249,093	$ 154,339
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(18,060)	(2,954)	(3,548)
28		Materials & Supplies	1.1	12,389,898	41,604	2,371	1,469
29		Prepayments	1.1	3,671,971	12,330	703	435
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(478,944)	(27,297)	(16,913)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	3,927,470	221,917	135,782

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 150	$ 26	$ 2
2	302	Franchise & Consent	1.1	1,213,609	4,258	735	48
3	303	Misc. Intangible	1.1	7,333	26	4	0
4		Total Intangible		$ 1,263,595	$ 4,434	$ 765	$ 50
5		Allocation Percentage	Intang. Plant	100.00%	0.35%	0.06%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 12,085	$ -	$ -
7	374	Rights of Way	1.0	739,109	8,234	-	-
8	375	Structures	1.0	46,534	518	-	-
9	376	Mains - Demand	1.0	353,902,646	3,942,463	-	-
10	376	Mains - Customer	5.0	275,401,498	-	29,098	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	185,599	1,370	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	288,362	-
15	381	Meters	6.0	196,168,747	-	396,961	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	46,991
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(1,086)	-	-
19		Total Distribution		$ 1,182,139,980	$ 4,147,813	$ 715,791	$ 46,991
20		Allocation Percentage	Dist. Plant	100.00%	0.35%	0.06%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 293,753	$ 50,693	$ 3,328
22		Total Net Plant-Direct		$ 1,267,124,121	$ 4,446,000	$ 767,249	$ 50,369
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 64,606	$ 11,149	$ 732
24	389-398	General Plant	1.1	$ 16,035,255	$ 56,263	$ 9,709	$ 637
25		Total Systems Allocable		34,448,206	120,870	20,859	1,369
26		Total Net Plant		$ 1,301,572,327	$ 4,566,869	$ 788,108	$ 51,738
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(18,872)	(12,116)	(1,189)
28		Materials & Supplies	1.1	12,389,898	43,473	7,502	493
29		Prepayments	1.1	3,671,971	12,884	2,223	146
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(500,459)	(86,364)	(5,670)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	4,103,896	699,353	45,518

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 71	$ 107	$ 3
2	302	Franchise & Consent	1.1	1,213,609	2,021	3,046	87
3	303	Misc. Intangible	1.1	7,333	12	18	1
4		Total Intangible		$ 1,263,595	$ 2,104	$ 3,171	$ 91
5		Allocation Percentage	Intang. Plant	100.00%	0.17%	0.25%	0.01%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 5,734	$ -	$ -
7	374	Rights of Way	1.0	739,109	3,907	-	-
8	375	Structures	1.0	46,534	246	-	-
9	376	Mains - Demand	1.0	353,902,646	1,870,737	-	-
10	376	Mains - Customer	5.0	275,401,498	-	122,159	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	88,069	5,751	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	1,133,019	-
15	381	Meters	6.0	196,168,747	-	1,706,018	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	85,134
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(515)	-	-
19		Total Distribution		$ 1,182,139,980	$ 1,968,178	$ 2,966,946	$ 85,134
20		Allocation Percentage	Dist. Plant	100.00%	0.17%	0.25%	0.01%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 139,389	$ 210,123	$ 6,029
22		Total Net Plant-Direct		$ 1,267,124,121	$ 2,109,671	$ 3,180,240	$ 91,254
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 30,656	$ 46,213	$ 1,326
24	389-398	General Plant	1.1	$ 16,035,255	$ 26,698	$ 40,245	$ 1,155
25		Total Systems Allocable		34,448,206	57,354	86,458	2,481
26		Total Net Plant		$ 1,301,572,327	$ 2,167,025	$ 3,266,699	$ 93,735
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(8,955)	(35,426)	(2,155)
28		Materials & Supplies	1.1	12,389,898	20,628	31,096	892
29		Prepayments	1.1	3,671,971	6,114	9,216	264
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(237,473)	(357,980)	(10,272)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	1,947,339	2,913,605	82,465

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 1	$ 14	$ 0
2	302	Franchise & Consent	1.1	1,213,609	30	399	1
3	303	Misc. Intangible	1.1	7,333	0	2	0
4		Total Intangible		$ 1,263,595	$ 31	$ 416	$ 1
5		Allocation Percentage	Intang. Plant	100.00%	0.00%	0.03%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 86	$ -	$ -
7	374	Rights of Way	1.0	739,109	58	-	-
8	375	Structures	1.0	46,534	4	-	-
9	376	Mains - Demand	1.0	353,902,646	27,970	-	-
10	376	Mains - Customer	5.0	275,401,498	-	163,102	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	1,317	7,678	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	217,983	-
15	381	Meters	6.0	196,168,747	-	-	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	666
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(8)	-	-
19		Total Distribution		$ 1,182,139,980	$ 29,427	$ 388,763	$ 666
20		Allocation Percentage	Dist. Plant	100.00%	0.00%	0.03%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 2,084	$ 27,533	$ 47
22		Total Net Plant-Direct		$ 1,267,124,121	$ 31,543	$ 416,711	$ 714
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 458	$ 6,055	$ 10
24	389-398	General Plant	1.1	$ 16,035,255	$ 399	$ 5,273	$ 9
25		Total Systems Allocable		34,448,206	858	11,329	19
26		Total Net Plant		$ 1,301,572,327	$ 32,400	$ 428,040	$ 734
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(134)	(2,000)	(17)
28		Materials & Supplies	1.1	12,389,898	308	4,075	7
29		Prepayments	1.1	3,671,971	91	1,208	2
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(3,551)	(46,907)	(80)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	29,116	384,416	645

SOUTHWEST GAS CORPORATION
ARIZONA
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 14,124,788	$ 43,989,468	$ 124,576
5	389-398	General	1.1	$ 4,919,293	$ 915,346	$ 2,850,705	$ 8,073
6		Total Direct Dep. Exp.		$ 80,829,317	$ 15,040,134	$ 46,840,173	$ 132,649
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 472,672	$ 1,472,063	$ 4,169
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	744,693	2,319,232	6,568
10		Structures-Leasehold Improvements	1.1	104,525	19,449	60,572	172
11		Total System Allocable Amortization		4,106,686	764,142	2,379,804	6,739
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	1,236,814	3,851,867	10,908
13		Total Depreciation Expense		87,476,255	16,276,948	50,692,039	143,557
14		Amortization	1.1	126,930	23,618	73,555	208
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(9,861)	(30,711)	(87)
16		Regulatory Amortizations	1.1	337,524	62,804	195,593	554
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 16,353,509	$ 50,930,477	$ 144,232
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	293,211
27		Materials & Expenses	3.0	59,983	-	-	27,411
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 320,622

SOUTHWEST GAS CORPORATION
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 951,770	$ 5,941,395	$ 47,236
3		Materials & Expenses	5.5	1,458,368	154,382	963,722	7,662
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	118,148
6		Materials & Expenses	3.0	113,250	-	-	51,754
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	1,355,024	3,360,569	0
9		Materials & Expenses	4.4	5,540,228	1,218,862	3,022,876	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	617,822	750,269	0
12		Materials & Expenses	2.2	697,287	231,660	281,323	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	5,452,280	-
15		Materials & Expenses	6.0	1,213,237	-	955,969	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	6,372,491	-
18		Materials & Expenses	6.0	1,490,584	-	1,174,505	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	692,725	4,324,314	34,380
21		Materials & Expenses	5.5	4,535,239	480,096	2,996,989	23,827
22	881	Rents	5.5	2,250,258	238,210	1,487,022	11,822
23		Total Distribution-Operations		$ 56,117,507	$ 5,940,551	$ 37,083,724	$ 294,830
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 552,838	$ 1,598,179	$ 0
26		Materials & Expenses	6.6	338,062	66,800	193,109	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	15,758	-	-
29		Materials & Expenses	1.0	80,753	47,706	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	2,823,963	3,429,357	0
32		Materials & Expenses	2.2	7,043,715	2,340,137	2,841,809	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	485,493	589,572	0
35		Materials & Expenses	2.2	580,480	192,853	234,196	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	5,077,400	-
38		Materials & Expenses	3.3	3,973,153	0	3,275,148	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	1,009,784	-
41		Materials & Expenses	6.0	781,684	-	615,927	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	38,835	112,266	0
44		Materials & Expenses	6.6	189,711	37,486	108,367	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 6,601,869	$ 19,085,113	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 12,542,420	$ 56,168,837	$ 294,830

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 3,534,733	$ -
3		Materials & Expenses	10.1	275,497	-	237,864	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	4,169,182	-
6		Materials & Expenses	13.0	2,194,002	-	1,881,952	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	346,938	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	13,777,920	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	6,382,699	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	2,745,192	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	349,214	-
16		Materials & Expenses	10.1	16,795	-	14,501	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 33,440,194	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 441,663	$ -
20		Materials & Expenses	13.0	564,797	-	484,466	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	21,551	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	18,852	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 966,533	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 12,542,420	$ 90,575,563	$ 615,452
39		Allocation Percentage	Total O&M	100.00%	9.64%	69.63%	0.47%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	5,490,519	39,649,994	269,418
41		Interest on Customer Deposits	8.0	1,915,314	-	1,781,727	-
42		Taxes Other Than Income	1.1	33,124,880	6,163,638	19,195,697	54,361
43		Total Allocated Operating Deductions		$ 222,074,648	$ 24,196,577	$ 151,202,981	$ 939,231
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	8,938,006	27,836,040	78,830
45		State South Georgia	1.1	29,686	5,524	17,203	49
46		Investment Tax Credit	1.1	(528,360)	(98,313)	(306,182)	(867)
47		Federal South Georgia	1.1	290,114	53,982	168,120	476

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 235,777,281	$ 734,291,902	$ 2,079,472
2		Systems Allocable Net Plant		34,448,206	6,409,873	19,962,558	56,533
3		Cash Working Capital	1.1	(10,379,937)	(1,000,782)	(7,227,188)	(49,108)
4		Materials & Supplies	1.1	12,389,898	2,305,422	7,179,882	20,333
5		Prepayments	1.1	3,671,971	683,254	2,127,888	6,026
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	(29,695,451)	-
8		Customer Advances	8.0	(37,910,017)	-	(35,265,919)	-
9		Deferred Taxes	1.1	(142,632,297)	(26,539,985)	(82,654,681)	(234,073)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 217,635,062	$ 608,718,991	$ 1,879,183
12		Net Operating Margin	Direct	$ 381,188,845	$ 156,910,084	$ 102,079,805	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 2,380,899	$ 1,548,924	$ -
14		Late Charges	Direct	$ 2,430,203	$ 1,166,826	$ 759,093	
15		Service Establishment Charges	9	$ 8,267,657	-	7,392,250	-
16		Reconnect / Reread Charges	4	$ 569,215	-	524,764	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 540	$ 351	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 1,079	$ 702	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	281,078	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	159,870	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 210,961	$ 137,244	$ -
22		Total Revenue		399,234,678	160,670,390	112,884,079	-
23		O & M		(130,087,761)	(12,542,420)	(90,575,563)	(615,452)
24		A & G	Total O&M	(56,946,694)	(5,490,519)	(39,649,994)	(269,418)
25		Depreciation Expense		(87,887,713)	(16,353,509)	(50,930,477)	(144,232)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	(1,781,727)	-
27		Taxes other than Income	1.1	(33,124,880)	(6,163,638)	(19,195,697)	(54,361)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 120,120,304	$(89,249,379)	$(1,083,463)
29		Interest Expense	1.1	(48,035,008)	(8,938,006)	(27,836,040)	(78,830)
30		State Taxable Income		$ 41,237,309	$ 111,182,297	$(117,085,418)	$(1,162,293)
31		State Income Tax		2,873,416	7,747,182	(8,158,512)	(80,989)
32		South Georgia	1.1	29,686	5,524	17,203	49
33		State Income Tax		2,903,102	7,752,706	(8,141,309)	(80,940)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	120,120,304	(89,249,379)	(1,083,463)
35		Interest Expense	1.1	(48,035,008)	(8,938,006)	(27,836,040)	(78,830)
36		Federal Taxable Income		41,237,309	111,182,297	(117,085,418)	(1,162,293)
37		Federal Income Tax		$ 13,427,363	$ 36,202,290	$(38,124,417)	$(378,457)
38		I T C	1.1	(528,360)	(98,313)	(306,182)	(867)
39		South Georgia	1.1	290,114	53,982	168,120	476
40		Total Federal Income Tax		$ 13,189,117	$ 36,157,959	$(38,262,480)	$(378,848)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 76,209,638	$(42,845,590)	$(623,676)
43		Rate of Return on Rate Base		6.68%	35.02%	(7.04%)	(33.19%)
44		Rate of Return by Class Total				3.95%	

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(h)	(i)	(j)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 264,307	$ 1,302,812	$ 2,953
5	389-398	General	1.1	$ 4,919,293	$ 17,128	$ 84,428	$ 191
6		Total Direct Dep. Exp.		$ 80,829,317	$ 281,436	$ 1,387,239	$ 3,144
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 8,845	$ 43,597	$ 99
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	13,935	68,687	156
10		Structures-Leasehold Improvements	1.1	104,525	364	1,794	4
11		Total System Allocable Amortization		4,106,686	14,299	70,481	160
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	23,144	114,079	259
13		Total Depreciation Expense		87,476,255	304,579	1,501,318	3,403
14		Amortization	1.1	126,930	442	2,178	5
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(185)	(910)	(2)
16		Regulatory Amortizations	1.1	337,524	1,175	5,793	13
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 306,012	$ 1,508,380	$ 3,419
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--(	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	6,951
27		Materials & Expenses	3.0	59,983	-	-	650
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 7,600

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(h)	(i)	(j)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 17,810	$ 195,869	$ 1,120
3		Materials & Expenses	5.5	1,458,368	2,889	31,771	182
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	2,801
6		Materials & Expenses	3.0	113,250	-	-	1,227
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	25,356	93,546	0
9		Materials & Expenses	4.4	5,540,228	22,808	84,146	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	11,561	28,140	0
12		Materials & Expenses	2.2	697,287	4,335	10,551	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	190,711	-
15		Materials & Expenses	6.0	1,213,237	-	33,438	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	222,898	-
18		Materials & Expenses	6.0	1,490,584	-	41,082	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	12,962	142,559	815
21		Materials & Expenses	5.5	4,535,239	8,984	98,801	565
22	881	Rents	5.5	2,250,258	4,457	49,022	280
23		Total Distribution-Operations		$ 56,117,507	$ 111,161	$ 1,222,533	$ 6,989
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 10,345	$ 44,742	$ 0
26		Materials & Expenses	6.6	338,062	1,250	5,406	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	295	-	-
29		Materials & Expenses	1.0	80,753	893	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	52,843	128,622	0
32		Materials & Expenses	2.2	7,043,715	43,789	106,586	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	9,085	22,113	0
35		Materials & Expenses	2.2	580,480	3,609	8,784	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	94,228	-
38		Materials & Expenses	3.3	3,973,153	0	60,781	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	35,320	-
41		Materials & Expenses	6.0	781,684	-	21,544	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	727	3,143	0
44		Materials & Expenses	6.6	189,711	701	3,034	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 123,536	$ 534,304	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 234,698	$ 1,756,837	$ 6,989

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(h)	(i)	(j)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 54,762	$ -
3		Materials & Expenses	10.1	275,497	-	3,685	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	55,104	-
6		Materials & Expenses	13.0	2,194,002	-	24,874	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	4,585	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	182,103	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	84,360	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	102,962	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	5,410	-
16		Materials & Expenses	10.1	16,795	-	225	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 518,071	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 5,837	$ -
20		Materials & Expenses	13.0	564,797	-	6,403	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	285	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	249	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 12,775	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 234,698	$ 2,287,683	$ 14,589
39		Allocation Percentage	Total O&M	100.00%	0.18%	1.76%	0.01%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	102,740	1,001,447	6,387
41		Interest on Customer Deposits	8.0	1,915,314	-	66,826	-
42		Taxes Other Than Income	1.1	33,124,880	115,336	568,508	1,289
43		Total Allocated Operating Deductions		$ 222,074,648	$ 452,774	$ 3,924,463	$ 22,265
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	167,251	824,405	1,869
45		State South Georgia	1.1	29,686	103	509	1
46		Investment Tax Credit	1.1	(528,360)	(1,840)	(9,068)	(21)
47		Federal South Georgia	1.1	290,114	1,010	4,979	11

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(h)	(i)	(j)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 4,411,937	$ 21,747,115	$ 49,294
2		Systems Allocable Net Plant		34,448,206	119,944	591,220	1,340
3		Cash Working Capital	1.1	(10,379,937)	(18,727)	(182,538)	(1,164)
4		Materials & Supplies	1.1	12,389,898	43,140	212,643	482
5		Prepayments	1.1	3,671,971	12,785	63,020	143
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	(1,113,765)	-
8		Customer Advances	8.0	(37,910,017)	-	(1,322,692)	-
9		Deferred Taxes	1.1	(142,632,297)	(496,624)	(2,447,938)	(5,549)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 4,072,454	$ 17,547,064	$ 44,546
12		Net Operating Margin	Direct	$ 381,188,845	$ 3,699,991	$ 3,415,605	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 56,142	$ 51,827	$ -
14		Late Charges	Direct	$ 2,430,203	$ 27,514	$ 25,399	
15		Service Establishment Charges	9	$ 8,267,657	-	277,256	-
16		Reconnect / Reread Charges	4	$ 569,215	-	19,682	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 13	$ 12	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 25	$ 23	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	10,542	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	5,996	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 4,975	$ 4,592	$ -
22		Total Revenue		399,234,678	3,788,660	3,810,935	-
23		O & M		(130,087,761)	(234,698)	(2,287,683)	(14,589)
24		A & G	Total O&M	(56,946,694)	(102,740)	(1,001,447)	(6,387)
25		Depreciation Expense		(87,887,713)	(306,012)	(1,508,380)	(3,419)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	(66,826)	-
27		Taxes other than Income	1.1	(33,124,880)	(115,336)	(568,508)	(1,289)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 3,029,875	$(1,621,908)	$(25,684)
29		Interest Expense	1.1	(48,035,008)	(167,251)	(824,405)	(1,869)
30		State Taxable Income		$ 41,237,309	$ 2,862,624	$(2,446,313)	$(27,552)
31		State Income Tax		2,873,416	199,468	(170,459)	(1,920)
32		South Georgia	1.1	29,686	103	509	1
33		State Income Tax		2,903,102	199,571	(169,950)	(1,919)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	3,029,875	(1,621,908)	(25,684)
35		Interest Expense	1.1	(48,035,008)	(167,251)	(824,405)	(1,869)
36		Federal Taxable Income		41,237,309	2,862,624	(2,446,313)	(27,552)
37		Federal Income Tax		$ 13,427,363	$ 932,105	$(796,549)	$(8,971)
38		I T C	1.1	(528,360)	(1,840)	(9,068)	(21)
39		South Georgia	1.1	290,114	1,010	4,979	11
40		Total Federal Income Tax		$ 13,189,117	$ 931,275	$(800,638)	$(8,981)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 1,899,028	$(651,321)	$(14,784)
43		Rate of Return on Rate Base		6.68%	46.63%	(3.71%)	(33.19%)
44		Rate of Return by Class Total				5.69%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(k)	(l)	(m)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 99,403	$ 25,560	$ 930
5	389-398	General	1.1	$ 4,919,293	$ 6,442	$ 1,656	$ 60
6		Total Direct Dep. Exp.		$ 80,829,317	$ 105,845	$ 27,216	$ 990
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 3,326	$ 855	$ 31
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	5,241	1,348	49
10		Structures-Leasehold Improvements	1.1	104,525	137	35	1
11		Total System Allocable Amortization		4,106,686	5,378	1,383	50
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	8,704	2,238	81
13		Total Depreciation Expense		87,476,255	114,549	29,454	1,072
14		Amortization	1.1	126,930	166	43	2
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(69)	(18)	(1)
16		Regulatory Amortizations	1.1	337,524	442	114	4
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 115,088	$ 29,593	$ 1,077
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	2,189
27		Materials & Expenses	3.0	59,983	-	-	205
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 2,394

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(k)	(l)	(m)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 6,698	$ 3,397	$ 353
3		Materials & Expenses	5.5	1,458,368	1,086	551	57
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	882
6		Materials & Expenses	3.0	113,250	-	-	386
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	9,536	1,971	0
9		Materials & Expenses	4.4	5,540,228	8,578	1,773	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	4,348	139	0
12		Materials & Expenses	2.2	697,287	1,630	52	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	3,236	-
15		Materials & Expenses	6.0	1,213,237	-	567	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	3,783	-
18		Materials & Expenses	6.0	1,490,584	-	697	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	4,875	2,472	257
21		Materials & Expenses	5.5	4,535,239	3,379	1,713	178
22	881	Rents	5.5	2,250,258	1,676	850	88
23		Total Distribution-Operations		$ 56,117,507	$ 41,807	$ 21,202	$ 2,201
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 3,891	$ 973	$ 0
26		Materials & Expenses	6.6	338,062	470	118	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	111	-	-
29		Materials & Expenses	1.0	80,753	336	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	19,874	636	0
32		Materials & Expenses	2.2	7,043,715	16,469	527	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	3,417	109	0
35		Materials & Expenses	2.2	580,480	1,357	43	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	4,931	-
38		Materials & Expenses	3.3	3,973,153	0	3,181	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	599	-
41		Materials & Expenses	6.0	781,684	-	366	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	273	68	0
44		Materials & Expenses	6.6	189,711	264	66	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 46,461	$ 11,617	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 88,267	$ 32,819	$ 2,201

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(k)	(l)	(m)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 1,958	$ -
3		Materials & Expenses	10.1	275,497	-	132	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	2,468	-
6		Materials & Expenses	13.0	2,194,002	-	1,114	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	205	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	8,157	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	3,779	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	509	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	193	-
16		Materials & Expenses	10.1	16,795	-	8	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 18,524	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 261	$ -
20		Materials & Expenses	13.0	564,797	-	287	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	13	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	11	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 572	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 88,267	$ 51,915	$ 4,595
39		Allocation Percentage	Total O&M	100.00%	0.07%	0.04%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	38,640	22,726	2,012
41		Interest on Customer Deposits	8.0	1,915,314	-	330	-
42		Taxes Other Than Income	1.1	33,124,880	43,377	11,153	406
43		Total Allocated Operating Deductions		$ 222,074,648	$ 170,284	$ 86,126	$ 7,013
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	62,901	16,174	589
45		State South Georgia	1.1	29,686	39	10	0
46		Investment Tax Credit	1.1	(528,360)	(692)	(178)	(6)
47		Federal South Georgia	1.1	290,114	380	98	4

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(k)	(l)	(m)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 1,659,285	$ 426,653	$ 15,527
2		Systems Allocable Net Plant		34,448,206	45,110	11,599	422
3		Cash Working Capital	1.1	(10,379,937)	(7,043)	(4,142)	(367)
4		Materials & Supplies	1.1	12,389,898	16,224	4,172	152
5		Prepayments	1.1	3,671,971	4,808	1,236	45
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	(5,508)	-
8		Customer Advances	8.0	(37,910,017)	-	(6,541)	-
9		Deferred Taxes	1.1	(142,632,297)	(186,775)	(48,026)	(1,748)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 1,531,609	$ 379,443	$ 14,031
12		Net Operating Margin	Direct	$ 381,188,845	$ 854,013	$ 118,080	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 12,958	$ 1,792	$ -
14		Late Charges	Direct	$ 2,430,203	$ 6,351	$ 878	
15		Service Establishment Charges	9	$ 8,267,657	-	2,350	-
16		Reconnect / Reread Charges	4	$ 569,215	-	97	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 3	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 6	$ 1	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	52	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	30	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 1,148	$ 159	$ -
22		Total Revenue		399,234,678	874,479	123,439	-
23		O & M		(130,087,761)	(88,267)	(51,915)	(4,595)
24		A & G	Total O&M	(56,946,694)	(38,640)	(22,726)	(2,012)
25		Depreciation Expense		(87,887,713)	(115,088)	(29,593)	(1,077)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	(330)	-
27		Taxes other than Income	1.1	(33,124,880)	(43,377)	(11,153)	(406)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 589,107	$ 7,721	$(8,090)
29		Interest Expense	1.1	(48,035,008)	(62,901)	(16,174)	(589)
30		State Taxable Income		$ 41,237,309	$ 526,206	$(8,453)	$(8,678)
31		State Income Tax		2,873,416	36,666	(589)	(605)
32		South Georgia	1.1	29,686	39	10	0
33		State Income Tax		2,903,102	36,705	(579)	(604)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	589,107	7,721	(8,090)
35		Interest Expense	1.1	(48,035,008)	(62,901)	(16,174)	(589)
36		Federal Taxable Income		41,237,309	526,206	(8,453)	(8,678)
37		Federal Income Tax		$ 13,427,363	$ 171,339	$(2,752)	$(2,826)
38		I T C	1.1	(528,360)	(692)	(178)	(6)
39		South Georgia	1.1	290,114	380	98	4
40		Total Federal Income Tax		$ 13,189,117	$ 171,027	$(2,833)	$(2,829)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 381,375	$ 11,133	$(4,657)
43		Rate of Return on Rate Base		6.68%	24.90%	2.93%	(33.19%)
44		Rate of Return by Class Total				20.15%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(n)	(o)	(p)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 276,225	$ 1,013,749	$ 2,100
5	389-398	General	1.1	$ 4,919,293	$ 17,901	$ 65,695	$ 136
6		Total Direct Dep. Exp.		$ 80,829,317	$ 294,126	$ 1,079,444	$ 2,236
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 9,244	$ 33,924	$ 70
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	14,563	53,447	111
10		Structures-Leasehold Improvements	1.1	104,525	380	1,396	3
11		Total System Allocable Amortization		4,106,686	14,944	54,843	114
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	24,187	88,767	184
13		Total Depreciation Expense		87,476,255	318,313	1,168,212	2,420
14		Amortization	1.1	126,930	462	1,695	4
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(193)	(708)	(1)
16		Regulatory Amortizations	1.1	337,524	1,228	4,508	9
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 319,811	$ 1,173,707	$ 2,431
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--I	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	4,942
27		Materials & Expenses	3.0	59,983	-	-	462
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 5,404

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(n)	(o)	(p)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 18,613	$ 160,522	$ 796
3		Materials & Expenses	5.5	1,458,368	3,019	26,037	129
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	1,992
6		Materials & Expenses	3.0	113,250	-	-	872
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	26,499	70,405	0
9		Materials & Expenses	4.4	5,540,228	23,836	63,330	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	12,082	14,270	0
12		Materials & Expenses	2.2	697,287	4,530	5,351	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	165,662	-
15		Materials & Expenses	6.0	1,213,237	-	29,046	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	193,621	-
18		Materials & Expenses	6.0	1,490,584	-	35,686	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	13,547	116,832	580
21		Materials & Expenses	5.5	4,535,239	9,389	80,971	402
22	881	Rents	5.5	2,250,258	4,658	40,176	199
23		Total Distribution-Operations		$ 56,117,507	$ 116,174	$ 1,001,909	$ 4,970
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 10,811	$ 35,084	$ 0
26		Materials & Expenses	6.6	338,062	1,306	4,239	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	308	-	-
29		Materials & Expenses	1.0	80,753	933	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	55,226	65,226	0
32		Materials & Expenses	2.2	7,043,715	45,764	54,051	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	9,494	11,214	0
35		Materials & Expenses	2.2	580,480	3,771	4,454	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	115,778	-
38		Materials & Expenses	3.3	3,973,153	0	74,682	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	30,681	-
41		Materials & Expenses	6.0	781,684	-	18,714	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	759	2,465	0
44		Materials & Expenses	6.6	189,711	733	2,379	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 129,107	$ 418,967	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 245,281	$ 1,420,877	$ 4,970

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(n)	(o)	(p)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 142,129	$ -
3		Materials & Expenses	10.1	275,497	-	9,564	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	176,771	-
6		Materials & Expenses	13.0	2,194,002	-	79,794	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	14,710	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	584,178	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	270,624	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	52,213	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	14,042	-
16		Materials & Expenses	10.1	16,795	-	583	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 1,344,608	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 18,726	$ -
20		Materials & Expenses	13.0	564,797	-	20,541	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	914	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	799	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 40,981	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 245,281	$ 2,806,465	$ 10,374
39		Allocation Percentage	Total O&M	100.00%	0.19%	2.16%	0.01%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	107,373	1,228,547	4,541
41		Interest on Customer Deposits	8.0	1,915,314	-	33,888	-
42		Taxes Other Than Income	1.1	33,124,880	120,537	442,370	916
43		Total Allocated Operating Deductions		$ 222,074,648	$ 473,190	$ 4,511,271	$ 15,832
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	174,792	641,489	1,329
45		State South Georgia	1.1	29,686	108	396	1
46		Investment Tax Credit	1.1	(528,360)	(1,923)	(7,056)	(15)
47		Federal South Georgia	1.1	290,114	1,056	3,874	8

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(n)	(o)	(p)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 4,610,880	$ 16,921,956	$ 35,052
2		Systems Allocable Net Plant		34,448,206	125,352	460,043	953
3		Cash Working Capital	1.1	(10,379,937)	(19,571)	(223,933)	(828)
4		Materials & Supplies	1.1	12,389,898	45,085	165,462	343
5		Prepayments	1.1	3,671,971	13,362	49,038	102
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	(564,803)	-
8		Customer Advances	8.0	(37,910,017)	-	(670,752)	-
9		Deferred Taxes	1.1	(142,632,297)	(519,018)	(1,904,800)	(3,946)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 4,256,089	$ 14,232,211	$ 31,676
12		Net Operating Margin	Direct	$ 381,188,845	$ 2,822,517	$ 5,045,125	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 42,828	$ 76,553	$ -
14		Late Charges	Direct	$ 2,430,203	$ 31,393	$ 56,114	
15		Service Establishment Charges	9	$ 8,267,657	-	241,028	-
16		Reconnect / Reread Charges	4	$ 569,215	-	9,981	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 10	$ 17	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 19	$ 35	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	5,346	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	3,041	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 3,795	$ 6,783	$ -
22		Total Revenue		399,234,678	2,900,562	5,444,022	-
23		O & M		(130,087,761)	(245,281)	(2,806,465)	(10,374)
24		A & G	Total O&M	(56,946,694)	(107,373)	(1,228,547)	(4,541)
25		Depreciation Expense		(87,887,713)	(319,811)	(1,173,707)	(2,431)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	(33,888)	-
27		Taxes other than Income	1.1	(33,124,880)	(120,537)	(442,370)	(916)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 2,107,561	$(240,955)	$(18,263)
29		Interest Expense	1.1	(48,035,008)	(174,792)	(641,489)	(1,329)
30		State Taxable Income		$ 41,237,309	$ 1,932,769	$(882,444)	$(19,592)
31		State Income Tax		2,873,416	134,675	(61,489)	(1,365)
32		South Georgia	1.1	29,686	108	396	1
33		State Income Tax		2,903,102	134,783	(61,092)	(1,364)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	2,107,561	(240,955)	(18,263)
35		Interest Expense	1.1	(48,035,008)	(174,792)	(641,489)	(1,329)
36		Federal Taxable Income		41,237,309	1,932,769	(882,444)	(19,592)
37		Federal Income Tax		$ 13,427,363	$ 629,333	$(287,334)	$(6,379)
38		I T C	1.1	(528,360)	(1,923)	(7,056)	(15)
39		South Georgia	1.1	290,114	1,056	3,874	8
40		Total Federal Income Tax		$ 13,189,117	$ 628,466	$(290,516)	$(6,386)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 1,344,312	$ 110,653	$(10,513)
43		Rate of Return on Rate Base		6.68%	31.59%	0.78%	(33.19%)
44		Rate of Return by Class Total				7.80%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 1,506,527	$ 2,633,236	$ 19,043
5	389-398	General	1.1	$ 4,919,293	$ 97,629	$ 170,645	$ 1,234
6		Total Direct Dep. Exp.		$ 80,829,317	$ 1,604,157	$ 2,803,881	$ 20,277
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 50,414	$ 88,119	$ 637
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	79,428	138,831	1,004
10		Structures-Leasehold Improvements	1.1	104,525	2,074	3,626	26
11		Total System Allocable Amortization		4,106,686	81,502	142,456	1,030
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	131,917	230,575	1,667
13		Total Depreciation Expense		87,476,255	1,736,073	3,034,456	21,944
14		Amortization	1.1	126,930	2,519	4,403	32
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(1,052)	(1,838)	(13)
16		Regulatory Amortizations	1.1	337,524	6,699	11,708	85
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 1,744,239	$ 3,048,729	$ 22,047
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	44,820
27		Materials & Expenses	3.0	59,983	-	-	4,190
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 49,010

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 101,514	$ 406,229	$ 7,221
3		Materials & Expenses	5.5	1,458,368	16,466	65,892	1,171
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	18,060
6		Materials & Expenses	3.0	113,250	-	-	7,911
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	144,525	186,210	0
9		Materials & Expenses	4.4	5,540,228	130,002	167,499	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	65,896	13,703	0
12		Materials & Expenses	2.2	697,287	24,708	5,138	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	425,310	-
15		Materials & Expenses	6.0	1,213,237	-	74,571	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	497,092	-
18		Materials & Expenses	6.0	1,490,584	-	91,618	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	73,885	295,665	5,255
21		Materials & Expenses	5.5	4,535,239	51,206	204,912	3,642
22	881	Rents	5.5	2,250,258	25,407	101,672	1,807
23		Total Distribution-Operations		$ 56,117,507	$ 633,610	$ 2,535,511	$ 45,068
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 58,965	$ 95,189	$ 0
26		Materials & Expenses	6.6	338,062	7,125	11,502	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	1,681	-	-
29		Materials & Expenses	1.0	80,753	5,088	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	301,199	62,635	0
32		Materials & Expenses	2.2	7,043,715	249,595	51,904	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	51,782	10,768	0
35		Materials & Expenses	2.2	580,480	20,569	4,277	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	462,297	-
38		Materials & Expenses	3.3	3,973,153	0	298,202	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	78,769	-
41		Materials & Expenses	6.0	781,684	-	48,046	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	4,142	6,687	0
44		Materials & Expenses	6.6	189,711	3,998	6,454	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 704,145	$ 1,136,731	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 1,337,754	$ 3,672,242	$ 45,068

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 219,913	$ -
3		Materials & Expenses	10.1	275,497	-	14,799	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	278,326	-
6		Materials & Expenses	13.0	2,194,002	-	125,635	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	23,161	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	919,784	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	426,095	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	50,139	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	21,726	-
16		Materials & Expenses	10.1	16,795	-	902	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 2,080,480	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 29,484	$ -
20		Materials & Expenses	13.0	564,797	-	32,342	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	1,439	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	1,258	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 64,524	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 1,337,754	$ 5,817,246	$ 94,078
39		Allocation Percentage	Total O&M	100.00%	1.03%	4.47%	0.07%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	585,610	2,546,534	41,183
41		Interest on Customer Deposits	8.0	1,915,314	-	32,542	-
42		Taxes Other Than Income	1.1	33,124,880	657,404	1,149,066	8,310
43		Total Allocated Operating Deductions		$ 222,074,648	$ 2,580,768	$ 9,545,388	$ 143,571
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	953,313	1,666,282	12,050
45		State South Georgia	1.1	29,686	589	1,030	7
46		Investment Tax Credit	1.1	(528,360)	(10,486)	(18,328)	(133)
47		Federal South Georgia	1.1	290,114	5,758	10,064	73

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$25,147,627	$ 43,955,154	$ 317,867
2		Systems Allocable Net Plant		34,448,206	683,667	1,194,971	8,642
3		Cash Working Capital	1.1	(10,379,937)	(106,742)	(464,169)	(7,507)
4		Materials & Supplies	1.1	12,389,898	245,893	429,792	3,108
5		Prepayments	1.1	3,671,971	72,875	127,377	921
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	(542,371)	-
8		Customer Advances	8.0	(37,910,017)	-	(644,112)	-
9		Deferred Taxes	1.1	(142,632,297)	(2,830,712)	(4,947,759)	(35,780)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$23,212,607	$ 39,108,882	$ 287,251
12		Net Operating Margin	Direct	$ 381,188,845	$17,915,706	$ 6,395,070	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 271,847	$ 97,037	$ -
14		Late Charges	Direct	$ 2,430,203	$ 199,266	$ 71,129	
15		Service Establishment Charges	9	$ 8,267,657	-	231,455	-
16		Reconnect / Reread Charges	4	$ 569,215	-	9,585	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 62	$ 22	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 123	$ 44	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	5,134	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	2,920	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 24,087	$ 8,598	$ -
22		Total Revenue		399,234,678	18,411,091	6,820,992	-
23		O & M		(130,087,761)	(1,337,754)	(5,817,246)	(94,078)
24		A & G	Total O&M	(56,946,694)	(585,610)	(2,546,534)	(41,183)
25		Depreciation Expense		(87,887,713)	(1,744,239)	(3,048,729)	(22,047)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	(32,542)	-
27		Taxes other than Income	1.1	(33,124,880)	(657,404)	(1,149,066)	(8,310)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$14,086,083	$(5,773,124)	$(165,618)
29		Interest Expense	1.1	(48,035,008)	(953,313)	(1,666,282)	(12,050)
30		State Taxable Income		$ 41,237,309	$13,132,770	$(7,439,407)	$(177,668)
31		State Income Tax		2,873,416	915,091	(518,378)	(12,380)
32		South Georgia	1.1	29,686	589	1,030	7
33		State Income Tax		2,903,102	915,681	(517,348)	(12,372)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	14,086,083	(5,773,124)	(165,618)
35		Interest Expense	1.1	(48,035,008)	(953,313)	(1,666,282)	(12,050)
36		Federal Taxable Income		41,237,309	13,132,770	(7,439,407)	(177,668)
37		Federal Income Tax		$ 13,427,363	$ 4,276,187	$(2,422,360)	$(57,851)
38		I T C	1.1	(528,360)	(10,486)	(18,328)	(133)
39		South Georgia	1.1	290,114	5,758	10,064	73
40		Total Federal Income Tax		$ 13,189,117	$ 4,271,459	$(2,430,625)	$(57,911)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 8,898,944	$(2,825,152)	$(95,335)
43		Rate of Return on Rate Base		6.68%	38.34%	(7.22%)	(33.19%)
44		Rate of Return by Class Total				9.55%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 4,115,293	$ 2,198,169	$ 62,411
5	389-398	General	1.1	$ 4,919,293	$ 266,689	$ 142,451	$ 4,044
6		Total Direct Dep. Exp.		$ 80,829,317	$ 4,381,982	$ 2,340,620	$ 66,456
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 137,714	$ 73,560	$ 2,089
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	216,968	115,893	3,290
10		Structures-Leasehold Improvements	1.1	104,525	5,667	3,027	86
11		Total System Allocable Amortization		4,106,686	222,635	118,920	3,376
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	360,349	192,479	5,465
13		Total Depreciation Expense		87,476,255	4,742,331	2,533,099	71,920
14		Amortization	1.1	126,930	6,881	3,676	104
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(2,873)	(1,535)	(44)
16		Regulatory Amortizations	1.1	337,524	18,298	9,774	278
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 4,764,637	$ 2,545,014	$ 72,259
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	146,895
27		Materials & Expenses	3.0	59,983	-	-	13,733
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 160,628

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 277,301	$ 420,875	$ 23,665
3		Materials & Expenses	5.5	1,458,368	44,979	68,268	3,839
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	59,191
6		Materials & Expenses	3.0	113,250	-	-	25,928
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	394,790	131,028	0
9		Materials & Expenses	4.4	5,540,228	355,119	117,861	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	180,004	6,047	0
12		Materials & Expenses	2.2	697,287	67,495	2,267	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	490,958	-
15		Materials & Expenses	6.0	1,213,237	-	86,082	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	573,820	-
18		Materials & Expenses	6.0	1,490,584	-	105,760	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	201,827	306,325	17,224
21		Materials & Expenses	5.5	4,535,239	139,877	212,300	11,937
22	881	Rents	5.5	2,250,258	69,403	105,337	5,923
23		Total Distribution-Operations		$ 56,117,507	$ 1,730,795	$ 2,626,928	$ 147,706
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 161,071	$ 72,743	$ 0
26		Materials & Expenses	6.6	338,062	19,462	8,790	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	4,591	-	-
29		Materials & Expenses	1.0	80,753	13,899	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	822,769	27,638	0
32		Materials & Expenses	2.2	7,043,715	681,805	22,903	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	141,450	4,751	0
35		Materials & Expenses	2.2	580,480	56,188	1,887	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	348,645	-
38		Materials & Expenses	3.3	3,973,153	0	224,892	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	90,927	-
41		Materials & Expenses	6.0	781,684	-	55,462	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	11,315	5,110	0
44		Materials & Expenses	6.6	189,711	10,922	4,932	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 1,923,472	$ 868,681	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 3,654,266	$ 3,495,609	$ 147,706

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 117,537	$ -
3		Materials & Expenses	10.1	275,497	-	7,909	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	149,490	-
6		Materials & Expenses	13.0	2,194,002	-	67,479	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	12,440	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	494,019	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	228,857	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	22,124	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	11,612	-
16		Materials & Expenses	10.1	16,795	-	482	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 1,111,949	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 15,836	$ -
20		Materials & Expenses	13.0	564,797	-	17,371	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	773	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	676	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 34,656	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 3,654,266	$ 4,642,214	$ 308,335
39		Allocation Percentage	Total O&M	100.00%	2.81%	3.57%	0.24%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	1,599,677	2,032,157	134,975
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	1,795,792	959,216	27,234
43		Total Allocated Operating Deductions		$ 222,074,648	$ 7,049,735	$ 7,633,587	$ 470,544
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	2,604,111	1,390,977	39,493
45		State South Georgia	1.1	29,686	1,609	860	24
46		Investment Tax Credit	1.1	(528,360)	(28,644)	(15,300)	(434)
47		Federal South Georgia	1.1	290,114	15,728	8,401	239

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 68,694,320	$ 36,692,829	$ 1,041,792
2		Systems Allocable Net Plant		34,448,206	1,867,533	997,536	28,322
3		Cash Working Capital	1.1	(10,379,937)	(291,581)	(370,411)	(24,603)
4		Materials & Supplies	1.1	12,389,898	671,691	358,781	10,187
5		Prepayments	1.1	3,671,971	199,068	106,331	3,019
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(7,732,493)	(4,130,284)	(117,268)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 63,408,538	$ 33,654,783	$ 941,450
12		Net Operating Margin	Direct	$ 381,188,845	$ 40,605,031	$ 12,398,950	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 616,127	$ 188,137	$ -
14		Late Charges	Direct	$ 2,430,203	$ 37,460	$ 11,439	
15		Service Establishment Charges	9	$ 8,267,657	-	102,130	-
16		Reconnect / Reread Charges	4	$ 569,215	-	4,229	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 140	$ 43	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 279	$ 85	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	2,265	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	1,288	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 54,592	$ 16,670	$ -
22		Total Revenue		399,234,678	41,313,629	12,725,236	-
23		O & M		(130,087,761)	(3,654,266)	(4,642,214)	(308,335)
24		A & G	Total O&M	(56,946,694)	(1,599,677)	(2,032,157)	(134,975)
25		Depreciation Expense		(87,887,713)	(4,764,637)	(2,545,014)	(72,259)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(1,795,792)	(959,216)	(27,234)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 29,499,257	$ 2,546,636	$(542,803)
29		Interest Expense	1.1	(48,035,008)	(2,604,111)	(1,390,977)	(39,493)
30		State Taxable Income		$ 41,237,309	$ 26,895,145	$ 1,155,659	$(582,296)
31		State Income Tax		2,873,416	1,874,054	80,526	(40,574)
32		South Georgia	1.1	29,686	1,609	860	24
33		State Income Tax		2,903,102	1,875,663	81,386	(40,550)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	29,499,257	2,546,636	(542,803)
35		Interest Expense	1.1	(48,035,008)	(2,604,111)	(1,390,977)	(39,493)
36		Federal Taxable Income		41,237,309	26,895,145	1,155,659	(582,296)
37		Federal Income Tax		$ 13,427,363	$ 8,757,382	$ 376,296	$(189,603)
38		I T C	1.1	(528,360)	(28,644)	(15,300)	(434)
39		South Georgia	1.1	290,114	15,728	8,401	239
40		Total Federal Income Tax		$ 13,189,117	$ 8,744,466	$ 369,397	$(189,798)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 18,879,127	$ 2,095,852	$(312,455)
43		Rate of Return on Rate Base		6.68%	29.77%	6.23%	(33.19%)
44		Rate of Return by Class Total				21.08%	

SOUTHWEST GAS CORPORATION
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 2,828,709	$ 267,012	$ 41,626
5	389-398	General	1.1	$ 4,919,293	$ 183,312	$ 17,304	$ 2,698
6		Total Direct Dep. Exp.		$ 80,829,317	$ 3,012,021	$ 284,316	$ 44,323
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 94,660	$ 8,935	$ 1,393
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	149,136	14,078	2,195
10		Structures-Leasehold Improvements	1.1	104,525	3,895	368	57
11		Total System Allocable Amortization		4,106,686	153,031	14,445	2,252
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	247,691	23,381	3,645
13		Total Depreciation Expense		87,476,255	3,259,712	307,697	47,968
14		Amortization	1.1	126,930	4,730	446	70
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(1,975)	(186)	(29)
16		Regulatory Amortizations	1.1	337,524	12,577	1,187	185
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 3,275,045	$ 309,144	$ 48,194
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	97,974
27		Materials & Expenses	3.0	59,983	-	-	9,159
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 107,133

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 190,607	$ 79,387	$ 15,784
3		Materials & Expenses	5.5	1,458,368	30,917	12,877	2,560
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	39,478
6		Materials & Expenses	3.0	113,250	-	-	17,293
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	271,365	7,469	0
9		Materials & Expenses	4.4	5,540,228	244,096	6,719	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	123,728	157	0
12		Materials & Expenses	2.2	697,287	46,394	59	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	105,934	-
15		Materials & Expenses	6.0	1,213,237	-	18,574	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	123,813	-
18		Materials & Expenses	6.0	1,490,584	-	22,820	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	138,729	57,780	11,488
21		Materials & Expenses	5.5	4,535,239	96,147	40,045	7,962
22	881	Rents	5.5	2,250,258	47,705	19,869	3,950
23		Total Distribution-Operations		$ 56,117,507	$ 1,189,688	$ 495,503	$ 98,515
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 110,714	$ 6,344	$ 0
26		Materials & Expenses	6.6	338,062	13,378	767	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	3,156	-	-
29		Materials & Expenses	1.0	80,753	9,554	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	565,543	718	0
32		Materials & Expenses	2.2	7,043,715	468,649	595	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	97,228	123	0
35		Materials & Expenses	2.2	580,480	38,622	49	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	21,092	-
38		Materials & Expenses	3.3	3,973,153	0	13,605	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	19,619	-
41		Materials & Expenses	6.0	781,684	-	11,967	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	7,777	446	0
44		Materials & Expenses	6.6	189,711	7,507	430	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 1,322,127	$ 75,756	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 2,511,815	$ 571,259	$ 98,515

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 5,106	$ -
3		Materials & Expenses	10.1	275,497	-	344	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	6,555	-
6		Materials & Expenses	13.0	2,194,002	-	2,959	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	545	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	21,661	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	10,035	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	575	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	504	-
16		Materials & Expenses	10.1	16,795	-	21	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 48,304	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 694	$ -
20		Materials & Expenses	13.0	564,797	-	762	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	34	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	30	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 1,520	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 2,511,815	$ 621,082	$ 205,648
39		Allocation Percentage	Total O&M	100.00%	1.93%	0.48%	0.16%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	1,099,562	271,882	90,024
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	1,234,364	116,516	18,164
43		Total Allocated Operating Deductions		$ 222,074,648	$ 4,845,741	$ 1,009,481	$ 313,836
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	1,789,975	168,962	26,340
45		State South Georgia	1.1	29,686	1,106	104	16
46		Investment Tax Credit	1.1	(528,360)	(19,689)	(1,858)	(290)
47		Federal South Georgia	1.1	290,114	10,811	1,020	159

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 47,218,073	$ 4,457,092	$ 694,839
2		Systems Allocable Net Plant		34,448,206	1,283,677	121,171	18,890
3		Cash Working Capital	1.1	(10,379,937)	(200,422)	(49,557)	(16,409)
4		Materials & Supplies	1.1	12,389,898	461,697	43,581	6,794
5		Prepayments	1.1	3,671,971	136,832	12,916	2,014
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(5,315,045)	(501,707)	(78,214)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 43,584,811	$ 4,083,496	$ 627,914
12		Net Operating Margin	Direct	$ 381,188,845	$ 18,488,799	$ 1,599,840	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 280,543	$ 24,275	$ -
14		Late Charges	Direct	$ 2,430,203	$ 17,057	$ 1,476	
15		Service Establishment Charges	9	$ 8,267,657	-	2,654	-
16		Reconnect / Reread Charges	4	$ 569,215	-	110	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 64	$ 6	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 127	$ 11	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	59	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	33	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 24,858	$ 2,151	$ -
22		Total Revenue		399,234,678	18,811,447	1,630,615	-
23		O & M		(130,087,761)	(2,511,815)	(621,082)	(205,648)
24		A & G	Total O&M	(56,946,694)	(1,099,562)	(271,882)	(90,024)
25		Depreciation Expense		(87,887,713)	(3,275,045)	(309,144)	(48,194)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(1,234,364)	(116,516)	(18,164)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 10,690,661	$ 311,990	$(362,030)
29		Interest Expense	1.1	(48,035,008)	(1,789,975)	(168,962)	(26,340)
30		State Taxable Income		$ 41,237,309	$ 8,900,686	$ 143,028	$(388,371)
31		State Income Tax		2,873,416	620,200	9,966	(27,062)
32		South Georgia	1.1	29,686	1,106	104	16
33		State Income Tax		2,903,102	621,306	10,071	(27,045)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	10,690,661	311,990	(362,030)
35		Interest Expense	1.1	(48,035,008)	(1,789,975)	(168,962)	(26,340)
36		Federal Taxable Income		41,237,309	8,900,686	143,028	(388,371)
37		Federal Income Tax		$ 13,427,363	$ 2,898,170	$ 46,571	$(126,458)
38		I T C	1.1	(528,360)	(19,689)	(1,858)	(290)
39		South Georgia	1.1	290,114	10,811	1,020	159
40		Total Federal Income Tax		$ 13,189,117	$ 2,889,292	$ 45,733	$(126,589)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 7,180,063	$ 256,186	$(208,396)
43		Rate of Return on Rate Base		6.68%	16.47%	6.27%	(33.19%)
44		Rate of Return by Class Total				14.97%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air-Conditioning Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 10,158	$ 1,766	$ 468
5	389-398	General	1.1	$ 4,919,293	$ 658	$ 114	$ 30
6		Total Direct Dep. Exp.		$ 80,829,317	$ 10,817	$ 1,880	$ 498
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 340	$ 59	$ 16
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	536	93	25
10		Structures-Leasehold Improvements	1.1	104,525	14	2	1
11		Total System Allocable Amortization		4,106,686	550	96	25
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	889	155	41
13		Total Depreciation Expense		87,476,255	11,706	2,035	539
14		Amortization	1.1	126,930	17	3	1
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(7)	(1)	(0)
16		Regulatory Amortizations	1.1	337,524	45	8	2
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 11,761	$ 2,045	$ 541
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	1,101
27		Materials & Expenses	3.0	59,983	-	-	103
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 1,204

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air-Conditioning Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 684	$ 286	$ 177
3		Materials & Expenses	5.5	1,458,368	111	46	29
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	444
6		Materials & Expenses	3.0	113,250	-	-	194
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	975	121	0
9		Materials & Expenses	4.4	5,540,228	877	109	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	444	22	0
12		Materials & Expenses	2.2	697,287	167	8	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	300	-
15		Materials & Expenses	6.0	1,213,237	-	53	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	351	-
18		Materials & Expenses	6.0	1,490,584	-	65	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	498	208	129
21		Materials & Expenses	5.5	4,535,239	345	144	89
22	881	Rents	5.5	2,250,258	171	72	44
23		Total Distribution-Operations		$ 56,117,507	$ 4,272	$ 1,784	$ 1,107
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 398	$ 61	$ 0
26		Materials & Expenses	6.6	338,062	48	7	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	11	-	-
29		Materials & Expenses	1.0	80,753	34	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	2,031	103	0
32		Materials & Expenses	2.2	7,043,715	1,683	85	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	349	18	0
35		Materials & Expenses	2.2	580,480	139	7	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	212	-
38		Materials & Expenses	3.3	3,973,153	0	137	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	56	-
41		Materials & Expenses	6.0	781,684	-	34	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	28	4	0
44		Materials & Expenses	6.6	189,711	27	4	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 4,748	$ 727	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 9,020	$ 2,511	$ 1,107

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air-Conditioning Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 100	$ -
3		Materials & Expenses	10.1	275,497	-	7	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	118	-
6		Materials & Expenses	13.0	2,194,002	-	53	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	10	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	389	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	180	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	82	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	10	-
16		Materials & Expenses	10.1	16,795	-	0	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 950	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 12	$ -
20		Materials & Expenses	13.0	564,797	-	14	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	1	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	1	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 27	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 9,020	$ 3,489	$ 2,311
39		Allocation Percentage	Total O&M	100.00%	0.01%	0.00%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	3,949	1,527	1,011
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	4,433	771	204
43		Total Allocated Operating Deductions		$ 222,074,648	$ 17,402	$ 5,787	$ 3,526
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	6,428	1,118	296
45		State South Georgia	1.1	29,686	4	1	0
46		Investment Tax Credit	1.1	(528,360)	(71)	(12)	(3)
47		Federal South Georgia	1.1	290,114	39	7	2

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air-Conditioning Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 169,567	$ 29,479	$ 7,807
2		Systems Allocable Net Plant		34,448,206	4,610	801	212
3		Cash Working Capital	1.1	(10,379,937)	(720)	(278)	(184)
4		Materials & Supplies	1.1	12,389,898	1,658	288	76
5		Prepayments	1.1	3,671,971	491	85	23
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(19,087)	(3,318)	(879)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 156,519	$ 27,058	$ 7,055
12		Net Operating Margin	Direct	$ 381,188,845	$ 110,707	$ 12,990	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 1,680	$ 197	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	380	-
16		Reconnect / Reread Charges	4	$ 569,215	-	16	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 0	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 1	$ 0	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	8	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	5	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 149	$ 17	$ -
22		Total Revenue		399,234,678	112,537	13,613	-
23		O & M		(130,087,761)	(9,020)	(3,489)	(2,311)
24		A & G	Total O&M	(56,946,694)	(3,949)	(1,527)	(1,011)
25		Depreciation Expense		(87,887,713)	(11,761)	(2,045)	(541)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(4,433)	(771)	(204)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 83,374	$ 5,782	$(4,068)
29		Interest Expense	1.1	(48,035,008)	(6,428)	(1,118)	(296)
30		State Taxable Income		$ 41,237,309	$ 76,946	$ 4,664	$(4,364)
31		State Income Tax		2,873,416	5,362	325	(304)
32		South Georgia	1.1	29,686	4	1	0
33		State Income Tax		2,903,102	5,366	326	(304)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	83,374	5,782	(4,068)
35		Interest Expense	1.1	(48,035,008)	(6,428)	(1,118)	(296)
36		Federal Taxable Income		41,237,309	76,946	4,664	(4,364)
37		Federal Income Tax		$ 13,427,363	$ 25,055	$ 1,519	$(1,421)
38		I T C	1.1	(528,360)	(71)	(12)	(3)
39		South Georgia	1.1	290,114	39	7	2
40		Total Federal Income Tax		$ 13,189,117	$ 25,023	$ 1,513	$(1,422)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 52,986	$ 3,943	$(2,341)
43		Rate of Return on Rate Base		6.68%	33.85%	14.57%	(33.19%)
44		Rate of Return by Class Total				28.63%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 2,602	$ 1,359	$ 74
5	389-398	General	1.1	$ 4,919,293	$ 169	$ 88	$ 5
6		Total Direct Dep. Exp.		$ 80,829,317	$ 2,770	$ 1,447	$ 79
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 87	$ 45	$ 2
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	137	72	4
10		Structures-Leasehold Improvements	1.1	104,525	4	2	0
11		Total System Allocable Amortization		4,106,686	141	74	4
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	228	119	7
13		Total Depreciation Expense		87,476,255	2,998	1,566	86
14		Amortization	1.1	126,930	4	2	0
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(2)	(1)	(0)
16		Regulatory Amortizations	1.1	337,524	12	6	0
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 3,012	$ 1,574	$ 86
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	175
27		Materials & Expenses	3.0	59,983	-	-	16
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 191

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 175	$ 165	$ 28
3		Materials & Expenses	5.5	1,458,368	28	27	5
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	70
6		Materials & Expenses	3.0	113,250	-	-	31
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	250	109	0
9		Materials & Expenses	4.4	5,540,228	224	98	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	114	18	0
12		Materials & Expenses	2.2	697,287	43	7	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	141	-
15		Materials & Expenses	6.0	1,213,237	-	25	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	165	-
18		Materials & Expenses	6.0	1,490,584	-	30	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	128	120	20
21		Materials & Expenses	5.5	4,535,239	88	83	14
22	881	Rents	5.5	2,250,258	44	41	7
23		Total Distribution-Operations		$ 56,117,507	$ 1,094	$ 1,031	$ 176
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 102	$ 52	$ 0
26		Materials & Expenses	6.6	338,062	12	6	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	3	-	-
29		Materials & Expenses	1.0	80,753	9	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	520	81	0
32		Materials & Expenses	2.2	7,043,715	431	67	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	89	14	0
35		Materials & Expenses	2.2	580,480	36	6	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	208	-
38		Materials & Expenses	3.3	3,973,153	0	134	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	26	-
41		Materials & Expenses	6.0	781,684	-	16	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	7	4	0
44		Materials & Expenses	6.6	189,711	7	4	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 1,216	$ 618	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 2,310	$ 1,649	$ 176

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 270	$ -
3		Materials & Expenses	10.1	275,497	-	18	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	341	-
6		Materials & Expenses	13.0	2,194,002	-	154	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	28	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	1,128	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	523	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	65	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	27	-
16		Materials & Expenses	10.1	16,795	-	1	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 2,556	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 36	$ -
20		Materials & Expenses	13.0	564,797	-	40	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	2	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	2	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 79	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 2,310	$ 4,284	$ 367
39		Allocation Percentage	Total O&M	100.00%	0.00%	0.00%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	1,011	1,875	161
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	1,135	593	32
43		Total Allocated Operating Deductions		$ 222,074,648	$ 4,457	$ 6,753	$ 560
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	1,646	860	47
45		State South Georgia	1.1	29,686	1	1	0
46		Investment Tax Credit	1.1	(528,360)	(18)	(9)	(1)
47		Federal South Georgia	1.1	290,114	10	5	0

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 43,426	$ 22,690	$ 1,239
2		Systems Allocable Net Plant		34,448,206	1,181	617	34
3		Cash Working Capital	1.1	(10,379,937)	(184)	(342)	(29)
4		Materials & Supplies	1.1	12,389,898	425	222	12
5		Prepayments	1.1	3,671,971	126	66	4
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(4,888)	(2,554)	(139)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 40,085	$ 20,699	$ 1,120
12		Net Operating Margin	Direct	$ 381,188,845	$ 30,174	$ 6,300	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 458	$ 96	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	301	-
16		Reconnect / Reread Charges	4	$ 569,215	-	12	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 0	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 0	$ 0	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	7	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	4	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 41	$ 8	$ -
22		Total Revenue		399,234,678	30,673	6,728	-
23		O & M		(130,087,761)	(2,310)	(4,284)	(367)
24		A & G	Total O&M	(56,946,694)	(1,011)	(1,875)	(161)
25		Depreciation Expense		(87,887,713)	(3,012)	(1,574)	(86)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(1,135)	(593)	(32)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 23,204	$(1,598)	$(646)
29		Interest Expense	1.1	(48,035,008)	(1,646)	(860)	(47)
30		State Taxable Income		$ 41,237,309	$ 21,558	$(2,459)	$(693)
31		State Income Tax		2,873,416	1,502	(171)	(48)
32		South Georgia	1.1	29,686	1	1	0
33		State Income Tax		2,903,102	1,503	(171)	(48)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	23,204	(1,598)	(646)
35		Interest Expense	1.1	(48,035,008)	(1,646)	(860)	(47)
36		Federal Taxable Income		41,237,309	21,558	(2,459)	(693)
37		Federal Income Tax		$ 13,427,363	$ 7,020	$(801)	$(226)
38		I T C	1.1	(528,360)	(18)	(9)	(1)
39		South Georgia	1.1	290,114	10	5	0
40		Total Federal Income Tax		$ 13,189,117	$ 7,011	$(805)	$(226)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 14,690	$(623)	$(372)
43		Rate of Return on Rate Base		6.68%	36.65%	(3.01%)	(33.19%)
44		Rate of Return by Class Total				22.12%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 30,491	$ 14,009	$ 862
5	389-398	General	1.1	$ 4,919,293	$ 1,976	$ 908	$ 56
6		Total Direct Dep. Exp.		$ 80,829,317	$ 32,467	$ 14,917	$ 917
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 1,020	$ 469	$ 29
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	1,608	739	45
10		Structures-Leasehold Improvements	1.1	104,525	42	19	1
11		Total System Allocable Amortization		4,106,686	1,650	758	47
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	2,670	1,227	75
13		Total Depreciation Expense		87,476,255	35,137	16,144	993
14		Amortization	1.1	126,930	51	23	1
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(21)	(10)	(1)
16		Regulatory Amortizations	1.1	337,524	136	62	4
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 35,302	$ 16,219	$ 998
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	2,028
27		Materials & Expenses	3.0	59,983	-	-	190
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 2,218

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 2,055	$ 3,412	$ 327
3		Materials & Expenses	5.5	1,458,368	333	553	53
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	817
6		Materials & Expenses	3.0	113,250	-	-	358
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	2,925	617	0
9		Materials & Expenses	4.4	5,540,228	2,631	555	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	1,334	20	0
12		Materials & Expenses	2.2	697,287	500	8	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	4,326	-
15		Materials & Expenses	6.0	1,213,237	-	759	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	5,057	-
18		Materials & Expenses	6.0	1,490,584	-	932	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	1,495	2,484	238
21		Materials & Expenses	5.5	4,535,239	1,036	1,721	165
22	881	Rents	5.5	2,250,258	514	854	82
23		Total Distribution-Operations		$ 56,117,507	$ 12,824	$ 21,298	$ 2,039
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 1,193	$ 400	$ 0
26		Materials & Expenses	6.6	338,062	144	48	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	34	-	-
29		Materials & Expenses	1.0	80,753	103	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	6,096	93	0
32		Materials & Expenses	2.2	7,043,715	5,052	77	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	1,048	16	0
35		Materials & Expenses	2.2	580,480	416	6	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	1,694	-
38		Materials & Expenses	3.3	3,973,153	0	1,093	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	801	-
41		Materials & Expenses	6.0	781,684	-	489	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	84	28	0
44		Materials & Expenses	6.6	189,711	81	27	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 14,251	$ 4,773	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 27,075	$ 26,070	$ 2,039

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 609	$ -
3		Materials & Expenses	10.1	275,497	-	41	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	780	-
6		Materials & Expenses	13.0	2,194,002	-	352	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	65	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	2,578	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	1,194	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	75	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	60	-
16		Materials & Expenses	10.1	16,795	-	2	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 5,757	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 83	$ -
20		Materials & Expenses	13.0	564,797	-	91	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	4	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	4	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 181	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 27,075	$ 32,008	$ 4,257
39		Allocation Percentage	Total O&M	100.00%	0.02%	0.02%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	11,852	14,012	1,863
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	13,305	6,113	376
43		Total Allocated Operating Deductions		$ 222,074,648	$ 52,233	$ 52,133	$ 6,496
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	19,294	8,865	545
45		State South Georgia	1.1	29,686	12	5	0
46		Investment Tax Credit	1.1	(528,360)	(212)	(98)	(6)
47		Federal South Georgia	1.1	290,114	117	54	3

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 508,969	$ 233,845	$ 14,383
2		Systems Allocable Net Plant		34,448,206	13,837	6,357	391
3		Cash Working Capital	1.1	(10,379,937)	(2,160)	(2,554)	(340)
4		Materials & Supplies	1.1	12,389,898	4,977	2,287	141
5		Prepayments	1.1	3,671,971	1,475	678	42
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(57,292)	(26,322)	(1,619)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 469,806	$ 214,290	$ 12,998
12		Net Operating Margin	Direct	$ 381,188,845	$ 350,226	$ 54,720	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 5,314	$ 830	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	344	-
16		Reconnect / Reread Charges	4	$ 569,215	-	14	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 1	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 2	$ 0	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	8	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	4	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 471	$ 74	$ -
22		Total Revenue		399,234,678	356,015	55,995	-
23		O & M		(130,087,761)	(27,075)	(32,008)	(4,257)
24		A & G	Total O&M	(56,946,694)	(11,852)	(14,012)	(1,863)
25		Depreciation Expense		(87,887,713)	(35,302)	(16,219)	(998)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(13,305)	(6,113)	(376)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 268,480	$(12,358)	$(7,494)
29		Interest Expense	1.1	(48,035,008)	(19,294)	(8,865)	(545)
30		State Taxable Income		$ 41,237,309	$ 249,185	$(21,222)	$(8,039)
31		State Income Tax		2,873,416	17,363	(1,479)	(560)
32		South Georgia	1.1	29,686	12	5	0
33		State Income Tax		2,903,102	17,375	(1,473)	(560)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	268,480	(12,358)	(7,494)
35		Interest Expense	1.1	(48,035,008)	(19,294)	(8,865)	(545)
36		Federal Taxable Income		41,237,309	249,185	(21,222)	(8,039)
37		Federal Income Tax		$ 13,427,363	$ 81,138	$(6,910)	$(2,618)
38		I T C	1.1	(528,360)	(212)	(98)	(6)
39		South Georgia	1.1	290,114	117	54	3
40		Total Federal Income Tax		$ 13,189,117	$ 81,042	$(6,954)	$(2,620)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 170,063	$(3,930)	$(4,314)
43		Rate of Return on Rate Base		6.68%	36.20%	(1.83%)	(33.19%)
44		Rate of Return by Class Total				23.21%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 1,207	$ 5,074	$ 32
5	389-398	General	1.1	$ 4,919,293	$ 78	$ 329	$ 2
6		Total Direct Dep. Exp.		$ 80,829,317	$ 1,285	$ 5,403	$ 34
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 40	$ 170	$ 1
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	64	268	2
10		Structures-Leasehold Improvements	1.1	104,525	2	7	0
11		Total System Allocable Amortization		4,106,686	65	275	2
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	106	444	3
13		Total Depreciation Expense		87,476,255	1,391	5,848	37
14		Amortization	1.1	126,930	2	8	0
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(1)	(4)	(0)
16		Regulatory Amortizations	1.1	337,524	5	23	0
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 1,398	$ 5,875	$ 37
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	76
27		Materials & Expenses	3.0	59,983	-	-	7
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 83

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 81	$ 635	$ 12
3		Materials & Expenses	5.5	1,458,368	13	103	2
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	31
6		Materials & Expenses	3.0	113,250	-	-	13
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	116	403	0
9		Materials & Expenses	4.4	5,540,228	104	362	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	53	90	0
12		Materials & Expenses	2.2	697,287	20	34	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	545	-
15		Materials & Expenses	6.0	1,213,237	-	96	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	637	-
18		Materials & Expenses	6.0	1,490,584	-	117	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	59	462	9
21		Materials & Expenses	5.5	4,535,239	41	320	6
22	881	Rents	5.5	2,250,258	20	159	3
23		Total Distribution-Operations		$ 56,117,507	$ 508	$ 3,964	$ 77
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 47	$ 188	$ 0
26		Materials & Expenses	6.6	338,062	6	23	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	1	-	-
29		Materials & Expenses	1.0	80,753	4	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	241	411	0
32		Materials & Expenses	2.2	7,043,715	200	341	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	41	71	0
35		Materials & Expenses	2.2	580,480	16	28	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	608	-
38		Materials & Expenses	3.3	3,973,153	0	392	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	101	-
41		Materials & Expenses	6.0	781,684	-	62	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	3	13	0
44		Materials & Expenses	6.6	189,711	3	13	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 564	$ 2,251	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 1,072	$ 6,215	$ 77

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 431	$ -
3		Materials & Expenses	10.1	275,497	-	29	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	510	-
6		Materials & Expenses	13.0	2,194,002	-	230	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	42	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	1,685	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	780	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	329	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	43	-
16		Materials & Expenses	10.1	16,795	-	2	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 4,081	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 54	$ -
20		Materials & Expenses	13.0	564,797	-	59	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	3	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	2	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 118	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 1,072	$ 10,414	$ 160
39		Allocation Percentage	Total O&M	100.00%	0.00%	0.01%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	469	4,559	70
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	527	2,214	14
43		Total Allocated Operating Deductions		$ 222,074,648	$ 2,068	$ 17,188	$ 244
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	764	3,211	20
45		State South Georgia	1.1	29,686	0	2	0
46		Investment Tax Credit	1.1	(528,360)	(8)	(35)	(0)
47		Federal South Georgia	1.1	290,114	5	19	0

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 20,151	$ 84,704	$ 540
2		Systems Allocable Net Plant		34,448,206	548	2,303	15
3		Cash Working Capital	1.1	(10,379,937)	(86)	(831)	(13)
4		Materials & Supplies	1.1	12,389,898	197	828	5
5		Prepayments	1.1	3,671,971	58	245	2
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(2,268)	(9,535)	(61)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 18,601	$ 77,715	$ 488
12		Net Operating Margin	Direct	$ 381,188,845	$ 13,151	$ 12,338	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 200	$ 187	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	1,519	-
16		Reconnect / Reread Charges	4	$ 569,215	-	63	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 0	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 0	$ 0	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	34	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	19	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 18	$ 17	$ -
22		Total Revenue		399,234,678	13,368	14,177	-
23		O & M		(130,087,761)	(1,072)	(10,414)	(160)
24		A & G	Total O&M	(56,946,694)	(469)	(4,559)	(70)
25		Depreciation Expense		(87,887,713)	(1,398)	(5,875)	(37)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(527)	(2,214)	(14)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 9,903	$(8,886)	$(281)
29		Interest Expense	1.1	(48,035,008)	(764)	(3,211)	(20)
30		State Taxable Income		$ 41,237,309	$ 9,139	$(12,097)	$(302)
31		State Income Tax		2,873,416	637	(843)	(21)
32		South Georgia	1.1	29,686	0	2	0
33		State Income Tax		2,903,102	637	(841)	(21)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	9,903	(8,886)	(281)
35		Interest Expense	1.1	(48,035,008)	(764)	(3,211)	(20)
36		Federal Taxable Income		41,237,309	9,139	(12,097)	(302)
37		Federal Income Tax		$ 13,427,363	$ 2,976	$(3,939)	$(98)
38		I T C	1.1	(528,360)	(8)	(35)	(0)
39		South Georgia	1.1	290,114	5	19	0
40		Total Federal Income Tax		$ 13,189,117	$ 2,972	$(3,955)	$(98)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 6,293	$(4,090)	$(162)
43		Rate of Return on Rate Base		6.68%	33.83%	(5.26%)	(33.19%)
44		Rate of Return by Class Total				2.11%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 254,898	$ 14,528	$ 9,001
5	389-398	General	1.1	$ 4,919,293	$ 16,518	$ 941	$ 583
6		Total Direct Dep. Exp.		$ 80,829,317	$ 271,416	$ 15,469	$ 9,585
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 8,530	$ 486	$ 301
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	13,439	766	475
10		Structures-Leasehold Improvements	1.1	104,525	351	20	12
11		Total System Allocable Amortization		4,106,686	13,790	786	487
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	22,320	1,272	788
13		Total Depreciation Expense		87,476,255	293,736	16,741	10,373
14		Amortization	1.1	126,930	426	24	15
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(178)	(10)	(6)
16		Regulatory Amortizations	1.1	337,524	1,133	65	40
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 295,117	$ 16,820	$ 10,422
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	21,186
27		Materials & Expenses	3.0	59,983	-	-	1,981
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 23,167

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 17,176	$ 4,466	$ 3,413
3		Materials & Expenses	5.5	1,458,368	2,786	724	554
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	8,537
6		Materials & Expenses	3.0	113,250	-	-	3,740
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	24,453	362	0
9		Materials & Expenses	4.4	5,540,228	21,996	326	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	11,149	18	0
12		Materials & Expenses	2.2	697,287	4,181	7	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	5,998	-
15		Materials & Expenses	6.0	1,213,237	-	1,052	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	7,010	-
18		Materials & Expenses	6.0	1,490,584	-	1,292	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	12,501	3,251	2,484
21		Materials & Expenses	5.5	4,535,239	8,664	2,253	1,722
22	881	Rents	5.5	2,250,258	4,299	1,118	854
23		Total Distribution-Operations		$ 56,117,507	$ 107,204	$ 27,876	$ 21,303
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 9,977	$ 331	$ 0
26		Materials & Expenses	6.6	338,062	1,205	40	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	284	-	-
29		Materials & Expenses	1.0	80,753	861	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	50,962	81	0
32		Materials & Expenses	2.2	7,043,715	42,230	67	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	8,761	14	0
35		Materials & Expenses	2.2	580,480	3,480	6	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	957	-
38		Materials & Expenses	3.3	3,973,153	0	617	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	1,111	-
41		Materials & Expenses	6.0	781,684	-	678	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	701	23	0
44		Materials & Expenses	6.6	189,711	676	22	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 119,138	$ 3,948	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 226,342	$ 31,824	$ 21,303

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 532	$ -
3		Materials & Expenses	10.1	275,497	-	36	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	683	-
6		Materials & Expenses	13.0	2,194,002	-	308	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	57	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	2,256	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	1,045	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	65	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	53	-
16		Materials & Expenses	10.1	16,795	-	2	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 5,037	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 72	$ -
20		Materials & Expenses	13.0	564,797	-	79	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	4	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	3	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 158	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 226,342	$ 37,019	$ 44,470
39		Allocation Percentage	Total O&M	100.00%	0.17%	0.03%	0.03%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	99,083	16,205	19,467
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	111,230	6,339	3,928
43		Total Allocated Operating Deductions		$ 222,074,648	$ 436,654	$ 59,564	$ 67,865
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	161,296	9,193	5,696
45		State South Georgia	1.1	29,686	100	6	4
46		Investment Tax Credit	1.1	(528,360)	(1,774)	(101)	(63)
47		Federal South Georgia	1.1	290,114	974	56	34

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 4,254,867	$ 242,501	$ 150,254
2		Systems Allocable Net Plant		34,448,206	115,673	6,593	4,085
3		Cash Working Capital	1.1	(10,379,937)	(18,060)	(2,954)	(3,548)
4		Materials & Supplies	1.1	12,389,898	41,604	2,371	1,469
5		Prepayments	1.1	3,671,971	12,330	703	435
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(478,944)	(27,297)	(16,913)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 3,927,470	$ 221,917	$ 135,782
12		Net Operating Margin	Direct	$ 381,188,845	$ 2,453,502	$ 75,828	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 37,229	$ 1,151	$ -
14		Late Charges	Direct	$ 2,430,203	$ 2,190	$ 68	
15		Service Establishment Charges	9	$ 8,267,657	-	301	-
16		Reconnect / Reread Charges	4	$ 569,215	-	12	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 8	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 17	$ 1	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	7	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	4	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 3,299	$ 102	$ -
22		Total Revenue		399,234,678	2,496,245	77,473	-
23		O & M		(130,087,761)	(226,342)	(37,019)	(44,470)
24		A & G	Total O&M	(56,946,694)	(99,083)	(16,205)	(19,467)
25		Depreciation Expense		(87,887,713)	(295,117)	(16,820)	(10,422)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(111,230)	(6,339)	(3,928)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 1,764,473	$ 1,089	$(78,287)
29		Interest Expense	1.1	(48,035,008)	(161,296)	(9,193)	(5,696)
30		State Taxable Income		$ 41,237,309	$ 1,603,176	$(8,104)	$(83,983)
31		State Income Tax		2,873,416	111,709	(565)	(5,852)
32		South Georgia	1.1	29,686	100	6	4
33		State Income Tax		2,903,102	111,809	(559)	(5,848)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	1,764,473	1,089	(78,287)
35		Interest Expense	1.1	(48,035,008)	(161,296)	(9,193)	(5,696)
36		Federal Taxable Income		41,237,309	1,603,176	(8,104)	(83,983)
37		Federal Income Tax		$ 13,427,363	$ 522,013	$(2,639)	$(27,346)
38		I T C	1.1	(528,360)	(1,774)	(101)	(63)
39		South Georgia	1.1	290,114	974	56	34
40		Total Federal Income Tax		$ 13,189,117	$ 521,213	$(2,684)	$(27,374)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 1,131,450	$ 4,332	$(45,064)
43		Rate of Return on Rate Base		6.68%	28.81%	1.95%	(33.19%)
44		Rate of Return by Class Total				25.45%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 266,348	$ 45,964	$ 3,017
5	389-398	General	1.1	$ 4,919,293	$ 17,260	$ 2,979	$ 196
6		Total Direct Dep. Exp.		$ 80,829,317	$ 283,608	$ 48,943	$ 3,213
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 8,913	$ 1,538	$ 101
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	14,043	2,423	159
10		Structures-Leasehold Improvements	1.1	104,525	367	63	4
11		Total System Allocable Amortization		4,106,686	14,409	2,487	163
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	23,322	4,025	264
13		Total Depreciation Expense		87,476,255	306,931	52,967	3,477
14		Amortization	1.1	126,930	445	77	5
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(186)	(32)	(2)
16		Regulatory Amortizations	1.1	337,524	1,184	204	13
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 308,374	$ 53,216	$ 3,494
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	7,102
27		Materials & Expenses	3.0	59,983	-	-	664
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 7,766

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 17,947	$ 11,083	$ 1,144
3		Materials & Expenses	5.5	1,458,368	2,911	1,798	186
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	2,862
6		Materials & Expenses	3.0	113,250	-	-	1,254
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	25,551	2,057	0
9		Materials & Expenses	4.4	5,540,228	22,984	1,851	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	11,650	86	0
12		Materials & Expenses	2.2	697,287	4,368	32	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	14,002	-
15		Materials & Expenses	6.0	1,213,237	-	2,455	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	16,365	-
18		Materials & Expenses	6.0	1,490,584	-	3,016	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	13,063	8,067	833
21		Materials & Expenses	5.5	4,535,239	9,053	5,591	577
22	881	Rents	5.5	2,250,258	4,492	2,774	286
23		Total Distribution-Operations		$ 56,117,507	$ 112,020	$ 69,178	$ 7,141
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 10,425	$ 1,319	$ 0
26		Materials & Expenses	6.6	338,062	1,260	159	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	297	-	-
29		Materials & Expenses	1.0	80,753	900	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	53,251	393	0
32		Materials & Expenses	2.2	7,043,715	44,127	326	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	9,155	68	0
35		Materials & Expenses	2.2	580,480	3,637	27	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	5,533	-
38		Materials & Expenses	3.3	3,973,153	0	3,569	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	2,593	-
41		Materials & Expenses	6.0	781,684	-	1,582	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	732	93	0
44		Materials & Expenses	6.6	189,711	707	89	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 124,490	$ 15,750	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 236,510	$ 84,929	$ 7,141

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 6,855	$ -
3		Materials & Expenses	10.1	275,497	-	461	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	8,872	-
6		Materials & Expenses	13.0	2,194,002	-	4,005	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	738	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	29,321	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	13,583	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	315	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	677	-
16		Materials & Expenses	10.1	16,795	-	28	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 64,856	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 940	$ -
20		Materials & Expenses	13.0	564,797	-	1,031	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	46	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	40	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 2,057	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 236,510	$ 151,841	$ 14,907
39		Allocation Percentage	Total O&M	100.00%	0.18%	0.12%	0.01%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	103,533	66,470	6,526
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	116,226	20,057	1,317
43		Total Allocated Operating Deductions		$ 222,074,648	$ 456,269	$ 238,368	$ 22,750
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	168,542	29,085	1,909
45		State South Georgia	1.1	29,686	104	18	1
46		Investment Tax Credit	1.1	(528,360)	(1,854)	(320)	(21)
47		Federal South Georgia	1.1	290,114	1,018	176	12

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 4,446,000	$ 767,249	$ 50,369
2		Systems Allocable Net Plant		34,448,206	120,870	20,859	1,369
3		Cash Working Capital	1.1	(10,379,937)	(18,872)	(12,116)	(1,189)
4		Materials & Supplies	1.1	12,389,898	43,473	7,502	493
5		Prepayments	1.1	3,671,971	12,884	2,223	146
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(500,459)	(86,364)	(5,670)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 4,103,896	$ 699,353	$ 45,518
12		Net Operating Margin	Direct	$ 381,188,845	$ 2,995,484	$ 109,440	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 45,452	$ 1,661	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	1,452	-
16		Reconnect / Reread Charges	4	$ 569,215	-	60	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 10	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 21	$ 1	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	32	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	18	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 4,027	$ 147	$ -
22		Total Revenue		399,234,678	3,044,995	112,812	-
23		O & M		(130,087,761)	(236,510)	(151,841)	(14,907)
24		A & G	Total O&M	(56,946,694)	(103,533)	(66,470)	(6,526)
25		Depreciation Expense		(87,887,713)	(308,374)	(53,216)	(3,494)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(116,226)	(20,057)	(1,317)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 2,280,351	$(178,773)	$(26,244)
29		Interest Expense	1.1	(48,035,008)	(168,542)	(29,085)	(1,909)
30		State Taxable Income		$ 41,237,309	$ 2,111,809	$(207,858)	$(28,153)
31		State Income Tax		2,873,416	147,151	(14,484)	(1,962)
32		South Georgia	1.1	29,686	104	18	1
33		State Income Tax		2,903,102	147,255	(14,466)	(1,961)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	2,280,351	(178,773)	(26,244)
35		Interest Expense	1.1	(48,035,008)	(168,542)	(29,085)	(1,909)
36		Federal Taxable Income		41,237,309	2,111,809	(207,858)	(28,153)
37		Federal Income Tax		$ 13,427,363	$ 687,630	$(67,681)	$(9,167)
38		I T C	1.1	(528,360)	(1,854)	(320)	(21)
39		South Georgia	1.1	290,114	1,018	176	12
40		Total Federal Income Tax		$ 13,189,117	$ 686,794	$(67,825)	$(9,176)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 1,446,301	$(96,482)	$(15,107)
43		Rate of Return on Rate Base		6.68%	35.24%	(13.80%)	(33.19%)
44		Rate of Return by Class Total				27.53%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 126,385	$ 190,520	$ 5,467
5	389-398	General	1.1	$ 4,919,293	$ 8,190	$ 12,346	$ 354
6		Total Direct Dep. Exp.		$ 80,829,317	$ 134,575	$ 202,866	$ 5,821
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 4,229	$ 6,376	$ 183
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	6,663	10,045	288
10		Structures-Leasehold Improvements	1.1	104,525	174	262	8
11		Total System Allocable Amortization		4,106,686	6,837	10,307	296
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	11,067	16,683	479
13		Total Depreciation Expense		87,476,255	145,642	219,549	6,300
14		Amortization	1.1	126,930	211	319	9
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(88)	(133)	(4)
16		Regulatory Amortizations	1.1	337,524	562	847	24
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 146,327	$ 220,581	$ 6,329
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	12,867
27		Materials & Expenses	3.0	59,983	-	-	1,203
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 14,070

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 8,516	$ 47,256	$ 2,073
3		Materials & Expenses	5.5	1,458,368	1,381	7,665	336
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	5,185
6		Materials & Expenses	3.0	113,250	-	-	2,271
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	12,124	8,135	0
9		Materials & Expenses	4.4	5,540,228	10,906	7,317	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	5,528	361	0
12		Materials & Expenses	2.2	697,287	2,073	135	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	60,177	-
15		Materials & Expenses	6.0	1,213,237	-	10,551	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	70,334	-
18		Materials & Expenses	6.0	1,490,584	-	12,963	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	6,198	34,395	1,509
21		Materials & Expenses	5.5	4,535,239	4,296	23,837	1,046
22	881	Rents	5.5	2,250,258	2,131	11,827	519
23		Total Distribution-Operations		$ 56,117,507	$ 53,154	$ 294,955	$ 12,938
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 4,947	$ 5,347	$ 0
26		Materials & Expenses	6.6	338,062	598	646	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	141	-	-
29		Materials & Expenses	1.0	80,753	427	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	25,268	1,650	0
32		Materials & Expenses	2.2	7,043,715	20,939	1,367	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	4,344	284	0
35		Materials & Expenses	2.2	580,480	1,726	113	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	21,739	-
38		Materials & Expenses	3.3	3,973,153	0	14,023	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	11,145	-
41		Materials & Expenses	6.0	781,684	-	6,798	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	347	376	0
44		Materials & Expenses	6.6	189,711	335	363	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 59,072	$ 63,850	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 112,226	$ 358,805	$ 12,938

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 8,729	$ -
3		Materials & Expenses	10.1	275,497	-	587	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	11,153	-
6		Materials & Expenses	13.0	2,194,002	-	5,035	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	928	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	36,858	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	17,075	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	1,321	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	862	-
16		Materials & Expenses	10.1	16,795	-	36	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 82,585	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 1,182	$ -
20		Materials & Expenses	13.0	564,797	-	1,296	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	58	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	50	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 2,586	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 112,226	$ 443,976	$ 27,008
39		Allocation Percentage	Total O&M	100.00%	0.09%	0.34%	0.02%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	49,128	194,353	11,823
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	55,151	83,137	2,386
43		Total Allocated Operating Deductions		$ 222,074,648	$ 216,504	$ 721,466	$ 41,217
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	79,975	120,559	3,459
45		State South Georgia	1.1	29,686	49	75	2
46		Investment Tax Credit	1.1	(528,360)	(880)	(1,326)	(38)
47		Federal South Georgia	1.1	290,114	483	728	21

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 2,109,671	$ 3,180,240	$ 91,254
2		Systems Allocable Net Plant		34,448,206	57,354	86,458	2,481
3		Cash Working Capital	1.1	(10,379,937)	(8,955)	(35,426)	(2,155)
4		Materials & Supplies	1.1	12,389,898	20,628	31,096	892
5		Prepayments	1.1	3,671,971	6,114	9,216	264
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(237,473)	(357,980)	(10,272)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 1,947,339	$ 2,913,605	$ 82,465
12		Net Operating Margin	Direct	$ 381,188,845	$ 2,313,564	$ 245,955	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 35,105	$ 3,732	$ -
14		Late Charges	Direct	$ 2,430,203	$ 14,961	$ 1,590	
15		Service Establishment Charges	9	$ 8,267,657	-	6,097	-
16		Reconnect / Reread Charges	4	$ 569,215	-	252	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 8	$ 1	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 16	$ 2	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	135	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	77	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 3,111	$ 331	$ -
22		Total Revenue		399,234,678	2,366,765	258,173	-
23		O & M		(130,087,761)	(112,226)	(443,976)	(27,008)
24		A & G	Total O&M	(56,946,694)	(49,128)	(194,353)	(11,823)
25		Depreciation Expense		(87,887,713)	(146,327)	(220,581)	(6,329)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(55,151)	(83,137)	(2,386)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 2,003,933	$(683,875)	$(47,546)
29		Interest Expense	1.1	(48,035,008)	(79,975)	(120,559)	(3,459)
30		State Taxable Income		$ 41,237,309	$ 1,923,959	$(804,434)	$(51,005)
31		State Income Tax		2,873,416	134,061	(56,053)	(3,554)
32		South Georgia	1.1	29,686	49	75	2
33		State Income Tax		2,903,102	134,111	(55,978)	(3,552)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	2,003,933	(683,875)	(47,546)
35		Interest Expense	1.1	(48,035,008)	(79,975)	(120,559)	(3,459)
36		Federal Taxable Income		41,237,309	1,923,959	(804,434)	(51,005)
37		Federal Income Tax		$ 13,427,363	$ 626,464	$(261,933)	$(16,608)
38		I T C	1.1	(528,360)	(880)	(1,326)	(38)
39		South Georgia	1.1	290,114	483	728	21
40		Total Federal Income Tax		$ 13,189,117	$ 626,067	$(262,531)	$(16,625)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 1,243,755	$(365,365)	$(27,369)
43		Rate of Return on Rate Base		6.68%	63.87%	(12.54%)	(33.19%)
44		Rate of Return by Class Total				17.22%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 1,890	$ 24,964	$ 43
5	389-398	General	1.1	$ 4,919,293	$ 122	$ 1,618	$ 3
6		Total Direct Dep. Exp.		$ 80,829,317	$ 2,012	$ 26,582	$ 46
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 63	$ 835	$ 1
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	100	1,316	2
10		Structures-Leasehold Improvements	1.1	104,525	3	34	0
11		Total System Allocable Amortization		4,106,686	102	1,351	2
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	165	2,186	4
13		Total Depreciation Expense		87,476,255	2,178	28,768	49
14		Amortization	1.1	126,930	3	42	0
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(1)	(17)	(0)
16		Regulatory Amortizations	1.1	337,524	8	111	0
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 2,188	$ 28,903	$ 50
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--I	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	101
27		Materials & Expenses	3.0	59,983	-	-	9
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 110

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 127	$ 1,489	$ 16
3		Materials & Expenses	5.5	1,458,368	21	241	3
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	41
6		Materials & Expenses	3.0	113,250	-	-	18
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	181	2,470	0
9		Materials & Expenses	4.4	5,540,228	163	2,222	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	83	482	0
12		Materials & Expenses	2.2	697,287	31	181	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	-	-
15		Materials & Expenses	6.0	1,213,237	-	-	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	-	-
18		Materials & Expenses	6.0	1,490,584	-	-	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	93	1,083	12
21		Materials & Expenses	5.5	4,535,239	64	751	8
22	881	Rents	5.5	2,250,258	32	373	4
23		Total Distribution-Operations		$ 56,117,507	$ 795	$ 9,291	$ 101
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 74	$ 1,071	$ 0
26		Materials & Expenses	6.6	338,062	9	129	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	2	-	-
29		Materials & Expenses	1.0	80,753	6	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	378	2,203	0
32		Materials & Expenses	2.2	7,043,715	313	1,826	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	65	379	0
35		Materials & Expenses	2.2	580,480	26	150	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	4,182	-
38		Materials & Expenses	3.3	3,973,153	0	2,698	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	-	-
41		Materials & Expenses	6.0	781,684	-	-	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	5	75	0
44		Materials & Expenses	6.6	189,711	5	73	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 883	$ 12,786	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 1,678	$ 22,077	$ 101

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CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 312	$ -
3		Materials & Expenses	10.1	275,497	-	21	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	130	-
6		Materials & Expenses	13.0	2,194,002	-	59	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	11	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	429	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	199	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	1,764	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	31	-
16		Materials & Expenses	10.1	16,795	-	1	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 2,956	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 14	$ -
20		Materials & Expenses	13.0	564,797	-	15	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	1	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	1	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 30	$ -
		Sales Expense					
28	911	Supervision					
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-
31	912	Demonstrating & Selling Exp.					
32		Labor & Labor Loading	4.0	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-
34	913	Advertising Expense					
35		Labor & Labor Loading	4.0	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 130,087,761	$ 1,678	$ 25,063	$ 211
39		Allocation Percentage	Total O&M	100.00%	0.00%	0.02%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	735	10,972	93
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	825	10,894	19
43		Total Allocated Operating Deductions		$ 222,074,648	$ 3,237	$ 46,929	$ 323
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	1,196	15,797	27
45		State South Georgia	1.1	29,686	1	10	0
46		Investment Tax Credit	1.1	(528,360)	(13)	(174)	(0)
47		Federal South Georgia	1.1	290,114	7	95	0

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 31,543	$ 416,711	$ 714
2		Systems Allocable Net Plant		34,448,206	858	11,329	19
3		Cash Working Capital	1.1	(10,379,937)	(134)	(2,000)	(17)
4		Materials & Supplies	1.1	12,389,898	308	4,075	7
5		Prepayments	1.1	3,671,971	91	1,208	2
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(3,551)	(46,907)	(80)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 29,116	$ 384,416	$ 645
12		Net Operating Margin	Direct	$ 381,188,845	$ 55,850	$ -	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 847	$ -	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	8,141	-
16		Reconnect / Reread Charges	4	$ 569,215	-	337	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 0	$ -	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 0	$ -	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	181	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	103	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 75	$ -	$ -
22		Total Revenue		399,234,678	56,773	8,761	-
23		O & M		(130,087,761)	(1,678)	(25,063)	(211)
24		A & G	Total O&M	(56,946,694)	(735)	(10,972)	(93)
25		Depreciation Expense		(87,887,713)	(2,188)	(28,903)	(50)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(825)	(10,894)	(19)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 51,348	$(67,071)	$(372)
29		Interest Expense	1.1	(48,035,008)	(1,196)	(15,797)	(27)
30		State Taxable Income		$ 41,237,309	$ 50,153	$(82,868)	$(399)
31		State Income Tax		2,873,416	3,495	(5,774)	(28)
32		South Georgia	1.1	29,686	1	10	0
33		State Income Tax		2,903,102	3,495	(5,764)	(28)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	51,348	(67,071)	(372)
35		Interest Expense	1.1	(48,035,008)	(1,196)	(15,797)	(27)
36		Federal Taxable Income		41,237,309	50,153	(82,868)	(399)
37		Federal Income Tax		$ 13,427,363	$ 16,330	$(26,983)	$(130)
38		I T C	1.1	(528,360)	(13)	(174)	(0)
39		South Georgia	1.1	290,114	7	95	0
40		Total Federal Income Tax		$ 13,189,117	$ 16,324	$(27,061)	$(130)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 31,529	$(34,245)	$(214)
43		Rate of Return on Rate Base		6.68%	108.29%	(8.91%)	(33.19%)
44		Rate of Return by Class Total				(0.71%)	

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Net Plant in Service															
		Direct															
		Intangible															
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,833	$ 28,598	$ 1,222	$ -	$ -	$ -
2	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	365,144	813,693	34,773	-	-	-
3	303	Misc. Intangible	-	-	-	-	-	-	-	-	-	2,206	4,917	210	-	-	-
		Total Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 380,183	$ 847,207	$ 36,205	$ -	$ -	$ -
		Production															
4	326	Other Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	332	Field Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	334	Field Meas & Reg. Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	336	Purification Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8		Total Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transmission															
9	365	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	365	Rights of Way	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	366	Structures-Compressor Stas.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	366	Structures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	367	Mains	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	367	Mains-Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	368	Compressor Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	369	Measuring & Reg. Sta. Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	370	Communication Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	371	Other Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19		Total Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Distribution															
20	374.1	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,084,811	$ -	$ -	$ -	$ -	$ -
21	374.2	Rights of Way	-	-	-	-	-	-	-	-	-	739,109	-	-	-	-	-
22	375	Structures	-	-	-	-	-	-	-	-	-	46,534	-	-	-	-	-
23	376	Mains	-	-	-	-	-	-	-	-	-	353,902,646	275,401,498	1	-	-	-
24	378	Measuring & Reg. Station	-	-	-	-	-	-	-	-	-	-	-	29,625,773	-	-	-
25	380	Services	-	-	-	-	-	-	-	-	-	0	321,023,126	0	-	-	-
26	381	Meters	-	-	-	-	-	-	-	-	-	-	196,168,747	-	-	-	-
27	385	Industrial Meas. & Reg. Sta.	-	-	-	-	-	-	-	-	-	-	-	4,245,215	-	-	-
28	386	Other Prop. on Cust. Premises	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	387	Other Equipment	-	-	-	-	-	-	-	-	-	(97,479)	-	-	-	-	-
30		Total Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 355,675,621	$ 792,593,371	$ 33,870,989	$ -	$ -	$ -
31		Total Trans., Dist., Prod.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 355,675,621	$ 792,593,371	$ 33,870,989	$ -	$ -	$ -

SCHEDULE G-5
SHEET 1 OF 2

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		General															
1	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,532,886	$ 5,644,324	$ 241,207	$ -	$ -	$ -
2	390.1	Structures & Improvements	-	-	-	-	-	-	-	-	-	5,503,084	12,263,163	524,059	-	-	-
3	390.2	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	80,738	179,917	7,689	-	-	-
4	391.0	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	1,424,835	3,175,126	135,687	-	-	-
5	391.1	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	2,835,666	6,319,045	270,040	-	-	-
6	392.1	Transp. Equip.-Light	-	-	-	-	-	-	-	-	-	8,415,404	18,753,025	801,399	-	-	-
7	392.0	Transp. Equip.-Heavy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	393	Stores Equipment	-	-	-	-	-	-	-	-	-	155,241	345,942	14,784	-	-	-
9	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	2,605,465	5,806,061	248,118	-	-	-
10	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	165,997	369,910	15,808	-	-	-
11	396	Power Operated Equip.	-	-	-	-	-	-	-	-	-	1,028,022	2,290,861	97,899	-	-	-
12	397.1	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	10,546	23,501	1,004	-	-	-
13	397.2	Comm. Equip.-Telemetering	-	-	-	-	-	-	-	-	-	168,478	375,439	16,044	-	-	-
14	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	263,004	586,083	25,046	-	-	-
15		Total General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,189,366	$ 56,132,396	$ 2,398,783	$ -	$ -	$ -
		Systems Allocable															
		Intangible															
16	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,546	$ 23,500	$ 1,004	$ -	$ -	$ -
17	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	303	Miscellaneous Intang.	-	-	-	-	-	-	-	-	-	5,529,439	12,321,893	526,568	-	-	-
19		Total Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,539,985	$ 12,345,393	$ 527,573	$ -	$ -	$ -
		General															
20	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,755	$ 148,759	$ 6,357	$ -	$ -	$ -
21	390.10	Structures & Improvements	-	-	-	-	-	-	-	-	-	1,744,804	3,888,149	166,158	-	-	-
22	390.20	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	190,023	423,451	18,096	-	-	-
23	391.00	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	1,394,943	3,108,513	132,840	-	-	-
24	391.10	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	333,451	743,068	31,755	-	-	-
25	392.11	Transp. Equip.-Light	-	-	-	-	-	-	-	-	-	486,161	1,083,368	46,297	-	-	-
26	392.12	Transp. Equip.-Heavy	-	-	-	-	-	-	-	-	-	21,153	47,139	2,014	-	-	-
27	392.22	Aircraft-Left Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	392.23	Aircraft-Right Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	393	Stores Equipment	-	-	-	-	-	-	-	-	-	3,208	7,150	306	-	-	-
30	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	43,850	97,716	4,176	-	-	-
31	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	35,054	78,114	3,338	-	-	-
32	397.0	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	301,138	671,062	28,677	-	-	-
33	397.2	Telemetering Equipment	-	-	-	-	-	-	-	-	-	44,235	98,574	4,213	-	-	-
34	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	159,822	356,150	15,220	-	-	-
35		Total General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,824,597	$ 10,751,212	$ 459,446	$ -	$ -	$ -
36		Total Net Plant-Direct	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 381,245,171	$ 849,572,973	$ 36,305,977	$ -	$ -	$ -
37		Total Net Plant-Systems Alloc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,364,582	$ 23,096,605	$ 987,019	$ -	$ -	$ -
38		Total Net Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 391,609,753	$ 872,669,578	$ 37,292,996	$ -	$ -	$ -
39		Cash Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$(3,123,057)	$(6,959,471)	$(297,409)	$ -	$ -	$ -
40		Materials and Supplies	-	-	-	-	-	-	-	-	-	3,727,803	8,307,096	354,999	-	-	-
41		Prepayments	-	-	-	-	-	-	-	-	-	1,104,802	2,461,959	105,210	-	-	-
42		Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Customer Deposits	-	-	-	-	-	-	-	-	-	-	(31,921,898)	-	-	-	-
44		Customer Advances	-	-	-	-	-	-	-	-	-	-	(37,910,017)	-	-	-	-
45		Deferred Taxes	-	-	-	-	-	-	-	-	-	(42,914,402)	(95,631,156)	(4,086,738)	-	-	-
46		Deferred Gain Headquarters Bldg.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47		Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 350,404,898	$ 711,016,091	$ 33,369,058	$ -	$ -	$ -

SCHEDULE G-5
SHEET 2 OF 2

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Depreciation Expense & Amortizatic															
		Direct															
		Intangible															
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	303	Misc. Intangible	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4		Total Intangible Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Production															
5	326	Other Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	332	Field Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	334	Field Meas & Reg. Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	336	Purification Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Production Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transmission															
10	365	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	365	Rights of Way	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	366	Structures-Compressor Stas.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	366	Structures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	367	Mains	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	367	Mains-Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	368	Compressor Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	369	Measuring & Reg. Sta. Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	370	Communication Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	371	Other Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20		Total Transmission Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	#$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Distribution															
21	374	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	374.2	Rights of Way	-	-	-	-	-	-	-	-	-	23,051	-	-	-	-	-
23	375	Structures	-	-	-	-	-	-	-	-	-	431	-	-	-	-	-
24	376	Mains	-	-	-	-	-	-	-	-	-	21,156,166	16,463,397	0	-	-	-
25	378	Measuring & Reg. Station	-	-	-	-	-	-	-	-	-	-	-	1,349,469	-	-	-
26	380	Services	-	-	-	-	-	-	-	-	-	0	32,079,098	0	-	-	-
27	381	Meters	-	-	-	-	-	-	-	-	-	-	4,487,932	-	-	-	-
28	385	Industrial Meas. & Reg. Sta.	-	-	-	-	-	-	-	-	-	-	-	326,141	-	-	-
29	386	Other Prop. on Cust. Premises															
30	387	Other Equipment	-	-	-	-	-	-	-	-	-	24,340	-	-	-	-	-
31		Total Distribution Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,203,987	$ 53,030,427	$ 1,675,610	$ -	$ -	$ -

SCHEDULE G-6
SHEET 1 OF 7

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		General															
1	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	390.1	Structures & Improvements	-	-	-	-	-	-	-	-	-	144,450	321,894	13,756	-	-	-
3	390.2	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	391	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	46,455	103,521	4,424	-	-	-
5	391	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	383,125	853,763	36,485	-	-	-
6	392	Transp. Equip.	-	-	-	-	-	-	-	-	-	717,058	1,597,903	68,285	-	-	-
7	393	Stores Equipment	-	-	-	-	-	-	-	-	-	3,395	7,566	323	-	-	-
8	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	34,114	76,020	3,249	-	-	-
9	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	3,300	7,353	314	-	-	-
10	396	Power Operated Equip.	-	-	-	-	-	-	-	-	-	50,306	112,104	4,791	-	-	-
11	397.1	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	71,022	158,268	6,763	-	-	-
12	397.2	Comm. Equip.-Telemetering	-	-	-	-	-	-	-	-	-	14,701	32,761	1,400	-	-	-
13	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	12,162	27,103	1,158	-	-	-
14		Total General Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,480,089	$ 3,298,255	$ 140,949	$ -	$ -	$ -
		Systems Allocable															
		Intangible															
15	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	302	Franchise & Consent															
17	303	Miscellaneous Intang.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18		Total Intangible Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		General															
19	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	390.1	Structures	-	-	-	-	-	-	-	-	-	59,535	132,669	5,670	-	-	-
21	390.2	Structures - Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	391	Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	131,436	292,895	12,517	-	-	-
23	391.1	Computer Equipment	-	-	-	-	-	-	-	-	-	407,512	908,105	38,807	-	-	-
24	392.11	Transportation Equipment - Light	-	-	-	-	-	-	-	-	-	42,939	95,686	4,089	-	-	-
25	392.12	Transportation Equipment - Heavy	-	-	-	-	-	-	-	-	-	1,060	2,362	101	-	-	-
26	393	Stores Equipment	-	-	-	-	-	-	-	-	-	659	1,469	63	-	-	-
27	394	Tools, Shop, & Garage Equipment	-	-	-	-	-	-	-	-	-	4,419	9,847	421	-	-	-
28	395	Laboratory Equipment	-	-	-	-	-	-	-	-	-	2,287	5,097	218	-	-	-
29	396	Power Operated Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	397.1	Communication Equipment	-	-	-	-	-	-	-	-	-	78,064	173,958	7,434	-	-	-
31	397.2	Telemetering Equipment	-	-	-	-	-	-	-	-	-	19,694	43,887	1,875	-	-	-
32	398	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-	16,692	37,197	1,590	-	-	-
33		Total General Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 764,297	$ 1,703,171	$ 72,784	$ -	$ -	$ -
		System Allocable Amortization															
34		Miscellaneous Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,204,148	$ 2,683,342	$ 114,671	$ -	$ -	$ -
35		Structures-Leasehold Improvements	-	-	-	-	-	-	-	-	-	31,449	70,081	2,995	-	-	-
36		Total System Allocable Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,235,597	$ 2,753,424	$ 117,666	$ -	$ -	$ -
37		Total Depreciation Exp.-Direct	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,684,077	$ 56,328,681	$ 1,816,559	$ -	$ -	$ -
38		Total Dep. Exp.-Systems Alloc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,999,893	$ 4,456,595	$ 190,450	$ -	$ -	$ -
39		Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 35,622	$ 88,455	$ 2,853	$ -	$ -	$ -
40		Amortization-Gas Plant Acquisition	-	-	-	-	-	-	-	-	-	(14,873)	(36,932)	(1,191)	-	-	-
41		Regulatory Amortizations	-	-	-	-	-	-	-	-	-	94,723	235,215	7,586	-	-	-
42			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43												-	-	-			
44			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45		Total Depreciation Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,799,442	$ 61,072,015	$ 2,016,256	$ -	$ -	$ -

SCHEDULE G-6
SHEET 2 OF 7

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Operation and Maintenance Expense															
		Gas Supply Expense															
1	800	Natural Gas Wellhead Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purc	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	805.1	Purchased Gas Cost Adj.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	641,618	-	-	-
7		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	59,983	-	-	-
8		Total Gas Supply Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 701,601	$ -	$ -	$ -
		Transmission Expenses															
9	850	Operation Supervision & Engin.															
10		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch															
13		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.															
16		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station															
19		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel															
22	856	Mains Expense															
23		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.															
26		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.															
31		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains															
35		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.															
38		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.															
41		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SCHEDULE G-6
SHEET 3 OF 7

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Distribution Expenses															
1	870	Operation Supervision & Eng.															
2		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,262,981	$ 6,965,368	$ 762,557	$ -	$ -	$ -
3		Materials & Expenses	-	-	-	-	-	-	-	-	-	204,862	1,129,816	123,690	-	-	-
4	871	Distribution Load Dispatching															
5		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	129,269	-	129,269	-	-	-
6		Materials & Expenses	-	-	-	-	-	-	-	-	-	56,625	-	56,625	-	-	-
7	874	Mains & Svcs. Expense															
8		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	2,293,669	3,865,472	0	-	-	-
9		Materials & Expenses	-	-	-	-	-	-	-	-	-	2,063,185	3,477,043	0	-	-	-
10	875	Meas. & Reg. Sta. Exp.-Gen.															
11		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	1,859,618	-	-	-
12		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	697,287	-	-	-
13	878	Meter & House Reg. Exp.															
14		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	6,919,581	-	-	-	-
15		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	1,213,237	-	-	-	-
16	879	Customer Installation Exp.															
17		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	8,087,437	-	-	-	-
18		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	1,490,584	-	-	-	-
19	880	Other Expenses															
20		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	919,233	5,069,590	555,010		-	-
21		Materials & Expenses	-	-	-	-	-	-	-	-	-	637,079	3,513,506	384,653		-	-
22	881	Rents	-	-	-	-	-	-	-	-	-	316,101	1,743,303	190,854		-	-
23		Total Distribution-Operations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,883,005	$ 43,474,938	$ 4,759,564	$ -	$ -	$ -
24	885	Maint. Supervision & Eng.															
25		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 828,312	$ 1,778,379	$ 191,127	$ -	$ -	$ -
26		Materials & Expenses	-	-	-	-	-	-	-	-	-	100,085	214,883	23,094		-	-
27	886	Maint. of Structures & Imp.															
28		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	26,673	-	-		-	-
29		Materials & Expenses	-	-	-	-	-	-	-	-	-	80,753	-	-		-	-
30	887	Maint. of Mains															
31		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	4,780,163	3,719,848	0		-	-
32		Materials & Expenses	-	-	-	-	-	-	-	-	-	3,961,184	3,082,531	0		-	-
33	889	Maint. of Meas. & Reg. Sta-Gen															
34		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	1,461,314		-	-
35		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	580,480		-	-
36	892	Maint. of Services															
37		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	0	6,159,505	0		-	-
38		Materials & Expenses	-	-	-	-	-	-	-	-	-	0	3,973,153	0		-	-
39	893	Maint of Meter & House Reg.															
40		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	1,281,534	-		-	-
41		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	781,684	-		-	-
42	894	Maint of Other Equip.															
43		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	58,186	124,924	13,426		-	-
44		Materials & Expenses	-	-	-	-	-	-	-	-	-	56,165	120,586	12,960		-	-
45		Total Distribution-Maintenance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,891,521	$ 21,237,027	$ 2,282,401	$ -	$ -	$ -
46		Total Distribution O & M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,774,526	$ 64,711,965	$ 7,041,965	$ -	$ -	$ -

SCHEDULE G-6
SHEET 4 OF 7

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Customer Accounts Expenses															
1	901	Supervision															
2		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,093,979
3		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	275,497
4	902	Meter Reading Exp.															
5		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,860,483
6		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,194,002
7	903	Customer Records & Collections															
8		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	404,465
10	903	Customer Records & Collections - L															
11		Labor & Labor Loading - LCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,062,467
12		Materials & Expenses - LCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7,441,028
13	904	Uncollectible Accounts Exp.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,977,729
14	905	Misc. Customer Accounts Exp.															
15		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	404,465
16		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,795
17		Total Customer Accounts Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,730,909
		Customer Service & Info. Exp.															
18	908	Customer Assistance Exp.															
19		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 514,896
20		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	564,797
21	909	Info. & Instructional Exp.															
22		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25,125
24	910	Misc. C.S. & I. Expense															
25		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21,977
27		Total Customer Service & Info. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,126,796
		Sales Expense															
28	911	Supervision															
29		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	912	Demonstrating & Selling Exp.															
32		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	913	Advertising Expense															
35		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37		Total Sales Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Total O & M Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,774,526	$ 64,711,965	$ 7,743,566	$ -	$ -	$ 39,857,704

SCHEDULE G-6
SHEET 5 OF 7

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1		Administrative & General Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,780,905	$ 28,328,049	$ 3,389,792	$ -	$ -	$ 17,447,948
2		Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,915,314
3		Taxes other than Income	-	-	-	-	-	-	-	-	-	10,602,142	21,513,095	1,009,642	-	-	-
4		Interest Expense	-	-	-	-	-	-	-	-	-	15,374,365	31,196,542	1,464,101	-	-	-
5		South Georgia - State	-	-	-	-	-	-	-	-	-	9,501	19,280	905	-	-	-
6		Investment Tas Credit (I T C)	-	-	-	-	-	-	-	-	-	(169,110)	(343,146)	(16,104)	-	-	-
7		South Georgia - Federal	-	-	-	-	-	-	-	-	-	92,856	188,416	8,843	-	-	-
8		Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		SIT Rate															
10		FIT Rate															
		Rate Base															
11		Direct Net Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 381,245,171	$ 849,572,973	$ 36,305,977	$ -	$ -	$ -
12		Systems Allocable Net Plant	-	-	-	-	-	-	-	-	-	10,364,582	23,096,605	987,019	-	-	-
13		Cash Working Capital	-	-	-	-	-	-	-	-	-	(3,123,057)	(6,959,471)	(297,409)	-	-	-
14		Materials & Supplies	-	-	-	-	-	-	-	-	-	3,727,803	8,307,096	354,999	-	-	-
15		Prepayments	-	-	-	-	-	-	-	-	-	1,104,802	2,461,959	105,210	-	-	-
16		Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Customer Deposits	-	-	-	-	-	-	-	-	-	-	(31,921,898)	-	-	-	-
18		Customer Advances	-	-	-	-	-	-	-	-	-	-	(37,910,017)	-	-	-	-
19		Deferred Taxes	-	-	-	-	-	-	-	-	-	(42,914,402)	(95,631,156)	(4,086,738)	-	-	-
20		Deferred Gain Hdqtrs Bldg	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21		Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 350,404,898	$ 711,016,091	$ 33,369,058	$ -	$ -	$ -
22		Net Operating Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 122,005,529	$ 247,564,730	$ 11,618,586	$ -	$ -	$ -
23		Special Contract & Optional	-	-	-	-	-	-	-	-	-	1,851,270	3,756,462	176,296	-	-	-
24		Late Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,430,203
25		Service Establishment Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,267,657
26		Reconnect / Reread Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	569,215
27		Other Revenue - Labor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,313
28		Other Revenue - Parts & Material	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,621
29		Other Revenue - Field Collection Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	304,887
30		Other Revenue - Returned Item Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	173,412
31		Other Revenue - Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	512,498
32		Total Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 123,856,799	$ 251,321,192	$ 11,794,883	$ -	$ -	$ 12,261,805
		Operating Deductions															
33		O & M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$(17,774,526)	$(64,711,965)	$(7,743,566)	$ -	$ -	$(39,857,704)
34		A & G	-	-	-	-	-	-	-	-	-	(7,780,905)	(28,328,049)	(3,389,792)	-	-	(17,447,948)
35		Depreciation Expense	-	-	-	-	-	-	-	-	-	(24,799,442)	(61,072,015)	(2,016,256)	-	-	-
36		Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,915,314)
37		Taxes other than Income	-	-	-	-	-	-	-	-	-	(10,602,142)	(21,513,095)	(1,009,642)	-	-	-

SCHEDULE G-6
SHEET 6 OF 7

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		State Income Tax															
1		Taxable Income before Interest Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,899,783	$ 75,696,068	$(2,364,373)	$ -	$ -	$(46,959,161)
2		Interest Expense	-	-	-	-	-	-	-	-	-	(15,374,365)	(31,196,542)	(1,464,101)	-	-	-
3		State Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,525,418	$ 44,499,526	$(3,828,474)	$ -	$ -	$(46,959,161)
4		State Income Tax @ 6.9680%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,311,571	$ 3,100,727	$(266,768)	$ -	$ -	$(3,272,114)
5		South Georgia	-	-	-	-	-	-	-	-	-	9,501	19,280	905	-	-	-
6		State Income Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,321,073	$ 3,120,007	$(265,863)	$ -	$ -	$(3,272,114)
		Federal Income Tax															
7		Taxable Income before Interest Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,899,783	$ 75,696,068	$(2,364,373)	$ -	$ -	$(46,959,161)
8		Interest Expense	-	-	-	-	-	-	-	-	-	(15,374,365)	(31,196,542)	(1,464,101)	-	-	-
9		Federal Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,525,418	$ 44,499,526	$(3,828,474)	$ -	$ -	$(46,959,161)
10		Federal Income Tax @ 32.5612%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,474,846	$ 14,489,580	$(1,246,597)	$ -	$ -	$(15,290,466)
11		I T C	-	-	-	-	-	-	-	-	-	(169,110)	(343,146)	(16,104)	-	-	-
12		South Georgia	-	-	-	-	-	-	-	-	-	92,856	188,416	8,843	-	-	-
13		Total Federal Income Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,398,592	$ 14,334,850	$(1,253,859)	$ -	$ -	$(15,290,466)
14		Regulatory Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15		Net Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,180,118	$ 58,241,212	$(844,651)	$ -	$ -	$(28,396,580)

SCHEDULE G-6
SHEET 7 OF 7

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Residential Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
1	CP Monthly Demand		118,455,410	69,979,561		
		1	100.0000%	59.076712%	0.000000%	0.000000%
2	NCP Demand		121,419,774	69,979,561		
		2	100.0000%	57.634402%	0.000000%	0.000000%
3	Throughput		651,784,739	0		297,856,607
		3	100.0000%	0.000000%	0.000000%	45.698616%
4	Customers		959,083		884,186	
		4	100.0000%	0.000000%	92.190770%	0.000000%
5	Customers With Mains		959,083	0	884,186	0
		5	100.0000%	0.000000%	92.190770%	0.000000%
6	Meters for Customers		1,122,135		884,186	
		6	100.0000%	0.000000%	78.794942%	0.000000%
7	Service Lines for Customers		1,072,625		884,186	
		7	100.0000%	0.000000%	82.431945%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479	0	884,186	0
		8	100.0000%	0.000000%	93.025331%	0.000000%
9	Service Establishment Charges		34,611,268	0	30,946,510	0
		9	100.0000%	0.000000%	89.411663%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	866,940	0
		13	100.0000%	0.000000%	85.777111%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	219,964,047	685,044,030	1,940,005
		1.1	100.0000%	18.607276%	57.949485%	0.164110%
17	Distribution Mains		629,304,144	209,074,046	253,894,761	0
		2.2	100.0000%	33.223052%	40.345318%	0.000000%
18	Distribution Services		321,023,126	0	264,625,607	0
		3.3	100.0000%	0.000000%	82.431945%	0.000000%
19	Distribution Mains & Services		950,327,271	209,074,046	518,520,368	0
		4.4	100.0000%	22.000215%	54.562295%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	3,423,368	21,370,282	169,902
		5.5	100.0000%	10.585914%	66.082273%	0.525379%
21	Allocable Distribution Maintenance Expenses		29,888,822	5,905,911	17,073,192	0
		6.6	100.0000%	19.759597%	57.122332%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	29,303,882	0
		10.1	100.0000%	0.000000%	86.339812%	0.000000%
26	Total O & M Expense		130,087,761	12,542,420	90,575,563	615,452
		11.2	100.0000%	9.641506%	69.626507%	0.473105%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(g)	(h)	(i)
1	CP Monthly Demand		118,455,410	1,309,479		
		1	100.0000%	1.105462%	0.000000%	0.000000%
2	NCP Demand		121,419,774	1,309,479		
		2	100.0000%	1.078473%	0.000000%	0.000000%
3	Throughput		651,784,739	0		7,060,702
		3	100.0000%	0.000000%	0.000000%	1.083287%
4	Customers		959,083		33,163	
		4	100.0000%	0.000000%	3.457730%	0.000000%
5	Customers With Mains		959,083	0	33,163	0
		5	100.0000%	0.000000%	3.457730%	0.000000%
6	Meters for Customers		1,122,135		30,927	
		6	100.0000%	0.000000%	2.756100%	0.000000%
7	Service Lines for Customers		1,072,625		16,409	
		7	100.0000%	0.000000%	1.529804%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479	0	33,163	0
		8	100.0000%	0.000000%	3.489031%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,160,688	0
		9	100.0000%	0.000000%	3.353496%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	11,458	0
		13	100.0000%	0.000000%	1.133719%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	4,116,035	20,288,568	45,988
		1.1	100.0000%	0.348185%	1.716258%	0.003890%
17	Distribution Mains		629,304,144	3,912,258	9,522,640	0
		2.2	100.0000%	0.621680%	1.513202%	0.000000%
18	Distribution Services		321,023,126	0	4,911,024	0
		3.3	100.0000%	0.000000%	1.529804%	0.000000%
19	Distribution Mains & Services		950,327,271	3,912,258	14,433,664	0
		4.4	100.0000%	0.411675%	1.518810%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	64,059	704,511	4,028
		5.5	100.0000%	0.198087%	2.178524%	0.012454%
21	Allocable Distribution Maintenance Expenses		29,888,822	110,513	477,978	0
		6.6	100.0000%	0.369748%	1.599188%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	453,989	0
		10.1	100.0000%	0.000000%	1.337616%	0.000000%
26	Total O & M Expense		130,087,761	234,698	2,287,683	14,589
		11.2	100.0000%	0.180415%	1.758569%	0.011215%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(j)	(k)	(l)
1	CP Monthly Demand		118,455,410	492,482		
		1	100.0000%	0.415753%	0.000000%	0.000000%
2	NCP Demand		121,419,774	492,482		
		2	100.0000%	0.405603%	0.000000%	0.000000%
3	Throughput		651,784,739			2,223,993
		3	100.0000%	0.000000%	0.000000%	0.341216%
4	Customers		959,083		164	
		4	100.0000%	0.000000%	0.017100%	0.000000%
5	Customers With Mains		959,083	0	164	0
		5	100.0000%	0.000000%	0.017100%	0.000000%
6	Meters for Customers		1,122,135		525	
		6	100.0000%	0.000000%	0.046771%	0.000000%
7	Service Lines for Customers		1,072,625		859	
		7	100.0000%	0.000000%	0.080050%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479	0	164	0
		8	100.0000%	0.000000%	0.017254%	0.000000%
9	Service Establishment Charges		34,611,268	0	9,840	0
		9	100.0000%	0.000000%	0.028430%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	513	0
		13	100.0000%	0.000000%	0.050783%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	1,548,000	398,038	14,485
		1.1	100.0000%	0.130949%	0.033671%	0.001225%
17	Distribution Mains		629,304,144	1,471,361	47,093	0
		2.2	100.0000%	0.233808%	0.007483%	0.000000%
18	Distribution Services		321,023,126	0	256,978	0
		3.3	100.0000%	0.000000%	0.080050%	0.000000%
19	Distribution Mains & Services		950,327,271	1,471,361	304,071	0
		4.4	100.0000%	0.154827%	0.031996%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	24,092	12,218	1,269
		5.5	100.0000%	0.074498%	0.037782%	0.003923%
21	Allocable Distribution Maintenance Expenses		29,888,822	41,563	10,392	0
		6.6	100.0000%	0.139058%	0.034769%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	16,233	0
		10.1	100.0000%	0.000000%	0.047828%	0.000000%
26	Total O & M Expense		130,087,761	88,267	51,915	4,595
		11.2	100.0000%	0.067852%	0.039908%	0.003533%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Small General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(m)	(n)	(o)
1	CP Monthly Demand		118,455,410	1,368,526		
		1	100.0000%	1.155309%	0.000000%	0.000000%
2	NCP Demand		121,419,774	1,368,526		
		2	100.0000%	1.127103%	0.000000%	0.000000%
3	Throughput		651,784,739			5,020,754
		3	100.0000%	0.000000%	0.000000%	0.770309%
4	Customers		959,083		16,817	
		4	100.0000%	0.000000%	1.753454%	0.000000%
5	Customers With Mains		959,083	0	16,817	0
		5	100.0000%	0.000000%	1.753454%	0.000000%
6	Meters for Customers		1,122,135		26,865	
		6	100.0000%	0.000000%	2.394098%	0.000000%
7	Service Lines for Customers		1,072,625		20,162	
		7	100.0000%	0.000000%	1.879671%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479	0	16,817	0
		8	100.0000%	0.000000%	1.769328%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,009,025	0
		9	100.0000%	0.000000%	2.915308%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	36,758	0
		13	100.0000%	0.000000%	3.636912%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	4,301,635	15,787,025	32,701
		1.1	100.0000%	0.363885%	1.335462%	0.002766%
17	Distribution Mains		629,304,144	4,088,669	4,829,040	0
		2.2	100.0000%	0.649713%	0.767362%	0.000000%
18	Distribution Services		321,023,126	0	6,034,177	0
		3.3	100.0000%	0.000000%	1.879671%	0.000000%
19	Distribution Mains & Services		950,327,271	4,088,669	10,863,217	0
		4.4	100.0000%	0.430238%	1.143103%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	66,948	577,371	2,864
		5.5	100.0000%	0.207019%	1.785377%	0.008856%
21	Allocable Distribution Maintenance Expenses		29,888,822	115,496	374,801	0
		6.6	100.0000%	0.386420%	1.253982%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	1,178,290	0
		10.1	100.0000%	0.000000%	3.471667%	0.000000%
26	Total O & M Expense		130,087,761	245,281	2,806,465	10,374
		11.2	100.0000%	0.188550%	2.157363%	0.007975%

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Line No.	Description	Allocation Factor No.	Total	Medium General Gas Service		
				Demand	Customer	Commodity
	(a)	(b)	(c)	(c)	(d)	(e)
1	CP Monthly Demand		118,455,410	7,463,908		
		1	100.0000%	6.301028%	0.000000%	0.000000%
2	NCP Demand		121,419,774	7,463,908		
		2	100.0000%	6.147193%	0.000000%	0.000000%
3	Throughput		651,784,739			45,530,269
		3	100.0000%	0.000000%	0.000000%	6.985476%
4	Customers		959,083		16,149	
		4	100.0000%	0.000000%	1.683813%	0.000000%
5	Customers With Mains		959,083	0	16,149	0
		5	100.0000%	0.000000%	1.683813%	0.000000%
6	Meters for Customers		1,122,135		68,972	
		6	100.0000%	0.000000%	6.146470%	0.000000%
7	Service Lines for Customers		1,072,625		80,505	
		7	100.0000%	0.000000%	7.505421%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479	0	16,149	
		8	100.0000%	0.000000%	1.699056%	0.000000%
9	Service Establishment Charges		34,611,268	0	968,950	0
		9	100.0000%	0.000000%	2.799522%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	57,875	0
		13	100.0000%	0.000000%	5.726294%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	23,461,013	41,007,147	296,549
		1.1	100.0000%	1.984622%	3.468891%	0.025086%
17	Distribution Mains		629,304,144	22,299,503	4,637,247	0
		2.2	100.0000%	3.543518%	0.736885%	0.000000%
18	Distribution Services		321,023,126	0	24,094,138	0
		3.3	100.0000%	0.000000%	7.505421%	0.000000%
19	Distribution Mains & Services		950,327,271	22,299,503	28,731,385	0
		4.4	100.0000%	2.346508%	3.023315%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	365,131	1,461,142	25,971
		5.5	100.0000%	1.129077%	4.518217%	0.080309%
21	Allocable Distribution Maintenance Expenses		29,888,822	629,915	1,016,899	0
		6.6	100.0000%	2.107527%	3.402271%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	1,823,140	0
		10.1	100.0000%	0.000000%	5.371628%	0.000000%
26	Total O & M Expense		130,087,761	1,337,754	5,817,246	94,078
		11.2	100.0000%	1.028348%	4.471785%	0.072319%

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Line No.	Description	Allocation Factor No.	Total	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(f)	(g)	(h)
1	CP Monthly Demand		118,455,410	20,388,726		
		1	100.0000%	17.212153%	0.000000%	0.000000%
2	NCP Demand		121,419,774	20,388,726		
		2	100.0000%	16.791932%	0.000000%	0.000000%
3	Throughput		651,784,739			149,222,854
		3	100.0000%	0.000000%	0.000000%	22.894499%
4	Customers		959,083		7,126	
		4	100.0000%	0.000000%	0.742984%	0.000000%
5	Customers With Mains		959,083	0	7,126	0
		5	100.0000%	0.000000%	0.742984%	0.000000%
6	Meters for Customers		1,122,135		79,618	
		6	100.0000%	0.000000%	7.095204%	0.000000%
7	Service Lines for Customers		1,072,625		60,714	
		7	100.0000%	0.000000%	5.660279%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	427,550	0
		9	100.0000%	0.000000%	1.235291%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	7,126	0
		12	100.0000%	0.000000%	97.467287%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	31,085	0
		13	100.0000%	0.000000%	3.075614%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	64,087,094	34,231,895	971,921
		1.1	100.0000%	5.421278%	2.895756%	0.082217%
17	Distribution Mains		629,304,144	60,914,264	2,046,189	0
		2.2	100.0000%	9.679622%	0.325151%	0.000000%
18	Distribution Services		321,023,126	0	18,170,806	0
		3.3	100.0000%	0.000000%	5.660279%	0.000000%
19	Distribution Mains & Services		950,327,271	60,914,264	20,216,995	0
		4.4	100.0000%	6.409820%	2.127372%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	997,407	1,513,823	85,119
		5.5	100.0000%	3.084233%	4.681121%	0.263209%
21	Allocable Distribution Maintenance Expenses		29,888,822	1,720,702	777,106	0
		6.6	100.0000%	5.757010%	2.599988%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	974,409	0
		10.1	100.0000%	0.000000%	2.870961%	0.000000%
26	Total O & M Expense		130,087,761	3,654,266	4,642,214	308,335
		11.2	100.0000%	2.809078%	3.568525%	0.237020%

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Line No.	Description	Allocation Factor No.	Total	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(i)	(j)	(k)
1	CP Monthly Demand		118,455,410	14,014,497		
		1	100.0000%	11.831032%	0.000000%	0.000000%
2	NCP Demand		121,419,774	14,014,497		
		2	100.0000%	11.542187%	0.000000%	0.000000%
3	Throughput		651,784,739			99,526,400
		3	100.0000%	0.000000%	0.000000%	15.269827%
4	Customers		959,083		185	
		4	100.0000%	0.000000%	0.019307%	0.000000%
5	Customers With Mains		959,083	0	185	0
		5	100.0000%	0.000000%	0.019307%	0.000000%
6	Meters for Customers		1,122,135		17,179	
		6	100.0000%	0.000000%	1.530930%	0.000000%
7	Service Lines for Customers		1,072,625		3,673	
		7	100.0000%	0.000000%	0.342431%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	11,110	0
		9	100.0000%	0.000000%	0.032099%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	185	0
		12	100.0000%	0.000000%	2.532713%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	1,363	0
		13	100.0000%	0.000000%	0.134854%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	44,051,226	4,158,161	648,237
		1.1	100.0000%	3.726397%	0.351749%	0.054836%
17	Distribution Mains		629,304,144	41,870,334	53,171	0
		2.2	100.0000%	6.653434%	0.008449%	0.000000%
18	Distribution Services		321,023,126	0	1,099,282	0
		3.3	100.0000%	0.000000%	0.342431%	0.000000%
19	Distribution Mains & Services		950,327,271	41,870,334	1,152,452	0
		4.4	100.0000%	4.405886%	0.121269%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	685,583	285,544	56,771
		5.5	100.0000%	2.119994%	0.882975%	0.175551%
21	Allocable Distribution Maintenance Expenses		29,888,822	1,182,751	67,770	0
		6.6	100.0000%	3.957167%	0.226739%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	42,329	0
		10.1	100.0000%	0.000000%	0.124716%	0.000000%
26	Total O & M Expense		130,087,761	2,511,815	621,082	205,648
		11.2	100.0000%	1.930862%	0.477433%	0.158084%

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Line No.	Description	Allocation Factor No.	Total	Air-Conditioning Gas Service		
				Demand	Customer	Commodity
	(a)	(b)	(c)	(c)	(d)	(e)
1	CP Monthly Demand		118,455,410	50,328		
		1	100.0000%	0.042487%	0.000000%	0.000000%
2	NCP Demand		121,419,774	175,550		
		2	100.0000%	0.144581%	0.000000%	0.000000%
3	Throughput		651,784,739			1,118,252
		3	100.0000%	0.000000%	0.000000%	0.171568%
4	Customers		959,083		27	
		4	100.0000%	0.000000%	0.002763%	0.000000%
5	Customers With Mains		959,083	0	27	0
		5	100.0000%	0.000000%	0.002763%	0.000000%
6	Meters for Customers		1,122,135		49	
		6	100.0000%	0.000000%	0.004335%	0.000000%
7	Service Lines for Customers		1,072,625		37	
		7	100.0000%	0.000000%	0.003436%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,590	0
		9	100.0000%	0.000000%	0.004594%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	25	0
		13	100.0000%	0.000000%	0.002424%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	158,194	27,502	7,283
		1.1	100.0000%	0.013382%	0.002326%	0.000616%
17	Distribution Mains		629,304,144	150,362	7,609	0
		2.2	100.0000%	0.023893%	0.001209%	0.000000%
18	Distribution Services		321,023,126	0	11,030	0
		3.3	100.0000%	0.000000%	0.003436%	0.000000%
19	Distribution Mains & Services		950,327,271	150,362	18,639	0
		4.4	100.0000%	0.015822%	0.001961%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	2,462	1,028	638
		5.5	100.0000%	0.007613%	0.003180%	0.001972%
21	Allocable Distribution Maintenance Expenses		29,888,822	4,247	650	0
		6.6	100.0000%	0.014211%	0.002176%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	833	0
		10.1	100.0000%	0.000000%	0.002454%	0.000000%
26	Total O & M Expense		130,087,761	9,020	3,489	2,311
		11.2	100.0000%	0.006934%	0.002682%	0.001776%

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Line No.	Description	Allocation Factor No.	Total	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(f)	(g)	(h)
1	CP Monthly Demand		118,455,410	12,889		
		1	100.0000%	0.010881%	0.000000%	0.000000%
2	NCP Demand		121,419,774	18,345		
		2	100.0000%	0.015109%	0.000000%	0.000000%
3	Throughput		651,784,739			177,495
		3	100.0000%	0.000000%	0.000000%	0.027232%
4	Customers		959,083		21	
		4	100.0000%	0.000000%	0.002190%	0.000000%
5	Customers With Mains		959,083	0	21	0
		5	100.0000%	0.000000%	0.002190%	0.000000%
6	Meters for Customers		1,122,135		23	
		6	100.0000%	0.000000%	0.002043%	0.000000%
7	Service Lines for Customers		1,072,625		36	
		7	100.0000%	0.000000%	0.003379%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,260	0
		9	100.0000%	0.000000%	0.003640%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	71	0
		13	100.0000%	0.000000%	0.007023%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	40,513	21,169	1,156
		1.1	100.0000%	0.003427%	0.001791%	0.000098%
17	Distribution Mains		629,304,144	38,508	6,030	0
		2.2	100.0000%	0.006119%	0.000958%	0.000000%
18	Distribution Services		321,023,126	0	10,847	0
		3.3	100.0000%	0.000000%	0.003379%	0.000000%
19	Distribution Mains & Services		950,327,271	38,508	16,877	0
		4.4	100.0000%	0.004052%	0.001776%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	631	594	101
		5.5	100.0000%	0.001950%	0.001837%	0.000313%
21	Allocable Distribution Maintenance Expenses		29,888,822	1,088	553	0
		6.6	100.0000%	0.003639%	0.001850%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	2,240	0
		10.1	100.0000%	0.000000%	0.006599%	0.000000%
26	Total O & M Expense		130,087,761	2,310	4,284	367
		11.2	100.0000%	0.001776%	0.003293%	0.000282%

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Line No.	Description	Allocation Factor No.	Total	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(i)	(j)	(k)
1	CP Monthly Demand		118,455,410	151,064		
		1	100.0000%	0.127528%	0.000000%	0.000000%
2	NCP Demand		121,419,774	202,347		
		2	100.0000%	0.166651%	0.000000%	0.000000%
3	Throughput		651,784,739			2,060,152
		3	100.0000%	0.000000%	0.000000%	0.316079%
4	Customers		959,083		24	
		4	100.0000%	0.000000%	0.002502%	0.000000%
5	Customers With Mains		959,083	0	24	0
		5	100.0000%	0.000000%	0.002502%	0.000000%
6	Meters for Customers		1,122,135		702	
		6	100.0000%	0.000000%	0.062524%	0.000000%
7	Service Lines for Customers		1,072,625		295	
		7	100.0000%	0.000000%	0.027503%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,440	0
		9	100.0000%	0.000000%	0.004160%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	162	0
		13	100.0000%	0.000000%	0.016052%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	474,834	218,161	13,418
		1.1	100.0000%	0.040167%	0.018455%	0.001135%
17	Distribution Mains		629,304,144	451,326	6,892	0
		2.2	100.0000%	0.071718%	0.001095%	0.000000%
18	Distribution Services		321,023,126	0	88,292	0
		3.3	100.0000%	0.000000%	0.027503%	0.000000%
19	Distribution Mains & Services		950,327,271	451,326	95,184	0
		4.4	100.0000%	0.047492%	0.010016%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	7,390	12,273	1,175
		5.5	100.0000%	0.022852%	0.037952%	0.003634%
21	Allocable Distribution Maintenance Expenses		29,888,822	12,749	4,269	0
		6.6	100.0000%	0.042655%	0.014284%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	5,045	0
		10.1	100.0000%	0.000000%	0.014864%	0.000000%
26	Total O & M Expense		130,087,761	27,075	32,008	4,257
		11.2	100.0000%	0.020813%	0.024605%	0.003272%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(l)	(m)	(n)
1	CP Monthly Demand		118,455,410	5,981		
		1	100.0000%	0.005049%	0.000000%	0.000000%
2	NCP Demand		121,419,774	6,936		
		2	100.0000%	0.005712%	0.000000%	0.000000%
3	Throughput		651,784,739			77,361
		3	100.0000%	0.000000%	0.000000%	0.011869%
4	Customers		959,083		106	
		4	100.0000%	0.000000%	0.011052%	0.000000%
5	Customers With Mains		959,083	0	106	0
		5	100.0000%	0.000000%	0.011052%	0.000000%
6	Meters for Customers		1,122,135		88	
		6	100.0000%	0.000000%	0.007882%	0.000000%
7	Service Lines for Customers		1,072,625		106	
		7	100.0000%	0.000000%	0.009872%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	6,360	0
		9	100.0000%	0.000000%	0.018376%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	106	0
		13	100.0000%	0.000000%	0.010488%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	18,800	79,023	504
		1.1	100.0000%	0.001590%	0.006685%	0.000043%
17	Distribution Mains		629,304,144	17,869	30,438	0
		2.2	100.0000%	0.002840%	0.004837%	0.000000%
18	Distribution Services		321,023,126	0	31,691	0
		3.3	100.0000%	0.000000%	0.009872%	0.000000%
19	Distribution Mains & Services		950,327,271	17,869	62,129	0
		4.4	100.0000%	0.001880%	0.006538%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	293	2,284	44
		5.5	100.0000%	0.000905%	0.007064%	0.000136%
21	Allocable Distribution Maintenance Expenses		29,888,822	505	2,013	0
		6.6	100.0000%	0.001689%	0.006737%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	3,576	0
		10.1	100.0000%	0.000000%	0.010537%	0.000000%
26	Total O & M Expense		130,087,761	1,072	10,414	160
		11.2	100.0000%	0.000824%	0.008006%	0.000123%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(c)	(d)	(e)
1	CP Monthly Demand		118,455,410	1,262,860		
		1	100.0000%	1.066106%	0.000000%	0.000000%
2	NCP Demand		121,419,774	2,613,148		
		2	100.0000%	2.152160%	0.000000%	0.000000%
3	Throughput		651,784,739			21,521,946
		3	100.0000%	0.000000%	0.000000%	3.302002%
4	Customers		959,083		21	
		4	100.0000%	0.000000%	0.002190%	0.000000%
5	Customers With Mains		959,083	0	21	0
		5	100.0000%	0.000000%	0.002190%	0.000000%
6	Meters for Customers		1,122,135		973	
		6	100.0000%	0.000000%	0.086677%	0.000000%
7	Service Lines for Customers		1,072,625		167	
		7	100.0000%	0.000000%	0.015541%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,260	0
		9	100.0000%	0.000000%	0.003640%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	142	0
		13	100.0000%	0.000000%	0.014046%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	3,969,499	226,236	140,177
		1.1	100.0000%	0.335789%	0.019138%	0.011858%
17	Distribution Mains		629,304,144	3,772,977	6,030	0
		2.2	100.0000%	0.599547%	0.000958%	0.000000%
18	Distribution Services		321,023,126	0	49,890	0
		3.3	100.0000%	0.000000%	0.015541%	0.000000%
19	Distribution Mains & Services		950,327,271	3,772,977	55,920	0
		4.4	100.0000%	0.397019%	0.005884%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	61,779	16,064	12,276
		5.5	100.0000%	0.191035%	0.049674%	0.037962%
21	Allocable Distribution Maintenance Expenses		29,888,822	106,579	3,532	0
		6.6	100.0000%	0.356584%	0.011816%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	4,414	0
		10.1	100.0000%	0.000000%	0.013006%	0.000000%
26	Total O & M Expense		130,087,761	226,342	37,019	44,470
		11.2	100.0000%	0.173992%	0.028457%	0.034185%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(f)	(g)	(h)
1	CP Monthly Demand		118,455,410	1,319,589		
		1	100.0000%	1.113996%	0.000000%	0.000000%
2	NCP Demand		121,419,774	1,466,488		
		2	100.0000%	1.207784%	0.000000%	0.000000%
3	Throughput		651,784,739			7,214,684
		3	100.0000%	0.000000%	0.000000%	1.106912%
4	Customers		959,083		101	
		4	100.0000%	0.000000%	0.010566%	0.000000%
5	Customers With Mains		959,083	0	101	0
		5	100.0000%	0.000000%	0.010566%	0.000000%
6	Meters for Customers		1,122,135		2,271	
		6	100.0000%	0.000000%	0.202357%	0.000000%
7	Service Lines for Customers		1,072,625		963	
		7	100.0000%	0.000000%	0.089826%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	6,080	0
		9	100.0000%	0.000000%	0.017567%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	1,845	0
		13	100.0000%	0.000000%	0.182541%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	4,147,813	715,791	46,991
		1.1	100.0000%	0.350873%	0.060550%	0.003975%
17	Distribution Mains		629,304,144	3,942,463	29,098	0
		2.2	100.0000%	0.626480%	0.004624%	0.000000%
18	Distribution Services		321,023,126	0	288,362	0
		3.3	100.0000%	0.000000%	0.089826%	0.000000%
19	Distribution Mains & Services		950,327,271	3,942,463	317,460	0
		4.4	100.0000%	0.414853%	0.033405%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	64,554	39,866	4,115
		5.5	100.0000%	0.199616%	0.123274%	0.012726%
21	Allocable Distribution Maintenance Expenses		29,888,822	111,366	14,090	0
		6.6	100.0000%	0.372602%	0.047141%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	56,834	0
		10.1	100.0000%	0.000000%	0.167452%	0.000000%
26	Total O & M Expense		130,087,761	236,510	151,841	14,907
		11.2	100.0000%	0.181808%	0.116722%	0.011460%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Natural Gas Engine Gas Service		
				Demand	Customer	Commodity
	(a)	(b)	(c)	(i)	(j)	(k)
1	CP Monthly Demand		118,455,410	626,158		
		1	100.0000%	0.528602%	0.000000%	0.000000%
2	NCP Demand		121,419,774	1,910,419		
		2	100.0000%	1.573400%	0.000000%	0.000000%
3	Throughput		651,784,739			13,070,981
		3	100.0000%	0.000000%	0.000000%	2.005414%
4	Customers		959,083		425	
		4	100.0000%	0.000000%	0.044357%	0.000000%
5	Customers With Mains		959,083	0	425	0
		5	100.0000%	0.000000%	0.044357%	0.000000%
6	Meters for Customers		1,122,135		9,759	
		6	100.0000%	0.000000%	0.869669%	0.000000%
7	Service Lines for Customers		1,072,625		3,786	
		7	100.0000%	0.000000%	0.352940%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	25,525	0
		9	100.0000%	0.000000%	0.073748%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	2,319	0
		13	100.0000%	0.000000%	0.229468%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	1,968,178	2,966,946	85,134
		1.1	100.0000%	0.166493%	0.250981%	0.007202%
17	Distribution Mains		629,304,144	1,870,737	122,159	0
		2.2	100.0000%	0.297271%	0.019412%	0.000000%
18	Distribution Services		321,023,126	0	1,133,019	0
		3.3	100.0000%	0.000000%	0.352940%	0.000000%
19	Distribution Mains & Services		950,327,271	1,870,737	1,255,178	0
		4.4	100.0000%	0.196852%	0.132078%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	30,631	169,974	7,456
		5.5	100.0000%	0.094720%	0.525603%	0.023055%
21	Allocable Distribution Maintenance Expenses		29,888,822	52,844	57,119	0
		6.6	100.0000%	0.176803%	0.191105%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	72,370	0
		10.1	100.0000%	0.000000%	0.213227%	0.000000%
26	Total O & M Expense		130,087,761	112,226	443,976	27,008
		11.2	100.0000%	0.086270%	0.341289%	0.020761%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Street Lighting Gas Service		
				Demand	Customer	Commodity
	(a)	(b)	(c)	(l)	(m)	(n)
1	CP Monthly Demand		118,455,410	9,362		
		1	100.0000%	0.007903%	0.000000%	0.000000%
2	NCP Demand		121,419,774	9,362		
		2	100.0000%	0.007710%	0.000000%	0.000000%
3	Throughput		651,784,739			102,289
		3	100.0000%	0.000000%	0.000000%	0.015694%
4	Customers		959,083		568	
		4	100.0000%	0.000000%	0.059223%	0.000000%
5	Customers With Mains		959,083	0	568	0
		5	100.0000%	0.000000%	0.059223%	0.000000%
6	Meters for Customers		1,122,135		0	
		6	100.0000%	0.000000%	0.000000%	0.000000%
7	Service Lines for Customers		1,072,625		728	
		7	100.0000%	0.000000%	0.067903%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	34,080	0
		9	100.0000%	0.000000%	0.098465%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	27	0
		13	100.0000%	0.000000%	0.002671%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	29,427	388,763	666
		1.1	100.0000%	0.002489%	0.032886%	0.000056%
17	Distribution Mains		629,304,144	27,970	163,102	0
		2.2	100.0000%	0.004445%	0.025918%	0.000000%
18	Distribution Services		321,023,126	0	217,983	0
		3.3	100.0000%	0.000000%	0.067903%	0.000000%
19	Distribution Mains & Services		950,327,271	27,970	381,085	0
		4.4	100.0000%	0.002943%	0.040100%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	458	5,354	58
		5.5	100.0000%	0.001416%	0.016556%	0.000180%
21	Allocable Distribution Maintenance Expenses		29,888,822	790	11,438	0
		6.6	100.0000%	0.002643%	0.038269%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	2,591	0
		10.1	100.0000%	0.000000%	0.007633%	0.000000%
26	Total O & M Expense		130,087,761	1,678	25,063	211
		11.2	100.0000%	0.001290%	0.019267%	0.000162%

Volume II

Supporting Schedules

H

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Revenues		Increase/(Decrease)		Line No.
			Present Rates [1]	Proposed Rates [2]	Dollars	Percent	
	(a)	(b)	(c)	(d)	(e)	(f)	
	Sales Service						
1	Residential Gas Service	G-5	$ 522,983,992	$ 562,696,282	$ 39,712,290	7.59%	1
2	Multi-Family Residential Gas Service	G-6	12,732,540	12,925,127	192,587	1.51%	2
3	Low Income Residential Gas Service	G-10	13,827,935	14,205,326	377,391	2.73%	3
4	Low Income Multi-Family Residential	G-11	932,166	963,216	31,050	3.33%	4
5	Special Residential Gas Service	G-15	201,538	226,215	24,677	12.24%	5
6	Master Metered Mobile Home Park Gas Service	G-20	3,055,730	3,125,364	69,634	2.28%	6
	General Gas Service	G-25					
7	Small		12,523,176	13,509,001	985,825	7.87%	7
8	Medium		66,520,230	69,301,266	2,781,036	4.18%	8
9	Large		191,013,943	194,731,910	3,717,967	1.95%	9
10	Transporation Eligible		108,820,468	110,552,881	1,732,413	1.59%	10
11	Optional Gas Service	G-30	43,678,213	43,678,213	0	0.00%	11
12	Air Conditioning Gas Service	G-40	1,119,715	1,126,427	6,712	0.60%	12
13	Street Lighting Gas Service	G-45	150,721	166,370	15,649	10.38%	13
	Gas Service for Compression on Customer's Premises	G-55					
14	Small		201,097	202,047	950	0.47%	14
15	Large		2,315,696	2,343,998	28,302	1.22%	15
16	Residential		97,240	101,598	4,358	4.48%	16
17	Electric Generation Gas Service	G-60	22,490,504	22,639,278	148,774	0.66%	17
18	Small Essential Agriculture User Gas Service	G-75	14,879,470	15,054,978	175,508	1.18%	18
19	Natural Gas Engine Gas Service	G-80	12,150,874	12,365,266	214,392	1.76%	19
20							20
21	Total Gas Sales		$1,029,695,248	$ 1,079,914,763	$ 50,219,515	4.88%	21
22	Special Contract Service	B-1	2,528,029	2,528,029	0	0.00%	22
23	Other Operating Revenue		12,261,805	12,261,805	0	0.00%	23
24	Total Arizona Revenue		$1,044,485,083	$ 1,094,704,598	$ 50,219,515	4.81%	24
25	Total Requirement			$ 1,094,703,780			25
26	Over/(Under) Requirement			$ 818			26
	Low Income Residential Including Discount [3]						
27	Low Income Residential Gas Service	G-10	$ 12,009,932	$ 12,350,661	$ 340,729	2.84%	27
28	Low Income Multi-Family Residential	G-11	$ 826,454	$ 855,050	$ 28,596	3.46%	28

[1] Schedule H-2, Sheets 1-4, including estimated gas cost for transporation customers.
[2] Schedule H-2, Sheets 5-9, including estimated gas cost for transportation customers.
[3] Revenue including low income benefit reflected on Schedule H-2, Sheet 9.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF MARGIN AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Margin		Increase/(Decrease)		Line No.
			Present Rates [1]	Proposed Rates [2]	Dollars	Percent	
	(a)	(b)	(c)	(d)	(e)	(f)	
	Sales Service						
1	Residential Gas Service	G-5	$ 252,170,209	$ 292,104,765	$ 39,934,556	15.84%	1
2	Multi-Family Residential Gas Service	G-6	6,635,205	6,462,646	(172,559)	(2.60%)	2
3	Low Income Residential Gas Service	G-10	6,749,399	7,377,773	628,374	9.31%	3
4	Low Income Multi-Family Residential	G-11	480,391	458,876	(21,515)	(4.48%)	4
5	Special Residential Gas Service	G-15	70,281	40,551	(29,730)	(42.30%)	5
6	Master Metered Mobile Home Park Gas Service	G-20	972,093	1,041,727	69,634	7.16%	6
	General Gas Service	G-25					
7	Small		7,867,642	8,853,467	985,825	12.53%	7
8	Medium		24,310,776	27,091,812	2,781,036	11.44%	8
9	Large		53,003,981	56,721,948	3,717,967	7.01%	9
10	Transporation Eligible		20,088,639	21,821,052	1,732,413	8.62%	10
11	Optional Gas Service	G-30	3,255,998	3,255,998	0	0.00%	11
12	Air Conditioning Gas Service	G-40	123,697	130,409	6,712	5.43%	12
13	Street Lighting Gas Service	G-45	55,850	71,499	15,649	28.02%	13
	Gas Service for Compression on Customer's Premises	G-55					
14	Small		36,474	37,424	950	2.60%	14
15	Large		404,946	433,248	28,302	6.99%	15
16	Residential		25,489	29,847	4,358	17.10%	16
17	Electric Generation Gas Service	G-60	2,529,330	2,678,104	148,774	5.88%	17
18	Small Essential Agriculture User Gas Service	G-75	3,104,924	3,280,432	175,508	5.65%	18
19	Natural Gas Engine Gas Service	G-80	2,559,519	2,773,911	214,392	8.38%	19
20	Total Sales and Full Margin Transportation		$ 384,444,843	$ 434,665,489	$ 50,220,646	13.06%	20
21	Special Contract Service	B-1	2,528,029	2,528,029	0	0.00%	21
22	Other Operating Revenue		12,261,805	12,261,805	0	0.00%	22
23	Total Arizona Revenue		$ 399,234,678	$ 449,455,324	$ 50,220,646	12.58%	23
24	Total Requirement			$ 449,454,506			24
25	Over/(Under) Requirement			$ 818			25

[1] Schedule H-2, Sheets 1-4.
[2] Schedule H-2, Sheets 5-9.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF GAS COST AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Schedule Number	Gas Cost Present Rates [1]	Gas Cost Proposed Rates [2]	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Sales Service						
1	Residential Gas Service	G-5	$ 270,813,783	$ 270,591,517	$(222,266)	(0.08%)	1
2	Multi-Family Residential Gas Service	G-6	6,097,335	6,462,481	365,146	5.99%	2
3	Low Income Residential Gas Service	G-10	7,078,536	6,827,553	(250,983)	(3.55%)	3
4	Low Income Multi-Family Residential	G-11	451,775	504,340	52,565	11.64%	4
5	Special Residential Gas Service	G-15	131,257	185,664	54,407	41.45%	5
6	Total Residential		$ 284,572,686	$ 284,571,555	$(1,131)	(0.00%)	6
7	Master Metered Mobile Home Park Gas Service	G-20	2,083,637	2,083,637	0	0.00%	7
	General Gas Service	G-25					
8	Small		4,655,534	4,655,534	0	0.00%	8
9	Medium		42,209,454	42,209,454	0	0.00%	9
10	Large		138,009,962	138,009,962	0	0.00%	10
11	Transporation Eligible		88,731,829	88,731,829	0	0.00%	11
12	Optional Gas Service	G-30	40,422,215	40,422,215	0	0.00%	12
13	Air Conditioning Gas Service	G-40	996,018	996,018	0	0.00%	13
14	Street Lighting Gas Service	G-45	94,871	94,871	0	0.00%	14
	Gas Service for Compression on Customer's Premises	G-55					
15	Small		164,623	164,623	0	0.00%	15
16	Large		1,910,750	1,910,750	0	0.00%	16
17	Residential		71,751	71,751	0	0.00%	17
18	Electric Generation Gas Service	G-60	19,961,174	19,961,174	0	0.00%	18
19	Small Essential Agriculture User Gas Service	G-75	11,774,546	11,774,546	0	0.00%	19
20	Natural Gas Engine Gas Service	G-80	9,591,355	9,591,355	0	0.00%	20
21	Total Gas Sales		$ 645,250,405	$ 645,249,274	$(1,131)	(0.00%)	21
22	Special Contract Service	B-1	0	0	0	n/a	22
23	Other Operating Revenue		0	0	0	n/a	23
24	Total Arizona Revenue		$ 645,250,405	$ 645,249,274	$(1,131)	(0.00%)	24

[1] Schedule H-2, Sheets 1-4.
[2] Schedule H-2, Sheets 5-9.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Present Margin Rates [1]: Basic Service Charge	Present Margin Rates [1]: Commodity Charge	Margin at Present Rates: Basic Service Charge	Margin at Present Rates: Commodity Charge	Margin at Present Rates: Total Margin	Revenue at Present Rates: Gas Cost [2]	Revenue at Present Rates: Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Single-Family Residential Gas Service	G-5										
	Summer (May - October)											
1	Basic Service Charge per Month		5,107,859		$ 9.70		$ 49,546,232		$ 49,546,232		$ 49,546,232	1
	Commodity Charge per Therm											
2	First 15 Therms			48,048,640		$ 0.54200		$ 26,042,363	26,042,363	$ 45,016,291	71,058,654	2
3	Over 15 Therms			16,007,105		0.50100		8,019,559	8,019,559	14,996,896	23,016,455	3
	Winter (November - April)											
4	Basic Service Charge per Month		5,190,171		$ 9.70		$ 50,344,659		$ 50,344,659		$ 50,344,659	4
	Commodity Charge per Therm											
5	First 35 Therms			133,956,357		$ 0.54200		72,604,346	72,604,346	125,502,371	198,106,717	5
6	Over 35 Therms			91,044,013		0.50100		45,613,050	45,613,050	85,298,225	130,911,275	6
						0.00000		0	0	0	0	
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 99,890,891	$ 152,279,318	$ 252,170,209	$ 270,813,783	$ 522,983,992	7
	Low Income Single-Family Residential Gas Svc	G-10										
	Summer (May - October)											
8	Basic Service Charge		153,923		$ 7.00		$ 1,077,461		$ 1,077,461		$ 1,077,461	8
	Commodity Charge per Therm											
	Summer (May - October)											
9	First 15 Therms			1,499,731		$ 0.54200		$ 812,854	812,854	$ 1,226,000	2,038,854	9
10	Over 15 Therms			343,792		0.50100		172,240	172,240	281,043	453,283	10
	Winter (November - April)											
11	Basic Service Charge per Month		156,983		$ 7.00		$ 1,098,881		$ 1,098,881		$ 1,098,881	11
	Commodity Charge per Therm											
12	First 35 Therms			4,229,842		0.54200		2,292,574	2,292,574	3,457,811	5,750,385	12
13	Next 115 Therms			2,532,839		0.50100		1,268,952	1,268,952	2,070,545	3,339,497	13
14	Over 150 Therms			52,769		0.50100		26,437	26,437	43,137	69,574	14
15	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,176,342	$ 4,573,057	$ 6,749,399	$ 7,078,536	$ 13,827,935	15
	Special Residential Gas Service for Air Conditioning	G-15										
	Summer (May - October)											
16	Basic Service Charge per Month		648		$ 9.70		$ 6,286		$ 6,286		$ 6,286	16
	Commodity Charge per Therm											
17	First 15 Therms			7,899		$ 0.54200		$ 4,281	4,281	$ 7,326	11,607	17
18	Over 15 Therms			65,327		0.28200		18,422	18,422	60,589	79,011	18
	Winter (November - April)											
19	Basic Service Charge per Month		648		$ 9.70		$ 6,286		$ 6,286		$ 6,286	19
	Commodity Charge per Therm											
20	First 35 Therms			19,309		0.54200		10,465	10,465	17,909	28,374	20
21	Over 35 Therms			48,985		0.50100		24,541	24,541	45,433	69,974	21
22	Total Special Residential Gas Service		1,296	141,520			$ 12,572	$ 57,709	$ 70,281	$ 131,257	$ 201,538	22

[1] Margin rates effective March 1, 2006 per Decision No. 68487.
[2] Gas Cost and Rate Adjustment effective May 1, 2007.

SCHEDULE H-2
SHEET 1 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Present Margin Rates [1]: Basic Service Charge	Present Margin Rates [1]: Commodity Charge	Margin at Present Rates: Basic Service Charge	Margin at Present Rates: Commodity Charge	Margin at Present Rates: Total Margin	Revenue at Present Rates: Gas Cost [2]	Revenue at Present Rates: Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Multi-Family Residential Gas Service	G-6										
	Summer (May - October)											
1	Basic Service Charge per Month		182,409		$ 8.70		$ 1,586,958		$ 1,586,958		$ 1,586,958	1
	Commodity Charge per Therm											
2	First 7 Therms			1,044,432		$ 0.54200		$ 566,082	566,082	$ 978,518	1,544,600	2
3	Over 7 Therms			950,005		$ 0.50100		475,953	475,953	890,050	1,366,003	3
	Winter (November - April)											
4	Basic Service Charge per Month		188,153		$ 8.70		$ 1,636,931		$ 1,636,931		$ 1,636,931	4
	Commodity Charge per Therm											
5	First 18 Therms			2,633,090		0.54200		1,427,135	1,427,135	2,466,916	3,894,051	5
6	Over 18 Therms			1,880,532		0.50100		942,146	942,146	1,761,851	2,703,997	6
7	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,223,889	$ 3,411,316	$ 6,635,205	$ 6,097,335	$ 12,732,540	7
	Low Income Multi-Family Residential Gas Svc	G-11										
	Summer (May - October)											
8	Basic Service Charge per Month		13,560		$ 7.00		$ 94,920		$ 94,920		$ 94,920	8
	Commodity Charge per Therm											
9	First 7 Therms			79,822		$ 0.54200		$ 43,264	43,264	$ 65,253	108,517	9
10	Over 7 Therms			78,071		0.50100		39,114	39,114	63,822	102,936	10
	Winter (November - April)											
11	Basic Service Charge per Month		13,828		$ 7.00		$ 96,796		$ 96,796		$ 96,796	11
	Commodity Charge per Therm											
12	First 18 Therms			207,982		0.54200		112,726	112,726	170,021	282,747	12
13	Next 132 Therms			186,423		0.50100		93,398	93,398	152,397	245,795	13
14	Over 150 Therms			345		0.50100		173	173	282	455	14
15	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 191,716	$ 288,675	$ 480,391	$ 451,775	$ 932,166	15
16	Total Residential Gas Service		11,008,182	304,917,309			105,495,410	160,610,075	266,105,485	284,572,686	550,678,171	16
	Master Metered Mobile Home Park Gas Service	G-20										
17	Basic Service Charge per Month		1,968		$ 60.00		$ 118,080		$ 118,080		$ 118,080	17
	Commodity Charge per Therm All Usage											
18	All Usage			2,223,993		$ 0.38400		$ 854,013	854,013	2,083,637	2,937,650	18
19	Total MMMHP Gas Service		1,968	2,223,993			$ 118,080	$ 854,013	$ 972,093	$ 2,083,637	$ 3,055,730	19
	General Gas Service - Small	G-25(S)										
20	Basic Service Charge Per Month		201,805		$ 25.00		$ 5,045,125		$ 5,045,125		$ 5,045,125	20
	Commodity Charge per Therm All Usage											
21	Transportation Customers			10,138		$ 0.56217		$ 5,699	5,699	$ 8,288	13,987	21
22	Sales Customers			5,010,616		0.56217		$ 2,816,818	$ 2,816,818	$ 4,647,246	7,464,064	22
23	Total Small General Gas Service		201,805	5,020,754			5,045,125	2,822,517	7,867,642	4,655,534	12,523,176	23
	General Gas Service - Medium	G-25(M)										
24	Basic Service Charge		193,790		$ 33.00		$ 6,395,070		$ 6,395,070		$ 6,395,070	24
	Commodity Charge per Therm All Usage											
25	Transportation Customers			172,365		$ 0.39349		$ 67,824	67,824	140,905	208,729	25
26	Sales Customers			45,357,904		0.39349		17,847,882	17,847,882	42,068,549	59,916,431	26
27	Total Medium General Gas Service		193,790	45,530,269			$ 6,395,070	$ 17,915,706	$ 24,310,776	$ 42,209,454	$ 66,520,230	27

[1] Margin rates effective March 1, 2006 per Decision No. 68487.
[2] Gas Cost and Rate Adjustment effective May 1, 2007.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Present Margin Rates [1]: Basic Service Charge	Present Margin Rates [1]: Commodity Charge	Margin at Present Rates: Basic Service Charge	Margin at Present Rates: Commodity Charge	Margin at Present Rates: Total Margin	Revenue at Present Rates: Gas Cost [2]	Revenue at Present Rates: Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	General Gas Service - Large	G-25(L)										
1	Basic Service Charge		85,510		$ 145.00		$ 12,398,950		$ 12,398,950		$ 12,398,950	1
	Commodity Charge per Therm All Usage											
2	Transportation Customers			3,556,829		$ 0.27211		$ 967,849	967,849	$ 2,907,637	3,875,486	2
3	Sales Customers			145,666,025		0.27211		39,637,182	39,637,182	135,102,325	174,739,507	3
4	Total Large General Gas Service		85,510	149,222,854			$ 12,398,950	$ 40,605,031	53,003,981	$ 138,009,962	$ 191,013,943	4
	General Gas Service - Transportation Eligible	G-25(TE)										
5	Basic Service Charge		2,222		$ 720.00		$ 1,599,840		1,599,840		$ 1,599,840	5
6	Demand Charge per Month			12,803,712	0.062340			9,578,201	9,578,201		9,578,201	6
	Commodity Charge per Therm All Usage											
7	Transportation Customers			32,517,415		$ 0.08953		$ 2,911,284	2,911,284	$ 26,582,336	29,493,620	7
8	Sales Customers			67,008,985		0.08953		5,999,314	5,999,314	62,149,493	68,148,807	8
9	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 1,599,840	$ 18,488,799	$ 20,088,639	$ 88,731,829	$ 108,820,468	9
10	Total General Gas Service		483,327	299,300,277			$ 25,438,985	$ 79,832,053	$ 105,271,038	$ 273,606,779	$ 378,877,817	10
	Air Conditioning Gas Service	G-40										
	Basic Service Charge											
11	With Other Service - No BSC		60		$ 0.00		$ 0		$ 0		$ 0	11
12	General Service - Small		198		25.00		4,950		4,950		4,950	12
13	General Service - Medium		0		33.00		0		0		0	13
14	General Service - Large		48		145.00		6,960		6,960		6,960	14
15	Essential Agricultural		12		90.00		1,080		1,080		1,080	15
	Commodity Charge per Therm All Usage											
16	Transportation Customers			373,987		$ 0.09900		$ 37,025	37,025	$ 305,727	342,752	16
17	Sales Customers			744,265		0.09900		73,682	73,682	690,291	763,973	17
18	Total Air Conditioning Gas Service		318	1,118,252			$ 12,990	$ 110,707	$ 123,697	$ 996,018	$ 1,119,715	18
	Street Lighting Gas Service	G-45										
	Commodity Charge per Therm of Rated Capacity											
19	All Usage		324	102,289		$ 0.54600		$ 55,850	55,850	94,871	150,721	19
20	Total Street Lighting Gas Service		324	102,289			$ 0	$ 55,850	$ 55,850	$ 94,871	$ 150,721	20
	Gas Service for Compression on Customer's Premises	G-55										
	Basic Service Charge											
21	Small		252		$ 25.00		$ 6,300		$ 6,300		$ 6,300	21
22	Large		288		190.00		54,720		54,720		54,720	22
23	Residential		1,272		9.70		12,338		12,338		12,338	23
	Commodity Charge per Therm All Usage											
24	Transportation Customers			0		$ 0.17000		$ 0	0	$ 0	0	24
	Sales Customers											
25	Small			177,495		0.17000		30,174	30,174	164,623	194,797	25
26	Large			2,060,152		0.17000		350,226	350,226	1,910,750	2,260,976	26
27	Residential			77,361		0.17000		13,151	13,151	71,751	84,902	27
28	Total CNG Gas Service		1,812	2,315,008			$ 73,358	$ 393,551	$ 466,909	$ 2,147,124	$ 2,614,033	28

[1] Margin rates effective March 1, 2006 per Decision No. 68487.
[2] Gas Cost and Rate Adjustment effective May 1, 2007.

SCHEDULE H-2
SHEET 3 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Present Margin Rates [1]: Basic Service Charge	Present Margin Rates [1]: Commodity Charge	Margin at Present Rates: Basic Service Charge	Margin at Present Rates: Commodity Charge	Margin at Present Rates: Total Margin	Revenue at Present Rates: Gas Cost [2]	Revenue at Present Rates: Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Electric Generation Gas Service	G-60										
	Basic Service Charge											
1	General Service - Small		36		$ 25.00		$ 900		$ 900		$ 900	1
2	General Service - Medium		36		33.00		1,188		1,188		1,188	2
3	General Service - Large		84		145.00		12,180		12,180		12,180	3
4	General Service - Transportation Eligible		84		720.00		60,480		60,480		60,480	4
5	Essential Agricultural		12		90.00		1,080		1,080		1,080	5
	Commodity Charge per Therm All Usage											
6	Transportation Customers			0		$ 0.11400		$ 0	0	$ 0	0	6
7	Sales Customers			21,521,946		0.11400		2,453,502	2,453,502	19,961,174	22,414,676	7
8	Total Electric Generation Gas Service		252	21,521,946			$ 75,828	$ 2,453,502	$ 2,529,330	$ 19,961,174	$ 22,490,504	8
	Essential Agriculture User Gas Service	G-75										
9	Basic Service Charge		1,216		$ 90.00		$ 109,440		$ 109,440		$ 109,440	9
	Commodity Charge per Therm All Usage											
10	Transportation Customers			6,217,976		$ 0.22300		$ 1,386,609	1,386,609	$ 5,083,071	6,469,680	10
11	Sales Customers			7,214,684		0.22300		1,608,875	1,608,875	6,691,475	8,300,350	11
12	Total Essential Agricultural Gas Service		1,216	13,432,660			$ 109,440	$ 2,995,484	$ 3,104,924	$ 11,774,546	$ 14,879,470	12
	Natural Gas Engine Gas Service	G-80										
	Basic Service Charge											
13	Off-Peak Season (Oct. - March)		2,516		$ 0.00		$ 0		$ 0		$ 0	13
14	Peak Season (April - September)		2,589		95.00		245,955		245,955		245,955	14
	Commodity Charge per Therm All Usage											
15	Transportation Customers			0		$ 0.17700		$ 0	0	$ 0	0	15
16	Sales Customers			13,070,981		0.17700		2,313,564	2,313,564	9,591,355	11,904,919	16
17	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 245,955	$ 2,313,564	$ 2,559,519	$ 9,591,355	$ 12,150,874	17
18	Total Tariff Sales		11,502,504	658,002,715			131,570,046	249,618,799	381,188,845	604,828,190	986,017,035	18
19	Optional Gas Service	G-30	84	49,447,344			$ 120,540	$ 3,135,458	$ 3,255,998	$ 40,422,215	$ 43,678,213	19
20	Special Contract Service	B-1	244	35,660,859			$ 449,274	$ 2,078,755	$ 2,528,029		$ 2,528,029	20
21	Other Operating Revenues						$ 12,261,805		$ 12,261,805		$ 12,261,805	21
22	Total		11,502,832	743,110,918			$ 144,401,665	$ 254,833,013	$ 399,234,678	$ 645,250,405	$1,044,485,083	22
23	Total Revenue Requirement								449,454,506			23
24	Over/(Under)								$ (50,219,828)			24

[1] Margin rates effective March 1, 2006 per Decision No. 68487.
[2] Gas Cost and Rate Adjustment effective May 1, 2007.

SCHEDULE H-2
SHEET 4 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge [1]	Revenue at Proposed Rates: Commodity Charge [1]	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Revenue at Proposed Rates: Gas Cost [2]	Revenue at Proposed Rates: Total Revenue	Revenue at Present Rates [3]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Single-Family Residential Gas Service	G-5													
	Summer (May - October)														
1	Basic Service Charge per Month		5,107,659		$ 12.80		$ 65,380,595		$ 65,380,595		$ 65,380,595	$ 49,546,232	$ 15,834,363		1
	Commodity Charge per Therm														
2	First 15 Therms			48,048,640		$ 0.88069		$ 42,315,957	42,315,957	$ 29,307,749	71,623,706	71,058,654	565,052		2
3	Over 15 Therms			16,007,105		0.00000		0	0	23,860,990	23,860,990	23,016,455	844,535		3
	Winter (November - April)														
4	Basic Service Charge per Month		5,190,171		$ 12.80		$ 66,434,189		$ 66,434,189		$ 66,434,189	$ 50,344,659	$ 16,089,530		4
	Commodity Charge per Therm														
5	First 35 Therms			133,956,357		0.88069		117,974,024	117,974,024	81,708,020	199,682,044	198,106,717	1,575,327		5
6	Over 35 Therms			91,044,013		0.00000		0	0	135,714,758	135,714,758	130,911,275	4,803,483		6
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 131,814,784	$ 160,289,981	$ 292,104,765	$ 270,591,517	$ 562,696,282	$ 522,983,992	$ 39,712,290	7.59%	7
	Low Income Single-Family Residential Gas Service	G-10													
	Summer (May - October)														
8	Basic Service Charge		153,923		$ 7.50		$ 1,154,423		$ 1,154,423		$ 1,154,423	$ 1,077,461	$ 76,962		8
	Commodity Charge per Therm														
	Summer (May - October)														
9	First 15 Therms			1,499,731		$ 0.88069		$ 1,320,798	1,320,798	$ 735,693	2,056,491	2,038,854	17,637		9
10	Over 15 Therms			343,792		0.00000		0	0	471,422	471,422	453,283	18,139		10
	Winter (November - April)														
11	Basic Service Charge per Month		156,983		$ 7.50		$ 1,177,373		$ 1,177,373		$ 1,177,373	$ 1,098,881	$ 78,492		11
	Commodity Charge per Therm														
12	First 35 Therms			4,229,842		0.88069		3,725,179	3,725,179	2,074,949	5,800,128	5,750,385	49,743		12
13	Next 115 Therms			2,532,839		0.00000		0	0	3,473,130	3,473,130	3,339,497	133,633		13
14	Over 150 Therms			52,769		0.00000		0	0	72,359	72,359	69,574	2,785		14
15	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,331,796	$ 5,045,977	$ 7,377,773	$ 6,827,553	$ 14,205,326	$ 13,827,935	$ 377,391	2.73%	15
	Multi-Family Residential Gas Service	G-6													
	Summer (May - October)														
16	Basic Service Charge per Month		182,409		$ 8.70		$ 1,586,958		$ 1,586,958		$ 1,586,958	$ 1,586,958	$ -		16
	Commodity Charge per Therm														
17	First 7 Therms			1,044,432		$ 0.88069		$ 919,821	919,821	$ 637,062	1,556,883	1,544,600	12,283		17
18	Over 7 Therms			950,005		0.00000		0	0	1,416,125	1,416,125	1,366,003	50,122		18
	Winter (November - April)														
19	Basic Service Charge per Month		188,153		$ 8.70		$ 1,636,931		$ 1,636,931		$ 1,636,931	$ 1,636,931	$ -		19
	Commodity Charge per Therm														
20	First 18 Therms			2,633,090		0.88069		2,318,936	2,318,936	1,606,080	3,925,016	3,894,051	30,965		20
21	Over 18 Therms			1,860,532		0.00000		0	0	2,803,214	2,803,214	2,703,997	99,217		21
22	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,223,889	$ 3,238,757	$ 6,462,646	$ 6,462,481	$ 12,925,127	$ 12,732,540	$ 192,587	1.51%	22

[1] Exhibit No. (ABC_3), Sheets 5-8.
[2] Schedule H-3, Columns (j) and (k).
[3] Schedule H-2, Sheets 1-4.

SCHEDULE H-2
SHEET 5 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge [1]	Revenue at Proposed Rates: Commodity Charge [1]	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Revenue at Proposed Rates: Gas Cost [2]	Revenue at Proposed Rates: Total Revenue	Revenue at Present Rates [3]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Low Income Multi-Family Residential Gas Service	G-11													
	Summer (May - October)														
1	Basic Service Charge per Month		13,560		$ 7.50		$ 101,700		$ 101,700		$ 101,700	$ 94,920	$ 6,780		1
	Commodity Charge per Therm														
2	First 7 Therms			79,822		$ 0.88069		$ 70,298	70,298	$ 39,157	109,455	108,517	938		2
3	Over 7 Therms			78,071		0.00000		0	0	107,054	107,054	102,936	4,118		3
	Winter (November - April)														
4	Basic Service Charge per Month		13,828		$ 7.50		$ 103,710		$ 103,710		$ 103,710	$ 96,796	$ 6,914		4
	Commodity Charge per Therm														
5	First 18 Therms			207,982		0.88069		183,168	183,168	102,026	285,194	282,747	2,447		5
6	Next 132 Therms			186,423		0.00000		0	0	255,630	255,630	246,250	9,380		6
7	Over 150 Therms			345		0.00000		0	0	473	473	932,621	(932,148)		7
8	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 205,410	$ 253,466	$ 458,876	$ 504,340	$ 963,216	$ 1,864,787	$ (901,571)	-48.35%	8
	Special Residential Gas Service for A/C	G-15													
	Summer (May - October)														
9	Basic Service Charge per Month		648		$ 12.80		$ 8,294		$ 8,294		$ 8,294	$ 6,286	$ 2,008		9
	Commodity Charge per Therm														
10	First 15 Therms			7,899		$ 0.88069		$ 6,957	6,957	$ 4,744	11,701	11,607	94		10
11	Over 15 Therms			65,327		$ 0.00000		0	0	96,765	96,765	79,011	17,754		11
	Winter (November - April)														
12	Basic Service Charge per Month		648		$ 12.80		$ 8,294		$ 8,294		$ 8,294	$ 6,286	$ 2,008		12
	Commodity Charge per Therm														
13	First 35 Therms			19,309		$ 0.88069		17,005	17,005	11,596	28,601	28,374	227		13
14	Over 35 Therms			48,985		$ 0.00000		0	0	72,559	72,559	69,974	2,585		14
15	Total Special Residential Gas Service		1,296	141,520			$ 16,589	$ 23,962	$ 40,551	$ 185,664	$ 226,215	$ 201,538	$ 24,677	12.24%	15
16	Total Residential Gas Service		11,008,182	304,917,309			$137,592,468	$ 168,852,143	$ 306,444,611	$ 284,571,555	$ 591,016,166	$ 551,610,792	$ 39,405,374	7.14%	16
	Master Metered Mobile Home Park Gas Service	G-20													
17	Basic Service Charge per Month		1,968		$ 60.00		$ 118,080		$ 118,080		$ 118,080	$ 118,080	$ -		17
	Commodity Charge per Therm All Usage														
18	All Usage			2,223,993		$ 0.41531		$ 923,647	923,647	2,083,637	3,007,284	2,937,650	69,634		18
19	Total MMMHP Gas Service		1,968	2,223,993			$ 118,080	$ 923,647	$ 1,041,727	$ 2,083,637	$ 3,125,364	3,055,730	69,634	2.28%	19
	General Gas Service - Small	G-25(S)													
20	Basic Service Charge		201,805		$ 25.00		$ 5,045,125		$ 5,045,125		$ 5,045,125	$ 5,045,125	0		20
	Commodity Charge per Therm All Usage														
21	Transportation Customers			10,138		$ 0.75852		$ 7,690	7,690	$ 8,288	15,978	13,987	1,991		21
22	Sales Customers			5,010,616		0.75852		3,800,652	$ 3,800,652	4,647,246	8,447,898	7,464,064	983,834		22
23	Total Small General Gas Service		201,805	5,020,754			$ 5,045,125	$ 3,808,342	$ 8,853,467	$ 4,655,534	$ 13,509,001	$ 12,523,176	$ 985,825	7.87%	23
	General Gas Service - Medium	G-25(M)													
24	Basic Service Charge		193,790		$ 43.50		$ 8,429,865		$ 8,429,865		$ 8,429,865	$ 6,395,070	$ 2,034,795		24
	Commodity Charge per Therm All Usage														
25	Transportation Customers			172,365		$ 0.40988		$ 70,649	70,649	$ 140,905	211,554	208,729	2,825		25
26	Sales Customers			45,357,904		0.40988		18,591,298	18,591,298	42,068,549	60,659,847	59,916,431	743,416		26
27	Total Medium General Gas Service		193,790	45,530,269			$ 8,429,865	$ 18,661,947	$ 27,091,812	$ 42,209,454	$ 69,301,266	$ 66,520,230	$ 2,781,036	4.18%	27

[1] Exhibit No. (ABC_3), Sheets 5-8.
[2] Schedule H-3, Columns (j) and (k).
[3] Schedule H-2, Sheets 1-4.

SCHEDULE H-2
SHEET 6 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge [1]	Revenue at Proposed Rates: Commodity Charge [1]	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Revenue at Proposed Rates: Gas Cost [2]	Revenue at Proposed Rates: Total Revenue	Revenue at Present Rates [3]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	General Gas Service - Large	G-25(L)													
1	Basic Service Charge		85,510		$ 160.00		$ 13,681,600		$ 13,681,600		$ 13,681,600	$ 12,398,950	$ 1,282,650		1
	Commodity Charge per Therm All Usage														
2	Transportation Customers			3,556,829		0.28843		1,025,896	1,025,896	$ 2,907,637	3,933,533	3,875,486	58,047		2
3	Sales Customers			145,666,025		0.28843		42,014,452	42,014,452	135,102,325	177,116,777	174,739,507	2,377,270		3
4	Total Large General Gas Service		85,510	149,222,854			13,681,600	43,040,348	56,721,948	138,009,962	194,731,910	$ 191,013,943	3,717,967	1.95%	4
	General Gas Service - Transportation Eligible	G-25(TE)													
5	Basic Service Charge		2,222		$ 950.00		$ 2,110,900		$ 2,110,900		$ 2,110,900	$ 1,599,840	$ 511,060		5
6	Demand Charge per Month			12,803,712	0.064142			9,855,048	9,855,048		9,855,048	9,578,201	276,847		6
	Commodity Charge per Therm All Usage														
7	Transportation Customers			32,517,415		$ 0.09902		$ 3,219,874	3,219,874	$ 26,582,336	29,802,210	29,493,620	308,590		7
8	Sales Customers			67,008,985		$ 0.09902		$ 6,635,230	6,635,230	62,149,493	68,784,723	68,148,807	635,916		8
9	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 2,110,900	$ 19,710,152	$ 21,821,052	$ 88,731,829	$ 110,552,881	$ 108,820,468	$ 1,732,413	1.59%	9
10	Total General Gas Service		483,327	299,300,277			$ 29,267,490	$ 85,220,789	$ 114,488,279	$ 273,606,779	$ 388,095,058	$ 378,877,817	$ 9,217,241	2.43%	10
	Air Conditioning Gas Service	G-40													
	Basic Service Charge														
11	W/ Other Service (No BSC)		60		$ 0.00		$ 0		$ 0		$ 0	$ 0	$ 0		11
12	General Service - Small		198		25.00		4,950		4,950		4,950	4,950	0		12
13	General Service - Medium		0		43.50		0		0		0	0	0		13
14	General Service - Large		48		160.00		7,680		7,680		7,680	6,960	720		14
15	General Service -Transportation Eligible		12		950.00		11,400		11,400		11,400		11,400		15
16	Essential Agricultural		0		120.00		0		0		0	1,080	(1,080)		16
	Commodity Charge per Therm All Usage														
17	Transportation Customers			373,987		$ 0.09513		$ 35,577	35,577	$ 305,727	341,304	342,752	(1,448)		17
18	Sales Customers			744,265		0.09513		70,802	70,802	690,291	761,093	763,973	(2,880)		18
19	Total Air Conditioning Gas Service		318	1,118,252			$ 24,030	$ 106,379	$ 130,409	$ 996,018	$ 1,126,427	$ 1,119,715	$ 6,712	0.60%	19
	Street Lighting Gas Service	G-45													
	Commodity Charge per Therm of Rated Capacity														
20	All Usage		324	102,289		$ 0.69899		$ 71,499	71,499	94,871	166,370	150,721	15,649		20
21	Total Street Lighting Gas Service		324	102,289			$ 0	$ 71,499	$ 71,499	$ 94,871	$ 166,370	$ 150,721	$ 15,649	10.38%	21
	Gas Service for Compression on Customer's Premises	G-55													
	Basic Service Charge														
22	Small		252		$ 25.00		$ 6,300		$ 6,300		$ 6,300	$ 6,300	$ 0		22
23	Large		288		250.00		72,000		72,000		72,000	54,720	17,280		23
24	Residential		1,272		12.80		16,282		16,282		16,282	12,338	3,944		24
	Commodity Charge per Therm All Usage														
25	Transportation Customers			0		$ 0.17535		$ 0	0	$ 0	0	0	0		25
	Sales Customers														
26	Small			177,495		0.17535		31,124	31,124	164,623	195,747	194,797	950		26
27	Large			2,060,152		0.17535		361,248	361,248	1,910,750	2,271,998	2,260,976	11,022		27
28	Residential			77,361		0.17535		13,565	13,565	71,751	85,316	84,902	414		28
29	Total CNG Gas Service		1,812	2,315,008			$ 94,582	$ 405,937	$ 500,519	$ 2,147,124	$ 2,647,643	$ 2,614,033	$ 33,610	1.29%	29

[1] Exhibit No. (ABC_3), Sheets 5-8.
[2] Schedule H-3, Columns (j) and (k).
[3] Schedule H-2, Sheets 1-4.

SCHEDULE H-2
SHEET 7 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge [1]	Revenue at Proposed Rates: Commodity Charge [1]	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Revenue at Proposed Rates: Gas Cost [2]	Revenue at Proposed Rates: Total Revenue	Revenue at Present Rates [3]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Electric Generation Gas Service	G-60													
	Basic Service Charge														
1	General Service - Small		36		$ 25.00		$ 900		$ 900		$ 900	$ 900	$ 0		1
2	General Service - Medium		36		43.50		1,566		1,566		1,566	1,188	378		2
3	General Service - Large		84		160.00		13,440		13,440		13,440	12,180	1,260		3
4	General Service - Transportation Eligible		84		0.00		0		0		0	60,480	(60,480)		4
5	Essential Agricultural		12		120.00		1,440		1,440		1,440	1,080	360		5
	Commodity Charge per Therm All Usage														
6	Transportation Customers			0		$ 0.12363		$ 0	0	$ 0	0	0	0		6
7	Sales Customers			21,521,946		0.12363		2,660,758	2,660,758	19,961,174	22,621,932	22,414,676	207,256		7
8	Total Electric Generation Gas Service		252	21,521,946			$ 17,346	$ 2,660,758	$ 2,678,104	$ 19,961,174	$ 22,639,278	$ 22,490,504	$ 148,774	0.66%	8
	Small Essential Agriculture User Gas Service	G-75													
9	Basic Service Charge		1,216		$ 120.00		$ 145,920		$ 145,920		$ 145,920	$ 109,440	$ 36,480		9
	Commodity Charge per Therm All Usage														
10	Transportation Customers			6,217,976		$ 0.23335		$ 1,450,965	1,450,965	$ 5,083,071	6,534,036	6,469,680	64,356		10
11	Sales Customers			7,214,684		0.23335		1,683,547	1,683,547	6,691,475	8,375,022	8,300,350	74,672		11
12	Total Essential Agricultural Gas Service		1,216	13,432,660			$ 145,920	$ 3,134,512	$ 3,280,432	$ 11,774,546	$ 15,054,978	$ 14,879,470	$ 175,508	1.18%	12
	Natural Gas Engine Gas Service	G-80													
	Basic Service Charge														
13	Off-Peak Season (Oct. - March)		2,516		$ 0.00		$ 0		$ 0		$ 0	$ 0	$ 0		13
14	Peak Season (April - September)		2,589		125.00		323,625		323,625		323,625	245,955	77,670		14
	Commodity Charge per Therm All Usage														
15	Transportation Customers			0		$ 0.18746		$ 0	0	$ 0	0	0	0		15
16	Sales Customers			13,070,981		0.18746		2,450,286	2,450,286	9,591,355	12,041,641	11,904,919	136,722		16
17	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 323,625	$ 2,450,286	$ 2,773,911	$ 9,591,355	$ 12,365,266	$ 12,150,874	$ 214,392	1.76%	17
18	Total Tariff Sales		11,502,504	658,002,715			$167,583,541	$263,825,950	$ 431,409,491	$ 604,827,059	$ 1,036,236,550	$ 986,017,035	$ 50,219,515	5.09%	18
19	Optional Gas Service	G-30	84	49,447,344			$ 120,540	$ 3,135,458	3,255,998	$ 40,422,215	$ 43,678,213	$ 43,678,213	$ 0	0.00%	19
20	Special Contract Service	B-1	244	35,660,859			$ 449,274	$ 2,078,755	$ 2,528,029		$ 2,528,029	$ 2,528,029	$ 0	0.00%	20
21	Other Operating Revenues						$ 12,261,805		$ 12,261,805		$ 12,261,805	$ 12,261,805	$ 0	0.00%	21
22	Total Revenue		11,502,832	743,110,918			$ 180,415,160	$ 269,040,163	$ 449,455,324	$ 645,249,274	$ 1,094,704,598	$ 1,044,485,083	$ 50,219,515	4.81%	22
23	Total Revenue Requirement								$ 449,454,506	$ 645,249,274	$ 1,094,703,780				23
24	Over/(Under)								$818	$ 0	$818				24

[1] Exhibit No. (ABC_3), Sheets 5-8.
[2] Schedule H-3, Columns (j) and (k).
[3] Schedule H-2, Sheets 1-4.

SCHEDULE H-2
SHEET 8 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF LOW INCOME DISCOUNT AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Total Revenue Before Discount: Basic Service Charge	Total Revenue Before Discount: Commodity Charge	Total Revenue Before Discount: Total Revenue	Total Revenue After Discount: Basic Service Charge	Total Revenue After Discount: Commodity Charge	Total Revenue After Discount: Total Revenue	Low Income Discount: Dollars	Low Income Discount: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(k)	(e)	(f)	(k)	(m)	(n)	
	Low Income Discount at Present Rates												
	Single-Family Residential Gas Service	G-10											
	Summer (May - October)												
1	Basic Service Charge		153,923		$ 9.70		$ 1,493,053	$ 7.00		$ 1,077,461	$ (415,592)		1
	Commodity Charge per Therm												
2	First 15 Therms			1,499,731		$ 1.47889	2,217,937		$ 1.35948	2,038,854	(179,083)		2
3	Over 15 Therms			343,792		1.43789	494,335		1.31848	453,283	(41,052)		3
	Winter (November - April)												
4	Basic Service Charge per Month		156,983		$ 9.70		$ 1,522,735	$ 7.00		$ 1,098,881	(423,854)		4
	Commodity Charge per Therm												
5	First 35 Therms			4,229,842		1.47889	6,255,471		$ 1.08758	4,600,291	(1,655,180)		5
6	Next 115 Therms			2,532,839		1.43789	3,641,943		1.05478	2,671,587	(970,356)		6
7	Over 150 Therms			52,769		1.43789	75,876		1.31848	69,575	(6,301)		7
8	Total Low Income Residential Gas Service		310,906	8,658,972			$ 15,701,350			$ 12,009,932	(3,691,418)	-23.51%	8
	Multi-Family Residential Gas Service	G-11											
	Summer (May - October)												
9	Basic Service Charge per Month		13,560		$ 8.70		$ 117,972	$ 7.00		$ 94,920	$ (23,052)		9
	Commodity Charge per Therm												
10	First 7 Therms			79,822		$ 1.47889	118,048		$ 1.35948	108,516	(9,532)		10
11	Over 7 Therms			78,071		1.43789	112,258		1.31848	102,935	(9,323)		11
	Winter (November - April)												
12	Basic Service Charge per Month		13,828		$ 8.70		$ 120,304	$ 7.00		$ 96,796	(23,508)		12
	Commodity Charge per Therm												
13	First 18 Therms			207,982		$ 1.47889	307,583		$ 1.08758	226,197	(81,386)		13
14	Next 132 Therms			186,423		1.43789	268,055		1.05478	196,635	(71,420)		14
15	Over 150 Therms			345		1.43789	496		1.31848	455	(41)		15
16	Total Low Income Multi-Family Residential Gas Service		27,388	552,843			$ 1,044,716			$ 826,454	(218,262)	-20.89%	16
17	Total Low Income Residential Gas Service at Present Rates		338,294	9,211,615			$16,746,066			$ 12,836,386	$ (3,909,680)	-23.35%	17
	Low Income Discount at Proposed Rates												
	Single-Family Residential Gas Service	G-10											
	Summer (April - November)												
18	Basic Service Charge		153,923		$ 12.80		$ 1,970,214	$ 7.50		$ 1,154,423	$ (815,791)		18
	Commodity Charge per Therm												
19	First 15 Therms			1,499,731		$ 1.49065	2,235,574		$ 1.37124	2,056,491	(179,083)		19
20	Over 15 Therms			343,792		1.49065	512,474		1.37124	471,422	(41,052)		20
	Winter (December - March)												
21	Basic Service Charge per Month		156,983		$ 12.80		$ 2,009,382	$ 7.50		$ 1,177,373	(832,009)		21
	Commodity Charge per Therm												
22	First 35 Therms			4,229,842		$ 1.49065	6,305,213		$ 1.09699	4,640,094	(1,665,119)		22
23	Next 115 Therms			2,532,839		1.49065	3,775,578		1.09699	2,778,499	(997,077)		23
24	Over 150 Therms			52,769		1.49065	78,660		1.37124	72,359	(6,301)		24
25	Total Low Income Residential Gas Service		310,906	8,658,972			16,887,093			12,350,661	(4,536,432)	-26.86%	25
	Multi-Family Residential Gas Service	G-11											
	Summer (April - November)												
26	Basic Service Charge per Month		13,560		$ 8.70		$ 117,972	$ 7.50		$ 101,700	$ (16,272)		26
	Commodity Charge per Therm												
27	First 7 Therms			79,822		$ 1.49065	118,987		$ 1.37124	109,455	(9,532)		27
28	Over 7 Therms			78,071		1.49065	116,377		1.37124	107,054	(9,323)		28
	Winter (December - March)												
29	Basic Service Charge per Month		13,828		$ 8.70		$ 120,304	$ 7.50		$ 103,710	(16,594)		29
	Commodity Charge per Therm												
30	First 18 Therms			207,982		$ 1.49065	310,029		$ 1.09699	228,154	(81,875)		30
31	Next 132 Therms			186,423		1.49065	277,891		1.09699	204,504	(73,387)		31
32	Over 150 Therms			345		1.49065	514		1.37124	473	(41)		32
33	Total Low Incom Multi-Family Residential Gas Service		27,388	552,643			1,062,074			855,060	(207,024)	-19.49%	33
34	Total Low Income Residential Gas Service at Proposed Rates		338,294	9,211,615			$17,949,167			$ 13,205,711	$ (4,743,456)	-26.43%	34
	Total Proposed Increase to Low Income Customers												
35	Dollars									$ 369,325			35
36	Percent									2.88%			36

SCHEDULE H-2
SHEET 9 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Schedule	Present Rates [1] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Description	Schedule	Proposed Rates [2] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Residential Gas Service	G-5					Single-Family Residential Gas Service	G-5					
	Summer (May - October)						Summer (May - October)						
1	Basic Service Charge per Month		$ 9.70			$ 9.70	Basic Service Charge per Month		$ 12.80			$ 12.80	1
	Commodity Charge per Therm						Commodity Charge per Therm						
2	First 15 Therms		$ 0.54200	$ 0.01263	$ 0.92426	$ 1.47889	First 15 Therms		$ 0.88069	$ 0.01263	$ 0.59733	$ 1.49065	2
3	Over 15 Therms		0.50100	0.01263	0.92426	1.43789	Over 15 Therms		0.00000	0.01263	$ 1.47802	1.49065	3
	Winter (November - April)						Winter (November - April)						
4	Basic Service Charge per Month		$ 9.70			$ 9.70	Basic Service Charge per Month		$ 12.80			$ 12.80	4
	Commodity Charge per Therm						Commodity Charge per Therm						
5	First 35 Therms		$ 0.54200	$ 0.01263	$ 0.92426	$ 1.47889	First 35 Therms		$ 0.88069	$ 0.01263	$ 0.59733	$ 1.49065	5
6	Over 35 Therms		0.50100	0.01263	0.92426	1.43789	Over 35 Therms		0.00000	0.01263	1.47802	1.49065	6
	Multi-Family Residential Gas Service	G-6					Multi-Family Residential Gas Service	G-6					
	Summer (May - October)						Summer (May - October)						
7	Basic Service Charge per Month		$ 8.70			$ 8.70	Basic Service Charge per Month		$ 8.70			$ 8.70	7
	Commodity Charge per Therm						Commodity Charge per Therm						
8	First 7 Therms		$0.54200	0.01263	0.92426	$1.47889	First 7 Therms		$ 0.88069	$ 0.01263	$ 0.59733	$ 1.49065	8
9	Over 7 Therms		0.50100	0.01263	0.92426	1.43789	Over 7 Therms		0.00000	0.01263	1.47802	1.49065	9
	Winter (November - April)						Winter (November - April)						
10	Basic Service Charge per Month		$ 8.70			$ 8.70	Basic Service Charge per Month		$ 8.70			$ 8.70	10
	Commodity Charge per Therm						Commodity Charge per Therm						
11	First 18 Therms		$0.54200	0.01263	0.92426	$1.47889	First 18 Therms		$ 0.88069	$ 0.01263	$ 0.59733	$ 1.49065	11
12	Over 18 Therms		0.50100	0.01263	0.92426	1.43789	Over 18 Therms		0.00000	0.01263	1.47802	1.49065	12
	Low Income Residential Gas Service	G-10					Single-Family Low-Income Residential Gas Service	G-10					
	Summer (May - October)						Summer (May - October)						
13	Basic Service Charge per Month		$ 7.00			$ 7.00	Basic Service Charge per Month		$ 7.50			$ 7.50	13
	Commodity Charge per Therm						Commodity Charge per Therm						
14	First 15 Therms		$ 0.54200	$ 0.00322	$ 0.81426	$ 1.35948	First 15 Therms		$ 0.88069	$ 0.00322	$ 0.48733	$ 1.37124	14
15	Over 15 Therms		0.50100	0.00322	0.81426	1.31848	Over 15 Therms		0.00000	0.00322	1.36802	1.37124	15
	Winter (November - April)						Winter (November - April)						
16	Basic Service Charge per Month		$ 7.00			$ 7.00	Basic Service Charge per Month		$ 7.50			$ 7.50	16
	Commodity Charge per Therm						Commodity Charge per Therm						
17	First 35 Therms		$ 0.27010	$ 0.00322	$ 0.81426	$ 1.08758	First 35 Therms		$ 0.60644	$ 0.00322	$ 0.48733	$ 1.09699	17
18	Next 115 Therms		0.23730	0.00322	0.81426	1.05478	Next 115 Therms		(0.27425)	0.00322	1.36802	1.09699	18
19	Over 150 Therms		0.50100	0.00322	0.81426	1.31848	Over 150 Therms		0.00000	0.00322	1.36802	1.37124	19
	Low Income Multi-Family Residential G S	G-11					Multi-Family Low-Income Residential Gas Service	G-11					
	Summer (May - October)						Summer (May - October)						
20	Basic Service Charge per Month		$ 7.00			$ 7.00	Basic Service Charge per Month		$ 7.50			$ 7.50	20
	Commodity Charge per Therm						Commodity Charge per Therm						
21	First 7 Therms		$ 0.54200	$ 0.00322	$ 0.81426	$ 1.35948	First 7 Therms		$ 0.88069	$ 0.00322	$ 0.48733	$ 1.37124	21
22	Over 7 Therms		0.50100	0.00322	0.81426	1.31848	Over 7 Therms		0.00000	0.00322	1.36802	1.37124	22
	Winter (November - April)						Winter (November - April)						
23	Basic Service Charge per Month		$ 7.00			$ 7.00	Basic Service Charge per Month		$ 7.50			$ 7.50	23
	Commodity Charge per Therm						Commodity Charge per Therm						
24	First 18 Therms		$ 0.27010	$ 0.00322	$ 0.81426	$ 1.08758	First 18 Therms		$ 0.60644	$ 0.00322	$ 0.48733	$ 1.09699	24
25	Next 132Therms		0.23730	0.00322	0.81426	1.05478	Next 132 Therms		(0.27425)	0.00322	1.36802	1.09699	25
26	Over 150 Therms		0.50100	0.00322	0.81426	1.31848	Over 150 Therms		0.00000	0.00322	1.36802	1.37124	26

[1] Margin rates effective March 1, 2006 per Decision No. 68487. Gas Cost and RateAdjustment effective May 1, 2007.
[2] Proposed margin rates per Exhibit No. (ABC_3), Sheets 5-8.

SCHEDULE H-3
SHEET 1 OF 3

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Schedule	Present Rates [1] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Description	Schedule	Proposed Rates [2] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Special Residential Gas Service for Air Conditioning	G-15					Special Residential Gas Service for Air Conditioning	G-15					
	Summer (May - October)						Summer (May - October)						
1	Basic Service Charge per Month		$ 9.70			$ 9.70	Basic Service Charge per Month		$ 12.80			$ 12.80	1
	Commodity Charge per Therm						Commodity Charge per Therm						
2	First 15 Therms		$ 0.54200	$ 0.00322	$ 0.92426	$ 1.46948	First 15 Therms		$ 0.88069	$ 0.00322	$ 0.59733	$ 1.48124	2
3	Over 15 Therms		0.28200	0.00322	0.92426	1.20948	Over 15 Therms		0.00000	0.00322	1.47802	1.48124	3
	Winter (November - April)						Winter (November - April)						
4	Basic Service Charge per Month		$ 9.70			$ 9.70	Basic Service Charge per Month		$ 12.80			$ 12.80	4
5	First 35 Therms		$ 0.54200	$ 0.00322	$ 0.92426	$ 1.46948	First 35 Therms		$ 0.88069	$ 0.00322	$ 0.59733	$ 1.48124	5
6	Over 35 Therms		0.50100	0.00322	0.92426	1.42848	Over 35 Therms		0.00000	0.00322	1.47802	1.48124	6
	Master Metered Mobile Home Park Gas Service	G-20					Master Metered Mobile Home Park Gas Service	G-20					
7	Basic Service Charge per Month		$ 60.00			$ 60.00	Basic Service Charge per Month		$ 60.00			$ 60.00	7
	Commodity Charge per Therm						Commodity Charge per Therm						
8	All Usage		$ 0.38400	$ 0.01263	$ 0.92426	$ 1.32089	All Usage		$ 0.41531	$ 0.01263	$ 0.92426	$ 1.35220	8
	General Gas Service	G-25					General Gas Service	G-25					
	Basic Service Charge per Month						Basic Service Charge per Month						
9	Small		$ 25.00			$ 25.00	Small		$ 25.00			$ 25.00	9
10	Medium		33.00			33.00	Medium		43.50			43.50	10
11	Large		145.00			145.00	Large		160.00			160.00	11
12	Transportation Eligible		720.00			720.00	Transportation Eligible		950.00			950.00	12
	Commodity Charge per Therm						Commodity Charge per Therm						
13	Small, All Usage		$ 0.56217	$ 0.00322	$ 0.92426	$ 1.48965	Small, All Usage		$ 0.75852	$ 0.00322	$ 0.92426	$ 1.68600	13
14	Medium, All Usge		0.39349	0.00322	0.92426	1.32097	Medium, All Usge		0.40988	0.00322	0.92426	1.33736	14
15	Large, All Usage		0.27211	0.00322	0.92426	1.19959	Large, All Usage		0.28843	0.00322	0.92426	1.21591	15
16	Transportation Eligible		0.08953	0.00322	0.92426	1.01701	Transportation Eligible, All Usage		0.09902	0.00322	0.92426	1.02650	16
	Demand Charge per Month						Demand Charge per Month						
	TE General Service Peak Winter Month Usage						Transportation Eligible Peak Month Usage						
17	Times Demand Rate per Therm		$0.062340			$0.062340	Times Demand Rate per Therm		$ 0.064142			$0.064142	17
	Optional Gas Service	G-30					Optional Gas Service	G-30					
18	Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 27.				Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 27.				18
	Commodity Charge per Therm						Commodity Charge per Therm						
19	All Usage		As Specified on A.C.C. Sheet No. 28.				All Usage		As Specified on A.C.C. Sheet No. 28.				19
	Air-Conditioning Gas Service	G-40					Air-Conditioning Gas Service	G-40					
20	Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 32.				Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 32.				20
	Commodity Charge per Therm						Commodity Charge per Therm						
21	All Usage		$ 0.09900	$ 0.00322	$ 0.92426	$ 1.02648	All Usage		$ 0.09513	$ 0.00322	$ 0.92426	$ 1.02261	21
	Street Lighting Gas Service	G-45					Street Lighting Gas Service	G-45					
	Commodity Charge per Therm of Rated Capacity						Commodity Charge per Therm of Rated Capacity						
22	All Usage		$ 0.54600	$ 0.00322	$ 0.92426	$ 1.47348	All Usage		$ 0.69899	$ 0.00322	$ 0.92426	$ 1.62647	22

[1] Margin rates effective March 1, 2006 per Decision No. 68487. Gas Cost and RateAdjustment effective May 1, 2007.
[2] Proposed margin rates per Exhibit No. (ABC_3), Sheets 5-8.

SCHEDULE H-3
SHEET 2 OF 3

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Schedule	Present Rates [1] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Description	Schedule	Proposed Rates [2] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Gas Service for Compression on Customer's Premises	G-55					Gas Service for Compression on Customer's Premises	G-55					
	Basic Service Charge per Month						Basic Service Charge per Month						
1	Small		$ 25.00			$ 25.00	Small		$ 25.00			$ 25.00	1
2	Large		190.00			190.00	Large		250.00			250.00	2
3	Residential		9.70			9.70	Residential		12.80			12.80	3
	Commodity Charge per Therm						Commodity Charge per Therm						
4	All Usage		$ 0.17000	$ 0.00322	$ 0.92426	$ 1.09748	All Usage		$ 0.17535	$ 0.00322	$ 0.92426	$ 1.10283	4
	Electric Generation Gas Service	G-60					Electric Generation Gas Service	G-60					
5	Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 40.				Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 40.				5
	Commodity Charge per Therm						Commodity Charge per Therm						
6	All Usage		$ 0.11400	$ 0.00322	$ 0.92426	$ 1.04148	All Usage		$ 0.12363	$ 0.00322	$ 0.92426	$ 1.05111	6
	Small Essential Agriculture User Gas Service	G-75					Small Essential Agriculture User Gas Service	G-75					
7	Basic Service Charge per Month		$ 90.00			$ 90.00	Basic Service Charge per Month		$ 120.00			$ 120.00	7
	Commodity Charge per Therm						Commodity Charge per Therm						
8	All Usage		$ 0.22300	$ 0.00322	$ 0.92426	$ 1.15048	All Usage		$ 0.23335	$ 0.00322	$ 0.92426	$ 1.16083	8
	Natural Gas Engine Gas Service	G-80					Natural Gas Engine Gas Service	G-80					
	Basic Service Charge per Month						Basic Service Charge per Month						
9	Off-Peak Season (October - March)		$ 0.00			$ 0.00	Off-Peak Season (October - March)		$ 0.00			$ 0.00	9
10	Peak Season (April - September)		95.00			95.00	Peak Season (April - September)		125.00			125.00	10
	Commodity Charge per Therm						Commodity Charge per Therm						
11	All Usage		$ 0.17700	$ 0.00322	$ 0.73057	$ 0.91079	All Usage		$ 0.18746	$ 0.00322	$ 0.73057	$ 0.92125	11

[1] Margin rates effective March 1, 2006 per Decision No. 68487. Gas Cost and RateAdjustment effective May 1, 2007.
[2] Proposed margin rates per Exhibit No. (ABC_3), Sheets 5-8.

SCHEDULE H-3
SHEET 3 OF 3

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
SINGLE-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	10	24.49	$ 27.71	$ 3.22	13.15%	1
2	Average Summer Use [1]	13	28.93	$ 32.18	3.25	11.23%	2
3	125 Percent Average Use	16	33.32	$ 36.65	3.33	9.99%	3
	Winter Season Bills						
4	75 Percent Average Use	32	57.02	$ 60.50	$ 3.48	6.10%	4
5	Average Winter Use [1]	43	72.96	$ 76.90	3.94	5.40%	5
6	125 Percent Average Use	54	88.78	$ 93.30	4.52	5.09%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 9.70
Commodity Charge Summer	
First 15 Therms	$ 1.47889
Over 15 Therms	1.43789
Commodity Charge Winter	
First 35 Therms	$ 1.47889
Over 35 Therms	1.43789

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 12.80
Commodity Charge	
All Usage	$ 1.49065

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES INCLUDING DISCOUNT
LOW-INCOME SINGLE-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	9	19.24	$ 19.84	$ 0.60	3.12%	1
2	Average Summer Use [1]	12	23.31	$ 23.95	0.64	2.75%	2
3	125 Percent Average Use	15	27.39	$ 28.07	0.68	2.48%	3
	Winter Season Bills						
4	75 Percent Average Use	32	41.80	$ 42.60	$ 0.80	1.91%	4
5	Average Winter Use [1]	43	53.50	$ 54.67	1.17	2.19%	5
6	125 Percent Average Use	54	65.11	$ 66.74	1.63	2.50%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.00
Commodity Charge Summer	
First 15 Therms	$ 1.35948
Over 15 Therms	1.31848
Commodity Charge Winter	
First 35 Therms	$ 1.08758
Next 115 Therms	1.05478
Over 150 Therms	1.31848

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 7.50
Commodity Charge Summer	
All Usage	$ 1.37124
Commodity Charge Winter	
First 150 Therms	$ 1.09699
Over 150 Therms	1.37124

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
MULTI-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	8	20.49	$ 20.63	$ 0.14	0.68%	1
2	Average Summer Use [1]	11	24.80	$ 25.10	0.30	1.21%	2
3	125 Percent Average Use	14	29.12	$ 29.57	0.45	1.55%	3
	Winter Season Bills						
4	75 Percent Average Use	18	35.32	$ 35.53	$ 0.21	0.59%	4
5	Average Winter Use [1]	24	43.95	$ 44.48	0.53	1.21%	5
6	125 Percent Average Use	30	52.57	$ 53.42	0.85	1.62%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 8.70
Commodity Charge Summer	
First 7 Therms	$ 1.47889
Over 7 Therms	1.43789
Commodity Charge Winter	
First 18 Therms	$ 1.47889
Over 18 Therms	1.43789

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 8.70
Commodity Charge	
All Usage	$ 1.49065

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES INCLUDING DISCOUNT
LOW-INCOME MULTI-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	9	19.15	$ 19.84	$ 0.69	3.60%	1
2	Average Summer Use [1]	12	23.11	$ 23.95	0.84	3.63%	2
3	125 Percent Average Use	15	27.06	$ 28.07	1.01	3.73%	3
	Winter Season Bills						
4	75 Percent Average Use	22	30.87	$ 31.63	$ 0.76	2.46%	4
5	Average Winter Use [1]	29	38.27	$ 39.31	1.04	2.72%	5
6	125 Percent Average Use	36	45.68	$ 46.99	1.31	2.87%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.00
Commodity Charge Summer	
First 7 Therms	$ 1.35948
Over 7 Therms	1.31848
Commodity Charge Winter	
First 18 Therms	$ 1.09080
Next 132 Therms	1.05800
Over 150 Therms	1.31848

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 7.50
Commodity Charge Summer	
All Usage	$ 1.37124
Commodity Charge Winter	
First 150 Therms	$ 1.09699
Over 150 Therms	1.37124

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
MASTER METERED MOBILE HOME PARK GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	354	527.60	538.68	$ 11.08	2.10%	1
2	Average Summer Use [1]	472	683.46	698.24	14.78	2.16%	2
3	125 Percent Average Use	590	839.33	857.80	18.47	2.20%	3
	Winter Season Bills						
4	75 Percent Average Use	1,341	1,831.31	1,873.30	41.99	2.29%	4
5	Average Winter Use [1]	1,788	2,421.75	2,477.73	55.98	2.31%	5
6	125 Percent Average Use	2,235	3,012.19	3,082.17	69.98	2.32%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 60.00
Commodity Charge	
All Usage	$ 1.32089

Proposed Tariff Rates [3]	
Basic Service Charge	$ 60.00
Commodity Charge	
All Usage	$ 1.35220

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GENERAL GAS SERVICE - SMALL

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	8	$ 36.92	$ 38.49	$ 1.57	4.25%	1
2	Average Summer Use [1]	10	$ 39.90	$ 41.86	1.96	4.92%	2
3	125 Percent Average Use	13	$ 44.37	$ 46.92	2.55	5.75%	3
	Winter Season Bills						
4	75 Percent Average Use	29	$ 68.20	$ 73.89	5.69	8.35%	4
5	Average Winter Use [1]	39	$ 83.10	$ 90.75	7.66	9.22%	5
6	125 Percent Average Use	49	$ 97.99	$ 107.61	9.62	9.82%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 1.48965
Proposed Tariff Rates [3]	
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 1.68600

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GENERAL GAS SERVICE - MEDIUM

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	115	$ 184.91	$ 197.30	$ 12.38	6.70%	1
2	Average Summer Use [1]	153	$ 235.11	$ 248.12	13.01	5.53%	2
3	125 Percent Average Use	191	$ 285.31	$ 298.94	13.63	4.78%	3
	Winter Season Bills						
4	75 Percent Average Use	236	$ 344.75	$ 359.12	14.37	4.17%	4
5	Average Winter Use [1]	315	$ 449.11	$ 464.77	15.66	3.49%	5
6	125 Percent Average Use	394	$ 553.46	$ 570.42	16.96	3.06%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 33.00
Commodity Charge	
All Usage	$ 1.32097
Proposed Tariff Rates [3]	
Basic Service Charge	$ 43.50
Commodity Charge	
All Usage	$ 1.33736

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GENERAL GAS SERVICE - LARGE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	929	$ 1,259.42	$ 1,289.58	$ 30.16	2.39%	1
2	Average Summer Use [1]	1,239	$ 1,631.29	$ 1,666.51	35.22	2.16%	2
3	125 Percent Average Use	1,549	$ 2,003.16	$ 2,043.44	40.28	2.01%	3
	Winter Season Bills						
4	75 Percent Average Use	1,665	$ 2,142.32	$ 2,184.49	42.17	1.97%	4
5	Average Winter Use [1]	2,220	$ 2,808.09	$ 2,859.32	51.23	1.82%	5
6	125 Percent Average Use	2,775	$ 3,473.86	$ 3,534.15	60.29	1.74%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 145.00
Commodity Charge	
All Usage	$ 1.19959

Proposed Tariff Rates [3]	
Basic Service Charge	$ 160.00
Commodity Charge	
All Usage	$ 1.21591

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - SMALL

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	605	$ 688.98	$ 692.21	$ 3.24	0.47%	1
2	Average Summer Use [1]	806	$ 909.57	$ 913.88	4.31	0.47%	2
3	125 Percent Average Use	1,008	$ 1,131.26	$ 1,136.65	5.39	0.48%	3
	Winter Season Bills						
4	75 Percent Average Use	452	$ 521.06	$ 523.48	2.42	0.46%	4
5	Average Winter Use [1]	602	$ 685.68	$ 688.90	3.22	0.47%	5
6	125 Percent Average Use	753	$ 851.40	$ 855.43	4.03	0.47%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 1.09748

Proposed Tariff Rates [3]	
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 1.10283

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - LARGE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	5,655	$ 6,396.25	$ 6,486.50	$ 90.25	1.41%	1
2	Average Summer Use [1]	7,540	$ 8,465.00	$ 8,565.34	100.34	1.19%	2
3	125 Percent Average Use	9,425	$ 10,533.75	$ 10,644.17	110.42	1.05%	3
	Winter Season Bills						
4	75 Percent Average Use	5,075	$ 5,759.71	$ 5,846.86	87.15	1.51%	4
5	Average Winter Use [1]	6,767	$ 7,616.65	$ 7,712.85	96.20	1.26%	5
6	125 Percent Average Use	8,459	$ 9,473.58	$ 9,578.84	105.26	1.11%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 190.00
Commodity Charge	
All Usage	$ 1.09748
Proposed Tariff Rates [3]	
Basic Service Charge	$ 250.00
Commodity Charge	
All Usage	$ 1.10283

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - RESIDENTIAL

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	47	$ 61.28	$ 64.63	$ 3.35	5.47%	1
2	Average Summer Use [1]	63	$ 78.84	$ 82.28	3.44	4.36%	2
3	125 Percent Average Use	79	$ 96.40	$ 99.92	3.52	3.65%	3
	Winter Season Bills						
4	75 Percent Average Use	44	$ 57.99	$ 61.32	3.34	5.75%	4
5	Average Winter Use [1]	59	$ 74.45	$ 77.87	3.42	4.59%	5
6	125 Percent Average Use	74	$ 90.91	$ 94.41	3.50	3.85%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 9.70
Commodity Charge	
All Usage	$ 1.09748

Proposed Tariff Rates [3]	
Basic Service Charge	$ 12.80
Commodity Charge	
All Usage	$ 1.10283

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
ESSENTIAL AGRICULTURAL USER GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	5,093	$ 5,949.39	$ 6,032.11	$ 82.71	1.39%	1
2	Average Summer Use [1]	6,791	$ 7,902.91	$ 8,003.20	100.29	1.27%	2
3	125 Percent Average Use	8,489	$ 9,856.42	$ 9,974.29	117.86	1.20%	3
	Winter Season Bills						
4	75 Percent Average Use	5,220	$ 6,095.51	$ 6,179.53	84.03	1.38%	4
5	Average Winter Use [1]	6,960	$ 8,097.34	$ 8,199.38	102.04	1.26%	5
6	125 Percent Average Use	8,700	$ 10,099.18	$ 10,219.22	120.05	1.19%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 90.00
Commodity Charge	
All Usage	$ 1.15048

Proposed Tariff Rates [3]	
Basic Service Charge	$ 120.00
Commodity Charge	
All Usage	$ 1.16083

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-5 CLASS = RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	168,759	168,759	0.00	3.30	4,939,100	0	0	0.00
1	68,554	68,554	68,554	237,314	0.11	4.65	4,870,545	4,870,545	4,939,100	7.71
2	214,312	282,866	107,156	344,470	0.44	6.74	4,763,389	9,526,779	9,809,645	15.31
3	752,867	1,035,733	250,956	595,425	1.62	11.66	4,512,434	13,537,302	14,573,035	22.75
4	1,245,252	2,280,986	311,313	906,738	3.56	17.75	4,201,121	16,804,483	19,085,469	29.80
5	1,645,582	3,926,568	329,116	1,235,855	6.13	24.20	3,872,004	19,360,022	23,286,589	36.35
6	2,070,541	5,997,109	345,090	1,580,945	9.36	30.95	3,526,914	21,161,485	27,158,594	42.40
7	2,453,632	8,450,741	350,519	1,931,464	13.19	37.81	3,176,395	22,234,767	30,685,508	47.90
8	2,819,751	11,270,492	352,469	2,283,933	17.59	44.71	2,823,926	22,591,411	33,861,903	52.86
9	2,514,042	13,784,534	279,338	2,563,271	21.52	50.18	2,544,588	22,901,295	36,685,830	57.27
10	2,898,078	16,682,613	289,808	2,853,078	26.04	55.86	2,254,781	22,547,805	39,230,418	61.24
11	3,203,528	19,886,141	291,230	3,144,308	31.05	61.56	1,963,551	21,599,057	41,485,198	64.76
12	2,890,299	22,776,440	240,858	3,385,167	35.56	66.27	1,722,692	20,672,309	43,448,749	67.83
13	2,782,216	25,558,656	214,017	3,599,183	39.90	70.46	1,508,676	19,612,785	45,171,441	70.52
14	1,962,138	27,520,794	140,153	3,739,336	42.96	73.21	1,368,523	19,159,324	46,680,117	72.87
15	2,444,815	29,965,608	162,988	3,902,324	46.78	76.40	1,205,535	18,083,032	48,048,640	75.01
16	2,309,769	32,275,378	144,361	4,046,684	50.39	79.22	1,061,175	16,978,798	49,254,176	76.89
17	2,161,681	34,437,059	127,158	4,173,842	53.76	81.71	934,017	15,878,292	50,315,351	78.55
18	1,970,234	36,407,293	109,457	4,283,299	56.84	83.86	824,560	14,842,075	51,249,368	80.01
19	1,817,229	38,224,522	95,644	4,378,943	59.67	85.73	728,916	13,849,406	52,073,928	81.29
20	1,109,872	39,334,394	55,494	4,434,437	61.41	86.82	673,422	13,468,450	52,802,844	82.43
25	6,879,217	46,213,611	295,839	4,730,275	72.15	92.61	377,584	9,439,590	55,653,201	86.88
30	3,856,399	50,070,010	134,865	4,865,141	78.17	95.25	242,718	7,281,552	57,351,562	89.53
35	2,550,561	52,620,571	75,600	4,940,741	82.15	96.73	167,118	5,849,131	58,469,702	91.28
40	1,687,846	54,308,418	43,544	4,984,285	84.78	97.58	123,574	4,942,951	59,251,368	92.50
45	1,246,282	55,554,700	28,492	5,012,777	86.73	98.14	95,082	4,278,680	59,833,379	93.41
50	926,798	56,481,498	18,978	5,031,755	88.18	98.51	76,104	3,805,197	60,286,695	94.12
55	723,501	57,204,999	13,411	5,045,166	89.31	98.77	62,693	3,448,113	60,653,111	94.69
60	595,001	57,800,000	10,076	5,055,242	90.23	98.97	52,617	3,157,030	60,957,030	95.16
65	547,469	58,347,469	8,520	5,063,762	91.09	99.14	44,097	2,866,305	61,213,774	95.56
70	418,225	58,765,693	6,005	5,069,767	91.74	99.25	38,092	2,666,459	61,432,152	95.90

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-5 CLASS = RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	366,033	59,131,727	4,892	5,074,658	92.31	99.35	33,201	2,490,047	61,621,773	96.20
80	314,624	59,446,350	3,945	5,078,603	92.80	99.43	29,256	2,340,471	61,786,822	96.46
85	268,917	59,715,267	3,173	5,081,776	93.22	99.49	26,083	2,217,086	61,932,354	96.69
90	236,755	59,952,023	2,639	5,084,414	93.59	99.54	23,445	2,110,034	62,062,057	96.89
95	227,035	60,179,058	2,393	5,086,807	93.95	99.59	21,052	1,999,940	62,178,997	97.07
100	191,144	60,370,202	1,914	5,088,721	94.25	99.63	19,138	1,913,780	62,283,982	97.23
105	197,916	60,568,117	1,882	5,090,603	94.56	99.66	17,256	1,811,863	62,379,981	97.38
110	157,865	60,725,983	1,429	5,092,032	94.80	99.69	15,827	1,740,963	62,466,946	97.52
115	143,877	60,869,860	1,245	5,093,277	95.03	99.71	14,582	1,676,925	62,546,785	97.64
120	138,340	61,008,200	1,148	5,094,425	95.24	99.74	13,434	1,612,133	62,620,333	97.76
125	127,436	61,135,636	1,015	5,095,439	95.44	99.76	12,420	1,552,447	62,688,082	97.86
130	117,024	61,252,659	897	5,096,336	95.62	99.77	11,523	1,497,975	62,750,635	97.96
135	101,756	61,354,415	750	5,097,086	95.78	99.79	10,773	1,454,354	62,808,769	98.05
140	100,830	61,455,245	717	5,097,803	95.94	99.80	10,056	1,407,832	62,863,078	98.14
145	102,746	61,557,991	704	5,098,507	96.10	99.82	9,352	1,356,019	62,914,011	98.22
150	83,914	61,641,906	555	5,099,062	96.23	99.83	8,797	1,319,537	62,961,442	98.29
155	81,817	61,723,723	523	5,099,585	96.36	99.84	8,274	1,282,416	63,006,138	98.36
160	75,656	61,799,379	469	5,100,054	96.48	99.85	7,805	1,248,727	63,048,106	98.43
165	69,896	61,869,275	420	5,100,475	96.59	99.86	7,384	1,218,408	63,087,683	98.49
170	68,002	61,937,277	397	5,100,872	96.69	99.86	6,987	1,187,838	63,125,115	98.55
175	65,285	62,002,562	370	5,101,242	96.79	99.87	6,617	1,157,965	63,160,527	98.60
180	62,571	62,065,133	345	5,101,587	96.89	99.88	6,272	1,128,973	63,194,106	98.65
185	65,497	62,130,629	351	5,101,938	96.99	99.88	5,921	1,095,372	63,226,001	98.70
190	60,733	62,191,362	316	5,102,254	97.09	99.89	5,605	1,064,874	63,256,237	98.75
195	56,169	62,247,531	285	5,102,539	97.18	99.90	5,320	1,037,362	63,284,893	98.80
200	44,943	62,292,475	222	5,102,762	97.25	99.90	5,097	1,019,486	63,311,961	98.84
999,999	1,763,270	64,055,745	5,097	5,107,859	100.00	100.00	0	0	64,055,745	100.00
TOTAL	64,055,745		5,107,859							
AVG. USE	12.5									

SCHEDULE H-5
SHEET 2 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-5 CLASS = RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	71,964	71,964	0.00	1.39	5,118,207	0	0	0.00
1	25,507	25,507	25,507	97,471	0.01	1.88	5,092,700	5,092,700	5,118,207	2.27
2	53,897	79,404	26,948	124,420	0.04	2.40	5,065,751	10,131,503	10,210,907	4.54
3	149,047	228,451	49,682	174,102	0.10	3.35	5,016,069	15,048,207	15,276,658	6.79
4	237,350	465,802	59,338	233,440	0.21	4.50	4,956,731	19,826,925	20,292,727	9.02
5	209,331	675,132	41,866	275,306	0.30	5.30	4,914,865	24,574,326	25,249,458	11.22
6	260,829	935,962	43,472	318,777	0.42	6.14	4,871,394	29,228,362	30,164,323	13.41
7	549,210	1,485,171	78,459	397,236	0.66	7.65	4,792,935	33,550,546	35,035,717	15.57
8	667,975	2,153,146	83,497	480,733	0.96	9.26	4,709,438	37,675,506	39,828,652	17.70
9	884,524	3,037,670	98,280	579,013	1.35	11.16	4,611,158	41,500,420	44,538,090	19.79
10	1,031,312	4,068,982	103,131	682,144	1.81	13.14	4,508,027	45,080,266	49,149,248	21.84
11	956,060	5,025,042	86,915	769,059	2.23	14.82	4,421,112	48,632,232	53,657,275	23.85
12	1,473,075	6,498,118	122,756	891,815	2.89	17.18	4,298,356	51,580,269	58,078,387	25.81
13	1,340,265	7,838,383	103,097	994,913	3.48	19.17	4,195,258	54,538,359	62,376,742	27.72
14	1,641,508	9,479,891	117,251	1,112,163	4.21	21.43	4,078,008	57,092,110	66,572,001	29.59
15	566,819	10,046,709	37,788	1,149,951	4.47	22.16	4,040,220	60,603,299	70,650,009	31.40
16	2,042,036	12,088,746	127,627	1,277,578	5.37	24.62	3,912,593	62,601,483	74,690,228	33.20
17	1,959,449	14,048,195	115,262	1,392,840	6.24	26.84	3,797,331	64,554,627	78,602,821	34.93
18	2,152,609	16,200,804	119,589	1,512,429	7.20	29.14	3,677,742	66,199,348	82,400,152	36.62
19	1,099,955	17,300,759	57,892	1,570,322	7.69	30.26	3,619,849	68,777,135	86,077,894	38.26
20	2,296,000	19,596,759	114,800	1,685,122	8.71	32.47	3,505,049	70,100,984	89,697,743	39.87
25	10,072,374	29,669,133	434,221	2,119,343	13.19	40.83	3,070,828	76,770,707	106,439,840	47.31
30	11,219,716	40,888,849	397,531	2,516,874	18.17	48.49	2,673,297	80,198,912	121,087,761	53.82
35	10,290,610	51,179,459	308,243	2,825,117	22.75	54.43	2,365,054	82,776,898	133,956,357	59.54
40	10,668,055	61,847,515	279,679	3,104,796	27.49	59.82	2,085,375	83,415,010	145,262,524	64.56
45	10,727,382	72,574,897	249,088	3,353,884	32.26	64.62	1,836,287	82,632,932	155,207,828	68.98
50	11,240,515	83,815,412	233,630	3,587,514	37.25	69.12	1,602,657	80,132,865	163,948,277	72.87
55	11,391,371	95,206,783	214,136	3,801,649	42.31	73.25	1,388,522	76,368,683	171,575,466	76.26
60	10,804,701	106,011,484	184,976	3,986,625	47.12	76.81	1,203,546	72,212,758	178,224,242	79.21
65	10,286,765	116,298,249	162,300	4,148,925	51.69	79.94	1,041,246	67,681,004	183,979,252	81.77
70	10,129,608	126,427,857	148,179	4,297,104	56.19	82.79	893,067	62,514,696	188,942,553	83.97

SCHEDULE H-5
SHEET 3 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-5 CLASS = RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	9,441,352	135,869,209	128,469	4,425,573	60.39	85.27	764,598	57,344,861	193,214,070	85.87
80	8,422,196	144,291,404	107,353	4,532,925	64.13	87.34	657,246	52,579,649	196,871,053	87.50
85	7,651,537	151,942,941	91,966	4,624,891	67.53	89.11	565,280	48,048,766	199,991,708	88.89
90	7,434,396	159,377,337	84,114	4,709,006	70.83	90.73	481,165	43,304,864	202,682,201	90.08
95	6,432,891	165,810,228	68,833	4,777,839	73.69	92.06	412,332	39,171,562	204,981,790	91.10
100	5,524,613	171,334,841	56,145	4,833,984	76.15	93.14	356,187	35,618,727	206,953,567	91.98
105	5,441,273	176,776,114	52,589	4,886,573	78.57	94.15	303,598	31,877,819	208,653,933	92.73
110	4,479,884	181,255,998	41,212	4,927,784	80.56	94.94	262,387	28,862,530	210,118,528	93.39
115	3,845,312	185,101,310	33,826	4,961,610	82.27	95.60	228,561	26,284,483	211,385,793	93.95
120	3,608,082	188,709,392	30,444	4,992,054	83.87	96.18	198,117	23,774,044	212,483,435	94.44
125	2,984,368	191,693,759	24,118	5,016,172	85.20	96.65	173,999	21,749,823	213,443,582	94.86
130	2,793,095	194,486,854	21,710	5,037,883	86.44	97.07	152,288	19,797,503	214,284,358	95.24
135	2,295,064	196,781,918	17,189	5,055,072	87.46	97.40	135,099	18,238,424	215,020,343	95.56
140	2,177,963	198,959,882	15,721	5,070,793	88.43	97.70	119,378	16,712,967	215,672,849	95.85
145	2,002,459	200,962,341	13,924	5,084,717	89.32	97.97	105,454	15,290,844	216,253,185	96.11
150	1,568,248	202,530,589	10,527	5,095,244	90.01	98.17	94,927	14,239,086	216,769,675	96.34
155	1,531,443	204,062,032	9,958	5,105,201	90.69	98.36	84,970	13,170,309	217,232,341	96.55
160	1,332,588	205,394,620	8,382	5,113,583	91.29	98.52	76,588	12,254,076	217,648,696	96.73
165	1,154,884	206,549,504	7,039	5,120,622	91.80	98.66	69,549	11,475,546	218,025,050	96.90
170	1,045,759	207,595,263	6,191	5,126,813	92.26	98.78	63,358	10,770,854	218,366,117	97.05
175	924,359	208,519,622	5,319	5,132,132	92.68	98.88	58,039	10,156,829	218,676,450	97.19
180	894,787	209,414,408	4,999	5,137,131	93.07	98.98	53,040	9,547,285	218,961,693	97.32
185	754,929	210,169,338	4,103	5,141,234	93.41	99.06	48,937	9,053,343	219,222,681	97.43
190	755,691	210,925,029	3,997	5,145,231	93.74	99.13	44,940	8,538,557	219,463,586	97.54
195	656,536	211,581,565	3,380	5,148,611	94.04	99.20	41,560	8,104,234	219,685,799	97.64
200	585,707	212,167,272	2,940	5,151,551	94.30	99.26	38,620	7,724,078	219,891,350	97.73
999,999	12,833,098	225,000,370	38,620	5,190,171	100.00	100.00	0	0	225,000,370	100.00
TOTAL	225,000,370		5,190,171							
AVG. USE	43.4									

SCHEDULE H-5
SHEET 4 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-6 CLASS = MULTI-FAMILY RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	10,195	10,195	0.00	5.59	172,214	0	0	0.00
1	4,090	4,090	4,090	14,285	0.21	7.83	168,124	168,124	172,214	8.63
2	9,960	14,050	4,980	19,265	0.70	10.56	163,144	326,288	340,338	17.06
3	31,957	46,008	10,652	29,918	2.31	16.40	152,491	457,474	503,482	25.24
4	46,591	92,599	11,648	41,565	4.64	22.79	140,844	563,375	655,973	32.89
5	53,297	145,895	10,659	52,225	7.32	28.63	130,184	650,922	796,817	39.95
6	76,522	222,418	12,754	64,978	11.15	35.62	117,431	704,583	927,001	46.48
7	90,315	312,733	12,902	77,881	15.68	42.70	104,528	731,699	1,044,432	52.37
8	97,204	409,937	12,150	90,031	20.55	49.36	92,378	739,023	1,148,960	57.61
9	100,182	510,119	11,131	101,162	25.58	55.46	81,247	731,219	1,241,338	62.24
10	101,555	611,673	10,155	111,318	30.67	61.03	71,091	710,911	1,322,585	66.31
11	107,480	719,153	9,771	121,089	36.06	66.38	61,320	674,522	1,393,676	69.88
12	102,777	821,930	8,565	129,654	41.21	71.08	52,755	633,066	1,454,996	72.95
13	92,374	914,304	7,106	136,759	45.84	74.97	45,650	593,447	1,507,752	75.60
14	67,986	982,290	4,856	141,615	49.25	77.64	40,794	571,111	1,553,401	77.89
15	80,060	1,062,350	5,337	146,953	53.27	80.56	35,456	531,845	1,594,195	79.93
16	74,273	1,136,624	4,642	151,595	56.99	83.11	30,814	493,028	1,629,651	81.71
17	70,082	1,206,705	4,122	155,717	60.50	85.37	26,692	453,760	1,660,466	83.25
18	62,801	1,269,507	3,489	159,206	63.65	87.28	23,203	417,651	1,687,157	84.59
19	57,343	1,326,849	3,018	162,224	66.53	88.93	20,185	383,511	1,710,360	85.76
20	53,805	1,380,655	2,690	164,914	69.23	90.41	17,495	349,890	1,730,545	86.77
25	212,586	1,593,241	8,176	173,091	79.88	94.89	9,318	232,962	1,826,203	91.56
30	135,448	1,728,689	4,234	177,325	86.68	97.21	5,084	152,526	1,881,214	94.32
35	75,076	1,803,765	1,995	179,319	90.44	98.31	3,090	108,137	1,911,901	95.86
40	48,960	1,852,725	1,122	180,442	92.89	98.92	1,967	78,687	1,931,412	96.84
45	30,311	1,883,036	616	181,058	94.41	99.26	1,351	60,810	1,943,846	97.46
50	20,664	1,903,700	375	181,432	95.45	99.46	977	48,829	1,952,529	97.90
55	12,490	1,916,190	206	181,638	96.08	99.58	771	42,402	1,958,593	98.20
60	9,713	1,925,903	146	181,784	96.56	99.66	625	37,505	1,963,408	98.44
65	7,236	1,933,139	100	181,884	96.93	99.71	525	34,135	1,967,274	98.64
70	6,866	1,940,005	88	181,972	97.27	99.76	437	30,590	1,970,595	98.80

SCHEDULE H-5
SHEET 5 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-6 CLASS = MULTI-FAMILY RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	5,570	1,945,575	67	182,039	97.55	99.80	370	27,777	1,973,352	98.94
80	3,424	1,948,999	43	182,082	97.72	99.82	327	26,177	1,975,176	99.03
85	3,815	1,952,814	45	182,127	97.91	99.85	282	23,982	1,976,796	99.12
90	3,152	1,955,966	35	182,162	98.07	99.86	247	22,214	1,978,180	99.18
95	2,144	1,958,110	23	182,185	98.18	99.88	224	21,306	1,979,416	99.25
100	1,667	1,959,777	17	182,201	98.26	99.89	208	20,762	1,980,539	99.30
105	1,344	1,961,121	13	182,214	98.33	99.89	195	20,461	1,981,582	99.36
110	3,337	1,964,458	30	182,245	98.50	99.91	164	18,091	1,982,549	99.40
115	1,469	1,965,927	13	182,257	98.57	99.92	152	17,452	1,983,379	99.45
120	1,063	1,966,990	9	182,266	98.62	99.92	143	17,152	1,984,142	99.48
125	1,225	1,968,215	10	182,276	98.69	99.93	133	16,640	1,984,855	99.52
130	1,525	1,969,740	12	182,288	98.76	99.93	121	15,778	1,985,518	99.55
135	1,736	1,971,476	13	182,300	98.85	99.94	109	14,663	1,986,139	99.58
140	1,241	1,972,717	9	182,309	98.91	99.95	100	13,974	1,986,691	99.61
145	715	1,973,432	5	182,314	98.95	99.95	95	13,764	1,987,196	99.64
150	890	1,974,322	6	182,320	98.99	99.95	89	13,358	1,987,680	99.66
155	612	1,974,934	4	182,324	99.02	99.95	85	13,195	1,988,129	99.68
160	1,261	1,976,195	8	182,332	99.09	99.96	77	12,364	1,988,559	99.71
165	818	1,977,013	5	182,337	99.13	99.96	72	11,942	1,988,955	99.73
170	1,009	1,978,022	6	182,342	99.18	99.96	67	11,307	1,989,329	99.74
175	519	1,978,541	3	182,345	99.20	99.97	64	11,125	1,989,666	99.76
180	714	1,979,255	4	182,349	99.24	99.97	60	10,736	1,989,991	99.78
185	1,100	1,980,355	6	182,355	99.29	99.97	54	9,951	1,990,306	99.79
190	944	1,981,299	5	182,360	99.34	99.97	49	9,287	1,990,586	99.81
195	773	1,982,072	4	182,364	99.38	99.98	45	8,769	1,990,841	99.82
200	594	1,982,666	3	182,367	99.41	99.98	42	8,405	1,991,071	99.83
999,999	11,771	1,994,437	42	182,409	100.00	100.00	0	0	1,994,437	100.00
TOTAL	1,994,437		182,409							
AVG. USE	10.9									

SCHEDULE H-5
SHEET 6 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-6 CLASS = MULTI-FAMILY RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	5,311	5,311	0.00	2.82	182,842	0	0	0.00
1	2,382	2,382	2,377	7,688	0.05	4.09	180,465	180,465	182,846	4.05
2	4,639	7,020	2,315	10,003	0.16	5.32	178,150	356,300	363,320	8.05
3	9,458	16,478	3,146	13,149	0.37	6.99	175,004	525,013	541,491	12.00
4	17,637	34,115	4,396	17,545	0.76	9.32	170,608	682,433	716,549	15.88
5	21,302	55,417	4,253	21,797	1.23	11.58	166,356	831,779	887,196	19.66
6	24,920	80,337	4,145	25,942	1.78	13.79	162,211	973,266	1,053,604	23.34
7	36,571	116,909	5,216	31,157	2.59	16.56	156,996	1,098,969	1,215,877	26.94
8	30,275	147,184	3,775	34,932	3.26	18.57	153,221	1,225,764	1,372,948	30.42
9	54,342	201,526	6,028	40,961	4.46	21.77	147,192	1,324,731	1,526,257	33.81
10	46,347	247,873	4,623	45,584	5.49	24.23	142,569	1,425,689	1,673,562	37.08
11	69,466	317,340	6,305	51,889	7.03	27.58	136,264	1,498,908	1,816,247	40.24
12	81,421	398,760	6,774	58,663	8.83	31.18	129,490	1,553,880	1,952,641	43.26
13	101,629	500,390	7,795	66,458	11.09	35.32	121,695	1,582,032	2,082,421	46.14
14	90,663	591,052	6,465	72,923	13.09	38.76	115,230	1,613,220	2,204,272	48.84
15	91,432	682,484	6,084	79,007	15.12	41.99	109,146	1,637,192	2,319,676	51.39
16	71,874	754,358	4,480	83,487	16.71	44.37	104,666	1,674,653	2,429,011	53.82
17	96,297	850,654	5,654	89,141	18.85	47.38	99,012	1,683,206	2,533,860	56.14
18	90,245	940,900	5,002	94,142	20.85	50.04	94,011	1,692,191	2,633,090	58.34
19	101,010	1,041,910	5,305	99,447	23.08	52.85	88,706	1,685,408	2,727,317	60.42
20	102,076	1,143,986	5,093	104,540	25.35	55.56	83,613	1,672,262	2,816,248	62.39
25	481,022	1,625,008	20,510	125,050	36.00	66.46	63,103	1,577,584	3,202,591	70.95
30	447,621	2,072,628	15,673	140,723	45.92	74.79	47,430	1,422,899	3,495,527	77.44
35	421,677	2,494,305	12,505	153,228	55.26	81.44	34,925	1,222,388	3,716,693	82.34
40	344,105	2,838,410	8,836	162,064	62.89	86.13	26,089	1,043,566	3,881,976	86.01
45	259,272	3,097,682	5,881	167,945	68.63	89.26	20,208	909,382	4,007,064	88.78
50	245,829	3,343,512	5,013	172,958	74.08	91.92	15,195	759,752	4,103,263	90.91
55	180,232	3,523,743	3,331	176,289	78.07	93.69	11,864	652,501	4,176,244	92.53
60	156,186	3,679,929	2,638	178,927	81.53	95.10	9,226	553,564	4,233,494	93.79
65	127,546	3,807,475	1,982	180,909	84.36	96.15	7,244	470,869	4,278,344	94.79
70	105,750	3,913,225	1,523	182,432	86.70	96.96	5,721	400,488	4,313,712	95.57

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-6 CLASS = MULTI-FAMILY RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	88,312	4,001,537	1,184	183,616	88.65	97.59	4,537	340,271	4,341,808	96.19
80	69,423	4,070,960	878	184,494	90.19	98.06	3,659	292,698	4,363,658	96.68
85	59,050	4,130,010	703	185,197	91.50	98.43	2,956	251,276	4,381,286	97.07
90	45,696	4,175,706	513	185,710	92.51	98.70	2,443	219,881	4,395,587	97.38
95	42,064	4,217,770	446	186,156	93.45	98.94	1,997	189,686	4,407,456	97.65
100	37,774	4,255,544	381	186,538	94.28	99.14	1,615	161,542	4,417,086	97.86
105	27,466	4,283,010	264	186,801	94.89	99.28	1,352	141,941	4,424,951	98.04
110	20,859	4,303,869	191	186,992	95.35	99.38	1,161	127,735	4,431,604	98.18
115	15,454	4,319,323	135	187,127	95.70	99.45	1,026	117,978	4,437,301	98.31
120	18,174	4,337,497	152	187,279	96.10	99.54	874	104,859	4,442,356	98.42
125	13,273	4,350,770	107	187,386	96.39	99.59	767	95,884	4,446,654	98.52
130	12,167	4,362,937	94	187,480	96.66	99.64	673	87,521	4,450,458	98.60
135	10,506	4,373,443	78	187,558	96.89	99.68	595	80,361	4,453,804	98.67
140	10,049	4,383,492	72	187,630	97.12	99.72	523	73,251	4,456,743	98.74
145	6,593	4,390,085	46	187,675	97.26	99.75	478	69,269	4,459,354	98.80
150	6,653	4,396,738	44	187,720	97.41	99.77	433	65,003	4,461,741	98.85
155	3,971	4,400,709	26	187,745	97.50	99.78	408	63,189	4,463,898	98.90
160	4,592	4,405,301	29	187,774	97.60	99.80	379	60,656	4,465,957	98.94
165	4,226	4,409,527	26	187,800	97.69	99.81	353	58,297	4,467,824	98.99
170	3,365	4,412,892	20	187,820	97.77	99.82	333	56,691	4,469,583	99.02
175	2,604	4,415,496	15	187,834	97.83	99.83	319	55,770	4,471,266	99.06
180	3,021	4,418,517	17	187,851	97.89	99.84	302	54,336	4,472,853	99.10
185	2,754	4,421,271	15	187,866	97.95	99.85	287	53,090	4,474,361	99.13
190	1,503	4,422,774	8	187,874	97.99	99.85	279	53,027	4,475,801	99.16
195	2,512	4,425,286	13	187,887	98.04	99.86	266	51,902	4,477,188	99.19
200	1,981	4,427,267	10	187,897	98.09	99.86	256	51,261	4,478,528	99.22
999,999	86,355	4,513,622	256	188,153	100.00	100.00	0	0	4,513,622	100.00
TOTAL	4,513,622		188,153							
AVG. USE	24.0									

SCHEDULE H-5
SHEET 8 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-10 CLASS = LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	3,281	3,281	0.00	2.13	150,642	0	0	0.00
1	2,061	2,061	2,061	5,342	0.11	3.47	148,581	148,581	150,642	8.17
2	5,730	7,791	2,865	8,207	0.42	5.33	145,716	291,432	299,223	16.23
3	19,582	27,373	6,527	14,734	1.48	9.57	139,189	417,566	444,939	24.14
4	36,012	63,385	9,003	23,737	3.44	15.42	130,186	520,743	584,128	31.69
5	48,643	112,028	9,729	33,466	6.08	21.74	120,457	602,286	714,314	38.75
6	60,782	172,810	10,130	43,596	9.37	28.32	110,327	661,960	834,771	45.28
7	70,245	243,055	10,035	53,631	13.18	34.84	100,292	702,042	945,097	51.27
8	82,696	325,751	10,337	63,968	17.67	41.56	89,955	719,638	1,045,389	56.71
9	84,658	410,409	9,406	73,375	22.26	47.67	80,548	724,935	1,135,344	61.59
10	74,335	484,744	7,433	80,808	26.29	52.50	73,115	731,149	1,215,892	65.95
11	104,566	589,309	9,506	90,314	31.97	58.67	63,609	699,698	1,289,007	69.92
12	93,891	683,201	7,824	98,138	37.06	63.76	55,785	669,415	1,352,616	73.37
13	91,193	774,394	7,015	105,153	42.01	68.32	48,770	634,007	1,408,401	76.40
14	86,931	861,325	6,209	111,363	46.72	72.35	42,560	595,846	1,457,170	79.04
15	77,017	938,341	5,134	116,497	50.90	75.69	37,426	561,389	1,499,731	81.35
16	56,033	994,375	3,502	119,999	53.94	77.96	33,924	542,782	1,537,157	83.38
17	74,757	1,069,132	4,397	124,397	57.99	80.82	29,526	501,948	1,571,081	85.22
18	67,942	1,137,074	3,775	128,171	61.68	83.27	25,752	463,533	1,600,607	86.82
19	61,497	1,198,570	3,237	131,408	65.02	85.37	22,515	427,789	1,626,359	88.22
20	60,296	1,258,866	3,015	134,423	68.29	87.33	19,500	390,008	1,648,874	89.44
25	221,701	1,480,567	9,374	143,797	80.31	93.42	10,126	253,149	1,733,717	94.04
30	132,648	1,613,215	4,636	148,433	87.51	96.43	5,490	164,699	1,777,914	96.44
35	90,964	1,704,179	2,682	151,115	92.44	98.18	2,808	98,272	1,802,451	97.77
40	44,352	1,748,531	1,126	152,242	94.85	98.91	1,681	67,259	1,815,790	98.50
45	29,499	1,778,029	665	152,907	96.45	99.34	1,016	45,738	1,823,768	98.93
50	16,773	1,794,802	340	153,247	97.36	99.56	676	33,799	1,828,601	99.19
55	14,466	1,809,268	264	153,511	98.14	99.73	412	22,644	1,831,912	99.37
60	6,912	1,816,180	115	153,626	98.52	99.81	297	17,815	1,833,995	99.48
65	4,782	1,820,962	73	153,699	98.78	99.85	224	14,540	1,835,502	99.56
70	3,905	1,824,867	55	153,755	98.99	99.89	168	11,779	1,836,645	99.63

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-10 CLASS = LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	2,257	1,827,124	30	153,784	99.11	99.91	139	10,393	1,837,517	99.67
80	2,099	1,829,223	27	153,811	99.22	99.93	112	8,948	1,838,171	99.71
85	1,583	1,830,806	19	153,830	99.31	99.94	93	7,909	1,838,715	99.74
90	1,322	1,832,128	15	153,845	99.38	99.95	78	7,038	1,839,166	99.76
95	1,111	1,833,239	12	153,857	99.44	99.96	66	6,300	1,839,539	99.78
100	1,268	1,834,507	13	153,870	99.51	99.97	53	5,345	1,839,852	99.80
105	615	1,835,122	6	153,875	99.54	99.97	48	4,989	1,840,111	99.81
110	967	1,836,089	9	153,884	99.60	99.97	39	4,247	1,840,336	99.83
115	673	1,836,762	6	153,890	99.63	99.98	33	3,757	1,840,519	99.84
120	707	1,837,469	6	153,896	99.67	99.98	27	3,208	1,840,677	99.85
125	611	1,838,080	5	153,901	99.70	99.99	22	2,723	1,840,803	99.85
130	0	1,838,080	0	153,901	99.70	99.99	22	2,832	1,840,912	99.86
135	134	1,838,214	1	153,902	99.71	99.99	21	2,807	1,841,021	99.86
140	416	1,838,630	3	153,905	99.73	99.99	18	2,496	1,841,126	99.87
145	145	1,838,775	1	153,906	99.74	99.99	17	2,441	1,841,216	99.87
150	149	1,838,924	1	153,907	99.75	99.99	16	2,376	1,841,300	99.88
155	152	1,839,076	1	153,908	99.76	99.99	15	2,302	1,841,378	99.88
160	314	1,839,390	2	153,910	99.78	99.99	13	2,059	1,841,449	99.89
165	491	1,839,881	3	153,913	99.80	99.99	10	1,634	1,841,515	99.89
170	338	1,840,219	2	153,915	99.82	99.99	8	1,346	1,841,565	99.89
175	173	1,840,392	1	153,916	99.83	100.00	7	1,213	1,841,605	99.90
180	177	1,840,569	1	153,917	99.84	100.00	6	1,069	1,841,638	99.90
185	367	1,840,936	2	153,919	99.86	100.00	4	732	1,841,668	99.90
190	0	1,840,936	0	153,919	99.86	100.00	4	752	1,841,688	99.90
195	193	1,841,129	1	153,920	99.87	100.00	3	579	1,841,708	99.90
200	0	1,841,129	0	153,920	99.87	100.00	3	594	1,841,723	99.90
999,999	2,394	1,843,523	3	153,923	100.00	100.00	0	0	1,843,523	100.00
TOTAL	1,843,523		153,923							
AVG. USE	12.0									

SCHEDULE H-5
SHEET 10 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-10 CLASS = LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	1,022	1,022	0.00	0.65	155,961	0	0	0.00
1	459	459	459	1,481	0.01	0.94	155,502	155,502	155,961	2.29
2	927	1,386	463	1,944	0.02	1.24	155,039	310,077	311,463	4.57
3	3,006	4,391	1,002	2,946	0.06	1.88	154,037	462,110	466,502	6.84
4	3,141	7,533	785	3,731	0.11	2.38	153,252	613,006	620,539	9.10
5	6,986	14,518	1,397	5,129	0.21	3.27	151,854	759,272	773,790	11.35
6	10,279	24,798	1,713	6,842	0.36	4.36	150,141	900,847	925,645	13.58
7	10,981	35,779	1,569	8,411	0.52	5.36	148,572	1,040,007	1,075,786	15.78
8	19,236	55,015	2,404	10,815	0.81	6.89	146,168	1,169,344	1,224,358	17.96
9	23,762	78,777	2,640	13,455	1.16	8.57	143,528	1,291,749	1,370,526	20.11
10	29,177	107,954	2,918	16,373	1.58	10.43	140,610	1,406,100	1,514,054	22.22
11	9,797	117,751	891	17,264	1.73	11.00	139,719	1,536,913	1,654,664	24.28
12	39,414	157,165	3,285	20,548	2.31	13.09	136,435	1,637,218	1,794,383	26.33
13	47,263	204,428	3,636	24,184	3.00	15.41	132,799	1,726,390	1,930,818	28.33
14	40,882	245,310	2,920	27,104	3.60	17.27	129,879	1,818,307	2,063,617	30.28
15	31,851	277,162	2,123	29,227	4.07	18.62	127,756	1,916,335	2,193,496	32.18
16	57,736	334,898	3,609	32,836	4.91	20.92	124,147	1,986,354	2,321,252	34.06
17	59,263	394,161	3,486	36,322	5.78	23.14	120,661	2,051,238	2,445,399	35.88
18	51,880	446,041	2,882	39,204	6.54	24.97	117,779	2,120,019	2,566,060	37.65
19	44,630	490,671	2,349	41,553	7.20	26.47	115,430	2,193,168	2,683,839	39.38
20	43,205	533,876	2,160	43,713	7.83	27.85	113,270	2,265,393	2,799,269	41.07
25	326,837	860,713	14,145	57,859	12.63	36.86	99,124	2,478,108	3,338,820	48.99
30	344,796	1,205,509	12,209	70,068	17.69	44.63	86,915	2,607,452	3,812,961	55.95
35	361,455	1,566,964	10,833	80,901	22.99	51.53	76,082	2,662,878	4,229,842	62.06
40	389,050	1,956,013	10,088	90,989	28.70	57.96	65,994	2,639,761	4,595,774	67.43
45	355,087	2,311,100	8,090	99,079	33.91	63.11	57,904	2,605,672	4,916,772	72.14
50	359,757	2,670,858	7,404	106,484	39.19	67.83	50,499	2,524,967	5,195,825	76.24
55	352,861	3,023,718	6,574	113,058	44.37	72.02	43,925	2,415,891	5,439,609	79.81
60	360,798	3,384,517	6,143	119,201	49.66	75.93	37,782	2,266,925	5,651,442	82.92
65	346,670	3,731,187	5,432	124,633	54.75	79.39	32,350	2,102,749	5,833,936	85.60
70	325,094	4,056,282	4,729	129,362	59.52	82.41	27,621	1,933,447	5,989,729	87.88

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-10 CLASS = LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	327,574	4,383,856	4,432	133,795	64.32	85.23	23,188	1,739,126	6,122,982	89.84
80	280,445	4,664,301	3,566	137,361	68.44	87.50	19,622	1,569,761	6,234,062	91.47
85	265,280	4,929,581	3,178	140,539	72.33	89.53	16,444	1,397,714	6,327,295	92.84
90	224,329	5,153,910	2,535	143,074	75.62	91.14	13,909	1,251,819	6,405,729	93.99
95	227,130	5,381,040	2,421	145,495	78.95	92.68	11,488	1,091,336	6,472,376	94.97
100	183,455	5,564,495	1,855	147,351	81.65	93.86	9,632	963,229	6,527,724	95.78
105	160,340	5,724,835	1,543	148,894	84.00	94.85	8,089	849,366	6,574,201	96.46
110	155,056	5,879,891	1,424	150,317	86.27	95.75	6,666	733,226	6,613,116	97.03
115	120,782	6,000,673	1,060	151,377	88.05	96.43	5,606	644,665	6,645,338	97.50
120	112,373	6,113,046	945	152,322	89.69	97.03	4,661	559,341	6,672,386	97.90
125	99,373	6,212,419	801	153,123	91.15	97.54	3,860	482,492	6,694,910	98.23
130	86,455	6,298,874	669	153,792	92.42	97.97	3,191	414,812	6,713,686	98.51
135	64,217	6,363,091	479	154,271	93.36	98.27	2,712	366,094	6,729,185	98.73
140	57,921	6,421,012	417	154,688	94.21	98.54	2,295	321,339	6,742,351	98.93
145	58,598	6,479,611	407	155,094	95.07	98.80	1,889	273,848	6,753,459	99.09
150	46,006	6,525,616	308	155,403	95.75	98.99	1,580	237,064	6,762,680	99.23
155	34,638	6,560,254	225	155,627	96.26	99.14	1,356	210,148	6,770,402	99.34
160	37,446	6,597,700	236	155,863	96.81	99.29	1,120	179,237	6,776,937	99.43
165	30,467	6,628,168	185	156,048	97.25	99.40	935	154,340	6,782,508	99.52
170	25,085	6,653,253	148	156,196	97.62	99.50	787	133,842	6,787,096	99.58
175	20,453	6,673,706	117	156,313	97.92	99.57	670	117,246	6,790,952	99.64
180	18,561	6,692,267	103	156,416	98.19	99.64	567	101,996	6,794,263	99.69
185	13,205	6,705,472	72	156,488	98.39	99.68	495	91,584	6,797,056	99.73
190	16,010	6,721,481	84	156,572	98.62	99.74	411	78,018	6,799,499	99.77
195	14,518	6,735,999	75	156,647	98.83	99.79	336	65,527	6,801,526	99.80
200	8,745	6,744,744	44	156,691	98.96	99.81	292	58,464	6,803,208	99.82
999,999	70,705	6,815,449	292	156,983	100.00	100.00	0	0	6,815,449	100.00
TOTAL	6,815,449		156,983							
AVG. USE	43.4									

SCHEDULE H-5
SHEET 12 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-11 CLASS = MULTI-FAMILY LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	784	784	0.00	5.78	12,776	0	0	0.00
1	309	309	309	1,093	0.20	8.06	12,467	12,467	12,776	8.09
2	450	759	225	1,318	0.48	9.72	12,242	24,484	25,243	15.99
3	1,759	2,518	586	1,905	1.59	14.05	11,655	34,966	37,485	23.74
4	2,466	4,984	616	2,521	3.16	18.59	11,039	44,156	49,140	31.12
5	4,024	9,008	805	3,326	5.71	24.53	10,234	51,171	60,179	38.11
6	4,953	13,961	825	4,151	8.84	30.61	9,409	56,453	70,413	44.60
7	5,742	19,703	820	4,972	12.48	36.66	8,588	60,119	79,822	50.55
8	6,515	26,218	814	5,786	16.61	42.67	7,774	62,192	88,410	55.99
9	7,240	33,458	804	6,590	21.19	48.60	6,970	62,727	96,184	60.92
10	7,396	40,854	740	7,330	25.87	54.06	6,230	62,300	103,154	65.33
11	8,514	49,369	774	8,104	31.27	59.76	5,456	60,015	109,384	69.28
12	8,319	57,688	693	8,797	36.54	64.88	4,763	57,152	114,840	72.73
13	6,367	64,055	490	9,287	40.57	68.49	4,273	55,547	119,603	75.75
14	7,971	72,026	569	9,856	45.62	72.69	3,704	51,850	123,876	78.46
15	6,968	78,994	465	10,321	50.03	76.11	3,239	48,585	127,579	80.80
16	6,438	85,431	402	10,723	54.11	79.08	2,837	45,387	130,818	82.85
17	6,295	91,726	370	11,094	58.09	81.81	2,466	41,928	133,655	84.65
18	6,133	97,859	341	11,434	61.98	84.32	2,126	38,262	136,121	86.21
19	5,393	103,252	284	11,718	65.39	86.42	1,842	34,994	138,247	87.56
20	4,903	108,155	245	11,963	68.50	88.23	1,597	31,933	140,089	88.72
25	20,253	128,408	800	12,763	81.33	94.13	797	19,913	148,321	93.94
30	11,575	139,983	378	13,141	88.66	96.91	419	12,556	152,538	96.61
35	7,155	147,137	196	13,337	93.19	98.36	223	7,801	154,939	98.13
40	2,974	150,112	74	13,411	95.07	98.90	149	5,946	156,058	98.84
45	2,745	152,857	61	13,472	96.81	99.35	88	3,961	156,818	99.32
50	1,870	154,727	36	13,508	97.99	99.61	52	2,616	157,343	99.65
55	846	155,573	17	13,524	98.53	99.74	36	1,953	157,526	99.77
60	402	155,975	7	13,532	98.79	99.79	28	1,690	157,665	99.86
65	634	156,609	10	13,542	99.19	99.87	18	1,152	157,761	99.92
70	477	157,086	7	13,550	99.49	99.92	10	731	157,817	99.95

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-11 CLASS = MULTI-FAMILY LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	220	157,306	3	13,553	99.63	99.95	7	549	157,855	99.98
80	155	157,461	2	13,555	99.73	99.96	5	419	157,880	99.99
85	165	157,626	2	13,557	99.83	99.98	3	267	157,893	100.00
90	267	157,893	3	13,560	100.00	100.00	0	0	157,893	100.00
95	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
100	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
105	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
110	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
115	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
120	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
125	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
130	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
135	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
140	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
145	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
150	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
155	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
160	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
165	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
170	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
175	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
180	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
185	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
190	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
195	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
200	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
999,999	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
TOTAL	157,893		13,560							
AVG. USE	11.6									

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-11 CLASS = MULTI-FAMILY LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	291	291	0.00	2.10	13,537	0	0	0.00
1	208	208	208	499	0.05	3.61	13,329	13,329	13,537	3.43
2	261	469	130	630	0.12	4.55	13,198	26,397	26,866	6.81
3	317	786	106	735	0.20	5.32	13,093	39,278	40,064	10.15
4	761	1,547	190	926	0.39	6.69	12,902	51,609	53,157	13.47
5	941	2,489	188	1,114	0.63	8.06	12,714	63,570	66,059	16.73
6	1,438	3,927	240	1,354	0.99	9.79	12,474	74,846	78,773	19.96
7	1,175	5,102	168	1,521	1.29	11.00	12,307	86,146	91,247	23.12
8	2,202	7,303	275	1,797	1.85	12.99	12,031	96,250	103,554	26.23
9	2,116	9,419	235	2,032	2.39	14.69	11,796	106,166	115,585	29.28
10	3,073	12,492	307	2,339	3.16	16.92	11,489	114,889	127,381	32.27
11	4,211	16,703	383	2,722	4.23	19.68	11,106	122,167	138,870	35.18
12	5,903	22,606	492	3,214	5.73	23.24	10,614	127,371	149,976	37.99
13	5,360	27,966	412	3,626	7.08	26.22	10,202	132,625	160,591	40.68
14	4,172	32,137	298	3,924	8.14	28.38	9,904	138,655	170,793	43.27
15	6,562	38,700	437	4,362	9.80	31.54	9,466	141,997	180,696	45.77
16	5,667	44,366	354	4,716	11.24	34.10	9,112	145,796	190,163	48.17
17	6,891	51,257	405	5,121	12.98	37.03	8,707	148,018	199,275	50.48
18	6,867	58,124	381	5,503	14.72	39.79	8,325	149,858	207,982	52.69
19	7,184	65,308	378	5,881	16.54	42.53	7,947	151,000	216,308	54.80
20	5,405	70,713	270	6,151	17.91	44.48	7,677	153,542	224,255	56.81
25	39,029	109,742	1,650	7,801	27.80	56.41	6,027	150,678	260,419	65.97
30	36,297	146,038	1,255	9,056	37.00	65.49	4,772	143,150	289,188	73.26
35	36,694	182,732	1,087	10,143	46.29	73.35	3,685	128,973	311,706	78.96
40	30,142	212,875	774	10,917	53.93	78.95	2,911	116,444	329,318	83.42
45	29,446	242,321	667	11,584	61.39	83.77	2,244	100,963	343,284	86.96
50	24,039	266,360	492	12,077	67.48	87.34	1,751	87,565	353,925	89.66
55	20,019	286,379	370	12,447	72.55	90.01	1,381	75,967	362,346	91.79
60	16,162	302,541	273	12,720	76.64	91.99	1,108	66,478	369,019	93.48
65	15,484	318,025	241	12,961	80.56	93.73	867	56,380	374,405	94.85
70	11,476	329,501	165	13,125	83.47	94.92	703	49,194	378,694	95.93

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-11 CLASS = MULTI-FAMILY LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	10,039	339,540	134	13,260	86.01	95.89	568	42,624	382,164	96.81
80	10,553	350,093	135	13,395	88.69	96.87	433	34,647	384,740	97.46
85	6,576	356,669	79	13,474	90.35	97.44	354	30,079	386,748	97.97
90	6,415	363,084	73	13,547	91.98	97.97	281	25,265	388,349	98.38
95	4,765	367,849	51	13,598	93.19	98.34	230	21,805	389,654	98.71
100	4,221	372,070	43	13,642	94.25	98.65	186	18,643	390,713	98.98
105	3,188	375,258	31	13,673	95.06	98.88	155	16,310	391,568	99.19
110	3,996	379,254	37	13,710	96.07	99.14	118	13,014	392,268	99.37
115	2,364	381,618	21	13,731	96.67	99.30	97	11,181	392,799	99.51
120	2,951	384,569	25	13,756	97.42	99.48	72	8,660	393,229	99.61
125	1,717	386,286	14	13,770	97.86	99.58	58	7,262	393,548	99.70
130	1,027	387,313	8	13,778	98.12	99.64	50	6,514	393,827	99.77
135	1,988	389,301	15	13,793	98.62	99.75	35	4,727	394,028	99.82
140	1,104	390,405	8	13,801	98.90	99.80	27	3,780	394,185	99.86
145	713	391,118	5	13,806	99.08	99.84	22	3,190	394,308	99.89
150	587	391,705	4	13,810	99.23	99.87	18	2,700	394,405	99.91
155	762	392,467	5	13,815	99.42	99.91	13	2,014	394,481	99.93
160	313	392,780	2	13,817	99.50	99.92	11	1,760	394,540	99.95
165	489	393,269	3	13,820	99.62	99.94	8	1,319	394,588	99.96
170	335	393,604	2	13,822	99.71	99.96	6	1,021	394,625	99.97
175	0	393,604	0	13,822	99.71	99.96	6	1,051	394,655	99.98
180	359	393,963	2	13,824	99.80	99.97	4	720	394,683	99.98
185	182	394,145	1	13,825	99.85	99.98	3	554	394,699	99.99
190	186	394,331	1	13,826	99.89	99.99	2	377	394,708	99.99
195	0	394,331	0	13,826	99.89	99.99	2	387	394,718	99.99
200	0	394,331	0	13,826	99.89	99.99	2	397	394,728	99.99
999,999	419	394,750	2	13,828	100.00	100.00	0	0	394,750	100.00
TOTAL	394,750		13,828							
AVG. USE	28.5									

SCHEDULE H-5
SHEET 16 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-15 CLASS = SPECIAL RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	21	21	0.00	3.24	627	0	0	0.00
1	8	8	8	29	0.01	4.48	619	619	627	0.86
2	2	10	1	30	0.01	4.63	618	1,236	1,246	1.70
3	33	43	11	41	0.06	6.33	607	1,821	1,864	2.55
4	80	123	20	61	0.17	9.41	587	2,348	2,471	3.37
5	130	253	26	87	0.35	13.43	561	2,805	3,058	4.18
6	108	361	18	105	0.49	16.20	543	3,258	3,619	4.94
7	161	522	23	128	0.71	19.75	520	3,640	4,162	5.68
8	120	642	15	143	0.88	22.07	505	4,040	4,682	6.39
9	108	750	12	155	1.02	23.92	493	4,437	5,187	7.08
10	180	930	18	173	1.27	26.70	475	4,750	5,680	7.76
11	198	1,128	18	191	1.54	29.48	457	5,027	6,155	8.41
12	180	1,308	15	206	1.79	31.79	442	5,304	6,612	9.03
13	169	1,477	13	219	2.02	33.80	429	5,577	7,054	9.63
14	182	1,659	13	232	2.27	35.80	416	5,824	7,483	10.22
15	105	1,764	7	239	2.41	36.88	409	6,135	7,899	10.79
16	224	1,988	14	253	2.71	39.04	395	6,320	8,308	11.35
17	85	2,073	5	258	2.83	39.81	390	6,630	8,703	11.89
18	306	2,379	17	275	3.25	42.44	373	6,714	9,093	12.42
19	95	2,474	5	280	3.38	43.21	368	6,992	9,466	12.93
20	120	2,594	6	286	3.54	44.14	362	7,240	9,834	13.43
25	663	3,257	29	315	4.45	48.61	333	8,325	11,582	15.82
30	862	4,119	31	346	5.63	53.40	302	9,060	13,179	18.00
35	888	5,007	27	373	6.84	57.56	275	9,625	14,632	19.98
40	761	5,768	20	393	7.88	60.65	255	10,200	15,968	21.81
45	592	6,360	14	407	8.69	62.81	241	10,845	17,205	23.50
50	575	6,935	12	419	9.47	64.66	229	11,450	18,385	25.11
55	481	7,416	9	428	10.13	66.05	220	12,100	19,516	26.65
60	635	8,051	11	439	10.99	67.75	209	12,540	20,591	28.12
65	567	8,618	9	448	11.77	69.14	200	13,000	21,618	29.52
70	410	9,028	6	454	12.33	70.06	194	13,580	22,608	30.87

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-15 CLASS = SPECIAL RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	360	9,388	5	459	12.82	70.83	189	14,175	23,563	32.18
80	702	10,090	9	468	13.78	72.22	180	14,400	24,490	33.44
85	1,155	11,245	14	482	15.36	74.38	166	14,110	25,355	34.63
90	178	11,423	2	484	15.60	74.69	164	14,760	26,183	35.76
95	834	12,257	9	493	16.74	76.08	155	14,725	26,982	36.85
100	392	12,649	4	497	17.27	76.70	151	15,100	27,749	37.90
105	309	12,958	3	500	17.70	77.16	148	15,540	28,498	38.92
110	535	13,493	5	505	18.43	77.93	143	15,730	29,223	39.91
115	339	13,832	3	508	18.89	78.40	140	16,100	29,932	40.88
120	591	14,423	5	513	19.70	79.17	135	16,200	30,623	41.82
125	124	14,547	1	514	19.87	79.32	134	16,750	31,297	42.74
130	254	14,801	2	516	20.21	79.63	132	17,160	31,961	43.65
135	533	15,334	4	520	20.94	80.25	128	17,280	32,614	44.54
140	415	15,749	3	523	21.51	80.71	125	17,500	33,249	45.41
145	426	16,175	3	526	22.09	81.17	122	17,690	33,865	46.25
150	292	16,467	2	528	22.49	81.48	120	18,000	34,467	47.07
155	302	16,769	2	530	22.90	81.79	118	18,290	35,059	47.88
160	316	17,085	2	532	23.33	82.10	116	18,560	35,645	48.68
165	977	18,062	6	538	24.67	83.02	110	18,150	36,212	49.45
170	504	18,566	3	541	25.35	83.49	107	18,190	36,756	50.20
175	349	18,915	2	543	25.83	83.80	105	18,375	37,290	50.92
180	354	19,269	2	545	26.31	84.10	103	18,540	37,809	51.63
185	548	19,817	3	548	27.06	84.57	100	18,500	38,317	52.33
190	0	19,817	0	548	27.06	84.57	100	19,000	38,817	53.01
195	385	20,202	2	550	27.59	84.88	98	19,110	39,312	53.69
200	593	20,795	3	553	28.40	85.34	95	19,000	39,795	54.35
999,999	52,431	73,226	95	648	100.00	100.00	0	0	73,226	100.00
TOTAL	73,226		648							
AVG. USE	113.0									

SCHEDULE H-5
SHEET 18 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-15 CLASS = SPECIAL RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	8	8	0.00	1.23	640	0	0	0.00
1	5	5	5	13	0.01	2.01	635	635	640	0.94
2	0	5	0	13	0.01	2.01	635	1,270	1,275	1.87
3	9	14	3	16	0.02	2.47	632	1,896	1,910	2.80
4	12	26	3	19	0.04	2.93	629	2,516	2,542	3.72
5	25	51	5	24	0.07	3.70	624	3,120	3,171	4.64
6	30	81	5	29	0.12	4.48	619	3,714	3,795	5.56
7	28	109	4	33	0.16	5.09	615	4,305	4,414	6.46
8	40	149	5	38	0.22	5.86	610	4,880	5,029	7.36
9	72	221	8	46	0.32	7.10	602	5,418	5,639	8.26
10	70	291	7	53	0.43	8.18	595	5,950	6,241	9.14
11	99	390	9	62	0.57	9.57	586	6,446	6,836	10.01
12	84	474	7	69	0.69	10.65	579	6,948	7,422	10.87
13	26	500	2	71	0.73	10.96	577	7,501	8,001	11.72
14	70	570	5	76	0.83	11.73	572	8,008	8,578	12.56
15	150	720	10	86	1.05	13.27	562	8,430	9,150	13.40
16	96	816	6	92	1.19	14.20	556	8,896	9,712	14.22
17	85	901	5	97	1.32	14.97	551	9,367	10,268	15.03
18	144	1,045	8	105	1.53	16.20	543	9,774	10,819	15.84
19	133	1,178	7	112	1.72	17.28	536	10,184	11,362	16.64
20	140	1,318	7	119	1.93	18.36	529	10,580	11,898	17.42
25	548	1,866	24	143	2.73	22.07	505	12,625	14,491	21.22
30	638	2,504	23	166	3.67	25.62	482	14,460	16,964	24.84
35	1,160	3,664	35	201	5.37	31.02	447	15,645	19,309	28.27
40	644	4,308	17	218	6.31	33.64	430	17,200	21,508	31.49
45	1,080	5,388	25	243	7.89	37.50	405	18,225	23,613	34.58
50	1,288	6,676	27	270	9.78	41.67	378	18,900	25,576	37.45
55	1,377	8,053	26	296	11.79	45.68	352	19,360	27,413	40.14
60	753	8,806	13	309	12.89	47.69	339	20,340	29,146	42.68
65	1,067	9,873	17	326	14.46	50.31	322	20,930	30,803	45.10
70	886	10,759	13	339	15.75	52.31	309	21,630	32,389	47.43

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-15 CLASS = SPECIAL RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	1,170	11,929	16	355	17.47	54.78	293	21,975	33,904	49.64
80	1,250	13,179	16	371	19.30	57.25	277	22,160	35,339	51.75
85	1,414	14,593	17	388	21.37	59.88	260	22,100	36,693	53.73
90	1,585	16,178	18	406	23.69	62.65	242	21,780	37,958	55.58
95	1,496	17,674	16	422	25.88	65.12	226	21,470	39,144	57.32
100	1,560	19,234	16	438	28.16	67.59	210	21,000	40,234	58.91
105	1,030	20,264	10	448	29.67	69.14	200	21,000	41,264	60.42
110	1,081	21,345	10	458	31.25	70.68	190	20,900	42,245	61.86
115	1,125	22,470	10	468	32.90	72.22	180	20,700	43,170	63.21
120	1,410	23,880	12	480	34.97	74.07	168	20,160	44,040	64.49
125	859	24,739	7	487	36.22	75.15	161	20,125	44,864	65.69
130	1,021	25,760	8	495	37.72	76.39	153	19,890	45,650	66.84
135	801	26,561	6	501	38.89	77.31	147	19,845	46,406	67.95
140	827	27,388	6	507	40.10	78.24	141	19,740	47,128	69.01
145	1,289	28,677	9	516	41.99	79.63	132	19,140	47,817	70.02
150	595	29,272	4	520	42.86	80.25	128	19,200	48,472	70.98
155	616	29,888	4	524	43.76	80.86	124	19,220	49,108	71.91
160	1,107	30,995	7	531	45.38	81.94	117	18,720	49,715	72.80
165	491	31,486	3	534	46.10	82.41	114	18,810	50,296	73.65
170	1,009	32,495	6	540	47.58	83.33	108	18,360	50,855	74.46
175	1,210	33,705	7	547	49.35	84.41	101	17,675	51,380	75.23
180	356	34,061	2	549	49.87	84.72	99	17,820	51,881	75.97
185	552	34,613	3	552	50.68	85.19	96	17,760	52,373	76.69
190	753	35,366	4	556	51.78	85.80	92	17,480	52,846	77.38
195	969	36,335	5	561	53.20	86.57	87	16,965	53,300	78.04
200	986	37,321	5	566	54.65	87.35	82	16,400	53,721	78.66
999,999	30,973	68,294	82	648	100.00	100.00	0	0	68,294	100.00
TOTAL	68,294		648							
AVG. USE	105.4									

SCHEDULE H-5
SHEET 20 OF 20

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-____

2007
ARIZONA
GENERAL RATE CASE

Volume III
TESTIMONY

August 31, 2007

SOUTHWEST GAS CORPORATION

ARIZONA GENERAL RATE CASE

VOLUME III

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Volume III

Testimony

1

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

PREPARED DIRECT TESTIMONY
OF
ROGER C. MONTGOMERY

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
Prepared Direct Testimony
Of
ROGER C. MONTGOMERY

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
ROGER C. MONTGOMERY

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Roger C. Montgomery and my business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

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

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) as the Vice President Pricing.

Q. 3 Does Appendix A summarize your educational background and business experience?

A. 3 Yes, it does.

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

A. 4 Yes. I have testified before the Arizona Corporation Commission (ACC or Commission), the California Public Utilities Commission, the Public Utilities Commission of Nevada, and the Federal Energy Regulatory Commission.

II. PURPOSE OF TESTIMONY

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

A. 5 The purpose of my testimony is to provide the Commission with a brief explanation of the significant challenges facing the Company in Arizona and to explain the broad

goals and objectives Southwest hopes to achieve in this general rate case (GRC) to help meet those challenges. Specifically, my testimony will:

(1) identify Southwest's witnesses and their subject area(s);

(2) support Southwest's application and need for increased rates and charges;

(3) summarize the financial and regulatory challenges Southwest faces; and

(4) discuss, from a policy perspective, Southwest's key proposals to address these challenges and why they should be approved by the Commission. Southwest's other witnesses will more fully describe Southwest's GRC and provide more specific detail concerning Southwest's proposals.

III. OTHER SOUTHWEST WITNESSES

Q. 6 Please identify Southwest's other witnesses in this GRC and their general subject or issue areas.

A. 6 Besides myself, Southwest sponsors the testimony of nine other witnesses:

(1) Robert Mashas - Overall deficiency/revenue requirement and various adjustments;

(2) Randi Aldridge - Cost of service and various adjustments;

(3) Laura Hobbs - Management Incentive Program (MIP) and Supplemental Executive Retirement

Plan (SERP);

(4) Theodore Wood - Capital structure, cost of debt, and overall rate of return;

(5) Frank Hanley - Cost of equity;

(6) Jamie Cattanach - Billing determinants and declining residential consumption per customer;

(7) Frank Maglietti - Class cost of service study and Purchased Gas Adjustment (PGA) mechanism;

(8) Ralph Miller - Revenue decoupling and energy efficiency; and

(9) A. Brooks Congdon - Rate design and regulatory/ratemaking mechanisms.

IV. OVERVIEW OF CURRENT AND LAST RATE CASE

Q. 7 Please provide a brief overview of Southwest's current GRC application.

A. 7 The current GRC is based on a test year for the 12 months ended April 30, 2007. Southwest's adjusted test year shows a deficiency of approximately $50.2 million and an earned return of only 6.68 percent. Southwest requests a capital structure consisting of 51 percent debt, four percent preferred equity, and 45 percent common equity, with a requested return on common equity (ROE) of 11.25 percent and an overall return on rate base of 9.45 percent. Mr. Robert Mashas and Ms. Randi Aldridge provide further details of the amount, reasons, and bases for the Company's revenue deficiency. The GRC also contains several proposals to modify the Company's rate

design and to employ specific regulatory mechanisms to address fixed cost recovery, declining residential consumption per customer and weather volatility.

Q. 8 How does the current GRC application compare to Southwest' previous GRC application (test year ended August 31, 2004).

A. 8 In Southwest's previous GRC, the Company's analysis indicated it was deficient by approximately $66.9 million and was earning only a 5.47 percent return on its investment in Arizona. In that proceeding, Southwest requested a hypothetical capital structure consisting of 53 percent debt, five percent preferred equity, and 42 percent common equity. Southwest recommended an ROE of 11.42 percent. Southwest also requested several rate design changes, including increases in residential basic service charges and a revenue decoupling mechanism to assist the Company in recovering its fixed cost of service in the face of declining residential consumption per customer and weather volatility.

Q. 9 What did the Commission decide in Southwest's last GRC?

A. 9 In its decision issued on February 23, 2006 (Decision No. 68487), the Commission granted Southwest approximately $49.3 million in rate relief effective March 1, 2006. However, with the exception of some moderate increases in basic service charges, including an increase of $1.70 in the residential basic service charge, the Commission did not adopt an overall rate design or a revenue decoupling

mechanism that would adequately address Southwest's inability to recover its fixed costs and provide a reasonable opportunity for Southwest to earn its authorized rate of return. The Commission also granted an ROE of only 9.50 percent on a 40 percent equity ratio.

Q. 10 How did the Commission's last GRC decision impact Southwest?

A. 10 The Company's earned rates of return in Arizona improved after the rate relief was in place for a full winter season. Southwest's earned returns for the 12-month periods ended March 31, 2006, September 30, 2006, and March 31, 2007, were 4.48 percent, 6.08 percent, and 7.85 percent, respectively. Southwest did not, however, earn its authorized return of 8.40 percent, and based on projected cost increases and continuing declines in customer usage, it will not earn the authorized return without further rate relief. As such, the Company filed this GRC.

Q. 11 How frequently does Southwest typically file GRCs in Arizona?

A. 11 Over the past decade or more, Southwest has filed a GRC with the Commission about every three years. For several reasons, filing a GRC much more often than every three years or so is not practicable. Despite the frequency of filing GRCs, Southwest was able to earn its authorized rate of return in only one year over the past decade or more. If Southwest were able to earn a rate of return

closer to the authorized rate of return, it could result in less frequent GRC applications, which Southwest believes its customers would welcome and the Commission would prefer.

V. MAJOR CHALLENGES FACING SOUTHWEST

Q. 12 What are the major challenges facing Southwest?

A. 12 In general, Southwest faces two major challenges. First, Southwest has been unable to earn its Commission-authorized return. Second, Southwest's authorized return is significantly below returns authorized for its peers in the industry and, more particularly, below the rates authorized for other energy utilities in Arizona.

VI. INABILITY TO EARN AUTHORIZED RATE OF RETURN

Q. 13 Please briefly summarize why Southwest has been unable to earn its authorized return?

A. 13 In general, there are three primary reasons Southwest has not earned its authorized return in Arizona. First, average usage by residential customers, who make up over 95 percent of the Company's customer base, continues to decline each year. If residential customers, on average, continue to use less natural gas each year, as has been the case for the past two decades, Southwest will not recover its fixed costs of providing utility service. Southwest's inability to earn its authorized return will continue unless and until this issue of declining residential consumption per customer is adequately addressed in the regulatory process. This problem is not

unique to Southwest; it is happening across the nation. There are several regulatory solutions to this problem, and several state regulatory commissions have approved various rate design or regulatory mechanisms to resolve the problem.

Second, the vagaries of weather in the desert southwest also plague Southwest and its customers. Weather volatility affects customers when it is colder-than-normal. In that situation, customers pay more than necessary for Southwest to recover its fixed costs (as long as fixed costs continue to be partially recovered through a commodity rate). Weather volatility also affects the Company. When weather is warmer-than-normal, fixed costs, those recovered through the commodity charge, are under-recovered, causing the Company financial distress. For example, during 2005 and 2006, weather was significantly warmer than normal. As a result, Southwest's earned return for 2005 and 2006 was substantially less than what was authorized by the Commission. Conversely, in some years, the weather has been colder-than-normal. The Company believes that removing weather from the general ratemaking equation will protect both Southwest and its customers.

Third, in the last several Arizona rate cases, a ratemaking theory was put into practice that Southwest believes is fundamentally flawed and unfair. It is the concept that if any program or service that the Company

performs benefits shareholders, then some portion of the costs for the program or service should be "shared". In the last Southwest Arizona GRC, this practice of "sharing" was even extended to programs imposed on the Company by the federal government. It is a long-standing and fundamental regulatory paradigm that a regulated utility should be allowed to recover all costs that are prudently incurred, are reasonable, and are necessary in providing utility service. Only those expenses or costs deemed to be imprudent or unreasonable should be disallowed. Southwest does not dispute the Commission's authority to disallow imprudent or unreasonable expenses. However, to "share" prudent, necessary, and reasonable expense merely because there is some benefit to shareholders is, in Southwest's view, confiscatory and amounts to nothing less than an explicit disallowance and erosion of Southwest's opportunity to realize its Commission-authorized return.

VII. NEED FOR A REASONABLE AND COMPARABLE RATE OF RETURN

Q. 14 Can you briefly elaborate on the need for the Commission to authorize a reasonable and comparable return to the Company on its investment in Arizona?

A. 14 Yes. As noted earlier in this testimony, in Southwest's last GRC, the Commission authorized an ROE of only 9.50 percent, which is significantly below what the Commission has authorized for other Arizona energy utilities and represents one of the lowest ROEs authorized by any state

regulatory commission in the nation in recent years. This is particularly troubling considering two of Southwest's credit ratings are just one step above "junk bond" status. Arizona is also one of the fastest growing states in the nation. Therefore, Southwest must compete with its peers in the utility industry for capital to fund this growth and to maintain and improve its natural gas system infrastructure.

The Company's inability to earn its authorized return is a major problem for Southwest's shareholders. It is also a major problem for customers if the authorized rate of return is not competitive in the financial marketplace and Southwest must obtain capital at less attractive (higher) rates. If the Commission approves an ROE for Southwest that is comparable to its peers, and also provides Southwest a reasonable opportunity to actually earn the return, the Company's financial condition would improve over time and help mitigate the need for future increases in base rates for customers.

Q. 15 Would Commission consideration and resolution of the challenges you previously identified eliminate Southwest management's need to effectively and efficiently run the business and serve customers?

A. 15 No, Southwest's management must still efficiently manage its workforce and pay close consideration to operating and capital costs to provide it a reasonable opportunity

to earn its authorized return. This is particularly true in a state like Arizona with growth rates still well above national averages. Nothing in Southwest's proposals guarantees the Company a specific return on its investment nor relieves management of its obligation and responsibility to serve its various constituencies. Southwest presents the Commission with a number of tools that should help it meet the substantial and multiple challenges of providing for the natural gas energy needs of Arizona.

Q. 16 Does this conclude your prepared direct testimony?

A. 16 Yes, it does.

SUMMARY OF QUALIFICATIONS
ROGER C. MONTGOMERY

I graduated from the University of Texas at El Paso in 1970 with a Bachelor of Business Administration degree. My principal area of concentration was in accounting. After graduation, I joined El Paso Natural Gas Company as a Technician in the Gas Marketing and Customer Relations department where my duties included preparation of gas sales and revenue analyses for rate and certificate filings with the Federal Energy Regulatory Commission ("FERC"). In 1974, I joined Northwest Pipeline as a Rate Analyst in the Rate department. In 1976, I joined Southwest as Rates Administrator in the Rates department. In 1982, I was promoted to Manager/Rates and in 1988 to Director/Rates, Certificates and Tariffs. In 1995, I assumed the position of Director/Rates and State Regulatory Affairs. In 1998, I was promoted to my current position where I am responsible for the activities of the Pricing and Tariffs, Revenue Requirements, and Federal Regulatory Affairs departments.

Volume III

Testimony

2

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

PREPARED DIRECT TESTIMONY
OF
ROBERT A. MAHSAS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
Prepared Direct Testimony
Of
ROBERT A. MASHAS

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Appendix A - Summary of Qualifications of Robert A. Mashas

Exhibit No.___(RAM-1)

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

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
ROBERT A. MASHAS

I. 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 89150-0002.

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

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) as the Director/Revenue Requirements.

Q. 3 Does Appendix A summarize your educational background and business experience?

A. 3 Yes, it does.

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

A. 4 Yes. I previously testified before the Arizona Corporation Commission (Commission or ACC), the Public Service Commission of Nevada (PUCN), the California Public Utilities Commission (CPUC). I also provided written testimony to the Federal Energy Regulatory Commission (FERC).

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

A. 5 My testimony comprises four parts. The first part of my testimony provides a broad overview of the test year,

adjustments to the test year data and the resulting deficiency. The second part addresses the major reasons and underlying causes for the deficiency. The third part discusses the proposed adjustments to the test year that Southwest is proposing and which I support. The last part supports the Company's rate base Schedules B-1 through B-6.

II. RATE CASE OVERVIEW

Q. 6 What is the test year for this rate application?

A. 6 The test year is the 12-month period ended April 30, 2007. The test year results were adjusted to normalize and annualize the effects of known and measurable changes that occurred through April 30, 2007. In addition, Southwest proposes certain adjustments related to events that will take place or be in effect after the end of the test year, but prior to the date new rates go into effect.

Q. 7 When was Southwest's last Arizona general rate case application?

A. 7 Southwest filed the Arizona 2004 general rate case (Docket No. G-1551A-04-0786) on December 9, 2004, nearly three years ago. The test year in that proceeding was based on the 12 months ended August 31, 2004. The 2004 rate case was fully litigated and resulted in Commission Decision No. 68487, which granted Southwest an increase in non-gas revenue ("Revenue") of approximately $49.3 million, effective March 1, 2006. Decision No. 68487

authorized an overall rate of return (ROR) of 8.40 percent, calculated using a 9.50 percent return cost of equity on a ratio of 40 percent common equity.

Q. 8 How does the Company determine if a revenue deficiency exists?

A. 8 A revenue deficiency occurs when a Company's annualized and normalized revenue, at its current rates, is less than the Company's annualized and adjusted cost of service (COS) including the cost of capital. If the resulting overall rate of return (ROR) is either less than authorized in the Company's last rate case, or is not equal to the ROR that would be deemed reasonable given current market conditions and the Company's overall cost of capital, a revenue deficiency exists.

Q. 9 What is Southwest's revenue deficiency in its Arizona operations?

A. 9 Schedule A-1, Sheet 2, Column (d) illustrates that the adjusted revenue of approximately $399.2 million at present rates yields a ROR of 6.68 percent. In this proceeding, Southwest requests that the Commission grant ROR of 9.45 percent. In order to produce the 9.45 percent ROR, a revenue increase in the amount of approximately $50.2 million is required.

Q. 10 What does the term revenue mean?

A. 10 The term revenue refers to non-gas revenues Southwest receives through base rates. Because there is a separate purchased gas adjustment mechanism to ensure that

Southwest's customers pay the actual cost incurred by Southwest to purchase natural gas (i.e., Southwest earns no profit on the natural gas itself), revenues and costs associated with the gas commodity are excluded from the general rate case.

Q. 11 Please indicate the Company witnesses who support the proposed adjustments to the recorded test year amounts.

A. 11 There are 17 adjustments to the test year data. These adjustments are listed on Schedule C-2, Sheets 1 through 2. Company witness A. Brooks Congdon supports Adjustment Nos. 1 and 2, Company witness Randi L. Aldridge supports Adjustment Nos. 3 through 7, and 11 through 17. I support Adjustment No. 8 Leak Survey and Repair, Adjustment No. 9, Surcharge Adjustment, and Adjustment No. 10, Injuries and Damages.

Q. 12 Identify the adjustments that Southwest is proposing related to events that occurred or will occur after April 30, 2007.

A. 12 There are four adjustments that fall into this category. They are: 1) wage increases and within-grade movement; 2) completed construction not classified (CCNC); 3) post test year new and expired software amortizations; and 4) the 2008 property tax assessment ratio.

Q. 13 Why has Southwest included these adjustments in this general rate case?

A. 13 Consistent with Southwest's prior Arizona rate cases, when events are known or reasonably certain to occur and

are measurable prior to hearing, the Commission has allowed adjustments similar to the four adjustments proposed herein. The test year more accurately reflects the level of expenses and costs Southwest will incur when the rates in this proceeding are in effect with these proposed adjustments. The four post test year adjustments are easily reconcilable to test year accounts without distortion or mismatching.

The adjustments for CCNC, post test year wage increases and within-grade movement, and post test year new and expiring amortizations were approved by the Commission in several previous rate cases.

In the Company's 2004 rate case (test year ended August 31, 2004), the Commission approved the use of the 2006 property tax assessment ratio. The Company's proposal to use the 2008 assessment ratio in this rate case is consistent with Decision No. 68487.

Ms. Aldridge's testimony provides additional detail related to the post test year wage increases, within-grade wage adjustment, CCNC, expiring and new amortizations, and the property tax assessment ratio.

III. MAJOR REASONS AND UNDERLYING CAUSES FOR THE DEFICIENCY

Q. 14 Please identify the major reasons and underlying causes for Southwest's revenue deficiency in Arizona.

A. 14 There are six major underlying causes for Southwest's present revenue deficiency: 1) declining average residential usage; 2) the loss of general service

customers who were taking service at the end of the 2004 rate case; 3) increased expenses; 4) the Company's "overall cost of capital" compared to what is currently authorized; 5) the Company's request for inclusion of the costs related to the management incentive plan (MIP) and supplemental executive retirement plan (SERP); and 6) the costs resulting from changes in rate base (gas plant net of depreciation and other rate base items, such as finance, depreciation, property tax and interest on customer deposits) net of new customer revenue derived from the customer-related portion of rate base.

IV. DECLINING AVERAGE RESIDENTIAL USAGE

Q. 15 How does declining average residential useage cause a revenue deficiency?

A. 15 At the time a rate case is filed, the Company proposes and ultimately the Commission establishes a COS that is deemed to be appropriate for the development of rates that each customer class will be charged. In most instances, a fixed and variable rate is developed to recover the revenue responsibility allocated to each rate class. The portion of the designed revenue responsibility recovered through the fixed component is predicated on the number of customers requesting service. The portion of the revenue responsibility that is designed to be recovered through the variable component is predicated on volume (therm) level used in the test year. Failure to sell the average therm level will

create a revenue deficiency that is not caused by an increase in costs.

Q. 16 How does the Company determine the revenue deficiency component resulting from residential declining average use?

A. 16 The Company calculates this deficiency by comparing the average use per customer utilized to establish its current rates to the average customer use experienced during the test year in the current rate case times the authorized revenue usage rate. Only the customers that were included in the previous rate case are used in this calculation. Customers added subsequent to the end of the test year used to establish rates in the Company's last rate case are excluded.

Q. 17 What is the impact of the decline in average residential usage per customer on the revenue deficiency in this rate case?

A. 17 In his prepared direct testimony, Company witness Jamie Cattanach states that average residential usage per customer declined 15 therms (from 347 therms to 332 therms) since Southwest's 2004 general rate case. The 15 therm reduction results in an $8.00 per customer revenue shortfall (15 therms x $.53 per therm average revenue rate). The 2004 rate case contained approximately 822,000 residential customers. The $8.00 per customer shortfall equates to a $6.5 million annual reduction in residential authorized revenue recovery due to declining

average residential use. Accordingly, if the Company did not add a single customer, and incurred no additional costs above those authorized, the Company would still be deficient by $6.5 million.

V. GENERAL SERVICE CUSTOMERS

Q 18 What impact does the general service customers no longer taking service since the last rate case have on the current deficiency?

A. 18 In the Company's 2004 rate case, the general service class (Small, Medium & Large) revenue responsibility was spread to 39,740 customers who were taking gas service on August 31, 2004. In the current proceeding, which is based on a test year ended April 30, 2007, the Company served 40,092 general service customers, which is 352 more than the number of customers served at the end of the test year used to establish rates in the 2004 rate case. Although the Company is providing service to 352 more customers, there are two underlying events in play. One is that 2,442 general service customers in the current rate case first began taking service subsequent to the end of the test year in the 2004 rate case. The second is that 2,090 general service customers left the system after the 2004 rate case and are no longer customers as of April 30, 2007. The revenue responsibility assigned to these 2,090 customers, for recovery through the basic service charge and commodity rate, has been lost. When applying the average revenue

per customer from the last rate case, the Company was expected to recover approximately $4.3 million of the designed revenue responsibility from these 2,090 customers. Accordingly, if the only change from the last general rate case was the loss of the 2,090 general service customers, the Company's revenue deficiency would be $4.3 million as a result of general service customer attrition.

Q. 19 Does the revenue realized from the 2,442 general service customers added since the last rate case offset the deficiency resulting from the 2,090 customers that are no longer taking service?

A. 19 No. In order to serve the new general service customers, new capital was required. The new capital was not included in the derivation of rates in the last proceeding. The "incremental" revenue received from the new customers is required to offset the new costs that result from providing the "incremental" facilities to serve new customers. As long as the incremental revenue is equal to, or greater, than the incremental cost of serving the new customers, the new customers do not create a deficiency. The addition of new customers and the loss of previously-served customers are separate events which independently impact the revenue deficiency.

VI. EXPENSES

Q. 20 What is the increase in expenses since the last general rate case?

A. 20 Excluding SERP and MIP, the expense level requested in this proceeding is approximately $21 million higher than the amount used to establish rates in the 2004 rate case. The $21 million increase can be grouped into three major categories: 1) labor directly charged to Arizona and corporate system allocable; 2) employee benefits, primarily basic retirement plan (BRP) and medical claims; and 3) expenses other than labor and employee benefits.

Q. 21 Please discuss the expense increase due to labor.

A. 21 The labor cost in this proceeding is approximately $6.3 million, or 8.9 percent greater than the amount authorized in the last general rate case. In the 2004 rate case, the Company requested, and the Commission approved, the Company's annualized labor at August 2004 adjusted for the impact of the June 2005 post test year wage increase. The Company's 2004 rate case did not include the cost related to the June 2006 wage increase because it was not known and measurable until after rates from the 2004 rate case went into effect. As a result, the cost related to the June 2006 wage increase is now a component of the revenue deficiency in the current rate case. On May 5, 2007, the Company's Board of Directors approved a three percent general wage increase. The test year labor requested by the Company in this proceeding includes the annualized labor as of April 2007, adjusted for the impact of the approved May 2007 general wage increase. In addition, the Company included the cost

related to the anticipated second quarter 2008 wage increase. Rates in this proceeding are not anticipated to go into effect until the fourth quarter of 2008. Thus, the actual second quarter 2008 wage increase will be known and measurable prior to the effective date of rates pursuant to this proceeding. Inclusion in the labor cost of the 2007 and 2008 wage increases reduces the impact of regulatory lag and is consistent with the Commission's decisions in Southwest's prior rate cases.

Q. 22 What is the increase in employee benefits since the last general rate case?

A. 22 The Company's requested expense includes an employee benefits cost component that is approximately $7.8 million higher than the level authorized in the last general rate case. Most of the increase is due to the BRP (approximately $3.9 million) and medical claims (approximately $2.0 million). The remaining $1.9 million is related to the labor loading on higher wages. Company witness Randi Aldridge supports the annualized labor calculation and benefits adjustment and describes the components of employee benefits in more detail.

Q. 23 Please discuss the increased expense related to costs other than labor and employee benefits.

A. 23 The increase in expense related to costs other than labor and employee benefits is $7 million. Factors impacting non-labor related costs include inflation, safety, code compliance and customer growth. In this proceeding, the

Company serves 958,542 customers compared to 863,474 customers in the last rate case. The current rate case includes 95,068 more customers, an increase of approximately 11 percent, which accounts for a significant portion of the $7 million.

VII. COST OF CAPITAL

Q. 24 What is the impact on the deficiency related to the Company's request for a higher level of, and a higher return on, common equity?

A. 24 The Company requests that the Commission establish rates resulting in a 9.45 overall rate of return, or 105 basis points higher than the 8.40 percent approved in the last rate case. In this proceeding, the Company requests rates be established using a 45 percent common equity weighting (40 percent approved in the last rate case) and 11.25 percent return on common (9.50 percent approved in the last rate case). Company witness Theodore Wood presents testimony supporting a 45 percent level of common equity weighting and the cost of debt and preferred. Company witness Frank J. Hanley presents testimony supporting an 11.25 percent return on common equity. The combination of the above cost of capital proposals increases the Company's deficiency by approximately $20.6 million.

VIII. MIP AND SERP

Q 25 What is the impact on the deficiency related to the Company's request for the inclusion in rates of the cost

of MIP and SERP.

A. 25 The cost of MIP and SERP is $2.0 million and $1.6 million, respectively.

Q. 26 Was the Commission's ruling in the Company's 1999 and 2004 rate cases regarding the inclusion of MIP and SERP in the COS the same?

A. 26 No. The Commission ruled differently on the MIP and the SERP in the 2004 rate case and the 1999 rate case (Docket No. G1551A-00-0309).

In the 1999 rate case, the Commission removed the cost of two of five factors used to calculate the MIP and allowed 100 percent of the remaining three factors. The Commission rejected the Residential Utility Consumers Organization (RUCO) proposal to disallow cost recovery of 50 percent of MIP expense. In the 2004 rate case, however, the Commission accepted a similar proposal to remove 50 percent of the MIP expense.

In the 1999 rate case the Commission rejected a RUCO proposal to remove 100 percent of SERP expense and ruled that it was appropriate to recover 100 percent of SERP expense. In the 2004 rate case, the Commission adopted RUCO's proposal to disallow 100 percent of SERP. The justification provided by RUCO was essentially identical in both the 1999 and 2004 rate cases.

Q. 27 Does the Company provide a witness supporting the reasonableness of Southwest's MIP and SERP costs?

A. 27 Yes, Company witness Laura Hobbs provides testimony

showing that Southwest's total management/executive compensation is reasonable.

IX. RATE BASE AND REVENUE OFFSET

Q. 28 What is the impact on the deficiency related to rate base changes?

A. 28 The deficiency is $6.2 million.

Q. 29 Please discuss the changes in rate base components since the end of the test year in the Company's last general rate case.

A. 29 Since the last rate case (September 2004 through April 2007), rate base increased by approximately $172.1 million (Commission authorized rate base is approximately $922.7 million compared to the requested amount of approximately $1,094.8 million). The $172.2 million rate base increase is the net of an approximately $212.1 million increase of net gas plant in service offset by approximately a $40 million credit increase in the other rate base items.

The net plant increase was the result of approximately $371 million of transfers to gas plant in service offset by approximately $149.6 million in depreciation and amortization expense. The $371 million of transfers include both revenue and non-revenue capital expenditures.

The $40 million increase in other rate base items is the net of approximate credit increases in deferred taxes ($7.1 million), customer advances ($30.8 million)

and customer deposits ($8.0 million) exceeded by the approximate debit increases in materials and supplies ($3.2 million), prepayments ($.9 million) and cash working capital ($.7 million).

Q. 30 What costs result from the increase in rate base?

A. 30 The cost to finance the approximate $172.1 million increase in rate base is $18.8 million when the pre-tax authorized return is applied. The resulting increases in depreciation expense, property tax and interest on customer deposits are approximately $13.1 million, $1.0 million and $0.5 million, respectively. The total cost related to the increase in rate base is approximately $33.4 million.

Q. 31 What is the offsetting new revenue from the revenue-producing portion of capital incurred since the last rate case?

A. 31 Decision No. 68487 authorized a $49.3 million revenue increase to the $322.8 million revenue at the then-present rates, resulting in $372.1 million revenue requirement. The revenue at present rates in this proceeding is $399.3 million or approximately $27.2 million greater. The approximate $33.4 million rate base related cost exceeds the approximate $27.2 million net increase in revenue by approximately $6.2 million.

Q. 32 Why do you refer to the $27.2 million as the net increase in revenue?

A. 32 The $27.2 million is the change from the revenue at

present rates in this proceeding to the authorized revenue resulting from the Company's last general rate case. Earlier in my testimony I addressed the decline in residential revenue resulting from the decline in average therm use. I also discussed the lost revenue that resulted from general service customers leaving the system since the last rate case. The authorized $372.1 million revenue requirement would only be realized by the Company if the residential customers requesting service at the end of the 2004 rate case test year, on average, were to use 347 therms. The $372.1 million amount also presumed that all general service customers would remain on the system. If Southwest did not add a single customer since the last rate case, the $372.1 million authorized revenue would have declined by approximately $10.6 million ($6.5 million Residential plus $4.3 million General Service) to approximately $361.5 million. If the approximately $399.3 million revenue at present rates is compared to the $361.5 million, then the increase due to new customers requesting service since the last rate case is approximately $38.0 million.

Q. 33 What is the deficiency impact of the new customer revenue and the costs related to changes in rate base?

A. 33 Exhibit No.___(RAM-1) provides a summary of the new revenue and rate base related cost that occurred since the end of the test year in the 2004 rate case. The approximate $38.0 million of new revenue exceeds the

$33.4 million cost of new rate base creating a reduction in the deficiency of approximately $4.6 million. Although cash outflow resulting from capital investment adds significant additional cost, these costs have been offset by the cash inflow due to depreciation expense, the aggressive management of other rate base items, along with the revenue acquired from the new customer portion of capital.

X. RATE CASE ADJUSTMENTS

Q. 34 Please explain Adjustment No. 8, Leak Survey and Repair.

A. 34 Adjustment No. 8, Leak Survey and Repair, reduces test year accelerated leak survey and leak repair expense related to both Aldyl A and Aldyl HD pipe by a percent calculated using the 40-year criteria adopted by the Commission in Decision No. 68487.

The year 2008 percentage is used to calculate Adjustment No. 8, and is consistent with the proposal approved by the Commission in the Company's 2004 general rate case.

Q. 35 Has the Company written-off a portion of the capital expenditures required to replace Aldyl A and Aldyl HD using the 40-year criteria ordered by the Commission?

A. 35 Yes. The Company prepares a journal entry each quarter which calculates the appropriate amount of replacement expenditures that need to be written-off and excluded from rate base. For the current rate application, the Company prepared a journal entry in April 2007 in order

to ensure that the recorded plant on the books as of April 2007 complies with prior Commission decisions.

Q. 36 Please explain Adjustment No. 9, Surcharge Adjustments.

A. 36 Adjustment No. 9 removes from Account 407.3, Regulatory Amortizations, the recorded test year expense for: 1) Research and Development (R&D); 2) Demand Side Management (DSM); and 3) the Transmission Integrity Management Program (TRIMP). The adjustment also transfers to distribution maintenance expense the amount removed from Account 407.3 for TRIMP.

Q. 37 Please explain why R&D and DSM expense recorded in Account 407.3, is removed from the COS?

A. 37 Decision No. 68487 directed the Company to fund annually $688,712 in R&D and $4,385,000 in DSM. The Commission also provided recovery through specific surcharges and balancing account mechanisms. The expenses resulting from funding R&D and DSM are recorded in Account 407.3. The Company proposes to continue funding both R&D and DSM in the same manner as set forth in Decision No. 68487. The surcharge revenue recorded during the test year is not included in the revenues at present rates; therefore, it is appropriate to remove the related expense.

Q. 38 Please explain why TRIMP expense recorded in Account 407.3 is removed from the COS?

A. 38 Decision No. 68487 provided for the recovery of fifty (50) percent of TRIMP-related cost through a surcharge and balancing account mechanism. The expense resulting

from funding 50 percent is recorded in Account 407.3 and the remaining 50 percent of the TRIMP cost is charged to Account 887, Maintenance of Mains. The TRIMP-related surcharge revenue recorded during the test year is not included in the revenue at present rates, therefore, it is appropriate to remove the related expense. In addition, the Company proposes to discontinue recovering 50 percent of TRIMP cost through a surcharge and to recover the test year TRIMP-related expense in Account 887 in base rates. Adjustment No. 9 removes the TRIMP cost recorded in account 407.3 and transfers it to Account 887.

Q. 39 What account has the Company used to record the balancing of TRIMP expense incurred and revenues recovered?

A. 39 The Company charges 50 percent of the TRIMP cost incurred and the related surcharge revenue billed to Account 182.3, Regulatory Assets.

Q. 40 When does the Company propose to cease charging expense to Account 182.3 and discontinue the TRIMP surcharge?

A. 40 The Company proposes to cease charging TRIMP-related expense to Account 182.3 the month the proposed new rates take effect. The surcharge will discontinue once the deferred balance in Account 182.3 reaches zero.

Q. 41 Explain why the Company proposes recovering all of its TRIMP-related costs in this proceeding?

A. 41 TRIMP-related maintenance costs are incurred as a result of the Federal Pipeline Safety Improvement Act of 2002

(2002 Act). Every gas utility subject to federal regulation must comply with the provisions of the 2002 Act. Southwest is not aware of any other gas utility in the nation that must comply with the provisions of this act that is not recovering 100 percent of the prudently-incurred cost of compliance. In fact, in the last UNS Gas rate case processed in 2006, neither UNS Gas nor any party to the proceeding proposed an adjustment limiting the recovery of TRIMP-related costs. Likewise, neither UNS Gas nor any of the parties to the proceeding proposed a surcharge mechanism to recover any of the TRIMP-related costs. The 2002 Act is only one of many federal, state and local safety regulations that must be complied with by any gas utility that provides natural gas service. Based on the foregoing, the Company believes it is fair and reasonable that 100 percent of the test year recorded TRIMP-related cost be recovered in base rates.

Q. 42 Please explain Adjustment No. 10, Injuries and Damages.

A. 42 Adjustment No. 10 adjusts the recorded self-insured accruals charged to Account 925 during the test year to a normalized level.

Q. 43 Please describe the types of charges included in Account 925, Injuries and Damages.

A. 43 Account 925 includes four types of charges: 1) insurance premiums; 2) the reserve for the self-insured portion of liability claims; 3) legal and other related expenses necessary to defend and process claims; and 4) worker

compensation claims.

Q. 44 What is the level of self-insurance that the Company has at the end of the test year.

A. 44 The Company is self-insured for up to $1.0 million of claims expense for each occurrence. To the extent that a specific claim exceeds $1.0 million, the Company is self-insured for the excess over $1.0 million up to an aggregate of $5.0 million. Once the $5.0 million aggregate is reached, any amount paid above the $5.0 million is the responsibility of the insurance carrier. The $5.0 million aggregate can be the result of payouts from more than one incident.

Q. 45 Please explain the accounting for the self-insured portion of liability claims.

A. 45 When an incident is identified that may require payment the Company accrues the estimated payment as a self-insured retention expense. The entry is a debit to Account 925, Injuries and Damages, and a credit to Account 228.2 Accumulated Provision for Injuries and Damages. Once the outcome of the claim becomes final, any costs paid are charged against the accrual in Account 228.2. If the amounts paid are different than the amount accrued, then the net difference is removed from Account 228.2 and charged back against Account 925.

Q. 46 Given the method used to account for the self-insured portion of liability claims, does the test year expense reflect on-going operations?

A. 46 Because of the nature of this process, it is not unusual to have fluctuations in the net charges to Account 925 from period-to-period. This can result in an amount in any recorded period in Account 925 not being representative of on-going operations. In fact, the recorded test year expense was a net credit of $567,165. The credit resulted from the net accruals to previous claims exceeding accruals for new claims. The Company uses a ten-year average of these fluctuating amounts to normalize this expense for ratemaking purposes.

Q. 47 Is the accounting and normalization method described above consistent with prior Company proposals and Commission decisions?

A. 47 Yes. The accounting described above is consistent with every Southwest rate case filed before the Commission for at least twenty years. The 10-year period and the method of normalization were approved by the Commission in Decision No. 68487.

XI. RATE BASE

Q. 48 What is the fair value and original cost rate base that Southwest requests be approved by the Commission?

A. 48 Southwest proposed and supports a fair value rate base of $1,469,159,432. The fair value rate base was determined by giving equal weight (50/50) to the original cost rate base of $1,094,814,020 and the reconstruction cost new rate base of $1,843,505,043. Schedule B-1 is a high-level summary of the various components that comprise

rate base. Rate base is presented on this schedule at original cost, reconstruction cost new, and at fair value. All measurements were performed for the twelve months ended April 30, 2007. Details of the various rate base components can be found in Schedules B-2 through B-6.

Q. 49 Is the company proposing any adjustments to the recorded rate base amounts at April 2007?

A. 49 Yes, Adjustment No. 17, CCNC, adds to rate base the recorded amounts as of April 2007 of non-revenue producing CCNC that resides in construction work-in-progress, along with an adjustment to System Allocable Miscellaneous Intangible Plant (to synchronize the plant with the adjustment to System Allocable amortization expense in Adjustment No. 14). This consists of two components: a direct Arizona component of $2,976,115 and a System Allocable component (after 4-Factor) of $1,373,330. Company witness Ms. Randi Aldridge discusses Adjustment Nos. 14 and 17 in her prepared direct testimony.

Q. 50 Please describe and explain Southwest's Schedules B-3 and B-4.

A. 50 Schedule B-3 is a summary of the reconstruction cost new study. The schedule contains both the direct and System Allocable plant assigned to Arizona. The development of the reconstruction cost new data is utilized to develop the fair value rate base as traditionally calculated by

the ACC. The detail supporting Schedule B-3 is contained in Schedule B-4. Schedule B-4 contains the Handy-Whitman indices that were used to trend original cost plant to obtain the reconstruction cost new data, and the reconstruction cost new data by vintage year, by FERC account.

Q. 51 Please describe and explain the items of other rate base items contained in Southwest's Schedule B-5 and B-6 that do not use the end of test year balance?

A. 51 Schedules B-5 and B-6 contain four items that employ the thirteen-month average balance method for inclusion in rate base: 1) materials and supplies; 2) prepayments; 3) customer advances for construction; and 4) customer deposits. The use of the 13-month average balance as the method of calculation has been used and accepted by this Commission in many past rate cases.

Q. 52 Please describe and explain the other items contained in Schedule B-5 and B-6 that do not employ the 13-month average balance method?

A. 52 The cash working capital allowance and the accumulated balance of deferred income taxes do not use the 13-month average balance method of calculation.

The cash working capital allowance is determined through a comprehensive lead-lag study. In performing the lead-lag study, Southwest examined every non-gas invoice over $10,000 processed during the test year. The Company also examined every gas invoice processed during

the test year regardless of the expense level. As a result, approximately 80 percent of total adjusted operating expenses were reviewed to determine the net lag attributable to operating expenses.

The April 2007 balance of accumulated deferred income taxes is used for the inclusion in rate base. The end of test year balance, rather than the 13-month average balance has been used and accepted by the Commission in many past rate cases.

Q. 53 Does this conclude your prepared direct testimony?

A. 53 Yes, it does.

SUMMARY OF QUALIFICATIONS
ROBERT A. MASHAS

I graduated from the University of Texas at El Paso in Wilkes College in Wilkes-Barre, Pennsylvania with a Bachelor of Science degree in Management, with an Economics concentration. I received a Master of Business Administration degree from Shippensburg State College in Shippensburg, Pennsylvania. I am a member of the American Institute of Certified Public Accountants.

Prior to joining Southwest in 1984, I held a positions as a staff accountant (one year) with Marriott Corporation, auditor (five years) with the Federal Energy Regulatory Commission (FERC) Office of Chief Accountant, and as a senior auditor (one year) Public Service Commission of Nevada (PSCN) now known as the Public Utilities Commission of Nevada (PUCN). My responsibilities at the FERC included conducting audits of natural gas transmission, electric and oil pipeline companies for compliance with the Uniform System of Accounts, rate orders and decisions of the FERC. My responsibilities at the PSCN included the examination of the books and records of gas, electric, and water utilities, as well as testifying as an expert witness.

I joined the Rate Department of Southwest, in 1984, as a cost analysis. In 1985, I was promoted to Manager/Revenue Requirements. In 1992, I was promoted to

Director, Revenue Requirements and Resource Planning, and in 1998, with the regulatory requirements for resource planning reduced, my focus was primarily revenue requirements. During my more than twenty years overseeing the Revenue Requirements Department, I have either directly or indirectly prepared and participated, as an expert witness, in every Southwest Gas and Paiute Pipeline general rate case since 1986. I have also represented the Company in numerous dockets that addressed accounting and regulatory issues.

SOUTHWEST GAS CORPORATION
ARIZONA
DEFICIENCY REDUCTION
NEW MARGIN NET OF NEW CAPITAL RELATED COST
($MILLIONS)

Line No.	Description	Increase / (Decrease) Detail	Increase / (Decrease) Result	Deficiency Impact	Line No.
	(a)	(b)	(c)	(d)	
	Margin				
1	Add: Net Margin Growth at Present rates		$ (27.2)		1
2	Add back Margin Attrition				2
3	Declining Residential Average Use		(6.5)		3
4	General Service Customer Attrition		(4.3)		4
5	**Adjusted New Margin Reducing Deficiency**		$ (38.0)	$ (38.0)	5
	Rate Base				
6	Authorized	$ 922.7			6
7	Requested	1,094.8			7
8	Change	$ 172.1			8
9	Authorized Pre Tax Return	10.90%			9
10	Finance Cost of New Rate Base		$ 18.8		10
	Depreciation				
11	Authorized	$ 74.7			11
12	Requested	87.8			12
13	Change		$ 13.1		13
	Property Tax				
14	Authorized	$ 32.1			14
15	Requested	33.1			15
16	Change		$ 1.0		16
	Interest on Customer Deposits				
17	Authorized	$ 1.4			17
18	Requested	1.9			18
19	Change		$ 0.5		19
20	**Investment Related Cost Increasing Deficiency**		$ 33.4	$ 33.4	20
21	**Deficiency Reduction**			$ (4.6)	21

Exhibit No.___(RAM-1)
Sheet 1 of 1

Volume III

Testimony

3

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

PREPARED DIRECT TESTIMONY
OF
RANDI L. ALDRIDGE

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
Prepared Direct Testimony
Of
RANDI L. ALDRIDGE

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Appendix A - Summary of Qualifications of James L. Cattanach

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Exhibit No.___(RLA-2)

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
RANDI L. ALDRIDGE

I. 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 By whom are you employed and in what capacity?

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) as Supervisor/Revenue Requirements.

Q. 3 Please describe Appendix A.

A. 3 Appendix A describes my educational and business background.

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

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

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

A. 5 First, I describe the Company's natural gas operations. Then I explain how the Company determines whether costs are assigned directly to one or more ratemaking jurisdictions or allocated to all rate jurisdictions,

along with a description of the allocation methodologies Southwest uses to allocate common costs. Next, I explain the rate case adjustments that I am sponsoring.

Finally, I describe how the Company has complied with the Commission's directive in Southwest's last general rate case to: 1) address how Southwest and its customers benefit from the activities of the American Gas Association (AGA); and 2) provide a detailed explanation of the duties that are associated with "sales, marketing, or promotional activities" of certain employees and offer a reasonable allocation of wage expense consistent with those duties.

II. DESCRIPTION OF NATURAL GAS UTILITY OPERATIONS

Q. 6 Please describe Southwest's natural gas operations.

A. 6 Southwest is primarily a natural gas local distribution company, providing service to over 1.7 million customers in three states. At the end of the test year, Southwest served over 945,000 customers in Arizona, or nearly 54 percent of its total customer base. Southwest has eight (8) ratemaking jurisdictions subject to the regulation of the ACC, the PUCN, the CPUC, and the Federal Energy Regulatory Commission (FERC). These eight ratemaking jurisdictions are as follows: Arizona, Southern Nevada, Northern Nevada, Southern California, Northern California, South Lake Tahoe, Paiute Pipeline Company (Paiute) and Southwest Gas Transmission Company (SGTC).

Southwest's operations are divided geographically

into five (5) operating divisions: Southern California, Northern Nevada, Southern Nevada, Central Arizona, and Southern Arizona. Each division operates independently of the others and may include portions of multiple ratemaking jurisdictions. All divisions are supported by Corporate staff.

III. JURISDICTIONAL COST RESPONSIBILITY AND ALLOCATIONS

Q. 7 Briefly describe how costs associated with Southwest's natural gas operations are treated in this rate application.

A. 7 Both operating and capital costs are incurred at the division level and at the corporate level. Costs incurred at the division level are charged directly to the ratemaking jurisdiction incurring the costs. Costs at the corporate level may be charged to one or more rate jurisdictions if the cost/activity was incurred on its behalf (i.e., "Corporate Direct" costs). Corporate costs that are beneficial to all of the Company's rate jurisdictions, or where the effort of tracking the jurisdictional allocation of the costs is burdensome and not cost justified, are allocated to all rate jurisdictions (i.e. "common" or "System Allocable" costs).

Q. 8 What do System Allocable costs consist of?

A. 8 System Allocable costs are primarily corporate administrative and general (A&G) expenses, and the costs associated with intangible plant (primarily software)

and general plant used to support the corporate administrative staff.

Q. 9 How does the Company allocate these common costs to Paiute and SGTC?

A. 9 System Allocable A&G expenses (except Account 924, Property Insurance) are first allocated to Paiute and SGTC using the Modified Massachusetts Formula (MMF), a FERC-authorized methodology that is calculated on Schedule C-1, Sheet 18. Property Insurance is allocated using an insurable property factor (Workpapers Schedule C-2). Paiute is also charged a rental fee for its use of System Allocable intangible and general plant.

System Allocable costs that are allocated and charged to Paiute are transferred to and recorded on Paiute's books monthly. Consequently, System Allocable A&G expenses shown on Southwest's books are net of the allocations to Paiute.

For this rate application, the MMF, the insurable property factor, and the Paiute rental charge were recalculated using end of test year data. The resulting pro forma adjustment is presented in Adjustment No. 12, which is discussed in more detail later in my testimony.

Q. 10 After System Allocable costs are allocated to Paiute and SGTC, how are the remaining costs allocated to Southwest's retail ratemaking jurisdictions?

A. 10 Property Insurance costs are allocated to each retail ratemaking jurisdiction using the same insurable

property factor discussed previously, and the remaining System Allocable costs are allocated using the 4-Factor allocation methodology as described below.

Q. 11 Please describe the 4-Factor Allocation Methodology.

A. 11 The 4-Factor is based on the average of four equally-weighted components: (a) direct operating expense; (b) average gross plant; (c) direct operating labor; and (d) average number of customers. The 4-Factor has been used for ratemaking purposes by Southwest since the 1950s, and has been accepted and approved by each of Southwest's jurisdictional state regulatory commissions. Schedule C-1, Sheet 17 provides the development of the 4-Factor allocation percentages for the test year.

IV. RATE CASE ADJUSTMENTS

A. Adjustment No. 3 - Labor

Q. 12 Please explain the adjustments you are supporting, starting with Adjustment No. 3, Labor.

A. 12 Adjustment No. 3 annualizes the labor and related labor loadings of Arizona and Corporate Staff employees employed by the Company at April 30, 2007.

The labor and labor loading annualization adjustment includes three components. First, a salary annualization is made for all Arizona and Corporate Staff employees at salaries in effect at the end of the last pay period beginning prior to April 30, 2007. Secondly, it annualizes labor loadings at the end of the test year and applies those costs to the employees on Southwest's

payroll at the end of the test year. Finally, the labor adjustment reflects the actual three percent general wage increase effective June 25, 2007, an estimated three percent general wage increase to be effective in June 2008, along with additional wage increases as a result of within-grade movement during the twelve months subsequent to the end of the test year (i.e., through April 2008).

Q. 13 Why is it appropriate to adjust labor expense for the 2007 and 2008 wage increases and within-grade movement?

A. 13 Under current Commission guidelines for processing major rate applications, it is expected that the hearing in this proceeding will not be conducted before June 2008. Historically, the Company has granted general wage increases effective each June after being approved by the Company's Board of Directors in May. Therefore, the year 2007 wage increase is known and measurable, and the 2008 wage increase and post-test year within-grade wage increases will be known and measurable prior to the hearing in this proceeding. As such, Staff and other interveners will have an opportunity to verify and quantify the 2008 wage increase and post-test year within grade movement.

Q. 14 Does this post-test year adjustment violate the matching principle?

A. 14 No. This adjustment only applies to employees on the payroll at April 30, 2007, the end of the test year. It

does not apply to any employees hired after April 30, 2007 to meet customer growth, changes to work requirements, etc. Therefore, the number of employees at the end of the test year is synchronized with test year customers that they serve. This adjustment simply recognizes the fact that by the time the rates from this docket become effective, test year customers will be served by test year-end employees who, on average, will be paid over six percent more than the wages in effect at the end of the test year.

Q. 15 Have previous Commission rulings in the Company's rate applications addressed this adjustment?

A. 15 Yes. The Commission has consistently allowed Southwest's post test year wage increases. Most recently, in Decision No. 68487, the Commission found that the "...wage increase should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenue and expenses."

Q. 16 Please describe the labor loading process.

A. 16 Pensions, benefits and payroll taxes are accumulated at the corporate level. These costs are then distributed amongst the various jurisdictions through a labor loading process. The labor loading rate is adjusted at the beginning of each year, based on budgeted pensions,

benefits, and payroll taxes and expected employee levels. The labor loading process applies the labor loading rate to each labor dollar, assigning an appropriate amount of pensions, benefits, and payroll taxes to each account to which labor has been charged.

Q 17 How were labor loadings for Arizona and Corporate Staff employees annualized?

A. 17 For benefits with premiums or regular monthly payments, I used the amount recorded in April 2007 times twelve months to more accurately reflect current expenses. If there were thirteen payments during the test year for any item, the extra payment was removed. For pensions, post employment benefits other than pension (PBOP), and supplemental executive retirement plan (SERP), Southwest's uses the most recent actuarial studies as the basis for the labor loading annualization. The Company removes certain costs in the Miscellaneous Benefits account from the cost of service, such as costs related to service awards, employee events, and employee recognition, consistent with prior Commission decisions. In addition, payroll taxes and indirect time were adjusted for the impact of annualizing payroll and overtime. For remaining costs in Account 926, recorded test year costs were used as the basis for the annualization.

There are two methods used to allocate labor loading costs to Arizona. First, the cost of pensions, PBOP,

SERP, executive deferred compensation, and employee investment plan (401k) are allocated based on each jurisdiction's labor cost as a percentage of total Company labor. Second, for the remaining benefits, a cost per employee was calculated based on adjusted cost divided by the average number of total Company employees during the test year. The cost per employee was multiplied by the number of jurisdictional employees at the end of the test year to determine the amount allocated to Arizona for ratemaking purposes.

Q. 18 Once the annualized labor and labor loadings were calculated, how was the adjustment determined?

A. 18 The annualized labor and labor loadings were assigned to each account based on the historical test year relationships. For example, during the test year, approximately 80 percent of Arizona direct labor and loadings were charged to operations and maintenance (O&M) accounts. Therefore, 80 percent of the annualized Arizona direct labor and loadings were assigned to operations and maintenance accounts. The difference between the annualized labor and loadings assigned to the O&M accounts and recorded labor and loadings is the adjustment for that account. As approximately 80 percent of the annualized Arizona direct labor and loadings were assigned to O&M, the remaining 20 percent was assigned to capital and deferred accounts, and does not impact the revenue requirement requested in this rate

application. A similar assignment is performed for corporate staff annualized labor and loadings to determine the adjustment required.

B. Adjustment No. 4 - Customer Billing

Q. 19 Please explain Adjustment No. 4, Customer Billing.

A. 19 Adjustment No. 4 annualizes costs associated with the customer billing function, such as bill stock, toner, envelopes, and postage, to account for the difference between recorded and annualized bills.

This annualization also takes into account the recent increase in postage of two cents per piece of first class mail, which was effective May 14, 2007. Southwest applied this increase to the annualized number of bills. Such an adjustment is consistent with Southwest's proposal in its most recent general rate case, which was approved by the Commission.

C. Adjustment No. 5 - Miscellaneous Adjustments

Q. 20 Please explain Adjustment No. 5, Miscellaneous Adjustments.

A. 20 Adjustment No. 5 identifies a number of items recorded during the test year for which Southwest is not requesting recovery in this proceeding. The amounts removed from the cost of service are summarized by account in Schedule C-2, Adjustment No. 5, and the supporting workpapers categorize the transactions removed by type of cost.

D. Adjustment No. 6 - Vehicle Compensation

Q. 21 Please explain Adjustment No. 6, Vehicle Compensation.

A. 21 Adjustment No. 6 removes the cost of Company vehicles related to personal use from test year expenses. This adjustment is consistent with Southwest's proposal in its most recent general rate case, which was approved by the Commission.

E. Adjustment No. 7 - Out-Of-Period Expenses

Q. 22 Please explain Adjustment No. 7, Out-of-Period Expenses.

A. 22 Adjustment No. 7, Out-of-Period Expenses, adjusts test year expenses for payments made to two vendors.

The payments made to the first vendor were charged to the Southern Nevada jurisdiction in error during the test year, but the correcting journal entry moving these charges to the Arizona jurisdiction was made subsequent to the end of the test year. This adjustment adds the correcting journal entry to test year expenses.

A reclassification journal entry was made during the test year for payments made to a second vendor, reducing test year expenses to correct an error for an expense that was incurred prior to the test year. This adjustment reverses the reclassification journal entry.

Q. 23 Which transactions were reviewed for the Out-of-Period Expenses adjustment?

A. 23 All Arizona jurisdictional expenses exceeding $50,000 were evaluated to determine whether an adjustment was necessary. This adjustment is consistent with Southwest's proposal in its most recent general rate

case, which was approved by the Commission.

F. Adjustment No. 11 - AGA Dues

Q. 24 Explain Adjustment No. 11, AGA Dues.

A. 24 Adjustment No. 11 removes the portion of the Company's dues to the AGA identified as promotional or lobbying in nature. This adjustment is consistent with previous Commission decisions not allowing the recovery of the promotional and lobbying portion of the Company's AGA dues.

Q. 25 What is AGA?

A. 25 AGA is a trade and professional organization representing 200 natural gas utilities. AGA focuses on the collection, use, and dissemination of natural gas-related information.

Q. 26 In Decision No. 68487, the Commission directed Southwest to provide more information about the functions of AGA, and how AGA's activities benefit the Company and its customers. Are you the witness who is sponsoring testimony responsive to the Commission's directive?

A. 26 Yes. This topic is discussed later in my testimony in the "Compliance Items" section.

G. Adjustment No. 12 - Paiute/SGTC Allocation

Q. 27 Please explain Adjustment No. 12, Paiute/SGTC Allocation, which you previously referred in your response to Question No. 10.

A. 27 Adjustment No. 12 annualizes the System Allocable A&G amounts allocated to Paiute through the MMF allocation

methodology, and the insurable property factor, and the rent revenue that Southwest receives from Paiute for the test year ended April 30, 2007. The supporting workpapers to Adjustment No. 12 show the detailed calculations needed to derive the Paiute rent expense and insurable property factor at April 30, 2007. This adjustment is consistent with the methodology approved by the Commission in the Company's last several rate cases.

The annualized MMF allocation factors are also used in the pro forma adjustments that impact System Allocable A&G costs, in order to allocate a portion of the adjustment to Paiute and SGTC before calculating the portion that is allocated to Arizona.

H. Adjustment No. 13 - Rate Case Expense

Q. 28 Please explain Adjustment No. 13, Rate Case Expense.

A. 28 The Company estimated the incremental costs that would be incurred to prepare and process this general rate case and divided this amount by a three-year period, roughly equal to one rate case cycle, to calculate an annual amortization to Account 928. The adjustment is the difference between this new amortization amount and the amount of rate case expense amortized on the Company's books during the test year. This adjustment is consistent with Southwest's proposal in its most recent general rate case, which was approved by the Commission.

I. Adjustment No. 14 - Depreciation and Amortization Expense

Q. 29 Please explain Adjustment No. 14, Depreciation and Amortization Expense.

A. 29 Adjustment No. 14 annualizes depreciation and amortization expense based on plant in service at April 30, 2007, using currently approved depreciation rates. The annualization also includes the depreciation and amortization related to the plant adjustments made in Adjustment No. 17, which is discussed in detail later in my testimony.

Q. 30 Please explain why an adjustment is necessary to annualize depreciation and amortization expense for the test year.

A. 30 This adjustment is necessary to synchronize the depreciation and amortization expense with the plant in service at the end of the test year, as adjusted. Like many utilities, Southwest employs a depreciation convention based on the month the plant is actually placed in service. Southwest begins depreciation on plant the month subsequent to the month it is first placed in service, and, in turn, takes a full month's depreciation in the month it is removed or retired from service. As a result, plant that is placed in service or retired after the beginning of the test year has a partial year's depreciation expense recorded on the books of the Company. To allow Southwest the opportunity to recover its reasonable and necessary operating

expenses and to avoid charging customers for assets removed/retired from service, depreciation and amortization must be annualized based on end of test year plant balances, as adjusted. This adjustment accomplishes those objectives, and is consistent with the methodology approved by the Commission in the Company's last several rate cases.

J. Adjustment No. 15 - Property Tax

Q. 31 Please explain Adjustment No. 15, Property Tax.

A. 31 Adjustment No. 15 annualizes property taxes on the Company's adjusted investment in plant and materials as of the end of the test year. For Arizona properties, the Company determines an estimated full cash value by using adjusted net plant in service at April 30, 2007, adding materials and supplies, and subtracting transportation equipment and land rights. The estimated full cash value is then multiplied by the 2008 assessment rate of 23 percent to determine the assessed value. The assessed value is then multiplied by the estimated property tax rate of 11.52 percent to determine the annualized property tax expense.

Q. 32 Why is Southwest proposing to use the statutory assessment rate for 2008 in its property tax annualization, rather than the assessment rate applicable for 2007?

A. 32 Based on recent changes in Arizona law, Southwest based its property tax calculation on a known and measurable

change that will be applicable when rates from this proceeding go into effect in 2008. Utilizing the 2008 assessment rate is consistent with the methodology approved by the Commission in Southwest's last general rate case.

K. Adjustment No. 16 - Interest on Customer Deposits

Q. 33 Please explain Adjustment No. 16, Interest on Customer Deposits.

A. 33 Adjustment No. 16 synchronizes interest expense on customer deposits with the amount of customer deposits used as a rate base reduction. Consistent with prior Commission decisions, interest expense is treated as an above-the-line expense.

L. Adjustment No. 17 - Completed Construction not Classified

Q. 34 Describe Adjustment No. 17, Completed Construction not Classified (CCNC).

A. 34 Adjustment No. 17 comprises two parts. First, an adjustment was made to gas plant for plant serving customers but not recorded in Account 101 - Gas Plant in Service (GPIS) at the end of the test year. Second, an adjustment was made to System Allocable Intangible Plant to better match cost recovery of these projects (primarily software) to the plant that will be amortized during the period that rates from this proceeding will be in effect.

The gas plant included in this adjustment reflects construction expenditures made before the end of the

test year. No expenditures for tangible plant incurred after April 30, 2007 are included in the adjustment. The tangible plant represented by these expenditures (i.e., CCNC) was either in-service at the end of the test year or shortly thereafter. However, the actual closing to GPIS was made after the end of the test year, largely due to delays in entering the required information into the Company's computer systems.

The CCNC requested to be included in rate base is non-revenue producing plant. In other words, it represents plant that was constructed to improve service or enhance reliability and safety for existing customers, and not constructed to serve new customers. Southwest will not realize any incremental operating revenues from the construction and addition of this plant. Examples of the CCNC included in the adjustment are: replacement mains, franchise requirements, pressure reinforcements, measuring and regulating station equipment, and general plant.

Customers existing in Southwest's system at the end of the test year are the primary beneficiaries of these construction expenditures. Consequently, the inclusion of CCNC in rate base more accurately matches the Company's investment needed to serve the customers in its system at the end of the test year, and should be allowed by the Commission.

Q. 35 Please explain the portion of the CCNC adjustment made

to System Allocable miscellaneous intangible plant.

A. 35 Most of the items in System Allocable miscellaneous intangible plant (Account 303) are software projects with a three-year amortization period. This amortization period is roughly equivalent to the Company's Arizona rate case cycle. Absent an adjustment, customers may end up double-paying for certain projects, and never paying for other projects through rates. To ameliorate this phenomenon, the Company proposes an adjustment to remove all projects with an amortization period expiring December 31, 2007 or earlier from rate base, and adding estimated amounts for projects to be closed to plant prior to December 31, 2007 to rate base. This is a conservative adjustment because many small software projects spend a relatively short time in Construction Work in Progress before being transferred to plant. Consequently, between the date this rate case was prepared and the end of 2007, more projects may close to plant than was indicated by the estimated balances when this rate case was prepared. Furthermore, the amounts estimated by the Company can be verified prior to the hearing in this rate case.

This adjustment strikes a fair balance between project amortizations that will expire shortly after the end of the test year, and projects commencing amortization and serving customers approximately one year prior to rates from this proceeding going into

effect.

The CCNC adjustment is equitable to both the Company and its customers, and was approved by the Commission in Southwest's last general rate case.

V. COMPLIANCE ITEMS

A. Sales, Marketing, and Promotional Activities

Q. 36 In Southwest's last general rate case, the Commission disallowed 10 percent of the compensation of certain employees in the Service Planning and Key Accounts Management (KAM) departments based on a belief that some portion of the employees' duties related to the "sales, marketing, and promotional activities" of natural gas. In making the disallowance, the Commission relied on outdated job descriptions. The Commission directed the Company to provide detailed information regarding the duties of the Service Planning and KAM employees in its next rate case to determine if any disallowance is appropriate. Has the Company provided updated job descriptions?

A. 36 Yes. Attached as Exhibit No. ____(RLA-1) are the current job descriptions for the Southwest's Service Planning and KAM employees referred to above.

Q. 37 What are the duties of Southwest's Service Planning and KAM employees?

A. 37 These groups are primarily responsible for the coordination and installation of new services. Service Planning focuses on residential and commercial

customers. KAM focuses on Southwest's largest customers.

The Service Planning and KAM employees concentrate on the following activities, which are further detailed in the attached job descriptions:

- Ensuring Southwest's system expands in a cost-effective manner, while ensuring that existing customers are not harmed by customer growth;
- Maintaining and improving service quality and customer satisfaction; and
- Ensuring that the Company's infrastructure is used in the most efficient manner, which reduces the average cost for all customers since the Company's infrastructure costs are primarily fixed.

Q. 38 Why did Southwest update job descriptions in the Service Planning and Key Account Management (KAM) departments over the last several years?

A. 38 The natural gas market has changed substantially over the past ten years. Recognizing the demands of its customers are individually unique, Southwest shifted the priorities of its Service Planning and KAM employees to reflect the changes in the market and tailored the duties and responsibilities of these employees to more suitably meet the needs of new and existing customers. Because customers now demand that natural gas be available in their homes and for commercial use, the Company no longer finds it necessary to market and promote the use of natural gas in the same manner as it

did in the past. As part of the change in the marketplace and the Company's priorities, Southwest eliminated the "sales, marketing, and promotional activities" responsibilities. The current job descriptions reflect these market changes.

Q. 39 What is a reasonable allocation of compensation consistent with the job duties attached to your testimony?

A. 39 Southwest's Service Planning and KAM employees do not perform "marketing" or "sales" functions. All of the job duties of these employees provide clear benefits to customers. Southwest believes that the compensation for the Service Planning and KAM positions are just and reasonable and should be included in rates with no disallowance.

B. AGA Activities

Q. 40 You discussed the AGA in your testimony describing Adjustment No. 11. Why are you including additional information about AGA in this proceeding?

A. 40 In Decision No. 68487, the Commission directed Southwest to describe the various functions of the AGA, and how the AGA's activities provide benefits to the Company and its customers.

Q. 41 What are some of the AGA activities that benefit its member utilities and their customers?

A. 41 The AGA provides a number of services and programs benefiting its individual members. The AGA serves as a

leader of research and programs for the natural gas industry. The AGA's ability to concentrate its efforts solely on the natural gas industry allows individual gas utilities, such as Southwest, to focus on regional service and business issues while remaining abreast of industry trends through its AGA membership. Southwest can then implement the programs or research developed by the AGA to help maximize its business efficiencies. The benefits of the AGA's latest research and programs concern the areas of new equipment, service and technical processes, natural gas supply trends, and newly identified business processes.

Moreover, when a utility experiences a problem unique to the natural gas sector, the AGA serves as an intermediary for the exchange of approaches and solutions through direct information exchanges, such as e-mail, message boards, and telephone. Other informational exchanges include newsletters, magazines, and workshops/seminars on topics specific to the natural gas sector.

In addition, the AGA's Codes of Standards publications serve as a precise, accurate and uniform source for technical matters. This concentration of resources and information saves the Company a considerable amount of time and money, because it has direct access to a network of information exchanges. Of course, customers are the ultimate beneficiary of the

savings.

A good example is the AGA's sponsorship and publication of ANZI Z380.1, Guide for Gas Transmission and Distribution Piping, which this Commission has relied upon in its own rulemaking. See Arizona Administrative Code 14-5-202(R).

The AGA also develops and implements public information campaigns. The campaigns directly target specific markets and media to inform the public about the gas industry's operations and utility and regulatory activities. The nationwide campaigns and partnerships advance important issues to the public, such as safety, pricing, the environment, the availability of low income assistance programs, and the "Call Before You Dig" program.

The AGA benefits Southwest and its customers by increasing Southwest's efficiencies which reduces the amount of time and money the Company must spend conducting its own research, continuing education, and outreach.

Q. 42 Please describe the various AGA functions?

A. 42 Exhibit No. ___(RLA-2) provides a list and description of the AGA's functions as listed in the March 2005 Annual Audit report to the National Association of Regulatory Utility Commissioners (NARUC).

Q. 43 Does the AGA provide a cost savings analysis for benefits to the Company and its Arizona customers?

A. 43 Yes. In 2006, the AGA's programs, services and advocacy efforts provided its members with $479 million in outright savings or avoided costs. The AGA collected under $18 million in membership dues which resulted in more than a $27 return on every $1 in paid AGA dues.

Q. 44 Is Southwest requesting recovery for the AGA's marketing and lobbying activities?

Q. 44 No. In accordance with previous Commission decisions Southwest is not requesting the recovery of dues associated with marketing and lobbying activities.

Q. 45 Does this conclude your prepared direct testimony?

A. 45 Yes, it does.

SUMMARY OF QUALIFICATIONS
RANDI L. ALDRIDGE

I graduated from the University of Washington in Seattle, Washington with a Bachelor of Arts in Business Administration, Accounting. My areas of concentration were accounting and finance. I graduated from the University of Nevada, Las Vegas with a Masters in Business Administration (MBA), with Beta Gamma Sigma honors. I am a Certified Management Accountant (CMA) and a member of the Institute of Management Accountants.

One year before completing my bachelor's degree, I accepted employment at Washington Mutual Savings Bank in Seattle, Washington as an Asset/Liability Management intern. Upon graduation in 1993, I accepted a full-time position as a Financial Analyst Trainee in the Financial Forecasting Department. In 1994, I was promoted to Financial Analyst I. My responsibilities included assisting in the budget and forecasting process, and various financial analyses.

In February 1995, I accepted a position as a Budget Analyst in the Budget and Forecasting Department at PriMerit Bank in Las Vegas, Nevada. In April 1996, I transferred to Southwest as a Corporate Accountant I in the

Accounting Control Department. In January 1998, I was promoted to Analyst I/Accounting. In February 1998, I transferred to the Revenue Requirements department as an Analyst. In January 2001 I was promoted to Specialist, in July 2003 I was promoted to Senior Specialist, and in May 2007 I was promoted to my present position. In my present position, I am responsible for supervising the activities of junior-level staff, as well as the preparation of general rate case filings for state and federal jurisdictions, the research, preparation, and presentation of various regulatory and financial analyses, studies, and reports, as well as other special projects.

I have attended numerous training and technical conferences related to utility ratemaking, regulatory, and accounting issues.

I have taught the Cost of Service Problem for "The Basics" conference presented by the Center for Public Utilities at New Mexico State University and the National Association of Regulatory Utility Commissioners since 2003.

SOUTHWEST GAS CORPORATION
ARIZONA
JOB DESCRIPTION TABLE OF CONTENTS

Department	Job Title	Job Code
Service Planning	Utilization Engineer	ENG0002017
Service Planning	Service Planner	SP00002059
Service Planning	Sr Service Planner	SP00002060
Service Planning	Director/Service Planning/CAZ	SP00002062
Service Planning	Manager/Service Planning/SAZ	SP00002065
Service Planning	Manager/Service Planning/CAZ	SP00002067
Service Planning	Supervisor/Service Planning	SP00002068
Service Planning	Supervisor/Industrial Service Planning	SP00002012
Key Account Managment (KAM)	Supervisor	GS00002038
Key Account Managment (KAM)	Manager	GS00002054
Key Account Managment (KAM)	Senior Manager	GS00002044
Key Account Managment (KAM)	Industrial Gas Engineer	GS00002060

TITLE: **Energy Utilization Engineer**
JOB CODE: ENG0002017
DIVISION:
DEPARTMENT: Service Planning
DATE: August 19, 1987

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is an individual contributor involved in energy services, engineering support, customer relations, trade relations and strategy & planning for a division of Southwest Gas Corporation.

POSITION DIMENSIONS

The incumbent does not have accountability for people or budgets.

NATURE AND SCOPE

The Energy Utilization Engineer reports to the Manager/Service Planning or Supervisor/Service Planning along with:

Note: This position involves the activities listed below. The activities in **bold** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Customer Relations

The incumbent is personally responsible to:

Work with customer to determine technical needs and specifications
Advise customers on gas products and availability

The incumbent, with others, is responsible to:

Participate in customer business meetings as consultant/advisor
Assure continuing relationships with key customers
Investigate and settle customer complaints

The incumbent assists others to:

Establish and maintain contact with top management of important customers
Advise dealers and distributors of programs

Strategy, Planning And Execution

The incumbent assists others to:

Energy Utilization Engineer
ENG0002017

Implement plans for assigned market sectors
Keep abreast of industry strategies and tactics
Analyze legislation impacting company products or services

Trade Relations

The incumbent is personally responsible to:

Make presentations to trade allies or prospective customers

The incumbent, with others, is responsible to:

Represent the company at association meetings

The incumbent assists others to:

Formulate and implement plans for trade association activities

MISCELLANEOUS ACTIVITIES

The incumbent is personally responsible to:

Design HVAC systems for residential applications
Build and maintain relationships with manufacturers, distributors, dealers and builders
Provide customers and/or colleagues with technical information on products/services
Keep abreast of technology or other changes within the industry
Keep up-to-date on tariffs and regulations

The incumbent assists others to:

Achieve assigned margin goals
Establish budgets and goals
Keep up-to-date on government regulations impacting company products or services
Develop company displays for trade shows

OTHER REQUIREMENTS

There are standardized methods and procedures that determine how this job is performed. This position requires 3 to 4 years of relevant work experience.

In this job, the incumbent must be able to influence customers and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management, senior management, department heads of units outside of marketing and outside consultants.

TITLE:	**Service Planner**
JOB CODE:	SP00002059
DIVISION:	All Divisions
DEPARTMENT:	Service Planning
DATE:	September 15, 2005

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is an individual contributor as a Service Planner involved in Service Planning, Customer Relations, Trade Relations and Strategy for a division of Southwest Gas. The Service Planner may require assistance and general direction.

POSITION DIMENSIONS

The incumbent does not have accountability for people or budgets.

NATURE AND SCOPE

The Service Planner reports to the Supervisor/Service Planning or Manager/Service Planning along with Senior Service Planners. Job is limited in size, scope or complexity in negotiating contracts and projects.

Note: This position involves the activities listed below. The activities underlined or in **bold-faced** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent is personally responsible and may need assistance to:

* **Build and maintain relationships with developers, builders and trade allies**
  Advise customers on gas products and availability
  Coordinate new business processes and contractual information requirements
  Work with customers to determine technical needs and specifications
* **Investigate, review and resolve issues to ensure customer satisfaction**
  Participate in customer business meetings as consultant/advisor
  Establish programs to educate customers
* **Interpret, apply and communicate tariffs to main/service extensions**

Service Planner
SP00002059

Ensure timely coordination of installation of natural gas facilities
Negotiate contracts/special agreements
Prepare studies and analyses
Make presentations to trade allies or potential customers
Participate in relevant trade associations
Keep up-to-date on government regulations impacting company products/ services
Keep abreast of technology or other changes within the industry.
Implement demand-side management programs
Provide customers and/or colleagues with technical information on products/ services
Provide Service Planning support material/demonstration equipment to distributors, dealers and customers

OTHER REQUIREMENTS

There are clear precedents and practices which the incumbent uses as guidelines to determine how this job is performed. A Bachelor's degree is preferred, plus 1-3 years of relevant work experience or equivalent experience.

In this job, the incumbent must be able to influence department heads of units outside of Service Planning, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management and senior management.

TITLE:	**Senior Service Planner**
JOB CODE:	SP00002060
DIVISION:	All Divisions
DEPARTMENT:	Service Planning
DATE:	September 15, 2005

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is an individual contributor as a Senior Service Planner involved in Service Planning, Customer Relations, Trade Relations and Strategy for a division of Southwest Gas. The Senior Service Planner may require assistance and general direction.

POSITION DIMENSIONS

The incumbent does not have accountability for people or budgets.

NATURE AND SCOPE

The Senior Service Planner reports to the Supervisor/Service Planning or Manager/Service Planning along with Service Planners.

Note: This position involves the activities listed below. The activities underlined or in **bold-faced** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent is personally responsible and may need assistance to:

* **Build and maintain relationships with developers, builders and trade allies**
  Advise customers on gas products and availability
  Coordinate new business processes and contractual information requirements
  Work with customers to determine technical needs and specifications
* **Investigate, review and resolve issues to ensure customer satisfaction**
  Participate in customer business meetings as consultant/advisor
  Establish programs to educate customers
* **Interpret, apply and communicate tariffs to main/service extensions**

Senior Service Planner
SP00002060

Ensure timely coordination of installation of natural gas facilities
Negotiate contracts/special agreements
Prepare studies and analyses
Make presentations to trade allies or potential customers
Participate in relevant trade associations
Keep up-to-date on government regulations impacting company products/ services
Keep abreast of technology or other changes within the industry.
Implement demand-side management programs
Provide customers and/or colleagues with technical information on products/ services
Provide Service Planning support material/demonstration equipment to distributors, dealers and customers

OTHER REQUIREMENTS

There are clear precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires a Bachelor's degree plus 1-5 years of relevant work experience, or equivalent experience.

In this job, the incumbent must be able to influence department heads of units outside of Service Planning, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management and senior management.

TITLE: **Director/Service Planning/CAZ**
JOB CODE: SP00002062
DIVISION: Central Arizona Division
DEPARTMENT: Service Planning
DATE: May 18, 2006

APPROVED BY:_____ **DATE:**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

This position is provides strategic leadership and direction for Service Planning, Communications and Consumer Affair activities within the division.

POSITION DIMENSIONS

Budget Accountable For:	$5 – 10 million
Personnel Managed	11 - 15 Exempt Employees
	2 - 4 Non-Exempt Employees

This job has three levels reporting to it.

NATURE AND SCOPE

The Director/Service Planning reports to the Division Vice President along with General Manager/Operations, Director/Administration, Director/Division Support and Manager/Human Resources. Reporting to the incumbent are Manager/ Service Planning, Manager Communications, and Administrator/Consumer Affairs.

Note: This position involves the activities listed below. The activities in **bold**-faced type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisks may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent directs others who:

* **Manage the building and maintaining of relationships with developers, builders and trade allies**
* **Oversee those who advise customers on gas products and availability**
* **Coordinate new business processes and contractual information requirements**
  Work with customers to determine technical needs and specifications
* Participate in customer business meetings as consultant/advisor
  Interpret, apply and communicate tariffs to main/service extensions
  Ensure timely coordination of installation of natural gas facilities
* Negotiate contracts/special agreements

Director/Service Planning
SP00002062

Prepare studies and analyses
Represent the company in civic organizations

The incumbent is personally responsible to:

* **Develop strategies that enhance ability to serve growth areas**
* **Facilitate communication between Service Planning, General Managers and the division Vice President**

Communications

The incumbent directs others who:

* Represent the Company in dealings with the media
* **Propose, plan, execute and evaluate internal and external communication activities, programs and strategies**
* Manage division locally placed advertising
* **Develop communications programs relative to regulatory filings and other company actions**
* Maintain liaison with local and state agencies

The incumbent is personally responsible to:

* **Ensure division communications proactively meet needs of constituencies**

Consumer Affairs

The incumbent directs others who:

* **Create, support and enhance public, private, and non-profit sector relationships**
* **Administer Philanthropic and Civic giving**
* Facilitate employee volunteerism programs
* Serve as advocates for the division Low-Income Community Outreach programs
* Promote supplier diversity programs

The incumbent is personally responsible to:

* **Ensure consistency and accountability of Philanthropic and Civic programs**
* **Develop division strategy enhancing image with Consumer Affairs constituent groups**

Miscellaneous

The incumbent is personally responsible to:

* **Provide leadership to achieve departmental goals**

Director/Service Planning
SP00002062

* **Assure performance against codes, regulations and company standards in areas of responsibility**
* **Develop and implement strategic initiatives**
* Communicate corporate policy
* Provide oversight of budget and expenditures
* Maintain liaison with other departments of the organization
* Represent the company in ways that will enhance its image in the public and business sectors

OTHER REQUIREMENTS

There are broad precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires 7-10 years of relevant work experience. A Bachelor's degree is preferred.

In this job, the incumbent must be able to influence department heads, suppliers, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with department heads, governmental officials and senior management.

TITLE: **Manager/Service Planning/SA**
JOB CODE: SP00002065
DIVISION: Southern Arizona
DEPARTMENT: Service Planning
DATE: September 15, 2005

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is concerned with Managing and Directing Service Planning related activities.

POSITION DIMENSIONS

Budget Accountable For:	$1.5 - $3.0 Million
Personnel Managed:	6 - 25 Exempt Employees 6 - 10 Nonexempt Employees

NATURE AND SCOPE

The Manager/Service Planning reports to the Director/Service Planning.

Note: This position involves the activities listed below. The activities underlined or in **bold-faced** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent directs others who:

* **Build and maintain relationships with developers, builders and trade allies**
  Advise customers on gas products and availability
* **Coordinate new business processes and contractual information requirements**
  Work with customers to determine technical needs and specifications
* **Investigate, review and resolve issues to ensure satisfactory customer satisfaction**
* Participate in customer business meetings as consultant/advisor
  Establish programs to educate customers
  Interpret, apply and communicate tariffs to main/service extensions
  Ensure timely coordination of installation of natural gas facilities
* Negotiate contracts/special agreements

Manager/Service Planning/SA
SP00002065

Prepare studies and analyses
Make presentations to trade allies or potential customers
* Participate in relevant trade associations
Keep up-to-date on government regulations impacting company products/ services
Keep abreast of technology or other changes within the industry
Implement demand-side management programs
Provide customers and/or colleagues with technical information on products/ services
Provide Service Planning support material/demonstration equipment to distributors, dealers and customers

The incumbent is personally responsible to:

Ensure adequate and timely coordination of services
Interpret and apply tariffs to main and service extensions
Keep up-to-date on tariffs and regulations
Represent the company in civic organizations
Keep up-to-date on government regulations impacting company products or services
Keep abreast of technology or other changes within the industry

The incumbent assists others to:

Establish and maintain relationships with government and regulatory agencies

OTHER REQUIREMENTS

There are clear precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires a Bachelor's degree plus 8-10 years of relevant work experience, or equivalent experience.

In this job, the incumbent must be able to influence department heads of units outside of Service Planning, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management and senior management.

TITLE:	**Manager/Service Planning/CAZ**
JOB CODE:	SP00002067
DIVISION:	Central Arizona
DEPARTMENT:	Service Planning
DATE:	September 15, 2006

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent directs Service Planning related activities including indirect oversight of Service Planning activities within the divisions New Business department. The incumbent also has indirect responsibility for Service Planning activities directly reporting to the division New Business Department.

POSITION DIMENSIONS

Budget Accountable For:	$1.5 - $3.0 Million
Personnel Managed:	6 - 8 Exempt Employees 1 - 3 Nonexempt Employees

NATURE AND SCOPE

The Manager/Service Planning is responsible for providing strategic direction for service planning activity for a division and reports to the Director/Service Planning, along with Manager Communications, Administrator/Consumer Affairs and an administrative secretary. Reporting to this position are Service Planning Supervisors.

Note: This position involves the activities listed below. The activities in **bold**-faced type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent directs others who:

* **Build and maintain relationships with developers, builders and trade allies Advise customers on gas products and availability**
* **Maintain liaison with developers and builders during design and construction phases**
* **Coordinate new business processes and contractual information requirements Work with customers to determine technical needs and specifications**

Manager/Service Planning/CAZ
SP00002067

* **Investigate, review and resolve issues to ensure customer satisfaction**
* Participate in customer business meetings as consultant/advisor
  Establish programs to educate customers
  Interpret, apply and communicate tariffs to main/service extensions
  Ensure timely coordination of installation of natural gas facilities
* Negotiate contracts/special agreements
  Prepare studies and analyses
  Make presentations to trade allies or potential customers
* Participate in relevant trade associations
  Keep up-to-date on government regulations impacting company products/ services
  Keep abreast of technology or other changes within the industry
  Implement demand-side management programs
  Provide customers and/or colleagues with technical information on products/ services
  Provide Service Planning support material/demonstration equipment to distributors, dealers and customers

The incumbent is personally responsible to:

* **Develop strategic direction for service planning activity with developers and builders**
* **Implement strategic service planning initiatives within a division**
  Ensure adequate and timely coordination of services
  Interpret and apply tariffs to main and service extensions
  Keep up-to-date on tariffs and regulations
  Represent the company in civic organizations
  Keep up-to-date on government regulations impacting company products or services
  Keep abreast of technology or other changes within the industry

The incumbent assists others to:

Establish and maintain relationships with government and regulatory agencies

Miscellaneous

The incumbent is personally responsible to:

* **Provide leadership to achieve departmental goals**
* Communicate corporate policy
* Provide oversight of budget and expenditures
* Maintain liaison with other departments of the organization

OTHER REQUIREMENTS

Manager/Service Planning/CAZ
SP00002067

There are clear precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires 5 to 7 years of relevant work experience. A Bachelors Degree is preferred.

In this job, the incumbent must be able to influence department heads of units outside of Service Planning, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management and senior management.

TITLE:	**Supervisor/Service Planning**
JOB CODE:	SP00002068
DIVISION:	All Divisions
DEPARTMENT:	Service Planning
DATE:	September 15, 2005

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is concerned with Supervising and Directing Service Planning related activities.

POSITION DIMENSIONS

Personnel Managed: 3 - 10 Exempt Employees
1 - 5 Nonexempt Employees

NATURE AND SCOPE

The Supervisor/Service Planning reports to the Manager/Service Planning or District Manager along with other supervisors. Reporting to the incumbent are Project Managers and Project Specialists.

Note: This position involves the activities listed below. The activities underlined or in **bold-faced** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent is personally responsible to supervise others who:

* **Build and maintain relationships with developers, builders and trade allies**
  Advise customers on gas products and availability
* **Coordinate new business processes and contractual information requirements**
  Work with customers to determine technical needs and specifications
* **Investigate, review and resolve issues to ensure satisfactory customer satisfaction**
* Participate in customer business meetings as consultant/advisor
  Establish programs to educate customers

Supervisor/Service Planning
SP00002013

Interpret, apply and communicate tariffs to main/service extensions
* Ensure timely coordination of installation of natural gas facilities
* **Negotiate contracts/special agreements**

Prepare studies and analyses
Make presentations to trade allies or potential customers
Participate in relevant trade associations
Keep up-to-date on government regulations impacting company products/ services
Keep abreast of technology or other changes within the industry
Implement demand-side management programs
Provide customers and/or colleagues with technical information on products/ services
Provide Service Planning support material/demonstration equipment to distributors, dealers and customers

The incumbent is personally responsible to:

Ensure adequate and timely coordination of services
Interpret and apply tariffs to main and service extensions
Keep up-to-date on tariffs and regulations
Represent the company in civic organizations
Keep up-to-date on government regulations impacting company products or services
Keep abreast of technology or other changes within the industry

The incumbent assists others to:

Establish and maintain relationships with government and regulatory agencies

OTHER REQUIREMENTS

There are clear precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires a Bachelor's degree plus 5-6 years of relevant work experience, or equivalent experience.

In this job, the incumbent must be able to influence department heads of units outside of Service Planning, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management and senior management.

TITLE: **Supervisor/Industrial Service Planning**
JOB CODE: SP00002012
DIVISION: Division
DEPARTMENT: Service Planning
DATE: June 26, 2003

APPROVED BY:_____ **DATE:**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

This position has supervisory responsibility for service planning activities in the Commercial, Industrial and Agricultural market sectors for a division of Southwest Gas Corporation. This includes technical support for the above market sectors and for demand side management activities throughout the division, including the outlying districts.

POSITION DIMENSIONS

Budget Accountable for:	$300,000 - $1,500,000
Personnel Managed:	3 – 10 Exempt Employees
	1 – 5 Non- Exempt Employees

This job has 2 subordinate levels reporting to it.

NATURE AND SCOPE

The Supervisor/Industrial Service Planning reports to the Manager/Service Planning along with other Supervisors/Service Planning, the Management Assistant and the Service Planning Representatives.

Note: This position involves the activities listed below. The activities in **bold** are the most critical for this job. The activities marked with an asterisk (*) are those in which the incumbent spends the most time. (Asterisks may be added by the supervisor for each incumbent.)

The incumbent directs others who:

Coordinate the new business process for commercial, industrial and agricultural customers
Complete customer specific feasibility studies on alternative gas technologies like cogeneration, natural gas cooling, water pumping
Collaborate with individual customers and Energy Services to establish and monitor new product introduction and prototype testing for alternative gas technologies
Identify, evaluate and pursue opportunities with multi-family, commercial, industrial and agricultural customers

Educate architects, consulting engineers and end-use customers about the benefits of natural gas technologies for commercial, industrial and agricultural applications
Manage the implementation of cost-effective Demand Side Management programs within the Division

The incumbent is personally responsible to:

Manage service planning and technical personnel to ensure the provision of high quality, efficient and cost effective service to new and existing commercial, industrial and agricultural customers
Develop and implement an integrated technical service planning plan for the Division
Evaluate the economic feasibility of capital intensive new business projects and present the results to senior management for approval
Train Service Planning personnel on the effective use of business analysis tools used to evaluate new business projects
Establish efficient communications between Division Service Planning and Key Account Management personnel to ensure the effective pursuit of service planning opportunities with large, at risk customers
Facilitate communications between the company and economic development authorities to optimize natural gas utilization by new, incoming customers

The incumbent, with others, is responsible to:

Develop and implement cost effective strategies designed to meet the company's market sector specific service planning goals
Collaborate with Energy Services to identify and develop targeted programs for the commercial, industrial and agricultural market sectors
Formulate cost effective new business practices
Evaluate the company's competitive position on an ongoing basis to ensure the effectiveness of its programs
Develop economic and service planning forecasts
Manage the contact management program to ensure its effective use
Hire and train service planning and technical personnel

OTHER REQUIREMENTS

There are clear precedents and practices that the incumbent uses to determine how this job is performed. This position requires 3 to 5 years of relevant work experience, plus a bachelor's degree in Engineering.

The incumbent frequently exchanges information with senior management, department heads outside of the incumbent's functional area, outside consultants and customers.

TITLE: **Supervisor/Key Account Management**
JOB CODE: GS00002038
DIVISION: Corporate
DEPARTMENT: Key Account Management
DATE 6/7/2000

APPROVED BY:_____ **DATE:**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The Supervisor/Key Account Management supervises and conducts the negotiation and administration of natural gas services for the company's large volume customers. Large volume customers include those customers which: are served under transportation rate schedules; require negotiated contract terms and rates in that they have the ability to physically bypass the company's services or use alternate fuels; consume in excess of 500 therms per day on average; or, are classified as industrial, gas engine, agricultural or electric generation. Large volume customers may require specific supply arrangements or the construction of significant pipeline facilities.

POSITION DIMENSIONS

Budget Accountable for: This incumbent does not have accountability for budgets. The annual margin from large volume customers under the control of the Supervisor ranges from $ to approximately $ million per year.

Personnel Managed: Direct- 1-3 Exempt Employees

This job has one (1) subordinate level reporting to it.

NATURE AND SCOPE

The Supervisor/Key Account Management reports to the Manager/Key Account Management, along with two other Supervisors/Key Account Management and either a Supervisor/Contract Administration or an Analyst/Key Account Management.

Reporting directly to incumbent are the Industrial Gas Engineers (IGEs).

Note: This position involves the activities listed below. The activities in **bold** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

The incumbent is personally responsible to:

* **Supervise IGE's negotiations and administrative activities with agricultural, gas engine large commercial, cogeneration, electric generation and industrial customers which qualify for transportation/optional sales/special contract service, or are not (or cannot) be served with standard rate schedules, or consume in excess of 500 therms per day on average.**
* **Coordinate and administer the implementation of the company's large volume customer programs and support activities.**
* **Coordinate margin/rate studies with Rates Department.**
* **Supervise the company's Strategic Accounts Program for large volume customers.**
* **Communicate to management market opportunities and problem areas**
* **Negotiate contract conditions and rates with Key Account Management Department customers.**
* **Maintain contact and working relationships with Key Account Management Department customers.**
* **Identify customers with bypass potential.**
* **Maintain up-to-date customer information file.**
* **Coordinate Division Engineering studies.**
* **Explain transportation imbalance management to customers.**
* **Coordinate studies regarding transmission and distribution capacity for large volume customers with upstream pipelines, corporate staff and division Sales and Engineering Departments.**
* **Coordinate, prepare and review draft service agreements and other binding documents to provide the necessary service to large volume customers and adequate protection for the Company.**
  Initiate and develop market opportunities.
* **Perform the activities related to the Strategic Accounts program.**
* **Coordinate the development of gas supply required for large volume customers.**
* Prepare alternate fuel studies.
* Prepare economic and sales forecasts.
* Explain the company's transportation policy and procedure to IGEs and customers.
  Advise customers of tariff provisions.
  Keep abreast of state, federal and upstream pipeline tariffs/regulations affecting large volume customers.
  Ensure Key Account Management Department customers are informed of state and federal regulations.
  Ensure Key Account Management Department customers are kept abreast of company filings.
  Develop plans and procedures to identify market opportunities. Keep up-to-date with system gas supply purchase issues. Coordinate activities between IGEs and customers regarding transportation issues.
  Coordinate with Energy Services or Service Planning to develop and maintain relationships with market/trade allies.
  Provide monthly report of activities for manager.
  Prepare quarterly news letter for distribution to large volume customers.

The incumbent, with others, is responsible to:

* **Prepare and participate in training and development of IGEs. Determine information required and prepare documentation and material for customer rate/margin analysis.**

* **Determine information required and prepare studies of distribution and/or transmission capacity studies for customers**
* Maintain a complete data base on each customer in this market **segment.**
* **Determine market and specific customer requirements and appropriate corporate action.**
  Determine validity, negotiate and resolve billing disputes between customers and the Company.
  Establish and assure continuing relationships with top management of Key Account customers, using the Corporation's Strategic Accounts Program.
  Implement and administer the company's gas procurement service Determine validity, negotiate and resolve billing disputes between customers and the Company.
* Ensure adequate and timely coordination of Company services for large volume customers. Identify emerging Transportation/Contract sales problems. Review analyses of competitive customer offerings vs. company programs to meet customer requirements. Recommend changes in tariff provisions. Prepare economic and sales forecasts.
  Monitor and analyze competition and provide recommendations for corporate response.
  Assemble and process data and information necessary to expedite rate applications.
  Conduct market analysis research/evaluation and recommend specific activities based on analysis.
  Coordinate activity with appropriate Division and corporate Staff personnel.
  Provide IGEs with training and support programs and activities necessary to negotiate service agreements with sophisticated customers.
  Ensure timely and accurate filings of commission ordered reports.
  Maintain and cultivate contacts with trade allies, architects and engineers to improve the environment for installing natural gas equipment.
  Meet with architects and engineers to ensure that all opportunities to specify gas equipment are identified and create a gas-friendly environment.

The incumbent assists others to:

* **Analyze trends to determine profitable opportunities.**
* **Coordinate the execution of approved service agreements and other binding documents between large volume customers, IGEs and corporate Staff.**
  Determine cost-effectiveness of support activities and programs. Establish programs to educate customers.
  Determine impact of competitive forces in the marketplace. Develop short-term and long-term plans for Key Account Management Department activity.
  Develop PC programs and systems for department functions.

Additional Activities

Ensure that all regulatory filings regarding large volume customer contracts are complete, accurate and filed in a timely manner.
Attend and participate in various conferences related to natural gas regulations.
Analyze legislation impacting activities with large volume customers.
Prepare responses to data requests during proceedings.

OTHER REQUIREMENTS

There are established precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires four to six years of experience.

College degree required with technical discipline preferred or equivalent work experience. The incumbent must, be able to establish working relationships with others not under the incumbent's supervision.

The incumbent frequently exchanges information with department heads of other company activities such as Rates, Demand Planning, Gas STET, Central Gas Dispatch, Legal, Energy Services, Accounting, and Division Service Planning and Operations, outside consultants, trade associates, and infrequently with senior management or shareholders.

Approximate percentage of time spent performing various duties.

JOB DUTIES	APPROXIMATE % TIME PERFORMED
Supervisory	20%
Market Studies & Plans	5%
Technical Knowledge	5%
Department & Commission Interaction	5%
Rate Analysis	5%
Administration	10%
Customer Interaction	50%

TITLE: **Manager/Key Account Management**
JOB CODE: GS00002054
DIVISION: Corporate
DEPARTMENT: Key Account Management
DATE: 9/27/2006

APPROVED BY:_____ **DATE:**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The Manager/Key Account Management manages the negotiation and administration of natural gas services for the company's large volume customers. Large volume customers include those customers which: are served under transportation rate schedules; require negotiated contract terms and rates in that they have the ability to physically bypass the company's services or use alternate fuels; consume in excess of 500 therms per day on average; or, are classified as industrial, gas engine, agricultural or electric generation. Large volume customers may require specific supply arrangements or the construction of significant pipeline facilities. This position is also responsible for Special Assignments as identified and required from time to time, to meet corporate needs.

POSITION DIMENSIONS

Budget Accountable for: $1,200,000+

Personnel Managed: 4 Exempt Employees

Personnel Supervised: 11 Total Employees
9 Exempt Employees
2 Non-Exempt Employees

This job has four subordinate levels reporting to it.

NATURE AND SCOPE

The Manager/Key Account Management reports to the Director/Key Account management. Reporting to the incumbent are three Supervisors/Key Account Management and the Supervisor/Contract Administration or the Analyst/Key Account Management.

Note: This position involves the activities listed below. The activities in **bold** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

The incumbent manages others who:

* **Negotiate, administer and coordinate natural gas service planning and transportation service to large volume customers.**
* **Negotiate and administer Southwest's transportation and special contract policies and pricing.**
* **Negotiate agreements and gas prices with customers to ensure maximum margin to company while maintaining existing or acquiring new gas load.**
* **Coordinate and administer the corporation's large volume customer programs and support activities.**
* **Assist and support Supervisor/Key Account Management and Industrial Gas Engineers (IGEs) with customer contact in agricultural, commercial, industrial, and electric generation sectors which require transportation/special contracts or are not (or cannot) be served with standard rate schedules, or consume in excess of 500 therms per day on average.**
* **Coordinate margin/rate studies with Rates Department.**
* **Provide Supervisor/Key Account Management and IGEs with training and support necessary to negotiate service agreements with sophisticated customers.**
* **Implement and administer the company's gas procurement service.**
* **Develop records and methodology to initiate timely action for all key dates in customer agreements; e.g., termination, rate changes, anniversary dates etc. Analyze trends to determine profitable opportunities.**
* Maintain a complete data base on each customer for which Key Account Management is responsible.
  Conduct research/evaluation and recommend specific activities based on analysis.
  Coordinate studies regarding transmission and distribution capacity for large volume customers with pipeline suppliers, corporate staff and division Service Planning and Engineering departments.
  Coordinate the development of gas supply required for large volume customers.
  Prepare draft service agreements, consult with Legal Department regarding transportation contracts and special contracts.
  Monitor and analyze competitor activities and provide recommendations for corporate response.
  Develop plans and procedures to identify opportunities.
  Maintain communication with operating divisions on customers with alternative fuel capabilities and/or gas bypass opportunities.
  Advise affected departments and IGEs of compliance requirements ordered by Commissions on transportation/contract matters.
  Assemble and process data/information necessary to prepare exhibits for Commission filings.
  Ensure timely and accurate filings of Commission-ordered reports.
  Assemble and process data and information necessary to expedite rate applications.
  Prepare exhibits and testimony for transportation/contract matters.
  Develop PC programs and systems for department functions.
  Research other utilities' transportation policies and agreements to stay current on regional and national transportation/contract service planning issues.

Identify emerging transportation/contract service planning problems. Maintain and cultivate contacts with trade allies, architects and engineers to improve the environment for installing natural gas equipment.
Maintain files for all Key Account Management Department customer contracts/agreements --active, pending and inactive.
Maintain database and files of all corporate gas contracts/agreements --active, pending and inactive.
Maintain database and design reports used in conjunction with the Strategic Accounts Program for division Service Planning Departments and Key Account Management.
Design and provide quarterly reports used by management in recommending IGE incentives.
Prepare customer agreements, exhibits and correspondence.
Provide reports and data sheets for transmittal to divisions and staff department.
Use GoldMine to transmit important notices to customers through GoldMine on short notice.
Provide clerical/secretarial backup to Director/Manager and departments in general.

The incumbent is personally responsible to:

* **Develop and implement programs to ensure that transportation and special contracts' activities achieve company goals and objectives.**
* **Establish and maintain communications with other corporate staff and Division Service Planning and Engineering Departments focusing on large volume customers and transportation/contract issues affecting the company. Implement and administer the company's gas procurement service.**
* Establish and maintain policies, procedures and records regarding corporate transportation and large volume customer contract activities.
* Develop programs and procedures for contract service planning, service and/or transportation in conjunction with the operating divisions.
  Provide the director and officers with recommendations on corporate strategy/policy regarding transportation and special contracts.
  Ensure company compliance regarding all matters contained in company tariffs for transportation/contracts.
* Direct the administration and maintenance of all large volume customer agreements (preparation, files, compliance, special conditions, etc.).
* Direct the development and administrating of the customer contact management/database information files.
  Determine project scope, contract amount and completion time line of outside consultants.

The incumbent, with others, is responsible to:

Develop short-term and long-term plans for Key Account Management department activity.

* Prepare tariff revisions on tariff/contract service planning matters.
  Establish service planning goals for IGEs.
  Monitor and analyze impact of alternative fuel prices.

Perform energy cost comparisons of current alternative fuel prices and assess trends.

The incumbent assists others to:

* **Ensure corporate compliance with Commission decisions regarding transportation/contract service planning matters.**
* **Establish and maintain communication with other departments at systems and operating divisions to ensure tariffs reflect current operation procedures.**
* **Develop tariffs which are consistent with regulatory, legal and corporate requirements for all jurisdictions.**

Provide expert testimony to regulatory Commissions and legislative bodies on transportation/contract service planning matters.
Maintain working knowledge of legal requirements for application of tariffs and agreements.
Advise affected departments of compliance requirements ordered by Commissions.
Review and analyze competitors' rate structures for consideration in developing future rate design proposals. Initiate and develop data/information necessary to prepare testimony and exhibits for Commission filings regarding regulatory matters.
Prepare exhibits and responses to data requests (interrogatories) from parties outside of the company.

Additional Activities

Provide monthly report of department activities to management.
Represent the corporation in outside industry/trade organizations.
Testify before regulatory commissions and legislative bodies.
Maintain working relationship with regulatory commission staffs regarding transportation and contract matters.

OTHER REQUIREMENTS

There are broad precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires 8 to 10 years of relevant work experience. The incumbent frequently exchanges information with senior management and department heads of the following departments: Rates, Demand Planning, Gas Resource Management, Central Gas Dispatch, Staff Engineering, State and Federal Regulatory Affairs, Legal, Energy Services, Accounting and Division Service Planning and Operations.

TITLE: **Senior Manager/Key Account Management**
JOB CODE: GS00002044
DIVISION: Corporate
DEPARTMENT: Key Account Management
DATE APPROVED: March 7, 2003

APPROVED BY:_____ **DATE:**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is accountable for the negotiation and administration of all transportation contracts and anti-bypass contracts and other special contracts, such as special purchase agreements and optional sales agreements for all customers of the corporation that exceed 50 MMBtu/d of usage to ensure that such agreements are in compliance with the terms of the tariff and meet the goals of the Company. The incumbent is also responsible for the development of programs that target key account segments to improve margin for the Company and improve efficiencies and effectiveness of the Key Account Management Department.

POSITION DIMENSIONS

Department budget accountable for:	$2,000,000 - $4,000,000
Personnel supervised:	12 Exempt
	3 Non-exempt

NATURE AND SCOPE

The Senior Manager/Key Account Management reports to the Vice President/Gas Resources and Energy Services, as does the Director/Gas Supply. Reporting directly to the position are the Manager/Key Account Management, one Supervisor/Key Account Management, and one Administrative Secretary.

Note: This position involves the activities listed below. The activities in **bold** are the most critical for this job. The activities marked with an asterisk (*) are those in which the incumbent spends the most time. (Asterisks may be added by supervisor for each incumbent)

The incumbent is personally responsible to:

* **Manage the negotiation and preparation of all gas transportation agreements with customers whose usage exceeds 50 MMBtu/d to ensure adequate return on investments for the Company, and compliance with the respective state tariffs;**
* **Manage and coordinate the administration of all customer transportation agreements and related agreements to ensure performance under these legal instruments;**

* **Manage the preparation and negotiation of all amendments to customer gas transportation agreements, special procurement agreements and optional fuel agreements;**
* **Provide guidance and oversight for the development and the implementation of programs for large customers to ensure such programs are in compliance with the respective state tariff and meet corporate goals;**
* **Analyze customers' transportation options and develop anti-bypass strategies that meet corporate goals;**
* **Negotiate all large generator contracts to provide compliance with the respective state's tariff and to ensure adequate return on investment for the corporation;**
* **Retain, train, and develop industrial gas engineers who the effectively represent the Company with large customers;**
* **Provide guidance, experienced insight and leadership to the department and others on contractual and financial issues related to large customers;**
* **Represent the Company with respect to large customers and related tariff issues in regulatory proceedings and/or settlement negotiations;**
* **Participate in contract litigation and regulatory issues, including preparation of discovery, depositions, analysis, and testifying as necessary;**
  Ensure compliance with Federal and State regulations;
  Establish and maintain close business relationships with the Company's largest customers, primarily electric generators;
  Stay abreast of changing market conditions that affect large customers;
  Act as the primary contact with both internal and external auditors on matters relating to contracting, administration of contracts, and compliance with corporate policy and procedures.

The incumbent manages other who:

* **Provide administration of customer gas transportation agreements, special procurement agreements, and optional sales agreements;**
* **Negotiate with customers for the installation of new equipment to provide additional margin for the corporation;**
* **Provide energy surveys to customers with recommendations for new gas field equipment;**
* **Negotiate anti-bypass agreements to provide maximum available benefit to the Company;**
* Analyze and develop marketing programs for the large customers that provide for improved profit for the Company;
* **Develop and maintain solid business relationships with large customers.**

The incumbent, with others, is responsible to:

Analyze industry trends and changes which may require changes in corporate strategy for large customers and make policy recommendations to ensure corporate objectives are met;
Review Company policies, procedures, and information systems as they relate to KAM business and make recommendations to senior management.

OTHER REQUIREMENTS

There are established precedents and practices that the incumbent uses as guidelines to determine the basis for how this job is performed. This position requires a bachelor's degree or equivalent, with a minimum of 10 years work experience.

The incumbent frequently exchanges information with other departments outside of Key Account Management, outside consultants, regulatory agencies having jurisdiction, and the Company's largest customers.

TITLE: **Industrial Gas Engineer**
JOB CODE: GS00002060
DIVISION:
DEPARTMENT: Key Account Management
DATE: January 1993

APPROVED BY: _____ **DATE:**
(For Sr. Evaluation Committee)

POSITION OVERVIEW

This position is directly involved with the negotiation, administration, and regulatory activities for key account customers. Key account customers are large customers who require transportation service, optional alternate fuel rates or other special investment, supply or anti-bypass contracts.

POSITION DIMENSIONS

The incumbent does not have accountability for personnel or budgets.

NATURE AND SCOPE

The Industrial Gas Engineer is a staff position, located in the division, which reports to the Supervisor/Key Account Management.

Note: This position involves the activities listed below. The activities in **bold** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

The incumbent is personally responsible to:

* **Negotiate contracts and rates with large customers which: (a) require transportation service; (b) have alternate fuel capability; (c) have the potential to bypass; or (d) require a special contract due to the investment or supply arrangement**
* **Maintain close contact and working relationships with key account customers**
* **Maintain up-to-date alternate fuel and energy price information**
* **Maintain up-to-date knowledge on upstream interstate pipeline rates and tariffs**
* **Prepare fuel and energy studies and analysis and develop proposals for transportation, optional and anti-bypass rates and service**
* **Identify customers with bypass potential**
* **Maintain up-to-date customer information file**
* **Initiate and develop market opportunities and develop plans to remain competitive**
* **Perform the activities related to the Strategic Accounts program**

Industrial Gas Engineer
GS00002060

* **Maintain communications with key account customers with respect to tariff provisions and state and federal regulations**
* **Administer Title Assignment and/or Capacity Release programs**
* **Ensure key account customers are kept informed of company filings**
* **Explain transportation imbalance management to customers**
* **Determine market and specific customer requirements and appropriate corporate action**
* **Identify opportunities to increase the corporate margin for key account customers**
* **Ensure that service agreements and other binding documents are executed between key account customers and the division vice president**
* Coordinate Division Engineering studies for key account customers
* Coordinate meetings with division management and the management of key account customers using the Corporation's Strategic Accounts Program
* Ensure adequate and timely coordination of company services for key account customers

Prepare alternate fuel studies
Prepare economic and sales forecasts

The incumbent assists others to:

* **Resolve billing disputes between key account customers and the company**
* **Ensure satisfactory customer service to key account customers**
* **Explain Company's transportation policy and procedure to division customers who may qualify for this tariff**
* Determine impact of competitive forces in the marketplace

Explain Company's transportation and alternate fuel rate policy and procedure to Commission Staff members

Additional Activities

Inform division management of key account activities

OTHER REQUIREMENTS

There are established precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires 3 to 4 years of relevant work experience. College degree required with engineering discipline preferred or equivalent work experience. The incumbent must be able to establish working relationships with others not under the incumbent's supervision.

The incumbent frequently exchanges information with department heads of other company activities (such as Division Engineering, Division Service Planning, Division Technical Services, Division Customer Service, Division Accounting and Division Legal), outside consultants, and trade associates.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 2007

Advertisement manages the development and placement of advertisements in national print and electronic media.

Corporate Affairs provides opportunities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

General and Administrative includes:

1. Office of the President provides senior management guidance for all AGA activities.
2. Human Resources develops and administers employee programs and provides office and personnel services.
3. Finance and Administration develops and administers financial accounting and treasury services and maintains computer services capability.

General Counsel provides legal counsel to the Association.

Industry Finance and Administration develops and implements programs in such areas as accounting, human resources, and risk management for member companies.

Operations and Engineering Management develops and implements programs and practices to meet the operational, safety, and engineering needs of the industry.

Policy, Planning, and Regulatory Affairs includes:

1. Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics, and the environment.
2. Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

Public Affairs provides members with information on legislative development; prepares testimony, comments, and filings regarding legislative activities, lobbies on behalf of the industry. It also includes Communications, which develops informational material for member companies and consumers and coordinates all media activity.

Volume III

Testimony

4

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

PREPARED DIRECT TESTIMONY
OF
LAURA LOPEZ HOBBS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
LAURA LOPEZ HOBBS

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
LAURA LOPEZ HOBBS

I. 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 89150-0002.

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

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) as Director of Human Resources.

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

A. 3 My background and experience are reflected in Appendix A to my direct testimony.

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

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada (PUCN).

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

A. 5 The purpose of my direct testimony is to support the test year expenses associated with Southwest's Supplemental Executive Retirement Plan (SERP) and the Management Incentive Program (MIP) as part of the Company's total

compensation package for management/executive employees (Total Compensation). The Company's Total Compensation is prudent and reasonable; therefore, the Commission should not disallow portions of the MIP costs or the SERP costs in this proceeding.

II. REASONABLENESS OF EXECUTIVE TOTAL COMPENSATION

Q. 6 Can you explain the Company's philosophy with regard to compensation of its management/executive employees?

A. 6 The Company's management compensation and benefits package is designed to attract, retain and motivate skilled management for the organization. In addition, the compensation package is intended to be reasonable, competitive, internally equitable and tied to performance.

Q. 7 How can the Company demonstrate that SERP and MIP are reasonable components of the Total Compensation Package?

A. 7 SEC executive compensation rules provide the ability to compare the Company's Total Compensation with that of other utilities within its geographical area. To make the comparison, the Company utilized the most recent publicly available proxy statements of the other major western energy utilities ("Proxy Peer Group"). Southwest compared its five highest paid employees' Total Compensation, which includes Base Salary, Bonus, Other, Restricted Stock Awards, Options Awards, Non-Equity Incentive Plan, Long Term Incentive Payout and All Other Compensation, to the five highest paid employees of each

Proxy Peer Group company.

Q. 8 Describe the Proxy Peer Group used in this proceeding?

A. 8 The Proxy Peer Group consists of all major utility companies in Arizona, California, Nevada, Oregon, Utah and Washington. The Proxy Peer Group is identified on Exhibit No.__(LLH-1) and is ranked by total compensation for the five highest paid employees (from highest to lowest); Southwest is included to show its ranking amongst its peer utilities.

Q. 9 Describe the Company's findings as a result of its analysis of the Proxy Peer Group.

A. 9 The Company compared the compensation for the five highest paid employees across the Proxy Peer Group with that of Southwest. (Exhibit No.__(LLH-1)). Although only 2 of the 13 companies listed in the Proxy Peer Group serve more customers per employee than Southwest, only 2 companies rank below Southwest in terms of total compensation - Northwest Natural and Portland General Electric, both of which rank well below Southwest in number of customers served and number of customers served per employee. These comparisons demonstrate that not only are management/executive employees at the Company compensated within a reasonable range, they are well below a majority of their peers.

Q. 10 Do other utilities in the Company's Proxy Peer Group offer incentive plans to their employees?

A. 10 Virtually all other utilities in the Proxy Peer Group

have incentive plans, including programs like the SERP and the MIP. Southwest must offer this compensation as part of its overall compensation package in order to remain competitive in the marketplace.

Q. 11 Briefly summarize the purpose of the SERP and the MIP.

A. 11 In general, these plans are offered to Southwest's senior management/executive employees to attract highly qualified individuals to manage and run the Company and to ensure their retention for the benefit of customers and shareholders. The Total Compensation package, including the MIP and the SERP, is crucial for the Company to remain competitive in attracting and maintaining quality management employees. If Southwest does not provide a Total Compensation package which includes a competitive collection of benefits, the chances of attracting and retaining a highly-skilled, well-motivated workforce is greatly reduced and ultimately increases costs and decreases service levels to customers.

Q. 12 Why is the MIP an important component of Southwest's management/executive compensation package?

A. 12 The Company's MIP provides variable compensation to management/executive employees for the achievement of specific goals and benchmarks important to both the short-term and long-term success of the Company. Forty (40) percent of the total award earned under the MIP is paid in cash immediately following the financial close

of the most recent calendar year. The remaining sixty (60) percent is awarded through the issuance of performance shares. These performance shares vest three years in the future. The longer-term performance shares act as a retention tool while aligning the interests of management/executive employees, shareholders and customers for continued financial and customer-oriented performance.

Q. 13 Why is the SERP an important component of Southwest's executive compensation program?

A. 13 The SERP compensates an officer for the limitations on compensation and the exclusion of deferred compensation in the basic (qualified) retirement plan (BRP) provided to other employees of the Company. The SERP is an unqualified plan and, as such, payments are not guaranteed (i.e., participants are general creditors of the corporation). Some form of SERP benefit is common in the utility industry.

Q. 14 How does the Company's executive compensation compare to the Proxy Peer Group?

A. 14 The difference is most evident in the compensation per customer amount. In Exhibit No.__(LLH-1) Southwest demonstrates that the total compensation per customer for the five highest paid Southwest executives is $2.47. Only one company in the Proxy Peer Group has lower total compensation per customer for the five highest paid executives. Yet, only one other company ranks higher in

productivity based on the number of customers served per employee.

Q. 15 Can the Company provide an example of the cost of executive compensation for other Arizona utilities?

A. 15 An analysis of Unisource and Pinnacle West data reveals a compensation per customer cost of $7.38 and $13.05, respectively.

Q. 16 Should the Commission include the MIP and SERP expenses in the cost of service in this proceeding?

A. 16 Yes. As demonstrated herein, Southwest's Total Compensation package, which includes the MIP and SERP as essential components, is prudent and reasonable. Virtually all other utilities in the proxy groups have MIP and SERP plans. As such, it is critical that Southwest continue its MIP and SERP plans to be competitive with its peers. Southwest ranks near the top in the customer-to-employee ratio (productivity) and near the bottom in management/executive compensation dollars per customer (reasonable). Therefore, a disallowance of part or all of the MIP or SERP would have a punitive effect on a compensation package that is already well below the market. Such a result is unfair and inequitable. Southwest concludes that the recovery of its MIP and SERP expense in this proceeding is appropriate not only because it is a normal, on-going, and necessary expense, but it is inherently reasonable when its Total Compensation package is measured against

other southwest regional utilities.

Q. 17 Does this conclude your prepared direct testimony?

A. 17 Yes, it does.

SUMMARY OF QUALIFICATIONS
LAURA LOPEZ HOBBS

I graduated from the University of Nevada - Las Vegas (UNLV) in 1981 with a Bachelor of Science degree in Business Administration and a Master degree in Business Administration from UNLV in 1990.

From 1981 to 1984, I was employed by Valley Bank of Nevada in various positions in the trust and audit departments.

In 1984, I began my career with Southwest as a Human Resource Analyst in the Human Resource Department. In 1987, I was promoted to Benefits Administrator. I was primarily responsible for day-to-day administrations of the various employee benefit plans, including medical, dental, and 401(k) employee investment plans, and development and distribution of employee benefits statements.

In 1989, I was promoted to Investor Relations Specialist and transferred to the Investor Relations Department. In 1993, I was promoted to Manager of Investor Relations, with managerial responsibility for Investor Relations and Shareholder Services Departments for Southwest. While in these positions, I was responsible for primary contact with the financial community, including institutional shareholders, portfolio managers, and specialists with the New York Stock Exchange. Further responsibilities included developing shareholder

communications, including annual and quarterly reports, as well as presentations and analyses for financial analysts, compliance with regulatory reporting and disclosure requirements, and being a member of the National Investor Relations Institute.

In January 2001, I was promoted to Senior Manager of Corporate Human Resources. My responsibilities included directing and managing executive, exempt, and nonexempt employee compensation programs; reviewing compensation trends throughout relevant industries and initiating action to ensure Company compensation programs are competitive and cost-effective; and all employment functions. These employment functions included employee relations; staffing; and equal employment opportunity (EEO) matters. I also managed the development and integrity of the Human Resources information systems. I continued to direct the Shareholder Services Department, which includes transfer agent and stock registration activities, annual meetings, proxy solicitation, and administration of the Dividend Reinvestment and Stock Purchase Plan.

In 2005, I was promoted to my present position as Director/Corporate Human Resources. In addition to the responsibilities mentioned above, I am responsible for the consistency of employee benefits programs throughout the Company. The Benefits Department identifies benefit program requirements and regulations, establishes and

tracks benefit budgets and is responsible for administering employee welfare, investment and retirement plans.

In addition, the Benefits and Compensation Departments work together to build employee awareness of total compensation which encompasses cash compensation and benefits.

Comparison of Major Western Energy Utilities' Executive Compensation per Customer and Number of Customers Served per Employee

Utility/(Stock Symbol)	Total Compensation of the Five Highest Paid Executives (000)	Number of Customers Served (000)	Number of Employees	Number of Customers Served per Employee	Executive Compensation per Customer
Sempra Energy (SRE)	$ 28,047	7,823	14,061	556	$ 3.59
Southern California Edison (EIX)	25,336	4,812	16,139	298	5.26
Pacific Gas & Electric (PCG)	15,071	9,252	20,400	453	1.63
Pinnacle West (PNW)	13,730	1,075	7,400	145	12.77
Questar (STR)	9,291	851	2,188	389	10.92
Sierra Pacific (SRP)	8,284	1,314	3,212	409	6.30
Avista (AVA)	7,321	650	1,995	326	11.26
PNM Resources (PNM)	6,980	1,191	3,294	362	5.86
Puget Sound (PSD)	5,994	1,752	2,400	730	3.42
Unisource (UNS)	4,650	631	1,732	364	7.37
Southwest Gas (SWX)	**4,410**	**1,784**	**2,525**	**707**	**2.47**
Northwest Natural (NWN)	3,997	637	1,211	526	6.27
Portland General (POR)	3,429	793	2,635	301	4.32

Exhibit No.___(LLH-1)
Sheet 1 of 1

Volume III
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IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-___

PREPARED DIRECT TESTIMONY
OF
THEODORE K. WOOD

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
THEODORE K. WOOD

I. 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 By whom are you employed and in what capacity?

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) as Senior Manager in the Treasury Services Department.

Q. 3 Does Appendix A summarize your educational background and business experience.

A. 3 Yes, it does.

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

A. 4 Yes. I previously testified before the Arizona Corporation Commission (ACC or Commission), the California Public Utilities Commission (CPUC) and the Public Utilities Commission of Nevada (PUCN). I also provided written testimony to the Federal Energy Regulatory Commission (FERC).

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

A. 5 The purpose of my direct testimony is to support the

Company's overall requested rate of return. Specifically, my direct testimony details the requested capital structure and the embedded cost of long-term debt and preferred equity used for determining the appropriate cost of capital for the Company's Arizona rate jurisdiction. In addition, I discuss the significant interdependence of the Company's proposed rate design, capital structure, and overall rate of return on the Company's bond ratings and financial profile.

My testimony comprises five main sections: (I) introduction; (II) the development and use of an appropriate capital structure for ratemaking; (III) a review of the Company's financial profile and the importance of the Company's requested rate design, capital structure, and overall rate of return on the Company's future financial profile; (IV) the development of the embedded cost of long-term debt; and (V) the development of the embedded cost of preferred equity. Southwest witness Frank Hanley discusses the development of the proposed cost of common equity.

Q. 6 Have you determined a reasonable rate of return necessary for Southwest to earn a fair return on its Arizona distribution properties?

A. 6 Yes. An overall rate of return of 9.45 percent for the Arizona jurisdiction is reasonable in this proceeding and properly reflects the Company's level of business, financial, and regulatory risks. This rate of return is

developed as follows:

Southwest Gas Corporation
Arizona Rate Jurisdiction

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	51.00%	7.96%	4.06%
Preferred Equity	4.00%	8.20%	0.33%
Common Equity	45.00%	11.25%	5.06%
Total	100.00%		9.45%

The recommended rate of return on fair value rate base is 7.04 percent.

Q. 7 Why is the proposed rate of return appropriate and necessary for Southwest?

A. 7 This rate of return is necessary to maintain the Company's financial integrity, to allow the Company to attract new capital and to permit Southwest's equity holders the opportunity to earn a fair and reasonable rate of return.

Moreover, this rate of return meets the standard of reasonableness set forth by the United States Supreme Court in Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) (Bluefield):

> "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."

Furthermore, this rate of return meets the comparability standard set by the court in the Federal Power Commission v. Hope Natural Gas Company , 320 U.S. 591 (1944)(Hope):

> ". . . the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

An explanation regarding the practical application of these two court rulings to a diversified utility such as Southwest is appropriate.

The Company has, since the late 1950s, filed rate cases as a "diversified" utility. The multi-jurisdictional rate case filings are based on the fact that Southwest, as a natural gas utility, serves three states with several different ratemaking jurisdictions. The Company requests only gas distribution utility required rates of return in all filings within each jurisdiction. The debt and preferred equity costs requested in this filing are utility-only costs. Southwest's practices assure that the costs of utility operations attributable to each of Southwest's jurisdictions are properly insulated from the impact of any non-utility activities.

In summary, Southwest's requested rate of return in this proceeding is fair to both customers and shareholders and properly reflects the risks and returns appropriate for its gas distribution properties.

II. RECOMMENDED CAPITAL STRUCTURE

Q. 8 What is Southwest's current ACC-authorized ratemaking capital structure and overall rate of return?

A. 8 In the Company's last general rate case (Decision No. 68487 in Docket No. G-01551A-04-0876, dated February 23, 2006), the Commission adopted the following capital structure, capital costs and overall rate of return:

Southwest Gas Corporation
ACC Authorized Rate of Return
Decision No. 68487

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	55.00%	7.61%	4.19%
Preferred Equity	5.00%	8.20%	0.41%
Common Equity	40.00%	9.50%	3.80%
Total	100.00%		8.40%

The authorized rate of return on fair value rate base was 6.63 percent. The authorized capital structure was based on a hypothetical capital structure, which contained approximately 6 percent more common equity than the actual common equity ratio at the end of the test period (August 31, 2004) of 34.1 percent. The use of a hypothetical capital structure was consistent with past Commission decisions, recognizing Southwest's higher financial risk (lower common equity ratio) relative to its peers in the natural gas local distribution companies (LDC) industry. In addition, in the Order, the Commission required Southwest to submit a recapitalization plan ". . . explaining how it intends to achieve a 40 percent

equity prior to the Company's next rate case"[1]. In compliance with the Commission's Order, the Company submitted its Recapitalization Plan on April 20, 2007 (attached hereto as Exhibit No.___(TKW-1)).

Q. 9 Has the Company achieved a 40 percent common equity ratio?

A. 9 Yes, the common equity ratio at April 30, 2007 was 42.9 percent as shown below:

Permanent Capital	Percent
Long-Term Debt	52.7%
Preferred Equity	4.4%
Common Equity	42.9%
Total	100.0%

Q. 10 Please compare the Company's current capital structure to its capital structure at the end of the previous test period, August 31, 2004.

A. 10 The Company's actual ratemaking capital structure at August 31, 2004 and April 30, 2007[2] is as follows:

SOUTHWEST'S ACTUAL RATEMAKING CAPITAL STRUCTURE ($ IN MILLIONS)

	Percent of Capital		Dollar	Percent of
Capital	8/31/2004	4/30/2007	Increase	Increase
Long-Term Debt	60.8%	52.7%	$ 10	3%
Preferred Securities	5.1%	4.4%	-	0%
Common Equity	34.1%	42.9%	306	97%
Total	100.0%	100.0%	$ 316	100.0%

During this 32-month period, total ratemaking

1 Decision No. 68487, Page 25, Line Nos. 12-14, dated February 23, 2006.

2 The ratemaking capital structure is the Company's gas segment permanent capital structure, which includes common equity, preferred securities and long-term debt. Short-term debt is excluded as short-term debt is used primarily to finance working capital and PGA receivable balances, and not long-term rate base assets.

capital increased by approximately $316 million. This total consists of a $306 million increase in common equity and a $10 million increase in long-term debt. Because Southwest was able to finance most of the incremental capital with common equity, the common equity ratio improved by 8.8 percentage points. Exhibit No.___(TKW-2) displays the detailed changes in the capital structure.

Q. 11 Please discuss how the Company increased its common equity since the previous test period of August 31, 2004.

A. 11 The $306 million increase in common equity came from three sources:

(1) the issuance of additional common equity shares from the Company's existing equity plans (Dividend Reinvestment and Stock Purchase Plan, Employee Investment Plan, Management Incentive Plan, and Stock Incentive Plan);

(2) the periodic secondary market issuances of additional common equity shares via the Company's Equity Shelf Program (ESP)[3]; and

(3) an increase in retained earnings. Approximately 58 percent of the growth of common equity during this period resulted from the issuance of additional shares of common stock, while 42 percent of the growth resulted

3 A description of the Company's ESP is provided in the Company's Recapitalization Plan, Page 7, attached as Exhibit No.___(TKW-1).

from increased retained earnings.

Southwest issued over 6.6 million shares of common equity, which represents an increase of 18.6 percent of its outstanding common equity shares since August 31, 2004. From August 2004 through April 2007, the Company issued approximately 3.8 million shares of common stock through its existing plans, with net proceeds of $104.9 million. From August 2004 through April 2007, the Company issued approximately 2.8 million common shares through the ESP with net proceeds of $74.6 million. The Company originally established a three-year, $60 million ESP in May 2004. The Company began issuing shares through the ESP in June 2004 and issued the entire $60 million ESP by the end of September 2005. In March 2006, the Company established a three-year, $45 million ESP. At April 30, 2007, the Company had approximately $16.7 million of remaining capacity under its existing $45 million ESP.

From August 2004 through April 2007, Southwest's retained earnings increased by $127.9 million. Contributing to this improvement were increased earnings from rate relief granted in Southwest's Nevada jurisdictions, rate relief and annual margin adjustments (attrition) in Southwest's California jurisdictions, and realized rate relief granted in Southwest's 2004 Arizona general rate case.

Q. 12 Please discuss the recommended capital structure used to

develop the overall proposed rate of return in this proceeding.

A. 12 The recommended capital structure used to determine the rate of return consists of 51 percent long-term debt, four percent preferred equity, and 45 percent common equity.

The recommended capital structure is referred to as a target capital structure rather than a hypothetical, as the Company reasonably expects to achieve this capital structure near or shortly after the time when new rates will become effective. During the 32-month period between the end of the test period (April 30, 2007) and the end of the test period in the prior rate general rate case (August 31, 2004), the Company has significantly improved its capital structure, improving its common equity ratio by 8.8 percentage points, from 34.1 percent to 42.9 percent common equity. Based on the Company's demonstrated rate of improvement, it is reasonable to assume that the Company will achieve 45 percent common equity ratio, which is only 2.1 percentage points higher than the test period actual common equity ratio of 42.9 percent.

The commitment to continue the improvement is reflected in Southwest's 2006 Annual Report, where the Company stated that it expects to issue $100 to $125 million from its various common stock programs during the three-year period ending December 31, 2009. During the

same three-year period, the Company estimates that capital expenditures will be approximately $880 million, with cash flow from operations (net of dividends) funding over 90 percent ($792 million) of the capital expenditures. The $100 to $125 million of external funds from the issuance of common equity will more than cover the external funding requirement ($88 million), with the remainder ($12-$37 million) available to reduce the net balance of outstanding debt.

Q. 13 How does the recommended target common equity ratio compare to the common equity ratio approved in general rate proceedings across the country?

A. 13 Analyzing the decisions of 45 general rate cases for gas utilities across the U.S. for the time period January 1, 2005 through March 31, 2007, the average authorized common equity ratio for ratemaking was 47.9 percent. This average is almost 300 basis points higher than the Company's requested target common equity ratio of 45 percent. Exhibit No.___ (TKW-3) displays the individual companies, the state jurisdiction, and the authorized common equity ratio used to compute the average.

Q. 14 How does the recommended target capital structure compare to a representative group of Southwest's peers?

A. 14 The Southwest actual, target, and five-year average permanent capital structures of the proxy group of eight LDCs used by Mr. Hanley in his testimony to estimate the cost of common equity are as follows:

Type of Capital	Permanent Capital Structure Ratios SWG Actual	SWG Target	Proxy Group of Eight LDCs[1]
Long-Term Debt	52.7%	51.0%	47.5%
Preferred Stock	4.4%	4.0	.4%
Common Equity	42.9%	45.0%	52.1%
Total	100.0%	100.0%	100.0%

1 Five-year (2002-2006) average permanent capital structure of a proxy group of eight local gas distribution companies included in F. Hanley's testimony. See F. Hanley's Exhibit__(FJH-4), Sheet 1 of 3.

Southwest's actual and target capital structures contain significantly more leverage when compared to the average capital structure of the proxy group of local gas distribution companies included in this table.

Q. 15 Will the capital structure authorized by the Commission in this proceeding be an important factor considered by credit rating agencies?

A. 15 Yes. Standard & Poor's Rating Services (S&P) analyzes rate case decisions as the key indicator of the level of regulatory support for the creditworthiness of utilities. S&P evaluates the authorized rate of return for a company by comparing the equity returns authorized for other utilities and the capital structure utilized to set rates. As stated in an article by Todd Shipman of S&P:

> "Once a decision is reached, Standard & Poor's analyzes its effect on the financial forecast for the company, and also to assess whether the actions and precedents being set by the commission in its decision will have a long-term effect on Standard & Poor's opinion of the regulatory environment in that jurisdiction. The analysis of the rate case

> fundamentally explores a two-fold question: are the new rates based on a rate of return consistent with the company's ratings, and is the utility being afforded a legitimate opportunity to actually earn that rate of return?
>
> On the former question, the analyst looks to equity returns being authorized for other utilities of the same credit quality, as well as the capital structure employed to arrive at the overall rate of return being used to set rates." [4]

The other key issue is whether the utility is afforded a reasonable opportunity to earn its authorized rate of return.

Q. 16 Please summarize why the Commission should authorize Southwest's requested target capital structure.

A. 16 The recommended target capital structure, together with Mr. Hanley's recommended cost of common equity, are essential to provide the Company with a fair and reasonable overall allowed rate of return. This is important for three principal reasons. First, the Company must compete for new capital to fund the continuing significant customer growth and to refinance maturing debt. Second, current investors must have the opportunity to earn a fair and reasonable rate of return to maintain their current investment in the Company relative to choosing comparable, equally risky, alternative investments. Third, the Company must also

---

4 Todd A. Shipman, "*Energy Risk - Fresh Look at US Utility Regulation*", PowerMarkers.com, February 2, 2004. See Exhibit No.___(TKW-4), Sheet 1 to Sheet 3.

have the opportunity to earn a fair and reasonable rate of return to maintain and, over time, improve its credit ratings, which, in the long-run, is in the best interest of all stakeholders, including customers.

Commission acceptance of the Company's proposed target capital structure would:

(1) Recognize Southwest's substantial improvement to its common equity ratio;

(2) Augment the Company's effort in sustaining that improvement by sending a positive signal of regulatory support to the capital markets and rating agencies; and

(3) Reflect the Company's common equity ratio expected to be achieved near or shortly after the time new rates will become effective.

III. SOUTHWEST'S FINANCIAL PROFILE

A. Credit Ratings

Q. 17 What is a credit rating?

A. 17 A credit rating reflects a rating agency's opinion of the creditworthiness of a particular company, security, or obligation. Credit ratings play an important role in capital markets by providing an effective and objective tool for market participants to evaluate and assess credit risk. As such, the Company's credit ratings are a key factor in determining the required yield on the Company's securities and bank facilities, and the amount and terms of available unsecured trade credit. Credit

rating agencies use both quantitative and qualitative information in the process of developing a credit rating. Exhibit No.___(TKW-5) displays the relationship between quantitative and qualitative credit rating factors, the credit rating, and the cost of debt and preferred securities.

Q. 18 How important is the regulatory environment in the determination of a credit rating for a public utility?

A. 18 For a public utility, credit rating agencies regard regulation as a key factor in determining a utility's financial performance, as regulation defines the environment in which the utility operates. The importance of regulation on the credit rating for a utility is reflected in the following statement by Todd Shipman of S&P:[5]

> "In the end, the regulation of public utilities is the defining element of the industry and is often the determining factor in the ratings of a utility."

Q. 19 What are the Company's current long-term unsecured credit ratings?

A. 19 Currently, Southwest's long-term unsecured credit ratings are "BBB" from Fitch, Inc. (Fitch), "Baa3" from Moody's Investor Services (Moody's) and "BBB-" from S&P. The Moody's and S&P ratings are at the lowest investment

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5 Todd A. Shipman, *Energy Risk - Fresh Look at US Utility Regulation*, PowerMarkers.com, February 2, 2004. See Exhibit No.___(TKW-4), Sheet 1 to Sheet 3.

grade rating, while the Fitch rating is one level above the threshold for an investment grade rating.

In addition, credit rating agencies provide a ratings outlook, which is an assessment of the direction of the credit rating over the intermediate to longer term. The current rating outlook for Southwest provided by both Fitch and Moody's is "stable". S&P, on March 27, 2007, changed the Company's ratings outlook from "stable" to "positive". The latest available credit agency reports are included in Exhibit No.____(TKW-6).

Q. 20 Have there been any changes in the credit ratings since the decision in the Company's last Arizona general rate case?

A. 20 Yes. On May 30, 2006, Moody's downgraded the Company's unsecured bond rating from "Baa2" to "Baa3". Moody's rationale for the downgrade was stated as follows:

> "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."

The key point in Moody's rationale is the Company's inability to achieve and sustain its allowed rate of return due to absence of protection in the Company's rate design to address declining average customer usage and margin variations due to weather. Also, Moody's pointed out the Company's continuing exposure to regulatory lag in addressing these issues. Moody's current assessment of regulatory support for Southwest, which is a core rating factor in the determination of the rating, is rated "Ba" or below investment grade[6]. A regulatory assessment of "Ba" is defined by Moody's as[7]:

> "Inadequate support from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner 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."

Q. 21 How does the length of the regulatory review period experienced by Southwest in Arizona compare to other regulated natural gas distribution companies?

A. 21 Reviewing the "AGA Gas Utility Rate Case Database" for 71

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6 Moody's Credit Opinion, Southwest Gas Corporation, Moody's Investor Services, June 21, 2007, p. 4.

7 Moody's Rating Methodology, *North American Regulated Gas Distribution Industry*, Moody's Investor Services, October 2006, p. 11.

general rate cases decided during the time period January 1, 2005 to March 31, 2007, the average length of the regulatory review period was 277 days. For the Company's last Arizona general rate case, the length of the review period was 433 days, which was 156 days longer than the average of 277 days. In principle, the longer the review period, the greater the negative financial impact of regulatory lag. As a result, the Company is exposed to a higher relative level of regulatory risk, which the Commission should consider when determining the overall allowed rate of return. Exhibit No.___(TKW-7) lists the general rate cases by jurisdiction to calculate the average regulatory review period.

Q. 22 What were S&P's reasons for the more recent change in its rating outlook for Southwest from "stable" to "positive"?

A. 22 In the March 13, 2007 S&P press release regarding the change in outlook, S&P stated the following:

> "Standard & Poor's Ratings Services affirmed its 'BBB-' rating on Southwest Gas and revised the outlook to positive from stable due to consistently strong cash flow measures and declining debt leverage."
>
> "Southwest Gas has made significant progress toward reducing its historically high debt leverage and will likely make further progress as a result of strong internal cash flows, minimal debt financing, and regular equity infusions," said Standard & Poor's credit analyst Leo Carrillo.
>
> "Supportive rate treatment will continue to be

> an important consideration with respect to ratings improvement, particularly as the company's customer growth rate slows to a more moderate pace and declining customer usage effects possibly become more pronounced in the absence of decoupling or weather normalization mechanisms in Arizona and Nevada."

The positive outlook recognized improved cash flows and the significant improvement the Company made in its common equity ratio. For ratings improvement, S&P stressed the importance of regulatory support in the form of rate design mechanisms to address declining average customer usage and sensitivity to weather.

Q. 23 Please discuss the importance of the Company's rate design proposals to the Company's financial profile.

A. 23 Given that a large portion of the Company's distribution costs are fixed, and to the extent that fixed cost recovery is based on rates using volumetric charges, declining per customer usage introduces asymmetric regulatory risk to the distribution of returns and cash flows for Southwest. The asymmetric nature of the risk associated with declining per customer usage and volumetric rate design has been recognized by the rating agencies.

In the decision for the Company's last general rate case, the Commission also recognized that Southwest "faces increased financial pressure due to declining usage on a per customer basis."[8] Improvements in rate

8 Decision No. 68487 p. 33.

design will help provide Southwest a realistic opportunity to achieve its authorized rate of return. The ability to achieve its authorized rate of return would provide Southwest with the cash flows needed to strengthen its financial metrics and improve its credit ratings.

Q. 24 What is the Company's target credit rating?

A. 24 It is management's long-run goal to achieve an "A" credit rating. The short-run goal, at a minimum, is to maintain an investment grade credit rating.

The Company believes that obtaining an "A" bond rating would provide the Company with an adequate amount of financial flexibility required to access the capital market at reasonable prices during both normal and turbulent market conditions. In addition, an "A" bond rating would be in the range that has been generally found to minimize the long-run average pre-tax cost of capital paid by customers[9].

Q. 25 Why is it important, at a minimum, for Southwest to maintain its investment grade bond rating?

A. 25 An investment grade credit rating is required for the Company to ensure that it can reliably and efficiently

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9 Roger A. Morin, *New Regulatory Finance*, (Arlington, Virginia: Public Utilities Reports, Inc., 2006), pp. 505-515, demonstrates using simulation analysis and a wide range of cost of common equity models that an "A" bond rating generally results in the lowest pre-tax cost of capital for electric utilities. In a study conducted by the National Economic Research Associates, "Capital Structure, Interest Coverage, & Optimal Credit Ratings", 1999, for UK water utilities also finds that an "A" bond rating is optimal.

raise capital to finance capital expenditures, accommodate its seasonal working capital requirements, facilitate its gas procurement function, and meet its obligations to serve customers.

As noted in the Company's 2006 Annual Report, Southwest anticipates capital expenditures during the three-year period ending December 31, 2009, of approximately $880 million. In addition, over the next six years (2007-2012), the Company has a total of $717 million of debt that will mature, a large portion of which will require refinancing. Falling below an investment grade credit rating would jeopardize the Company's ability to raise the required capital for this level of capital expenditures and to refinance maturing debt instruments, without considerably increasing the cost of funds and placing upward pressure on customers' rates.

Thus, it is in the best interest of customers and investors for the Company, at a minimum, to remain investment grade, as failing to do so would significantly increase the cost of capital and gas procurement costs, all of which would translate into higher rates for customers and higher risks for investors.

B. Relative Investment Risk

Q. 26 How do Southwest's credit ratings, interest coverage, and return on common equity compare to the proxy group of natural gas distribution companies?

A. 26 The comparative average bond ratings, funds from operations interest coverage, and actual return on common equity are shown below:

Description	SWG Actual	Proxy Group of Eight LDCs
Bond Ratings[1]:		
S&P	BBB-	A
Moody's	Baa3	A3
FFO Interest Coverage[2]	3.38	4.88
Return on Common Equity[2]	7.38%	11.99%

[1] See F. Hanley's Exhibit__(FJH-10), Sheet 2 of 9.
[2] Five-year (2002-2006) average ratio. See F. Hanley's Exhibit__(FJH-3), Sheet 1 of 2 and Exhibit__(FJH-4), Sheet 1 of 3.

The credit ratings for Southwest are approximately three notches lower than the proxy group. The Company's five-year average interest coverage ratio and realized return on common equity are both significantly lower than the proxy group measures, both indicating higher risk for Southwest.

Q. 27 In terms of other relative investment risk measures, what is Southwest's risk position in comparison to the proxy group of natural gas distribution companies?

A. 27 To determine the risk of investing in Southwest common stock relative to the proxy group, three additional measures of risk are employed, all of which indicate higher relative investment risk for Southwest: (1) S&P Business Position; (2) *Value Line Investment Survey* (Value Line) Safety Rank; and (3) the common stock book-

to-market ratio. The values for these risk measures for the individual proxy group companies and Southwest are displayed in Exhibit No.__(TKW-8). These relative risk measures provide collaborative evidence to support Mr. Hanley's recommended return on common equity for Southwest relative to the proxy group.

Q. 28 Please discuss the S&P Business Position profile score.

A. 28 The S&P Business Position profile score is a 10-point business profile assessment that assesses the qualitative attributes of a firm, with "1" considered lowest risk and "10" the highest risk. The business profile score is determined using five categories: (1) regulation, (2) markets, (3) operations, (4) competitiveness, and (5) management. S&P states that the emphasis placed on each category may be influenced by the dominant strategy of the company or other factors. For example, "for a regulated transmission and distribution company, regulation may account for 30 to 40 percent of the business profile score because regulation can be the single-most important credit driver for this type of company." Southwest has been assigned a business position score of 3. The proxy group business profile scores range between 1 to 3, with an average score of 2.3. This measure indicates higher relative investment risk for Southwest.

Q. 29 Please discuss the Value Line Safety Rank.

A. 29 The Value Line ranks stocks for safety by analyzing the

total risk of a stock compared to the approximately 1,700 stocks in the Value Line universe. Value Line ranks each stock from 1 (highest) to 5 (lowest). Each of the stocks tracked in The Value Line is ranked in relationship to each other, from 1 (highest) to 5 (lowest). Value Line defines safety as a quality rank, not a performance rank, and stocks ranked 1 and 2 are most suitable for conservative investors, while those ranked 4 and 5 will be more volatile. The major influences on a stock's Safety Rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years. Southwest's Value Line Safety Rank is 3, while the average for the proxy group is 1.88. This measure indicates higher relative investment risk for Southwest.

Q. 30 Please discuss the book-to-market value ratio.

A. 30 The book-to-market ratio is the common stock book value per share divided by the market price per share. In a well-known study of the capital asset pricing model by Fama and French[10], they find that actual realized returns on a firm's equity are highly positively correlated with a firm's common stock book-to-market ratio. They conclude that the book-to-market ratio can be used as a proxy for risk. Based on a comparison of the five-year average book-to-market ratio for Southwest of 0.73 to the

10 Eugene F. Fama and Kenneth R. French, 1992, "The Cross-Section of Expected Stock Returns," *Journal of Finance* Vol.47:2, 427-466.

average of the proxy group of 0.57, Southwest has a relatively higher level of investment risk.

C. Capital Attraction

Q. 31 Given the Company's operating environment, what are the key factors that will enable the Company to continue to attract the capital necessary to meet its ongoing capital requirements?

A. 31 Generally, investors will choose between alternative investments based on the risk and reward characteristics of the available investment opportunities. Consequently, the Company must compete with other utilities and alternative investment opportunities in fully competitive capital markets to attract equity capital.

For Southwest to successfully attract equity capital, it must demonstrate an ability to achieve a competitive return on that equity capital. As a regulated natural gas utility, the Company's overall authorized net income available for its shareholders is ultimately determined by the authorized rate base in each jurisdiction multiplied by the applicable authorized equity ratio in the capital structure and the applicable authorized cost of equity.

Mr. Hanley has provided testimony in this proceeding regarding a fair and reasonable cost of common equity, considering the Company's specific risk factors and costs of common equity for proxy groups of "similar" natural gas utilities. His recommended return on common

equity also factors in the requested capital structure with a common equity ratio of 45 percent. The cost of common equity and the common equity weighting in the capital structure must be viewed together in determining a fair and reasonable return likely to attract the equity capital the Company will require on a going-forward basis. Accordingly, if investors are to have the opportunity to earn a fair and reasonable rate of return, as the Bluefield and Hope cases support, any adjustment downward from the requested 45 percent common equity ratio would require a corresponding increase in the cost of common equity, and vice versa. For these reasons, the requested capital structure, with a 45 percent common equity ratio, and Mr. Hanley's recommended cost of common equity of 11.25 percent, are interdependent and critical to the Company in this proceeding.

Q. 32 How does the overall rate of return, based on the recommended capital structure and the recommended cost of equity, balance the interests of both customers and investors of the Company?

A. 32 The components of the recommended capital structure were developed in an attempt to balance the interests of both investors and customers. The Company's financial health is, over time, important in determining the rates it must charge its customers. The Company's credit ratings are significantly influenced by the financial strength of the Company. The Company's cost of debt and preferred equity

capital are, in large part, determined by the Company's credit ratings. All other things being equal, with higher credit ratings, the Company's cost of capital and the rates it charges its customers would be lower.

With the recommended capital structure and Mr. Hanley's recommended cost of equity, the Company will have an adequate authorized overall rate of return that will help further strengthen Southwest's financial condition and, over time, improve the Company's credit ratings and reduce the overall cost of capital.

It is also important that investors be given the opportunity to earn a rate of return commensurate with the level of risk associated with their investment. Investor confidence in Southwest is important for both its existing shareholders and for the Company's future ability to issue additional common equity. If the overall allowed rate of return is set below the Company's actual cost of capital, then in the short-run, the Company's customers will pay lower prices for natural gas service to the detriment of the Company's current investors. However, in the long-run, without achieving an adequate level of return, the Company may be unable to attract sufficient financing at reasonable rates to continue to fund the required capital expenditures and maintain its quality of customer service. The Company cannot simply rely on issuing new equity to improve its capital structure, but must also increase common equity

through retained earnings, as Southwest must strive to preserve the integrity of its existing shareholders. The recommended capital structure, together with Mr. Hanley's recommended cost of common equity, will help sustain the Company's improved financial condition and support continued improvement. In the long-run, this will benefit both the Company's customers and investors.

D. Summary

Q. 33 Please summarize the importance of the Company's proposed capital structure, overall rate of return, and rate design on the Company's financial profile.

A. 33 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, the Company made significant progress in improving its common equity ratio, primarily by the issuance of additional shares of common stock and secondarily, by additional retained earnings. Given the high-growth environment in which the Company exists, the ability of the Company to sustain and continue to improve its financial profile is largely dependent on the regulatory support it receives in this proceeding.

First, the Commission must establish an adequate overall rate of return that fairly compensates investors for Southwest's higher level of business, financial, and regulatory risk. The Company will continue to need

frequent access to the capital markets. In order for the Company to attract additional capital at reasonable rates, and maintain its financial integrity (which benefits its customers), it must earn a rate of return which adequately compensates its investors for the degree of risk they assume.

Second, the Company needs a realistic opportunity to earn its authorized rate of return. Investors do not make investment decisions based on authorized rates of return, but on actual and expected realized rates of return. The proposed overall rate of return assumes that the Commission will approve the Company's rate design proposals. If the rate design proposals are rejected, the rate of return must be adjusted upward. Both S&P and Moody's have stated the importance of improvements in rate design as a key consideration for rating upgrades. Additional rate relief without a significant change in rate design will only treat the symptoms of what has been a key cause of Southwest's chronic inability to earn its authorized rate of return and has hindered the Company's efforts to improve its credit rating. This was made clearly evident when Southwest's bond rating was downgraded by Moody's just three months after receiving $49.3 million of rate relief, but without a significant improvement in rate design.

With the regulatory support of the Commission in approving the Company's proposed rate design

improvements, an overall rate of return of 9.45 percent, based on a common equity ratio of 45 percent and an 11.25 percent return on common equity, Southwest can continue to build on the substantial progress it has made in improving its financial profile. Obtaining a realistic opportunity to earn its authorized rate of return will give the Company the ability to finance a higher percentage of its significant annual capital expenditures from internally-generated funds, reduce its net debt balances, and improve its interest coverage ratios, all of which will facilitate achieving improved bond ratings. Such improvement benefits Southwest's customers by reducing the long-run average capital costs embedded in customers' rates.

IV. EMBEDDED COST OF LONG-TERM DEBT

Q. 34 Have you determined the appropriate cost rate for long-term debt capital?

A. 34 Yes. Southwest's appropriate cost rate for long-term debt is 7.96 percent. This rate is summarized on line 1, column (c), of Schedule D-1, Sheet 1 of 2. Schedule D-2, Sheets 1 through 4, contains the development of the long-term debt cost rate. The cost of long-term debt is comprised of the cost of fixed-rate debentures, fixed-rate medium-term notes, and a variable-rate term facility.

Q. 35 Please describe the development of the cost rates of the debentures and notes.

A. 35 The Company had three outstanding debenture and note issues, totaling $475 million of gross principal, at the end of the test year (April 30, 2007). The debentures and notes had a weighted average cost of 8.30 percent, as shown on line 4, column (e), of Schedule D-2, Sheet 2 of 4.

Q. 36 Please describe the cost rate of the medium-term notes.

A. 36 The Company established a $150 million medium-term note program in November 1997. The name is somewhat of a misnomer as medium-term notes can be issued with maturities ranging from nine months to 30 years. The Company issued all of its medium-term note program and had six outstanding medium-term note issues totaling $125 million of gross principal at April 30, 2007. The medium-term notes had a weighted average cost of 7.38 percent, as shown on line 11, column (e), of Schedule D-2, Sheet 2 of 4.

Q. 37 How are the effective cost rates of debentures, notes, and medium-term notes calculated?

A. 37 The effective cost rates of debentures, notes, and medium-term notes are calculated through the use of the yield-to-maturity (YTM) or effective interest rate method.

Q. 38 Please describe the YTM method.

A. 38 The YTM method is based on an internal rate of return calculation which takes into account the actual cash flows of each debt security. Specifically, the Company

receives a cash inflow at the debt's issuance, consisting of the face value less any associated issuance expenses and debt discount. The Company's cash outflows consist of interest payments and principal repayments. The effective rate is the percentage rate that discounts those cash outflows to the net cash inflow the Company receives at issuance. Once the effective rate is calculated, it is then multiplied by the net proceeds (i.e., the principal amount outstanding less any unamortized discounts) to determine the total expense per payment period for each issue. The weighted average cost is then determined by weighting the effective cost of each issue by the current net proceeds amount. When used for ratemaking, the YTM method results in an effective cost that remains constant over the life of the debt security. The calculations for the effective cost of debentures, notes, and medium-term notes are shown in Exhibit No. ___ (TKW-9).

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

A. 39 The Company has a five-year (April 2006 - April 2011) $300 million revolving credit facility. In addition, the Company has a $50 million uncommitted F-2 commercial paper program, supported by the revolving credit facility. The Company continues to view $150 million of the facility as a permanent intermediate-term component of its debt portfolio. Accordingly, the Company has

classified it as long-term debt. Southwest continues to use the remaining $150 million of the facility to fund recurring, seasonal working capital needs.

At the end of the test period, the Company had outstanding approximately $53.2 million as part of the long-term debt portion of the facility. Of this amount, approximately $30.5 million was outstanding as London Interbank Offered Rate (LIBOR) loans and approximately $22.7 million was outstanding as commercial paper. The all-in effective rate of the long-term debt portion of the facility at the end of the test year was 6.27 percent, as shown on line 1, column (c) of Schedule D-2, Sheet 3 of 4. This all-in rate includes the interest on the loans, an annual fee, and unused commitment fees for amounts outstanding as commercial paper and amortization of debt expenses incurred to establish the facility. Exhibit No. ___ (TKW-10), displays the calculation of the effective cost of the LIBOR loans and commercial paper under the term facility.

Q. 40 Why are the Clark County and Big Bear Industrial Development Revenue Bonds (IDRBs) excluded in calculating the cost of long-term debt?

A. 40 Southwest issued IDRBs in two of its rate jurisdictions. The IDRB issues and applicable rate jurisdictions are as follows: (1) the Clark County, Nevada IDRBs (1993 Series A, 1999 Series A, C & D, 2003 Series A, B, C, D & E, 2004 Series A & B, 2005 Series A and 2006 Series A) for its

Southern Nevada rate jurisdiction, and (2) the City of Big Bear, California IDRBs (1993 Series A) for its Southern California rate jurisdiction. As reflected in the IDRB indentures and financing agreements, the proceeds from the issuance of this type of debt are restricted to funding qualified construction expenditures for additions and improvements in the specific distribution systems to which the IDRBs relate. In addition, there are strict Internal Revenue Service (IRS) rules which mandate that the benefits of the tax-exempt, lower cost IDRBs must accrue to customers in the specific jurisdiction to which the IDRBs apply. Deviation from the requirements of this IRS ruling could result in the loss of the IDRB tax-exempt status, which would, in turn, cause the Company to refinance its debt at a much higher cost.

Q. 41 How have regulatory jurisdictions treated the cost of Southwest's IDRBs in past regulatory proceedings?

A. 41 Southwest has historically excluded the IDRBs from the cost of debt calculation in all regulatory jurisdictions, except for the specific jurisdictions (Southern Nevada for Clark County IDRBs and Southern California for City of Big Bear IDRBs), to which the relevant IDRBs apply. This Commission, the PUCN, the CPUC, and the FERC have accepted this treatment for IDRBs in past regulatory proceedings.

V. EMBEDDED COST OF PREFERRED EQUITY

Q. 42 Please discuss the development of the cost of preferred equity.

A. 42 The Company's requested cost of preferred equity is 8.20 percent, as shown on line 2, column (c) of Schedule D-1, Sheet 1 of 2. In August 2003, through a public offering, the Company issued $100 million in trust originated preferred securities (TOPrS), of which $60 million of the proceeds were used to refinance the Company's then-existing 9.125 percent preferred securities, which had an effective all-in cost of 9.51 percent. The $100 million in securities have a $25 per share liquidation value and pay a dividend at an annual rate of 7.70 percent paid quarterly. The effective all-in cost of these securities is 8.20 percent and is determined using the YTM method previously described. Exhibit No.___(TKW-11) details the calculation of the effective cost for preferred equity.

Q. 43 What are the main benefits of issuing preferred securities in the form of TOPrS?

A. 43 Generally, the benefits are two-fold: (1) the positive tax treatment of these securities, and (2) the favorable rating agency treatment. Dividends paid on traditional preferred stock by the issuer are not tax-deductible and require the effective cost to be grossed-up for taxes in determining the revenue requirement. The TOPrS were issued by a wholly-owned business trust of the Company (Southwest Gas Capital II), the sole purpose of which was

to issue such securities. By using the trust structure, the Company is able to deduct for tax purposes the payments made in connection with the securities. As a result, the tax-deductibility feature provides an overall lower revenue requirement for customers as compared to traditional preferred stocks.

Due to certain equity-like characteristics of the TOPrS securities, S&P affords a level of "equity credit" in its evaluation of the credit quality of a company. These equity-like characteristics include a longer-maturity (typically 30 years), subordination of interest payments to the trust, and deferability of distributions to security holders for up to five years. Currently, S&P assigns a 40 percent "equity credit" for TOPrS.

Q. 44 Are the TOPrS securities convertible into common stock?

A. 44 No. The Company's TOPrS securities contain no conversion feature.

Q. 45 Does this conclude your prepared direct testimony?

A. 45 Yes, it does.

SUMMARY OF QUALIFICATIONS
THEODORE K. WOOD

I graduated from the University of Nevada, Reno (UNR) in 1985 with a Bachelor of Science degree with a major in agricultural economics. In 1989, I earned a Masters of Science degree from UNR in agricultural economics with a minor in finance. I have attained the professional designations of Chartered Financial Analyst (CFA), Certified Rate of Return Analyst (CRRA), Certified Management Accountant (CMA), Certified in Financial Management (CFM), and Certified Treasury Professional (CTP). I am a member of the Institute of Management Accountants, the CFA Institute, Association for Financial Professionals, Financial Management Association, and the Society of Regulatory and Utility Financial Analysts.

From 1985 to 1988, I was employed as a research associate in the Department of Agricultural Economics at UNR in Reno, Nevada. My primary role was to assist with ongoing research projects in the Department including secondary data collection, statistical analysis, FORTRAN programming, and the development of microcomputer spreadsheets for farm management decision analysis.

In 1989, I was employed by First Interstate Bank of Nevada in Reno, Nevada, as a financial analyst in the Finance Department. My duties entailed maintenance of the general ledger system, creation of monthly management and

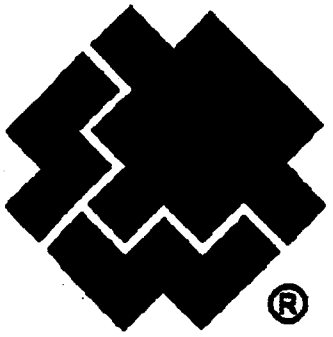
financial reports, and special projects.

From 1990 to 1992, I was employed as a planning analyst with Valley Bank of Nevada, in Las Vegas, Nevada, in the Planning Department. My primary responsibilities included preparation of the annual budget, quarterly budget variance analysis, supporting the Asset/Liability Committee of the bank, and other financial analyses.

From 1992 to 1994, I was employed by PriMerit Bank, FSB, then a wholly-owned subsidiary of Southwest, as a Senior Financial Analyst in the Budget and Forecasting Department. My primary responsibilities included creation and maintenance of a microcomputer-based budgeting system, preparation of the annual budget, monthly budget variance analysis, product profitability analysis, and other special projects.

In 1994, I accepted a Senior Financial Analyst position in the Treasury Services Department of Southwest. My responsibilities included daily cash management, preparation of financial forecasts and analyses, and assisting in the preparation of rate of return testimony for the Company's various ratemaking jurisdictions. I was promoted to Supervisor of the Treasury Services Department in May 1997, to Manager in June 2000 and to Senior Manager in May 2005. I supervise three other financial analysts in the Treasury Services Department.

EXHIBIT NO.___(TKW-1)



SOUTHWEST GAS CORPORATION
RECAPITALIZATION PLAN
G-01551A-04-0876
DECISION NO. 68487

Submitted: April 20, 2007

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	Docket No. G-01551A-04-0876

SOUTHWEST GAS CORPORATION
RECAPITALIZATION PLAN

In Southwest Gas Corporation's ("Southwest" or "Company") last general rate case ("GRC") order, the Arizona Corporation Commission ("ACC" or "Commission") required Southwest to submit a recapitalization plan "... explaining how it intends to achieve a 40 percent equity prior to the Company's next rate case... "[1]. Southwest respectfully submits this Recapitalization Plan in accordance with the Commission's decision.

I. INTRODUCTION

At August 31, 2004, which was the last day of the test year of Southwest's 2004 Arizona GRC[2], the Company's common equity ratio was 34.1 percent. At December 31, 2006, the Company's common equity ratio had improved to 39.8 percent[3]. Southwest anticipates achieving a 40 percent common equity ratio in the near future, and the Company's progress in improving its equity ratio is further explained in Section III.

Notwithstanding the recent improvement in Southwest's equity ratio, and consistent with the Commission's directive in this regard, Southwest has developed a plan that would bring the Company's common equity ratio more in line with its peers (i.e. comparable natural gas utilities, also see Section IV), and provide it the necessary capitalization to fund the substantial capital investment necessary in the rapidly growing state of Arizona. If Southwest can achieve and sustain a higher common equity ratio in the 45 to 50 percent range, the Company will improve its credit rating, decrease its financial risk, experience lower overall capital costs, and customers would benefit from a lower cost of capital and a utility that is financially strong and healthy.

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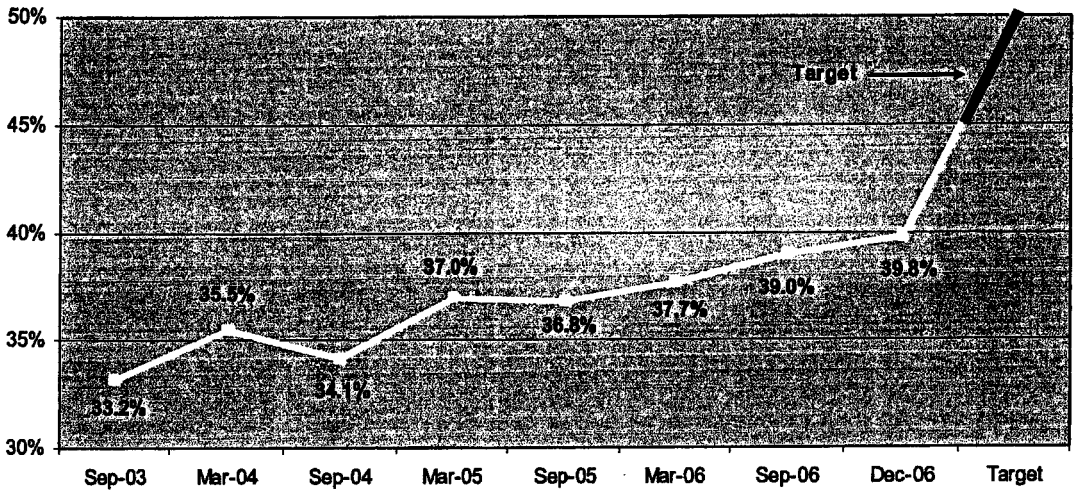
[1] Decision No. 68487, Page 25, Line Nos. 12-14, dated February 23, 2006.
[2] Southwest's 2004 Arizona general rate case was assigned Docket No. G-01551A-04-0876.
[3] See Exhibit 1.

The incremental improvement in the common equity ratio during this period has been primarily a result of additional common stock issuances. The secondary source of improvement in the common equity ratio has been the Company's actual improved financial performance (i.e., additional retained earnings).

Figure 1 shows the Company's common equity ratio bi-annually for the last three years, at December 2006, and the Company's long-term equity ratio target.

Figure 1 – COMMON EQUITY RATIO



There were three significant events during the last three years that have contributed to the Company's improved financial performance:

1) The California Public Utilities Commission ("CPUC") approved a full margin decoupling mechanism in Southwest's 2003 GRC and Southwest began collecting $10.1 million in annual rate relief in May 2003. Southwest has also received annual revenue increases of approximately $2.5 million per year in its California jurisdiction since its 2003 GRC.

2) In September 2004, Southwest began to collect $13.7 million in annual rate relief in its Nevada jurisdictions. The Public Utilities Commission of Nevada ("PUCN") authorized a declining block rate structure, reducing the second tier commodity margin rate to just 15.387 cents per therm, compared to 34.486 cents per therm for the first tier, significantly increasing Southwest's probability of recovering its fixed costs.

3) In March 2006, the ACC authorized Southwest to begin collecting $49.3 million in annual rate relief. As part of this rate relief, the ACC increased the residential BSC by $1.70 per month.

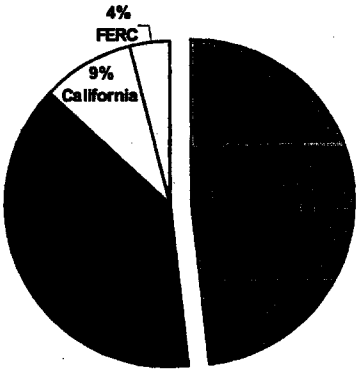
As a result of these and other contributing factors, Southwest has nearly achieved the hypothetical common equity ratio used to set rates in the 2004 Arizona GRC within ten months of the effective date of the Commission's decision.

Despite the recent improvement in its common equity ratio, Southwest believes that it is reasonable to target a common equity ratio that is in line with its peers as the level to achieve and sustain in the long run. In order to achieve and sustain this higher common equity ratio, the Company will request regulatory support from the Commission in future proceedings. This Recapitalization Plan will explain the steps Southwest feels are necessary to give it the opportunity to meet this goal.

II. DESCRIPTION OF THE COMPANY AND ITS RISKS

Southwest is a diversified company with natural gas distribution operations in the states of Arizona, Nevada, and California, a federally-regulated natural gas pipeline, and a wholly-owned pipeline construction subsidiary. As such, the ability of the Company to obtain a certain equity ratio is largely dependent on the Company's level of earnings and cash flows in each of the Company's regulatory jurisdictions.

Figure 2 – RATE BASE BY JURISDICTION



The size of each regulatory jurisdiction compared to the overall size of the Company can be measured by rate base. Figure 2 shows the rate base percentage of each jurisdiction, as a percentage of total Company rate base, at December 31, 2006.

Arizona comprises approximately 48 percent of the Company as measured by rate base. Therefore, any actions taken by this Commission that support Company initiatives to improve its capital structure would have a significant impact.

Southwest recognizes that while Arizona makes up a significant portion of its natural gas distribution operations, it does not depend solely on this Commission to improve its capital structure. Southwest has been proactive in seeking needed regulatory assistance from all of its jurisdictions to help the Company remove the obstacles it faces in improving its capital structure. As a result of these regulatory initiatives, Southwest has improved its earned rates of return in its California, Nevada, and FERC-regulated jurisdictions. Throughout this document Southwest will discuss

several regulatory mechanisms approved in other states that have assisted the Company in improving its capital structure over the last few years.

There are numerous risk factors that may cause the Company's realized common equity ratio to differ materially from the target outlined in this Recapitalization Plan. These risks include, but are not limited to: the impact of variations in customer usage and growth rates, changes in natural gas prices, weather, the Company's ability to recover gas costs through its PGA mechanisms on a timely basis, the timing and amount of rate relief, changes in rate design, changes in capital requirements and funding, capital market conditions, and changes in costs.

III. SOUTHWEST'S PROGRESS IN IMPROVING ITS CAPITAL STRUCTURE

The Company's actual ratemaking capital structure at August 31, 2004 and December 31, 2006[4] are shown below in Table 1:

Table 1 – SOUTHWEST'S ACTUAL RATEMAKING CAPITAL STRUCTURE ($ IN MILLIONS)

Ratemaking Capital	8/31/04	12/31/06	$ Increase	% of New Cap.
Long-Term Debt	60.8%	55.9%	$103	29%
Preferred Equity	5.1%	4.3%	0	0%
Common Equity	34.1%	39.8%	251	71%
Total	100.0%	100.0%	$354	100%

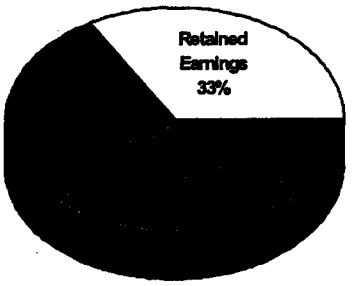
During this 28-month period, total ratemaking capital increased by approximately $354 million. This total consists of a $251 million increase in common equity and a $103 million increase in long-term debt. Since Southwest was able to finance most of the incremental capital with common equity, the common equity ratio has improved by over five percentage points.

At December 31, 2006, the Company had a Purchased Gas Adjustment ("PGA") receivable balance of approximately $77 million Company-wide and no short-term debt outstanding. Adjusting the balance sheet for the after-tax effects of the PGA balances, the Company's common equity ratio would have improved to approximately 40.6 percent.

[4] The ratemaking capital structure is the Company's gas segment permanent capital structure, which includes common equity, preferred securities and long-term debt. Short-term debt is excluded as short-term debt is used primarily to finance working capital and PGA receivable balances, and not long-term rate base assets. See Exhibit 1 for details.

The $251 million increase in common equity was primarily from three sources: the issuance of additional common equity shares from the Company's existing equity plans (Dividend Reinvestment and Stock Purchase Plan, Employee Investment Plan, Management Incentive Plan, and Stock Incentive Plan); the Equity Shelf Program ("ESP"); and an increase in retained earnings. As Figure 3 illustrates, 67 percent of the growth of common equity during this period was a result of issuing additional shares of common stock, while just 33 percent of the growth was from increased retained earnings.

Figure 3 –NEW COMMON EQUITY, BY SOURCE



a. Common Equity Issued Through Existing Plans

From August 2004 through December 2006, the Company issued approximately 3.4 million shares of common stock through its existing plans, with net proceeds of $93.6 million.

b. Common Equity Issued Through the ESP

An ESP is a service offered by institutional bankers that provides for the issuance of relatively small amounts of new common equity continuously and discreetly as part of regular daily trading flows. All aspects of the ESP are under the Company's control including the number of shares, trading period, and minimum sales price. The sales of common stock are made in "at the market" offerings in sales made directly on the New York Stock Exchange or sales made to or through a market maker or an electronic communications network. In addition, shares of common stock may be offered and sold by other methods, including privately-placed negotiated transactions. The ESP is a very cost-effective method of issuing new shares. While a traditional equity placement may incur administrative costs of approximately 3 to 5 percent, the referenced ESP used by Southwest incurs administrative costs of just 1 percent.

From August 2004 through December 2006, the Company issued approximately 2.8 million common shares through the ESP with net proceeds of $74.6 million. The Company originally established a three-year, $60 million ESP in May 2004. The Company began issuing shares through the ESP in June 2004 and had completely issued the $60 million ESP by the end of September 2005. In March 2006, the Company established a three-year, $45 million ESP. At December 30, 2006, the Company had approximately $16.7 million of remaining capacity under its existing $45 million ESP.

c. Increase in Retained Earnings

From August 2004 through December 2006, Southwest's retained earnings increased by $83.9 million. Contributing to this improvement were increased earnings from timely rate relief granted in Southwest's Nevada jurisdictions, rate relief and annual margin adjustments in Southwest's California jurisdictions, and ten months of realized rate relief from Southwest's 2004 Arizona GRC.

The increase in retained earnings is also attributable to the Company's prudent management of its costs. One measure the Company uses to evaluate productivity is its customer-to-employee ratio. From August 2004 through December 2006, Southwest added nearly 88,000 new customers in its Arizona jurisdiction, an increase of over 10 percent. During this same time period, the customer-to-employee ratio (a measure of employee productivity) improved from 754 to 871 in Southwest's Arizona jurisdiction, an improvement of roughly 15 percent during this 28-month period. The more productive the Company's work force, the lower costs will be to serve customers.

IV. SOUTHWEST'S PLAN TO ACHIEVE A CAPITAL STRUCTURE THAT IS IN LINE WITH ITS PEERS

The recent improvement in capital structure has been achieved primarily from common stock issuances. However, there is a limit to the number of shares the Company can prudently issue. Simply issuing additional common stock in an attempt to build equity, without regard for the dilution effect on existing shares, can result in realizing less than the maximum possible proceeds from future common stock issuances. Achieving and then maintaining a common equity ratio that is near the industry average will only be accomplished if the Company can consistently realize a fair opportunity to earn its authorized rate of return.

Southwest will continue to follow its ongoing balance sheet management strategy. An essential part of that strategy is to improve the Company's opportunity to earn its authorized rate of return and increase common equity through retained earnings. The Company bears much of the responsibility to ensure it can realize a sufficient level of net income in order to build retained earnings. The Company will continue to make efforts to control costs, improve productivity, make prudent investments in technology, operate in a safe and efficient manner, add new customers without burdening existing customers (in accordance with its tariffs), file for rate relief when revenues become deficient, and ask the Commission to act favorably on rate design changes and other

regulatory mechanisms to address shortcomings in Southwest's ability to recover its cost of service and earn its authorized rate of return.

To expand on the last point in the proceeding paragraph, Southwest will describe various regulatory mechanisms that, if adopted by the Commission, will assist the Company in improving its capital structure. These regulatory mechanisms are discussed in the following section.

V. REGULATORY MECHANISMS OR ACTIONS THAT WOULD IMPROVE SOUTHWEST'S CAPITAL STRUCTURE

Due to its current residential rate design in Arizona, Southwest depends to a large extent on the volumes of gas delivered to residential customers to recover its cost of service. This dependency has historically caused the Company to earn less than its authorized rate of return due to margin shortfalls from two distinct causes: (1) a decline in average use per customer; and (2) weather variations.

The variability in customer consumption of natural gas is a risk that is recognized by the capital markets. If this risk is reduced, the markets may react favorably and the Company may experience lower overall capital costs, which benefit customers. In fact, when Moody's downgraded Southwest's senior unsecured debt to Baa3 from Baa2 on May 30, 2006, roughly 3 months after Southwest implemented an increase in revenues pursuant to its 2004 rate case application in Arizona, it noted that one of the factors in the downgrade was: "... the absence of revenue decoupling in Arizona ... that would serve to protect this company from weather variation and customer conservation."[5] Also, in a recent industry outlook, Moody's stated that it: "... believes that having a rate design that compensates the LDCs for margin losses caused by variations in gas consumption due to conservation as well as those due to weather would serve to stabilize the utility's credit metrics and credit ratings..." and that the rate design proposals "... generally involve "de-coupling" or other rate mechanisms that would de-couple the LDC's margins from its volumes."[6] In addition, Standard and Poor's ("S&P") recently affirmed its "BBB-" rating on Southwest and revised the outlook from stable to positive, citing progress in cash flow and declining debt leverage, but noting that "...supportive rate treatment will continue to be an important consideration with respect to ratings improvement, particularly as the company's customer growth rate slows to a more moderate pace and declining customer usage effects possibly become more

[5] See Exhibit 2 for the full text of Moody's downgrade announcement.
[6] Moody's Industry Outlook, North American Natural Gas Transmission & Distribution, October 2006.

pronounced in the absence of decoupling or weather normalization mechanisms in Arizona and Nevada."[7]

There are several rate and regulatory mechanisms that Southwest can propose in future regulatory filings that can assist Southwest in stabilizing its earned margin, and reduce its dependency on recovering a disproportionate percentage of its fixed cost of service based on customer consumption.

a. Decoupling Mechanism

In its 2004 Arizona GRC Application, Southwest proposed a decoupling mechanism to address the Company's ongoing inability to achieve its authorized rate of return due, in part, to declining per customer use on its system. This mechanism was proposed to "... accomplish Southwest's rate design objective of stabilizing margin recovery for the residential classes and allow a more gradual movement towards cost based rates for the residential classes."[8] The mechanism, as designed by Southwest, would have decoupled Southwest's residential margin recovery from the volume of gas delivered in a given month and re-couple residential margin recovery to the number of customers served for that month. In other words, Southwest would recover the authorized margin per customer. Such mechanisms do not guarantee that the utility will earn its authorized rate of return, since general inflationary cost trends can cause earnings shortfalls even when revenues have been stabilized.

While the Commission did not adopt the mechanism as proposed, it did order Southwest to coordinate its efforts with other interested parties to pursue implementation of a decoupling mechanism[9]. Southwest formed a collaborative working group, consisting of the Company, ACC Staff, the Residential Utility Consumer Office ("RUCO"), and the Southwest Energy Efficiency Project ("SWEEP"). Several meetings of the collaborative working group have been held to date, and additional meetings are anticipated during 2007. Southwest hopes that this process will result in the identification of one or more margin stability mechanisms that can be supported by all parties, and can be presented to the Commission for review and approval in a future general rate case proceeding.

There is increasing momentum throughout the country, led by various organizations, to encourage state commissions to support natural gas LDC efforts to

[7] See Exhibit 3 for full press release, dated March 14, 2007.
[8] Docket No. G-01551A-04-0876, direct testimony of Southwest witness Edward Gieseking, page 4, lns 20-23.
[9] Decision No. 68487, Page 68, Line Nos. 3-7.

manage volatility in gas prices and reduce volatility risks for customers. In July 2004, the American Gas Association ("AGA") and the Natural Resources Defense Council ("NRDC") issued a joint statement, which was later adopted by the National Association of Regulatory Utility Commissioners' ("NARUC") Board of Directors, which encourages state commissions to eliminate a utility's dependence on sales to recover its authorized margin. These organizations agree that "...traditional rate structures often act as disincentives for natural gas utilities to aggressively encourage their customers to use less gas. Among the mechanisms supported ... are the use of automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales."[10]

In addition, in July 2006 the National Action Plan for Energy Efficiency (NAPEE)[11] presented policy recommendations for creating a sustainable, aggressive national commitment to energy efficiency. NAPEE observed that traditional ratemaking encourages utilities to increase throughput in order to earn their authorized rate of return, since growth in sales can offset cost increases that may occur between rate cases. NAPEE recommends policy changes that can remove this impediment to greater investment in energy efficiency, such as the implementation of a decoupling mechanism that allows utilities to recover their revenue requirement with less dependency on sales volume. On August 2, 2006, NARUC adopted a resolution endorsing the principal objectives and recommendations of the NAPEE. Finally, the Energy Policy Act of 2005 (Section 139) has provided similar policy direction insofar as it has required that a study of state and regional policies that promote cost-effective programs to reduce energy consumption be conducted and submitted to Congress within one year of the date of enactment, and that methods of reducing disincentives for utilities to implement energy efficiency programs be considered.

At this time, decoupling mechanisms are in place for natural gas utilities in California, Georgia, Indiana, Maryland, Missouri, New Jersey, North Carolina, North Dakota, Ohio, Oregon, Utah, and Washington. Southwest is subject to a decoupling mechanism in its California jurisdiction. Utilities in other states, including Arkansas, Colorado, Delaware, Illinois, Michigan, Minnesota, New Mexico, New York, and Virginia,

[10] Resolution on Gas and Electric Energy Efficiency adopted by NARUC, July 14, 2004.

[11] More than 50 organizations collaborated in developing the NAPEE, including investor-owned and municipal utilities, regulators, large corporations, and organizations dedicated to energy efficiency. The U.S. Department of Energy and the U.S. Environmental Protection Agency facilitated the work of the NAPEE.

have pending requests for their respective commissions to approve decoupling mechanisms.[12]

b. Weather Normalization Mechanism

Similar to a decoupling mechanism, a weather normalization mechanism would reduce the weather-related volatility the Company faces in recovering its authorized margin. Once again, such a mechanism would not guarantee that a utility will earn its authorized rate of return. Generally, the purpose of such a mechanism is to allow the Company to realize the authorized weather-normalized margin on a per customer basis; increases in overall expenses and/or rate base may still cause earning shortfalls. The margin variance due to weather would be calculated based on the extent that weather varies from normal. If weather is colder-than-normal, the utility would overcollect its authorized revenue per customer and seek Commission approval for a rate credit to return the overcollection to customers. If weather is warmer-than-normal, there would be an undercollection on the utility's authorized revenue per customer, and a surcharge would be sought. Under such a mechanism, customers are protected from higher winter bills resulting from colder-than-normal weather, yet the utility recovers its authorized revenues during warmer-than-normal weather. Over 20 states have approved weather normalization mechanisms providing this symmetric margin stabilization for consumers and utilities from weather fluctuations[13]

c. Increased Basic Service Charge

Excluding gas costs (which are recovered through the PGA mechanism), Southwest's costs of providing distribution service are primarily fixed. The Company can reduce its dependency on volumetric recovery of its cost of service by seeking Commission approval of higher residential monthly basic service charges ("BSC"). Higher residential basic service charges are supported by the cost of service studies included in general rate case applications. In the Company's 2004 GRC, the Commission approved increasing the Company's residential BSC from $8.00 to $9.70 per month. Further increases in the residential BSC move residential customers closer to cost-based rates, and help alleviate high winter bills.

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[12] "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives, American Council for an Energy-Efficient Economy, October 2006, Page iii.
[13] Ibid.

d. Enhance Declining Block Rate Structure

Another way Southwest can reduce its dependency on volumetric cost recovery is to seek a declining block rate structure that recovers a greater portion of fixed costs in the less variable (first) consumption block. In other words, to the extent that the first rate block is higher than subsequent rate blocks, a higher percentage of Southwest's costs are recovered in the therms most likely to be consumed. If weather or conservation cause actual consumption to decrease, the Company is somewhat shielded from a portion of the otherwise anticipated revenue loss. This would also protect customers from higher bills in periods of increased consumption due to cold weather.

A variation of the declining block rate structure rate design was recently approved by the Missouri Public Service Commission for Laclede Gas Company ("Laclede").[14] The rate design approved for Laclede shifts, for accounting purposes, more margin (and less gas cost) to the first block rate of residential usage per month, without any change to the total commodity rate. As a result of this rate design, Laclede's dependency on volumetric cost recovery is reduced, while, at the same time, the total bills that customers pay remain unchanged.

e. Reduce the Impact of Regulatory Lag and Attrition

Regulatory lag is the amount of time between the date a utility measures its cost of service and the date the Commission responds by authorizing increases or decreases in the utility's rates. Historically, regulatory lag has been detrimental to a utility's earnings and its ability to maintain its capital structure due to costs increasing faster than revenue. The adverse impact of regulatory lag on utility earnings may hamper a utility's ability to raise capital for infrastructure at desirable rates, which is detrimental to customers. Thus, the Commission may have an incentive to reduce regulatory lag, so neither the utility nor its customers are harmed.

The Commission itself has expressed some concern regarding the impact of regulatory lag on regulated utilities in Arizona. Recently, during the processing of the Arizona Public Service ("APS") GRC, then Chairman Hatch-Miller wrote a letter to APS, referencing a report published by S&P, which explained the advantages that public power utilities have over investor-owned utilities in terms of weathering significant increases in natural gas prices and purchased power costs, as well as preserving credit ratings and financial margins. He requested APS to "...provide testimony on what

[14] Case No. GR-2002-356.

measures the Commission could take in helping APS gradually improve its creditworthiness."[15] APS presented several proposals in its testimony[16], under the heading "Regulatory Lag and Attrition", in response to the Chairman's request. The heading highlights the fact that regulatory lag and attrition, and its impact on a utility's credit ratings, earnings, and capitalization are all interrelated.

Southwest faces financial challenges that are similar to those faced by APS, and believes that it could be very productive for the Commission, Arizona utilities, and other interested parties to work together to develop regulatory mechanisms to address these issues. In addition to the issues raised by S&P, Moody's noted in its recent "Industry Outlook" for North American Natural Gas Transmission and Distribution companies that: "Ratings may be negatively affected if new rates do not adequately address regulatory lag..."[17] Any measures the Commission adopts that help reduce the impact of regulatory lag may help Southwest improve its credit ratings and ability to raise capital.

f. Improve Return on Common Equity

Southwest is currently authorized a 9.5 percent return on common equity in Arizona. At the present time, the hypothetical common equity percentage and authorized return on common equity ("ROE") are lower than those authorized for Southwest by the CPUC, the PUCN, and FERC[18].

The AGA's Gas Utility Rate Case Database ("Database") shows that commission-authorized ROE percentages in 2005 and 2006 averaged 10.5 percent, and commission-authorized common equity ratios averaged 47.6 percent.[19] A survey conducted by ValueLine of the earned results of natural gas LDCs for the twelve months ended June 30, 2006 shows similar percentages.

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[15] ACC Chairman Hatch-Miller letter to APS, re: Arizona Public Service Company General Rate Case (Docket No. E-01345A-05-0816) dated July 21, 2006.

[16] Rebuttal testimony of APS witness Stephen Wheeler, pp 13-20.

[17] Moody's Industry Outlook, October 2006.

[18] The docket number and effective dates by jurisdiction are as follows: Arizona, Docket No. G-01551A-04-0876, March 31, 2006; Paiute, Docket No. RP05-163, August 1, 2005; Nevada, Docket No. 04-3011, September 1, 2004; and California: Docket No. 02-02-012, January 1, 2005 (authorized return on common equity updated per mechanism adopted by CPUC to 10.38%).

[19] AGA maintains a database of ROE and common equity percentages requested and authorized for natural gas utilities. For details, see Exhibit 4.

Table 2 shows the authorized common equity ratios and authorized returns on common equity authorized by each Commission that regulates the natural gas operations of Southwest, along with industry averages from AGA (authorized):

Table 2 - COMMON EQUITY PERCENTAGE AND RETURN ON COMMON EQUITY

	Southwest Authorized Percentages				Industry Averages
Description	Arizona	Nevada	California	FERC[20]	Authorized
Common Equity	40%	40%	42%	45%	47.6%
ROE	9.5%	10.5%	10.9%	11.8%	10.5%

Despite the progress Southwest has made in improving its earned rates of return, more progress needs to be made to approach the ROE and common equity ratios achieved by the peers with which it competes in the capital markets. This observation has been noted by the investment community: in a recent research summary for Southwest, S&P notes that "Ratings improvement hinges on achieving better rates of return and rate design improvements in Arizona..."[21] Future potential improvements in Southwest's authorized return on equity can be expected to be favorably received by the credit rating agencies and strengthen Southwest's ability to raise investment capital to fund Arizona infrastructure.

g. Timely Recovery of Purchased Gas Costs

While a large cumulative difference between the actual cost of gas and the cost of gas in Southwest's tariff does not impact the Company's earnings, it can have a significant impact on the Company's cash flows and its common equity ratio, to the extent that short-term under-recoveries are funded with short-term debt. This impact can be magnified during periods of rapidly increasing or decreasing gas prices.

Currently, Southwest's monthly gas cost can change by a maximum of thirteen cents per therm in any twelve-month period in Arizona. This thirteen-cent cap on the annual change in gas cost rates results in greater under-recovery of actual gas costs when market prices have quickly increased beyond the cap and, conversely, greater over-recovery of costs as market prices decrease rapidly below the cap. If the thirteen-cent cap is eliminated or significantly expanded to more closely mirror today's natural

[20] Authorized common equity and return on common equity percentages estimated by Southwest (based on stipulation).
[21] RatingsDirect, Publication date: September 15, 2006. S&P provides independent credit ratings, investment research, and other data for investors.

gas marketplace, large over- or under-recovered purchased gas cost balances are less likely to build up. Southwest believes that an expansion, or elimination, of the thirteen cent cap is warranted, and will look to propose such in future rate proceedings.

VI. CONCLUSION

Southwest's Recapitalization Plan outlines several potential rate and regulatory mechanisms that Southwest may propose in future regulatory filings that can help it achieve a common equity percentage that is more in line with its peers. If Southwest is able to continue to build on the substantial progress it has made in the last two years to improve earnings and increase its common equity ratio, the Company will be able to finance a higher percentage of its significant annual capital expenditures from internally-generated funds, reduce its net debt balances, and eventually improve its credit rating, all of which will benefit Southwest's customers in the long run by reducing the capital costs embedded in customers' rates.

Respectfully submitted,
SOUTHWEST GAS CORPORATION

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Southwest Gas Corporation
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702.876.7321

SOUTHWEST GAS CORPORATION
RATEMAKING CAPITAL STRUCTURE
AT AUGUST 31, 2004 AND AT DECEMBER 31, 2006
($000,000s)

Line No.	Description	August 31, 2004	December 31, 2006	Change	% New Capital	Line No.
	(a)	(b)	(c)	(d) (c) - (b)	(e) (d) / Ln 8(d)	
	Common Equity					
1	Common Stock, $1 par	$ 37	$ 43	$ 6		1
2	Capital Surplus	546	709	163		2
3	Capital Stock Expense	(9)	(11)	(1)		3
4	Retained Earnings	90	173	83		4
5	Total Common Equity[1]	$ 664	$ 915	$ 251	71%	5
6	Preferred Securities	100	100	-	0%	6
7	Long-Term Debt[2]	1,181	1,284	103	29%	7
8	Total Capital	$ 1,945	$ 2,299	$ 354	100%	8
	Capital Ratios					
9	Common Equity	34.1%	39.8%	5.7%		9
10	Preferred Securities	5.1%	4.3%	-0.8%		10
11	Long-Term Debt	60.7%	55.9%	-4.9%		11
12	Total	100.0%	100.0%			12
13	Shares Outstanding[3]	36	42	6		13
14	PGA Balance	$ 54	$ 77	$ 23		14
15	Short-Term Debt	27	-	(27)		15

[1] Does not include accumulated other comprehensive income(loss)
[2] Includes current maturities of long-term debt
[3] In millions

MOODY'S DNG SR UNSEC DEBT OF SOUTHWEST GAS CORPORATION TO Baa3
2006-05-30 16:48 (New York)

New York
John Diaz
Managing Director

Corporate Finance Group
Moody's Investors Service
JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

New York
Edward Tan
Vice President - Senior Analyst
Corporate Finance Group
Moody's Investors Service
JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

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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SWX US: S&P: Outlook On Southwest Gas Corp's Rating Revised
2007-03-14 10:52 (New York)

MCGRAW-HILL COS INC ("MHP-BHDNPX3")
SOUTHWEST GAS CORP ("SWX-BHDNPX3")
- S&P: Outlook On Southwest Gas Corp's Rating Revised To
- Positive On Strengthening Financial Measures

Standard & Poor's Ratings Services affirmed its 'BBB-' rating on Southwest Gas and revised the outlook to positive from stable due to consistently strong cash flow measures and declining debt leverage.

"Southwest Gas has made significant progress toward reducing its historically high debt leverage and will likely make further progress as a result of strong internal cash flows, minimal debt financing, and regular equity infusions," said Standard & Poor's credit analyst Leo Carrillo.

"Supportive rate treatment will continue to be an important consideration with respect to ratings improvement, particularly as the company's customer growth rate slows to a more moderate pace and declining customer usage effects possibly become more pronounced in the absence of decoupling or weather normalization mechanisms in Arizona and Nevada."

Las Vegas, Nev.-based Southwest Gas, the largest distributor of natural gas in Arizona and Nevada, provides service to such high growth cities as Phoenix, Las Vegas, and Tucson. At Dec. 30, 2006, the company had approximately $1.4 billion of debt.

Complete ratings information is available to subscribers of RatingsDirect, the real-time Web-based source for Standard & Poor's credit ratings, research, and risk analysis, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search.

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SOUTHWEST GAS CORPORATION
AMERICAN GAS ASSOCIATION UTILITY RATE CASE DATABASE
UTILITY DECISIONS IN UNITED STATES
2005 AND 2006

Decision Year	Utility	ROE Granted	CE % Granted
2006	Aquila, Inc. d/b/a Aquila Networks	Black Box	51.40%
2005	Wisconsin Public Service	12.05%	59.73%
2005	Superior Water, Light and Power Company	11.70%	
2005	Wisconsin Power & Light	11.50%	31.75%
2006	Wisconsin Energy	11.20%	
2006	Wisconsin Gas	11.20%	
2005	Semco	11.00%	
2005	Michigan Consolidated	11.00%	39.31%
2005	MGE - Gas Utility	11.00%	56.65%
2005	Baltimore Gas & Electric	11.00%	48.40%
2005	Xcel - Northern States Power	11.00%	53.63%
2005	Atlanta Gas Light	10.90%	
2005	Vectren Energy Delivery of Ohio	10.60%	51.90%
2006	Sierra Pacific Power	10.60%	40.76%
2006	Central Hudson Gas & Electric	10.60%	45.00%
2005	Northern Illinois Gas dba Nicor Gas	10.51%	56.37%
2005	Entergy Gulf States	10.50%	47.52%
2006	Xcel - Pub. Service CO	10.50%	55.49%
2005	Xcel Energy	10.40%	50.24%
2005	Interstate Power and Light Company	10.40%	49.35%
2005	Avista Utilities	10.40%	40.00%
2006	Atmos Energy Louisiana Gas	10.40%	48.00%
2005	Puget Sound Energy	10.30%	43.00%
2005	South Carolina Electric & Gas	10.25%	50.75%
2005	Union Light Heat & Power	10.20%	54.45%
2005	CenterPoint Minnegasco	10.18%	50.27%
2005	AmerenIP	10.00%	53.09%
2005	Bay State Gas	10.00%	53.95%
2005	Southern Connecticut Gas	10.00%	51.28%
2006	Roanoke Gas	10.00%	
2005	Oklahoma Natural Gas	9.90%	46.73%
2005	Arkansas Western Gas Company	9.70%	33.23%
2006	Southwest Gas	9.50%	40.00%
2005	Centerpoint Arkla	9.45%	31.80%
	Average Authorized Percentages	**10.54%**	**47.64%**

SOUTHWEST GAS CORPORATION
RATEMAKING CAPITAL STRUCTURE
AT AUGUST 31, 2004 AND AT APRIL 30, 2007
($000,000s)

Line No.	Description	August 31, 2004	April 30, 2007	Change	% New Capital	Line No.
	(a)	(b)	(c)	(d) (c) - (b)	(e) (d) / Ln 8(d)	
	Common Equity					
1	Common Stock, $1 par	$ 37	$ 44	$ 7		1
2	Capital Surplus	546	719	173		2
3	Capital Stock Expense	(9)	(11)	(1)		3
4	Retained Earnings	90	217	127		4
5	Total Common Equity[1]	$ 664	$ 970	$ 306	97%	5
6	Preferred Securities	100	100	-	0%	6
7	Long-Term Debt[2]	1,181	1,192	10	3%	7
8	Total Capital	$ 1,945	$ 2,262	$ 316	100%	8
	Capital					
9	Common Equity	34.1%	42.9%	8.7%		9
10	Preferred Securities	5.1%	4.4%	-0.7%		10
11	Long-Term Debt	60.7%	52.7%	-8.0%		11
12	Total	100.0%	100.0%			12
13	Shares Outstanding[3]	36	42	7		13
14	PGA Balance	$ 54	$ 43	$ (11)		14
15	Short-Term Debt	27	-	(27)		15

[1] Does not include accumulated other comprehensive income(loss)
[2] Includes current maturities of long-term debt
[3] In millions

SOUTHWEST GAS CORPORATION
AMERICAN GAS ASSOCIATION UTILITY RATE CASE DATABASE
UTILITY DECISIONS IN UNITED STATES
GRANTED COMMON EQUITY RATIOS FOR RATEMAKING
January 1, 2005 - March 31, 2007

Line No.	Company	State	Filing Date	Decision Date	Granted CE Ratio	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Puget Sound Energy	WA	2/15/06	1/5/07	44.13%	1
2	Wisconsin Power & Light	WI	3/17/06	1/11/07	54.00%	2
3	Wisconsin Public Service	WI	3/31/06	1/11/07	57.46%	3
4	PPL	PA	4/27/06	2/8/07	51.79%	4
5	Connecticut Natural Gas Corp	CT	9/29/06	3/14/07	53.60%	5
6	Pacific Gas & Electric	CA	12/2/05	3/15/07	52.00%	6
7	Delmarva Power & Light	DE	8/31/06	3/20/07	46.90%	7
8	Missouri Gas Energy	MO	5/1/06	3/22/07	36.06%	8
9	Atmos	TX	5/31/06	3/29/07	48.10%	9
10	Xcel - Pub. Service CO	CO	5/27/05	1/19/06	55.49%	10
11	Southwest Gas	AZ	12/9/04	2/15/06	40.00%	11
12	Aquila, Inc. d/b/a Aquila Networks	IA	5/2/05	3/1/06	51.40%	12
13	Sierra Pacific Power	NV	10/3/05	4/27/06	40.76%	13
14	Central Hudson Gas & Electric	NY	7/29/05	7/19/06	45.00%	14
15	Vermont Gas Systems	VT	3/10/06	8/10/06	55.00%	15
16	Kinder Morgan	WY	2/26/06	9/19/06	46.56%	16
17	Chesapeake Utilities Corp	MD	5/5/06	9/26/06	53.00%	17
18	National Fuel	NY	11/28/05	10/18/06	48.00%	18
19	Orange & Rockland	NY	11/28/05	10/18/06	48.00%	19
20	CentrerPoint Energy Minnegasco	MN	11/2/05	11/2/06	46.14%	20
21	Public Service Electric & Gas	NJ	9/30/05	11/9/06	47.40%	21
22	Consumers Energy	MI	7/1/05	11/21/06	35.06%	22
23	Chatanooga Gas	TN	6/30/06	12/5/06	44.80%	23
24	Puget Sound Energy	WA	4/5/04	2/18/05	43.00%	24
25	Vectren Energy Delivery of Ohio	OH	4/16/04	4/13/05	51.90%	25
26	AmerenIP	IL	6/25/04	5/17/05	53.09%	26
27	CenterPoint Minnegasco	MN	7/1/04	5/17/05	50.27%	27
28	Michigan Consolidated	MI	9/1/03	5/28/05	39.31%	28
29	Entergy Gulf States	LA	7/2/04	6/15/05	47.52%	29
30	Wisconsin Power & Light	WI	9/17/04	7/19/05	31.75%	30
31	Xcel Energy	MN	9/17/04	7/21/05	50.24%	31
32	Centerpoint Arkla	AR	11/24/04	9/19/05	31.80%	32
33	Northern Illinois Gas dba Nicor Gas	IL	11/4/04	9/28/05	56.37%	33
34	Oklahoma Natural Gas	OK	1/28/05	10/4/05	46.73%	34
35	Interstate Power and Light Company	IA	4/15/05	10/14/05	49.35%	35
36	South Carolina Electric & Gas	SC	4/26/05	10/14/05	50.75%	36
37	Arkansas Western Gas Company	AR	12/29/04	10/31/05	33.23%	37
38	Bay State Gas	MA	4/27/05	11/30/05	53.95%	38
39	MGE - Gas Utility	WI	4/19/05	12/12/05	56.65%	39
40	Wisconsin Public Service	WI	4/1/05	12/12/05	59.73%	40
41	Avista Utilities	WA	3/30/05	12/21/05	40.00%	41
42	Baltimore Gas & Electric	MD	4/29/05	12/21/05	48.40%	42
43	Union Light Heat & Power	KY	2/25/05	12/22/05	54.45%	43
44	Xcel - Northern States Power	WI	6/1/05	12/22/05	53.63%	44
45	Southern Connecticut Gas	CT	4/29/05	12/28/05	51.28%	45
46	Average Authorized Common Equity Ratio				47.87%	46

Source: AGA Ratecase Database - http:\www.aga.org

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Electric & Natural Gas Transmission Maps

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Energy Risk - Fresh Look at US Utility Regulation (RiskCenter.com - Feb. 2)

02 02, 2004 - PowerMarketers Industry Publications

Location: New York Author: Todd A Shipman, CFA Date: Monday, February 2, 2004

Standard & Poor's Ratings Services has been tracking the ups and downs of utility regulation for years, and in the past year or so has noted the recent upswing in the amount of attention that regulators and their activities are attracting.

With the renewed and increasing influence that regulators are asserting on the creditworthiness of utilities, especially as many managements scramble back under the protective umbrella of comprehensive regulation, Standard & Poor's offers this primer on how we analyze the effect of regulation on utility credit ratings. The entire range of regulatory actions and inactions is examined, but inevitably it is the analysis of rate case decisions that provides the key indicator of the level of support.

First, however, it is useful to remember the legal status of utility regulatory bodies when developing the basic analytical approach to their activities and decisions. Most utility commissions are, in a legal sense, "creatures of the legislature"; that is, the role they play is essentially legislative and not judicial. The responsibility for setting utility rates and for other various functions is actually that of legislators, but has been delegated to regulators for practical reasons. Thus, despite the trappings of a court (testimony, rules of evidence, administrative law "judges") and a long history of accumulated case law governing their activities, the decision-making process of utility commissioners more often resembles that of legislators, with its emphasis on compromise and political considerations, than that of jurists who weigh evidence, construe the law, follow legal precepts, and the like.

The implication for the analyst is that the behavior of regulators can more often be explained by looking to political factors than to analyzing legal precedents or assessing the arguments of opposing parties. That's why Standard & Poor's analysts spend considerable time meeting with regulators and staff members and accumulating knowledge about the local and regional political climate and its effect on a utility, in addition to analyzing the impact of a particular rate decision or other commission pronouncements. Nevertheless, rate cases, once

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thought to be obsolete as competition spread across the country, appear to be returning to the forefront again.

For major rate cases that can directly affect ratings, the analyst will follow the developments in a rate proceeding from the initial filing. The company's request for rate relief, the local public reaction to the filing, the rebuttals of important parties and intervenors, and the conduct of the hearings are all monitored, assessed, and commented upon, if necessary, as the case proceeds through its schedule. The ability of the commission to render a fair and balanced decision that appropriately considers the interests of all the participants in the process can sometimes be affected by incidents that occur while the case is developing. Standard & Poor's tracks whether the case is drawing a lot of attention, influential parties are staking out extreme positions, or outside events such as upcoming elections are affecting the chances of a rate decision that is consistent with the financial projections the ratings are based on.

Once a decision is reached, Standard & Poor's analyzes its effect on the financial forecast for the company, and also to assess whether the actions and precedents being set by the commission in its decision will have a long-term effect on Standard & Poor's opinion of the regulatory environment in that jurisdiction. The analysis of the rate case fundamentally explores a two-fold question: are the new rates based on a rate of return consistent with the company's ratings, and is the utility being afforded a legitimate opportunity to actually earn that rate of return?

On the former question, the analyst looks to equity returns being authorized for other utilities of the same credit quality, as well as the capital structure employed to arrive at the overall rate of return being used to set rates. On the latter, the test year and all of the adjustments made to the company's filed data are inspected to arrive at the final conclusion. Generally, decisions that feature the most up-to-date information in determining rates, including current test years and all "known-and-measurable" changes, are viewed as providing companies with the best chance to earn a reasonable and cash-rich return.

Importantly, credit analysis also incorporates the cash-flow effect of a decision, especially if it is the result of a full or partial settlement between the parties. A common method to achieve the compromise often sought by the parties or the regulators is to defer cost recovery into the future, which can preserve earnings but weaken cash flow. Standard & Poor's places much emphasis on cash flow protection measures when assessing credit quality, and a rate decision that ostensibly looks favorable for investors can sometimes come at the expense of bondholders. Attention to the details is crucial in analyzing a rate decision because some that appear to be favorable on the surface can hide the "bite" that regulators took in the less conspicuous parts of the case, such as a change in the depreciation rate.

Finally, one of the most important issues affecting ratings may or may not be part of the rate-case process, but is constantly tracked by Standard & Poor's: the recovery of fuel and

purchased-power and gas costs. The analysis concentrates on stability of cash flows and the relative certainty of full recovery of these items, the largest expenses for almost all utilities, in arriving at a consensus on the level of a utility's business risk.

The stability that leads to improved credit quality can be supported by legislators and regulators either through rate design or by carving out fuel and commodity expenses and treating them separately from the normal rate case process. Rate design is established as part of a rate-case decision, and can be used to promote stability by allocating a greater percentage of fixed costs for recovery through the standard monthly charge. The more common method is a separate clause in the tariff that fluctuates automatically or near-automatically as commodity costs rise and fall. The presence of a fuel and purchased-power or gas clause that helps a utility manage its exposure to commodity price moves is positive for credit ratings. Not all are created equal, however, and each mechanism is studied to determine how closely it allows for matching of customer rates with expenses.

Many other factors outside the scope of this commentary can play an important part in the overall assessment of the regulatory environment in which a utility operates. Incentive ratemaking, special rate riders to recover extraordinary costs (e.g., environmental compliance), deregulation developments, the degree to which regulation insulates a utility from its parent, legislative initiatives, and other non-ratemaking considerations can all affect Standard & Poor's opinion of the quality of regulation. The ability of management to control its regulatory risk and the historical attitude of regulators toward the interests of utility bondholders also enter into the analysis. In the end, the regulation of public utilities is the defining element of the industry and is often the determining factor in the ratings of a utility.

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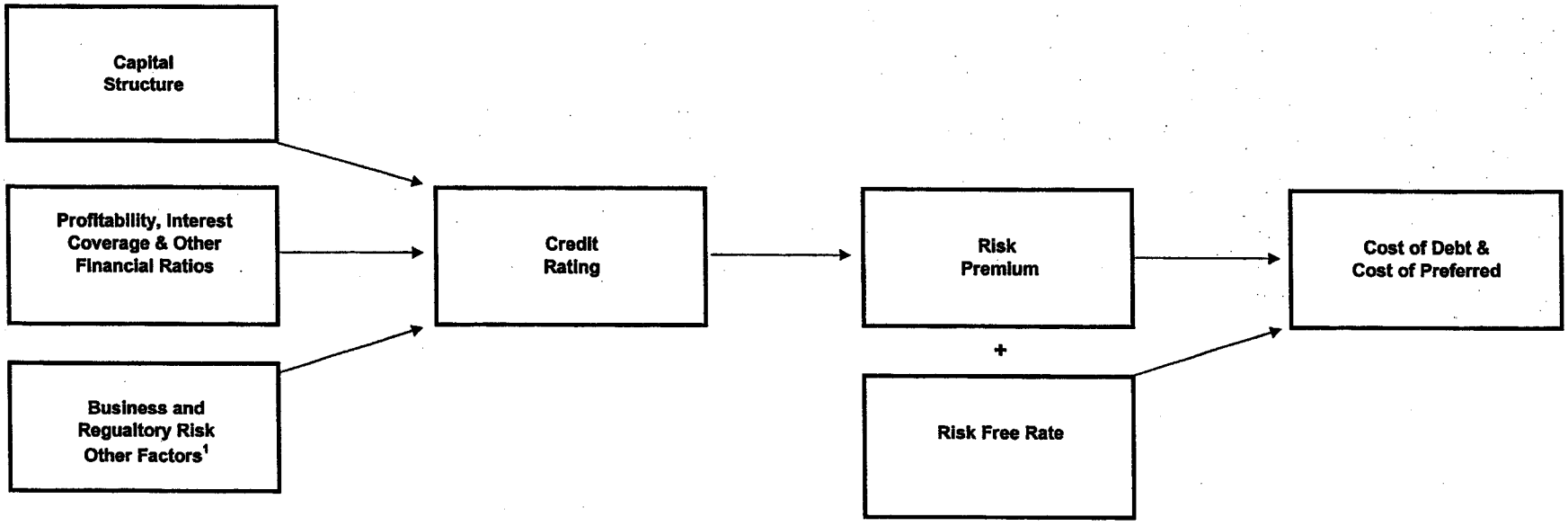
SOUTHWEST GAS CORPORATION

Relationship Between Capital Structure, Financial Ratios, Business and Regulatory Risks, Credit Rating and Cost of Debt & Preferred Equity



[1] Credit rating agencies also analyze other factors such as liquidity, management, legal structure, corporate governance, etc.

EXHIBIT NO.___(TKW-5)
SHEET 1 OF 1

Moody's Investors Service

Global Credit Research
Credit Opinion
21 JUN 2007

Credit Opinion: Southwest Gas Corporation

Southwest Gas Corporation

Las Vegas, Nevada, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured	Baa3
Preferred Shelf	(P)Ba2
Southwest Gas Capital II	
Outlook	Stable
Bkd Preferred Stock	Ba1
Southwest Gas Capital III	
Outlook	Stable
Bkd Preferred Shelf	(P)Ba1
Southwest Gas Capital IV	
Outlook	Stable
Bkd Preferred Shelf	(P)Ba1

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John Diaz/New York	

Key Indicators

[1]
Southwest Gas Corporation

	LTM 3/31/2007	12/31/2006	12/31/2005	12/31/2004	12/31/2003
Net Income to Average Common Equity	11.22%	10.40%	5.71%	8.17%	5.62%
EBIT/Customer Base	136.2	131.5	97.1	109.1	89.4
EBIT/Interest Expense	2.25x	2.13x	1.57x	1.78x	1.52x
Retained Cash Flow to Adjusted Debt	13.35%	13.82%	10.04%	13.55%	13.51%
Debt / Book Capitalization (Excluding Goodwill)	56.49%	58.54%	67.39%	65.07%	64.03%
Free Cash Flow/Funds From Operations	8.54%	-32.78%	-40.59%	-70.79%	-26.07%

[1] Ratios defined in "Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non- FinancialCorporations- Part I (US/Canadian GAAP, February 2006)"

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Southwest Gas Corporation (Southwest) was incorporated in March 1931 under the laws of the state of California. The company is composed of two business segments: purchasing, transporting and distributing natural gas in the southwest of the United States (the largest portion of its business which is regulated by individual state utility commissions) and Northern Pipeline Construction Co. (NPL), which is a wholly owned unregulated subsidiary engaged in underground piping providing utility companies with trenching and installation, replacement and maintenance services for energy distribution systems.

Southwest is the largest distributor of natural gas used primarily for space heating, in central and southern portions of Arizona including the rapidly-growing Phoenix and Tucson metropolitan areas. It is also the largest natural gas distributor and transporter in Nevada, serving the Las Vegas metropolitan area and northern Nevada. It also distributes and transports natural gas in portions of California, including the Lake Tahoe area and the high desert and mountain areas in San Bernardino County. As of March 2007, Southwest purchased, transported and distributed natural gas to nearly 1.8 million residential, commercial and industrial customers in these three states, where it is regulated by the Arizona Corporation Commission (ACC), the Public Utilities Commission of Nevada (PUCN) and the California Public Utilities Commission (CPUC). Certain accounting practices, transmission facilities and rates are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

Recent Developments

In October 2006, the CPUC granted a $2.7 million increase in operating margin which took effect January 2007. Southwest continues to receive an annual attrition allowance of $3 million which was approved in January 2005. In February 2006, the ACC granted the company $49.3 million of the total $66.9 million requested in a general rate case filed in December 2004 which took effect on March 1, 2006, but rejected requests to decouple revenues, continuing to expose the company to further variances in earnings related to warmer than normal weather or customer conservation efforts. Southwest plans to file another rate case late 2007 or early 2008 and continues to work with ACC staff to explore ways to address rate design. In March 2005, the company filed an application with the PUCN requesting approval of a weather normalization adjustment provision in advance of the company's next general rate case, however the commission recently declined to adopt this provision and deferred the issue to be considered in future rate case proceedings.

During 2007, Southwest plans to implement a stand-alone derivative financial instruments program for the first time, aiming to supplement the company's current volatility mitigation program of fixed-price contracts. The company expects that with natural gas price volatility projected to continue in the near future, proper hedging activities with stand-alone derivative financial instruments could help stabilize operating expenses allowing the company increased flexibility and increase supplier diversification.

Rating Rationale

Southwest Gas Company (Southwest, Moody's sr. uns. debt rating Baa3, stable outlook) is especially challenged as one of the fastest growing gas distribution companies in the country serving two of the most rapidly growing states of Arizona and Nevada in terms of population (at 4% per year, almost three times the national average). The company provides natural gas distribution service in Arizona (56% of operating margins), Nevada (35% of operating margins) and California (9% of operating margins). Moody's Investors Service downgraded the senior unsecured debt ratings of Southwest in May 2006 to Baa3 from Baa2 and concurrently changing the outlook for the ratings to stable from negative.

The year 2006 was the 2nd warmest year on record in the contiguous United States, with warmer than normal temperatures in Southwest's service territory. Though slightly cooler than the previous year (2005 was one of the warmest years on record in its service territory) the company's financial condition continues to be pressured by the warmer temperatures. Given the rate design currently in place in Arizona and Nevada, the company's earnings are directly linked to the volume of natural gas that is consumed by its customers and people tend to burn less gas for heating when weather is warmer than normal. Unlike the California regulatory framework where it obtains 9% of its operating margins, Southwest's attempts at revenue decoupling have not been successful in the key states of Arizona and Nevada, where the public utility commissions have advised the company to undertake further public consultations and hearings with stakeholders before the key rate design factors of weather normalization or gas conservation margin protection could be implemented.

Southwest anticipates continuing its high level of construction capital expenditures with approximately $880 million from 2007 to 2009, of which $337 million is expected during 2007. For several years the company's capital expenditures have exceeded the level of cash flow from operations after dividend payments (retained cash flow), necessitating funding from outside sources. The company plans to fund approximately 90% of the construction expenditures with retained cash flow and expects to raise another $100-$125 million in equity through various common stock programs. Additional funding is expected to be provided by credit facilities and/or other external financing programs. Even with an organic customer growth averaging 4-5% in recent years, the construction expenditures and increased operating expenses associated with creating and maintaining the infrastructure required to support the customer growth has outpaced the revenue growth from customer additions. Regulatory lag has for several years delayed the recovery of these costs, resulting in suppressed earnings. Even with the most recent rate case decision in Arizona that resulted in a $49.3 million rate increase, it failed to address the company's predicted rapid pace of growth. Southwest will continue to be challenged to recover costs as regulatory filings typically take a year to resolve in its largest service jurisdiction. Due to the regulatory lag and gaps in the company's rate design in Arizona and Nevada, this has placed Southwest among the lowest rated investment grade gas utility companies.

Drivers of Rating Change

Factor 1: Sustainable Profitability

a) ROE - ROE was 10.4% for fiscal year ending 2006, a significant improvement versus the 5.7% for fiscal year

2005. The 10.4% ROE is above average when compared with the Baa-rated LDC peers. The higher ROE year over year is primarily due to the impact of changes in the base rate in Arizona and California and the company's focus on operating efficiency and productivity. By not increasing the size of its workforce and by adopting technology (electronic order routing, an electronic meter reading and a work management system) the company has managed to significantly reduce operating costs per customer. Southwest's Baa peers average 9.5% in ROE.

b) EBIT/Customer Base - For fiscal year 2006, the company scores $131.50 which is in line with the Baa-rated gas peer group for the EBIT/customer base ratio. This is a marked improvement over the previous years and is a result of the improved operating efficiencies. Southwest's Baa peers average $110.9 in EBIT/customer base.

Factor 2: Regulation - Southwest has an overall weak score on regulatory support, as its requests for improving rate design have not been achieved in Arizona or Nevada, although discussions with interested parties continue post-rate case decisions.

Factor 3: Ring Fencing - Southwest scores high for ring-fencing, as its operations are overwhelmingly regulated and there is little danger of non-regulated operations diverting utility resources toward risky businesses. The parent company is the utility and is subject to regulation by the Arizona Corporation Commission, the Public Utilities Commission of Nevada, and the California Public Utilities Commission.

Factor 4: Financial Strength and Flexibility

a) EBIT/Interest Expense - EBIT/Interest was 2.13 times for fiscal year 2006 versus 1.57 times for fiscal year 2005. The 2.13 times is in line with the Baa-rated LDC gas peers. The higher EBIT/Interest expense is due primarily to the increase in earnings. Southwest's Baa peers average is 2.75 times.

b) Retained Cash Flow/Debt - Retained Cash Flow/Debt was 13.8% for fiscal year 2006 versus 10.0% for fiscal year 2005. The 13.8% is in line with Baa-rated LDC gas peers. The Baa average is 14.9%

c) Debt to Book Capitalization (excluding goodwill) - This ratio was 58.5% for fiscal year 2006 versus the 67.4% from the previous year. The 58.5% is in line with the Baa-rated LDC gas peers. The improvements reflect the issuance of approximately 947,000 shares through the company's equity shelf program. Southwest's Baa peers average 60.9%.

d) Free Cash Flow/Funds From Operations - This ratio was (32.8%) for fiscal year 2006 versus (40.6%) for fiscal year 2005. The (32.8%) is in line for Baa-rated LDC gas companies. This measure has historically been volatile form year to year due to changes in working capital. Southwest's Baa peer average is (5.5%).

Rating Outlook

Southwest's rating outlook is stable reflecting the gradual and steady improvement in many of credit measures mentioned above. The stable outlook assumes that Southwest will continue to pursue changes to improve rate design and cost control measures.

What Could Change the Rating - Down

Continuing high leverage, continuing earnings volatility on account of weather variations, eroding margins from declining customer consumption related to gas conservation and continuing lags in recovery of capital investment costs or increases in operating expenses that erode the company's profitability could all be causes for a possible downgrade.

What Could Change the Rating - Up

Ratings could improve should the company demonstrate a significant improvement in its rate-making design and tempering capital expenditures with cash flow available from internal operations that translate into a stronger and sustainable financial profile accompanied by significantly reducing growth in operating expenses.

Rating Factors

Southwest Gas Corporation

Local Gas Distribution	Aaa	Aa	A	Baa	Ba	B	Caa
Factor 1: Sustainable Profitability (20%)							
a) Return on Equity (15%)				8.1%			
b) EBIT to Customer Base (5%)				$112.6			

Factor 2: Regulatory Support (10%)							
a) Regulatory Support and Relationship					X		
Factor 3: Ring Fencing (10%)							
a) Ring Fencing	X						
Factor 4: Financial Strength and Flexibility (60%)							
a) EBIT/Interest (15%)					1.8		
b) Retained Cash Flow/Debt (15%)				12.5%			
c) Debt to Book Capitalization (excluding goodwill) (15%)				63.7%			
d) Free Cash Flow/Funds from Operations (15%)					-48.1%		
Rating:							
a) Methodology Model Implied Senior Unsecured Rating	**Baa2**						
b) Actual Senior Unsecured Equivalent Rating	**Baa3**						

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Southwest Gas Corp.

Major Rating Factors

Corporate Credit Rating
BBB-/Positive/--

Strengths:

- Low risk natural gas distribution business;
- A favorable customer mix and high growth service territories in Nevada and Arizona, although customer growth rates have begun to moderate;
- Purchased gas adjustment (PGA) cost recovery mechanisms in all three states in which the company operates;
- Strong cash flow measures, with funds from operations (FFO)/debt of 17% for the 12-month period ended Dec. 31, 2006; and
- Declining debt leverage due to strong internal cash flows, minimal debt financing and regular equity infusions.

Weaknesses:

- Dependence on future rate relief;
- Exposure to customer conservation and weather-related sales variation in Arizona and Nevada;
- Low customer usage and a lengthy payback period on capital investment;
- Elevated projected capital expenditures of about $290 million per year;
- Moderate exposure to the effects of natural gas price volatility on PGA receivable balances and potential liquidity requirements; and
- Long-term capital or contracting requirements with regards to natural gas storage capability for the company's Arizona and Southern Nevada service areas.

Rationale

The ratings on Southwest Gas Corp. are based on its strong business position as a regulated local gas distribution company serving the high-growth service territories in Arizona, Nevada, and, to a lesser extent, California. The ratings also reflect improving operating efficiency and an intermediate financial risk profile. These factors are partially offset by low customer usage due to its geographic location, challenges associated with improving regulatory treatment in certain jurisdictions, and a moderately sized unregulated utility construction and maintenance business.

Las Vegas, Nev.-based Southwest Gas, which has about $1.4 billion of debt, has two business segments: natural gas operations and construction services. Southwest Gas, the largest distributor of natural gas in Arizona and Nevada, serves the cities of Phoenix, Las Vegas, and Tucson. About 10%-15% of operating income is derived from the construction services business, Northern Pipeline Construction Co. (NPL), which has performed adequately over the past few years. Standard & Poor's Ratings Services expects this unregulated operation to account for a relatively stable share of company sales and operating income over the foreseeable future.

The company provides natural gas to more than 1.7 million customers in Arizona (54% of customers), Nevada (36%), and California (10%). Residential and small commercial customers account for nearly all of retail consumption and around 85% of the company's total operating margin. Retail sales are sensitive to weather, which

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has been a particular challenge for Southwest Gas given the gradual warming trend observed in its region. For example, winter season heating degree days in Phoenix have declined by a compounded annual rate of about 2.5% from 1997 to 2006. Other factors, such as higher energy efficiency new construction and customer conservation, have contributed to declining consumption per customer (estimated to be around 1% per year from 2001 to 2006), which poses a challenge to the company with respect to fixed cost recovery.

Strong customer growth, averaging 5% annually from 2001 to 2006, has helped to offset the effects of declining per capita consumption, keeping retail gas deliveries essentially constant from 2001 to 2006. Nevada and Arizona have accounted for most of the increase, exhibiting growth rates of 6% and 4%, respectively. Customer growth has also driven capital requirements, which increased by about 5.4% annually over the same period. The company projects capital spending will remain relatively steady at about $290 million per year over the 2007-2009 period.

Southwest Gas depends on regulatory approval of retail rates to cover the cost requirements associated with rapid growth, high natural gas price volatility, and exposure to weather variation. All three of the state regulatory commissions that oversee Southwest's retail rates have allowed the company to recover its actual purchased gas costs through a purchased gas adjustment mechanism (PGA). In 2006, the Nevada commission approved that the company's gas-cost adjust on a quarterly basis.

The company has mitigated its exposure to gas price volatility through risk management practices designed in consultation with its regulators and under which prices for about one-half of the company's normal weather supply needs were hedged well in advance of the winter heating season. Prices for the remainder of its natural gas requirements are set under variable price contracts and on the spot market.

Both the Nevada and Arizona commissions have responded to appeals for targeted rate action to address occasionally large gas cost receivable balances and the liquidity and regulatory lag pressures they create. In October 2005, the PUC issued an order approving a $78 million annual rate increase in Nevada to recover the PGA under-collections as well as expected gas costs. Arizona's commission implemented a temporary PGA surcharge in Arizona, effective February 2006, that helped reduce the company's PGA balance receivables to $77 million as of Dec. 31, 2006, down from $120 million in March 2006.

Despite the company's recent requests, both the Arizona and Nevada utility commissions have declined to adopt weather normalization or decoupling mechanisms that would insulate company earnings from weather or conservation-related sales variation. The Public Utility Commission (PUC) of Nevada has signaled its willingness to consider a weather normalization adjustment mechanism, as recommended by the commission's staff in July 2006, but only as part of the company's next general rate case, the timing of which remains uncertain. Although the ACC did not approve the company's request for a conservation tracker in 2006, it did authorize an increase in the residential customer charge of $1.70 per month.

In February 2006, the Arizona Corporation Commission (ACC) authorized a $49.3 million rate increase that improved company cash flows but provided for only a 9.5% allowed return on equity, albeit on a hypothetical 40% equity layer that exceeded an actual equity ratio of about 35% applicable to the Arizona portion of the company's utility system.

Financial performance measurably improved in the second and third quarters of 2006 as a result of regulatory relief and customer growth. Capital outlays remain high, although the company funded about 66% of capital outlays with internal cash flow after dividends in fiscal 2006.

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Credit measures remain adequate for the rating, with adjusted funds from operations (FFO) to total debt of about 17% and adjusted FFO interest coverage of about 3.5x for the 12-month period ended Dec. 31, 2006. Meanwhile, debt leverage has decreased, with adjusted debt to capital at 63% in Dec. 31, 2006, down substantially from 69% in 2005.

Liquidity

The company's liquidity is sufficient, with a $300 million credit facility that expires in April 2011. As of Dec. 31, 2006, the company had available the entire $150 million facility capacity it designates for working-capital purposes and, in addition, the company had about $18.7 million cash. Natural gas purchases and capital outlays to service growth in its territory are the primary draws on liquidity. Natural gas sales are seasonal with usage peaks in the winter months. The combination of elevated natural gas prices and weather patterns will be the major determinant of liquidity needs in the near term.

Operating cash flows for the past 12 months had been negatively affected by rising natural gas prices, as under-collected PGA balances were about $77 million as of Dec. 31, 2006. The company uses short-term borrowings, in part, to temporarily finance under-collected balances.

With continued healthy customer growth, capital outlays will remain substantial and will require external financing. Capital expenditures in 2007-2009 are expected to be around $880 million. Southwest also has $42.5 million in long-term debt maturities over the three-year period. The company expects to raise $100 million-$115 million from external sources, including the issuance of common stock through the company's common equity shelf program.

Outlook

The positive outlook reflects our expectation of consistently strong cash flow measures and declining debt leverage, primarily as a result of anticipated high levels of internal funding of capital expenditures, minimal new debt financing, and regular annual equity infusions under the company's common equity shelf program. Significant rate design improvements in Arizona and Nevada could further engender ratings improvement.

The outlook assumes adequate rate relief and healthy retail demand despite moderating customer growth rates and observed declines in customer consumption. The outlook also assumes that the company will manage its liquidity resources to ensure adequacy under adverse market and credit scenarios.

The outlook could return to stable if financial performance expectations are not met, particularly if a result of unfavorable regulatory actions, a significant increase in capital requirements, or more aggressive reliance on debt financing. Continued declines in customer usage without adequate regulatory protections or sustained increases in PGA receivables could also limit potential ratings improvement.

Accounting

Southwest Gas' financial statements are prepared in accordance with U.S. GAAP and are audited by PricewaterhouseCoopers, LLP. The financial statements include the accounts of Southwest Gas Corporation and all subsidiaries, except for Southwest Gas Capital II, a financing trust created for the express purpose of issuing trust preferred securities for the benefit of the company. All significant inter-company balances and transactions have been eliminated with the exception of transactions between Southwest Gas and NPL in accordance with SFAS 71

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(Accounting for the Effects of Certain Types of Regulation).

SFAS No. 71 also allows for the deferral as regulatory assets, costs, that otherwise would be expensed if it is probable future recovery from customers will occur. The company has a net regulatory asset of $142 million, of which $77 million is attributable to deferred gas costs and $101 million is for accrued pension and other postretirement benefit costs.

When calculating credit measures, Standard & Poor's considers off-balance-sheet (OBS) obligations, such as operating leases, to be fixed commitments, and imputes debt and interest components, including these amounts in adjusted financial ratios. After accounting for operating leases, Southwest's debt and interest expense increase by about $23.5 million and $1.7 million, respectively. FFO is increased by $3.7 million of imputed depreciation on operating leases.

We also adjust reported financial results for pension and postretirement obligations (on a tax-adjusted basis). For Southwest Gas, this increases adjusted debt by $100.8 million for the unfunded projected benefit obligations and increases FFO by $7.1 million. Southwest Gas' aggregate pension funding ratio is about 73% (Standard & Poor's defines this ratio as the fair value of the plan assets relative to the plan's projected benefit obligation).

Table 1

Southwest Gas Corp.--Peer Comparison*

Industry Sector: REGULATED T&D

	--Average of past three fiscal years--		
	Southwest Gas Corp.	**Atmos Energy Corp.**	**Cascade Natural Gas Corp.**
Rating as of March 13, 2007	BBB-/Stable/--	BBB/Stable/A-2	BBB+/Stable/--
(Mil. $)			
Total revenues	1,738.7	4,681.9	366.9
Net income from continuing operations	61.5	123.2	11.7
Funds from operations (FFO)	243.3	347.8	33.5
Capital expenditures	313.0	354.3	29.5
Cash and investments	20.7	117.8	3.4
Debt	1,533.1	2,059.1	187.3
Preferred stock	0.0	122.3	0.0
Common equity	744.2	1,492.3	119.4
Total capital	2,277.3	3,673.7	306.7
Adjusted ratios			
EBIT interest coverage (x)	2.0	2.7	2.6
FFO interest coverage (x)	3.5	3.7	3.7
FFO/debt (%)	15.9	16.9	17.9
Discretionary cash flow/debt (%)	(7.44)	(5.68)	(1.53)
Net cash flow/Capex (%)	67.8	72.9	76.6
Debt/total capital (%)	67.3	56.0	61.1
Return on common equity (%)	7.9	9.1	9.7
Common dividend payout ratio - unadjusted (%)	50.7	72.5	93.1

*Fully adjusted (including post-retirement obligations). N.M. - Not meaningful.

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Table 2

Southwest Gas Corp. -- Financial Summary*

Industry Sector: REGULATED T&D

	--Fiscal year ended Dec. 31--				
	2006	**2005**	**2004**	**2003**	**2002**
Rating history	BBB-/Stable/--	BBB-/Stable/--	BBB-/Stable/--	BBB-/Stable/--	BBB-/Negative/--
($ Mil. As Reported)					
Total revenues	2,024.8	1,714.3	1,477.1	1,231.0	1,320.9
Net income from continuing operations	83.9	43.8	56.8	38.5	44.0
Funds from operations (FFO)	259.3	219.3	251.2	226.0	185.4
Capital expenditures	343.0	294.1	301.9	239.8	286.8
Cash and investments	18.8	29.6	13.6	17.2	19.4
Debt	1,538.1	1,557.3	1,503.9	1,375.1	1,254.7
Preferred stock	0.0	0.0	0.0	0.0	60.0
Common equity	901.4	696.4	634.6	569.3	534.0
Total capital	2,439.6	2,253.7	2,138.5	1,944.4	1,848.7
Adjusted ratios					
EBIT interest coverage (x)	2.3	1.7	1.9	1.6	1.7
FFO int. cov. (x)	3.5	3.2	3.7	3.6	3.0
FFO/debt (%)	16.9	14.1	16.7	16.4	14.8
Discretionary cash flow/debt (%)	(5.66)	(5.27)	(11.50)	(3.86)	(0.87)
Net Cash Flow / Capex (%)	65.8	63.9	73.7	82.7	55.2
Debt/total capital (%)	63.0	69.1	70.3	70.7	67.9
Return on common equity (%)	9.6	5.6	8.4	5.9	7.1
Common dividend payout ratio (un-adj.) (%)	39.9	71.3	50.8	71.9	61.4

*Fully adjusted (including post-retirement obligations).

Ratings Detail (As Of March 16, 2007)*

Southwest Gas Corp.	
Corporate Credit Rating	BBB-/Positive/--
Preferred Stock	
Local Currency	BB
Senior Unsecured	
Local Currency	BBB-
Corporate Credit Ratings History	
13-Mar-2007	BBB-/Positive/--
11-Aug-2003	BBB-/Stable/--
01-Feb-2001	BBB-/Negative/--
Business Risk Profile	1 2 **[3]** 4 5 6 7 8 9 10
Financial Risk Profile	Intermediate

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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Global Power/North America
Credit Update

Southwest Gas Corporation

Ratings

Security Class	Current Rating	Previous Rating	Date Changed
IDR	BBB	NR	12/6/05
Unsecured Debt	BBB	NR	8/5/96
Commercial Paper	F2	NR	10/22/02
Southwest Gas Capital II			
Trust Preferred	BBB–	NR	8/20/03

IDR – Issuer default rating. NR – Not rated.

Rating Watch..... None
Rating Outlook..... Stable

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Profile

SWX is a gas distribution company serving more than 1.7 million customers in portions of Nevada, Arizona and California. Cities served include high-growth Las Vegas, Phoenix and Tucson, Ariz. Other investments include Paiute Pipeline, an intrastate gas pipeline in northern Nevada, and Northern Pipeline Construction Co.

Related Research

- Press Release, Jan. 17, 2007.

Key Credit Strengths

- Positive demographics and customer mix.
- Favorable regulatory track record.
- Credit measures are expected to be stable.

Key Credit Concerns

- Regulatory lag.
- Relatively high levels of growth capital spending.

■ Rating Rationale

Southwest Gas Corporation's (SWX) ratings reflect the operating, regulatory and financial characteristics associated with its dynamic service territory. Increasing operating and capital costs associated with a high growth rate requires periodic rate relief and results in moderate regulatory lag. However, on-balance regulation has been reasonably responsive. In addition to seeking general rate increases, recent efforts have been made to request rate design changes to separate the recovery of fixed operating costs from the volume of gas sold through increased basic service charges, increased differences in block rates, weather normalization and margin trackers.

SWX's affirmed ratings recognize the relatively supportive regulatory environment and strong growth within SWX's service territory. SWX continues to profitably grow its operations, and while the company has experienced some regulatory lag, increased operating costs and increased debt, these factors are neither surprising given the amount of growth SWX has experienced, nor overly worrisome. SWX has been able to pursue rate relief with moderate success.

Fitch expects SWX's credit metrics to remain stable over the course of the next few years, with slight improvements to debt leverage and coverage ratios. EBITDA-to-interest coverage should average approximately 4.0 times (x), and debt-to-EBITDA should average 4.0x or below. In addition, the company's debt-to-total capital is expected to decrease.

SWX's financial ratios can be affected by recovery cost lag associated with gas supply acquisition. Gas costs that are incurred in excess of amounts embedded in customer rates are generally deferred and recovered under purchase gas adjustment (PGA) mechanisms. Timeliness of allowed PGA filings and in recoveries varies by state, and full recovery could extend beyond one year. The company typically uses its bank lines for borrowings to fund gas purchases. In periods of under-recovery, there may be some near-term negative effect on coverage ratios and capital structure. SWX is allowed monthly PGA adjustments in California and Arizona. While in Nevada, SWX moved to a quarterly PGA from an annual filing at the start of 2006, which contributed to more timely recovery. At Sept. 30, 2006, SWX had total outstanding PGA balances receivable of $63.7 million. It is likely that this balance will be paid down during the first half of 2007.

■ Recent Developments

SWX received a general rate decision from the Arizona Corporation Commission (ACC) in February 2006, which allowed an increase of rates in Arizona by $49.3 million annually, effective March 1, 2006.

The decision did not include the requested rate design changes or a conservation tracker. The ACC did not rule out a future rate design change, and ACC staff and other interested parties are currently working with SWX to try to come to a mutually acceptable plan. .

In September 2006, SWX issued $56 million in 4.75% industrial development revenue bonds due in 2036 to expand and upgrade facilities in Clark County, Nev.

In August 2006, SWX retired $75 million of 7.5% debentures.

■ Liquidity and Debt Structure

In April 2006, the company amended its $300 million credit facility, extending its expiration to April 2011 from April 2010. Of the $300 million, $150 million is designated as long-term debt and $150 million is for short-term working capital purposes. As of Sept. 30, 2006, the short-term portion of SWX's credit facility had zero outstanding borrowings. In addition, SWX had cash balances of approximately $50 million.

SWX's capital expenditure program over the course of the next two years is expected to be 90% financed with internally generated cash flow, with the remainder financed through equity. Total debt-to-capitalization was at 63% as of Sept. 30, 2006, down from 65.6% at Dec. 31, 2005. This is expected to decrease over the course of the next few years. During the first nine months of 2006, the company issued $28 million of equity under its equity shelf program. In total, SWX plans on issuing between $75 million–$100 million in common stock during the next two years through its company benefits program and equity shelf program.

Southwest Gas Capital Trust II has $100 million outstanding trust preferred securities due 2043 (hybrids). Under Fitch's criteria for hybrid securities, the hybrids qualify for 75% equity credit.

Rating Outlook Rationale

The current Stable Rating Outlook reflects the effectiveness of SWX's proactive regulatory approach.

What Could Lead to Positive Rating Action?

- Material debt reduction.

What Could Lead to Negative Rating Action?

- Unresponsive regulation.

FitchRatings
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Corporate Finance

Financial Summary — Southwest Gas Corporation

($ Mil., Fiscal Years Ended Dec. 31)

	LTM				
	9/30/06	9/30/05	2005	2004	2003
Fundamental Ratios (x)					
Funds from Operations/Interest Expense	3.5	3.5	3.3	3.8	3.6
Cash from Operations/Interest Expense	3.7	3.7	3.6	2.7	3.4
Debt/Funds from Operations	5.6	5.3	6.5	5.4	5.5
Operating EBIT/Interest Expense	2.0	1.9	1.6	1.9	1.6
Operating EBITDA/Interest Expense	3.7	3.6	3.4	3.6	3.2
Debt/Operating EBITDA	3.8	3.7	4.4	4.2	4.4
Common Dividend Payout (%)	48.6	55.8	71.3	50.8	71.9
Internal Cash/Capital Expenditures (%)	69.0	69.6	70.1	40.5	74.8
Capital Expenditures/Depreciation (%)	198.9	200.3	188.4	207.3	176.4
Profitability					
Revenues	1,957	1,678	1,714	1,477	1,231
Net Revenues	967	873	886	831	749
O&M Expense	582	521	540	478	441
Operating EBITDA	351	323	307	316	272
Depreciation and Amortization Expense	165	154	156	146	136
Operating EBIT	186	169	151	170	135
Interest Expense	95	90	91	87	85
Net Income for Common	67	54	44	57	39
O&M % of Net Revenues	60.1	59.7	61.0	57.5	58.9
Operating EBIT % of Net Revenues	19.2	19.4	17.0	20.4	18.1
Cash Flow					
Cash Flow from Operations	259	244	238	151	208
Change in Working Capital	23	15	30	(90)	(10)
Funds from Operations	237	229	208	242	218
Dividends	(33)	(30)	(31)	(29)	(28)
Capital Expenditures	(328)	(308)	(294)	(303)	(241)
Free Cash Flow	(102)	(94)	(88)	(180)	(61)
Net Other Investment Cash Flow	15	(0)	2	6	(18)
Net Change in Debt	33	23	38	112	55
Net Change in Equity	68	78	64	59	21
Capital Structure					
Short-Term Debt	27	29	107	130	58
Long-Term Debt	1,291	1,174	1,250	1,188	1,146
Total Debt	1,318	1,203	1,357	1,318	1,205
Preferred and Minority Equity	75	75	75	75	75
Common Equity	823	751	751	706	630
Total Capital	2,217	2,030	2,183	2,098	1,910
Total Debt/Total Capital (%)	59.5	59.3	62.2	62.8	63.1
Preferred and Minority Equity/Total Capital (%)	3.4	3.7	3.4	3.6	3.9
Common Equity/Total Capital (%)	37.1	37.0	34.4	33.6	33.0

LTM – Latest 12 months. Operating EBIT – Operating income before nonrecurring items. Operating EBITDA – Operating income before nonrecurring items plus depreciation and amortization expense. O&M – Operations and maintenance. Source: Financial data obtained from SNL Energy Information System, provided under license by SNL Financial, LC of Charlottesville, Va.

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SOUTHWEST GAS CORPORATION
AMERICAN GAS ASSOCIATION UTILITY RATE CASE DATABASE
UTILITY DECISIONS IN UNITED STATES
REGULATORY REVIEW PERIOD
January 1, 2005 - March 31, 2007

Line No.	Company	State	Filing Date	Decision Date	Review Days	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Wisconsin Energy	WI	6/1/05	1/11/06	224	1
2	Wisconsin Gas	WI	6/1/05	1/11/06	224	2
3	Xcel - Pub. Service CO	CO	5/27/05	1/19/06	237	3
4	Southwest Gas	AZ	12/9/04	2/15/06	433	4
5	Aquila, Inc. d/b/a Aquila Networks	IA	5/2/05	3/1/06	303	5
6	Roanoke Gas	VA	9/15/05	4/6/06	203	6
7	Sierra Pacific Power	NV	10/3/05	4/27/06	206	7
8	Central Hudson Gas & Electric	NY	7/29/05	7/19/06	355	8
9	Virginia Natural Gas	VA	7/1/05	7/24/06	388	9
10	Vermont Gas Systems	VT	3/10/06	8/10/06	153	10
11	Kinder Morgan	WY	2/26/06	9/19/06	205	11
12	Chesapeake Utilities Corp	MD	5/5/06	9/26/06	144	12
13	South Carolina Electric and Gas	SC	6/15/06	9/27/06	104	13
14	National Fuel	NY	11/28/05	10/18/06	324	14
15	Orange & Rockland	NY	11/28/05	10/18/06	324	15
16	Citizens Gas & Coke	IN	12/29/04	10/19/06	659	16
17	Public Service Co. of North Carolina	NC	4/3/06	10/23/06	203	17
18	CentrerPoint Energy Minnegasco	MN	11/2/05	11/2/06	365	18
19	Public Service Electric & Gas	NJ	9/30/05	11/9/06	405	19
20	Kansas Gas Service	KS	5/15/06	11/16/06	185	20
21	Consumers Energy	MI	7/1/05	11/21/06	508	21
22	National Fuel	PA	5/31/06	11/30/06	183	22
23	PG Energy	PA	4/12/06	11/30/06	232	23
24	Chatanooga Gas	TN	6/30/06	12/5/06	158	24
25	Columbia Gas	VA	5/1/06	12/26/06	239	25
26	Kinder Morgan	NE	6/2/06	12/27/06	208	26
27	Puget Sound Energy	WA	4/5/04	2/18/05	319	27
28	Atlanta Gas Light	GA	9/15/04	3/23/05	189	28
29	Semco	MI	12/1/04	3/29/05	118	29
30	Vectren Energy Delivery of Ohio	OH	4/16/04	4/13/05	362	30
31	Aquila	KS	11/1/04	5/2/05	182	31
32	AmerenIP	IL	6/25/04	5/17/05	326	32
33	CenterPoint Minnegasco	MN	7/1/04	5/17/05	320	33
34	Superior Water, Light and Power Company	WI	6/3/04	5/17/05	348	34
35	Michigan Consolidated	MI	9/1/03	5/28/05	635	35
36	Atlanta Gas Light	GA	10/15/04	6/10/05	238	36
37	Entergy Gulf States	LA	7/2/04	6/15/05	348	37
38	Wisconsin Power & Light	WI	9/17/04	7/19/05	305	38
39	National Fuel Gas	NY	8/27/04	7/20/05	327	39
40	Xcel Energy	MN	9/17/04	7/21/05	307	40
41	Centra Gas Manitoba Inc.	MB	1/10/05	7/27/05	198	41
42	Mountaineer Gas	WV	9/27/04	8/24/05	331	42
43	Centerpoint Arkla	AR	11/24/04	9/19/05	299	43
44	Northern Illinois Gas dba Nicor Gas	IL	11/4/04	9/28/05	328	44
45	Laclede Gas Company	MO	2/18/05	9/30/05	224	45
46	Oklahoma Natural Gas	OK	1/28/05	10/4/05	249	46
47	Interstate Power and Light Company	IA	4/15/05	10/14/05	182	47
48	South Carolina Electric & Gas	SC	4/26/05	10/14/05	171	48
49	Piedmont Natural Gas	NC	4/1/05	10/19/05	201	49
50	Dominion Hope Gas	WV	3/7/05	10/21/05	228	50
51	Arkansas Western Gas Company	AR	12/29/04	10/31/05	306	51
52	Bay State Gas	MA	4/27/05	11/30/05	217	52
53	MGE - Gas Utility	WI	4/19/05	12/12/05	237	53
54	Wisconsin Public Service	WI	4/1/05	12/12/05	255	54
55	Avista Utilities	WA	3/30/05	12/21/05	266	55
56	Baltimore Gas & Electric	MD	4/29/05	12/21/05	236	56
57	Union Light Heat & Power	KY	2/25/05	12/22/05	300	57
58	Xcel - Northern States Power	WI	6/1/05	12/22/05	204	58
59	Southern Connecticut Gas	CT	4/29/05	12/28/05	243	59
60	Puget Sound Energy	WA	2/15/06	1/5/07	324	60
61	SEMCO Energy Gas Company	MI	5/25/06	1/9/07	229	61
62	Wisconsin Power & Light	WI	3/17/06	1/11/07	300	62
63	Wisconsin Public Service	WI	3/31/06	1/11/07	286	63
64	Cascade Natural Gas	WA	2/14/06	1/12/07	332	64
65	PPL	PA	4/27/06	2/8/07	287	65
66	Atmos	MO	4/7/06	2/22/07	321	66
67	Connecticut Natural Gas Corp	CT	9/29/06	3/14/07	166	67
68	Pacific Gas & Electric	CA	12/2/05	3/15/07	468	68
69	Ameren UE	MO	7/7/06	3/15/07	251	69
70	Delmarva Power & Light	DE	8/31/06	3/20/07	201	70
71	Missouri Gas Energy	MO	5/1/06	3/22/07	325	71
72	Atmos	TX	5/31/06	3/29/07	302	72
73	Mean				277	73
74	Median				253	74

Source: AGA Ratecase Database - http:\www.aga.org

SOUTHWEST GAS CORPORATION
PROXY GROUP - GAS DISTRIBUTION COMPANIES
RELATIVE RISK MEASURES

Line No.	Company	S&P Business Position[1]	Value Line Safety[2]	Book-to-Market 5-Year Average[3]	Line No.
	(a)	(b)	(c)	(d)	
1	AGL Resources Inc.	3.0	2.00	0.53	1
2	Atmos Energy Corp.	3.0	2.00	0.70	2
3	The Laclede Group, Inc.	3.0	2.00	0.60	3
4	NICOR Inc.	2.0	3.00	0.46	4
5	Northwest Natural Gas Co.	1.0	1.00	0.62	5
6	Piedmont Natural Gas Co., Inc.	2.0	2.00	0.50	6
7	South Jersey Industries, Inc.	2.0	2.00	0.51	7
8	WGL Holdings, Inc.	2.0	1.00	0.63	8
9	**Proxy Group Average**	**2.3**	**1.88**	**0.57**	9
10	Southwest Gas Corporation	3.0	3.00	0.73	10

Notes:
[1] Source: Frank Hanley's Exhibit____(FJH-10), Sheet 2 of 9.
[2] Source: Value Line Investment Survey, June 15, 2007.
[3] Source: Bloomberg - 5-year Average for the Period Ended March 31, 2007
Book-to-Market Ratio = 1/(Market-to-Book)

Definitions:
S&P Business Position Rating is a 10-point business profile assessment. The Business Position assesses the qualitative attributes of a firm , with "1" being considered lowest risk and "10" highest risk.

Value Line Safety Rank - is a measure of total investment risk of a stock, with a rank of "1" being highest safety and "5" being lowest safety.

Book-to-Market Ratio - Book value of common equity divided by market value of equity. This ratio can be used as proxy for risk, with higher values indicating higher risk.

EXHIBIT NO.___(TKW-8)
SHEET 1 OF 1

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
8.0% Debenture, Due 8/1/2026

															Effective Rate
														Internal Rate of Return =	8.89%
		Unamortized Balance						Amortization of							
Semi-Annual Payment	Outstanding Principal	Debt Expense	Reacquired Debt Expense	Discount	Carrying Value	Redemption	Interest Expense	Debt Expense	Reacquired Debt Expense	Discount	Total Expense	Annual Cost	Cash Flows		
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)		
8/1/1996	$ 75,000,000	$ 150,000	$ 5,898,405	$ 894,750	$ 68,056,845	$ -	$ -	$ -	$ -	$ -	$ -		$ 68,056,845		
2/1/1997	75,000,000	149,470	5,877,575	891,590	68,081,364	-	3,000,000	530	20,830	3,160	3,024,520	8.89%	(3,000,000)		
8/1/1997	75,000,000	148,917	5,855,819	888,290	68,106,974	-	3,000,000	553	21,756	3,300	3,025,609	8.89%	(3,000,000)		
2/1/1998	75,000,000	148,339	5,833,097	884,843	68,133,721	-	3,000,000	578	22,723	3,447	3,026,747	8.89%	(3,000,000)		
8/1/1998	75,000,000	147,736	5,809,364	881,243	68,161,657	-	3,000,000	604	23,732	3,600	3,027,936	8.89%	(3,000,000)		
2/1/1999	75,000,000	147,105	5,784,577	877,483	68,190,835	-	3,000,000	630	24,787	3,760	3,029,178	8.89%	(3,000,000)		
8/1/1999	75,000,000	146,447	5,758,688	873,556	68,221,309	-	3,000,000	658	25,889	3,927	3,030,474	8.89%	(3,000,000)		
2/1/2000	75,000,000	145,759	5,731,649	869,454	68,253,137	-	3,000,000	688	27,039	4,102	3,031,829	8.89%	(3,000,000)		
8/1/2000	75,000,000	145,041	5,703,408	865,170	68,286,380	-	3,000,000	718	28,241	4,284	3,033,243	8.89%	(3,000,000)		
2/1/2001	75,000,000	144,291	5,673,912	860,696	68,321,101	-	3,000,000	750	29,496	4,474	3,034,720	8.89%	(3,000,000)		
8/1/2001	75,000,000	143,508	5,643,106	856,023	68,357,364	-	3,000,000	783	30,807	4,673	3,036,263	8.89%	(3,000,000)		
2/1/2002	75,000,000	142,689	5,610,930	851,142	68,395,239	-	3,000,000	818	32,176	4,881	3,037,875	8.89%	(3,000,000)		
8/1/2002	75,000,000	141,835	5,577,324	846,044	68,434,797	-	3,000,000	855	33,606	5,098	3,039,558	8.89%	(3,000,000)		
2/1/2003	75,000,000	140,942	5,542,225	840,720	68,476,114	-	3,000,000	893	35,099	5,324	3,041,316	8.89%	(3,000,000)		
8/1/2003	75,000,000	140,010	5,505,566	835,159	68,519,266	-	3,000,000	932	36,659	5,561	3,043,152	8.89%	(3,000,000)		
2/1/2004	75,000,000	139,036	5,467,277	829,351	68,564,336	-	3,000,000	974	38,288	5,808	3,045,070	8.89%	(3,000,000)		
8/1/2004	75,000,000	138,019	5,427,287	823,284	68,611,409	-	3,000,000	1,017	39,990	6,066	3,047,073	8.89%	(3,000,000)		
2/1/2005	75,000,000	136,957	5,385,520	816,949	68,660,574	-	3,000,000	1,062	41,767	6,336	3,049,165	8.89%	(3,000,000)		
8/1/2005	75,000,000	135,848	5,341,897	810,331	68,711,924	-	3,000,000	1,109	43,623	6,617	3,051,350	8.89%	(3,000,000)		
2/1/2006	75,000,000	134,689	5,296,335	803,420	68,765,556	-	3,000,000	1,159	45,562	6,911	3,053,632	8.89%	(3,000,000)		
8/1/2006	75,000,000	133,479	5,248,748	796,201	68,821,571	-	3,000,000	1,210	47,587	7,219	3,056,015	8.89%	(3,000,000)		
2/1/2007	75,000,000	132,215	5,199,047	788,662	68,880,076	-	3,000,000	1,264	49,702	7,539	3,058,505	8.89%	(3,000,000)		
8/1/2007	75,000,000	130,895	5,147,137	780,787	68,941,181	-	3,000,000	1,320	51,910	7,874	3,061,105	8.89%	(3,000,000)		
2/1/2008	75,000,000	129,516	5,092,919	772,563	69,005,002	-	3,000,000	1,379	54,217	8,224	3,063,820	8.89%	(3,000,000)		
8/1/2008	75,000,000	128,076	5,036,293	763,973	69,071,658	-	3,000,000	1,440	56,627	8,590	3,066,657	8.89%	(3,000,000)		
2/1/2009	75,000,000	126,572	4,977,149	755,001	69,141,277	-	3,000,000	1,504	59,143	8,972	3,069,619	8.89%	(3,000,000)		
8/1/2009	75,000,000	125,001	4,915,378	745,631	69,213,990	-	3,000,000	1,571	61,772	9,370	3,072,713	8.89%	(3,000,000)		
2/1/2010	75,000,000	123,360	4,850,861	735,844	69,289,935	-	3,000,000	1,641	64,517	9,787	3,075,944	8.89%	(3,000,000)		
8/1/2010	75,000,000	121,647	4,783,477	725,623	69,369,254	-	3,000,000	1,714	67,384	10,222	3,079,319	8.89%	(3,000,000)		
2/1/2011	75,000,000	119,857	4,713,098	714,947	69,452,098	-	3,000,000	1,790	70,379	10,676	3,082,844	8.89%	(3,000,000)		
8/1/2011	75,000,000	117,988	4,639,592	703,796	69,538,625	-	3,000,000	1,869	73,506	11,150	3,086,526	8.89%	(3,000,000)		
2/1/2012	75,000,000	116,035	4,562,819	692,150	69,628,996	-	3,000,000	1,952	76,773	11,646	3,090,371	8.89%	(3,000,000)		
8/1/2012	75,000,000	113,996	4,482,634	679,987	69,723,384	-	3,000,000	2,039	80,185	12,164	3,094,388	8.89%	(3,000,000)		
2/1/2013	75,000,000	111,866	4,398,885	667,282	69,821,966	-	3,000,000	2,130	83,748	12,704	3,098,582	8.89%	(3,000,000)		
8/1/2013	75,000,000	109,642	4,311,415	654,014	69,924,930	-	3,000,000	2,224	87,470	13,269	3,102,963	8.89%	(3,000,000)		
2/1/2014	75,000,000	107,319	4,220,057	640,155	70,032,469	-	3,000,000	2,323	91,358	13,858	3,107,539	8.89%	(3,000,000)		
8/1/2014	75,000,000	104,892	4,124,639	625,681	70,144,787	-	3,000,000	2,427	95,418	14,474	3,112,318	8.89%	(3,000,000)		
2/1/2015	75,000,000	102,358	4,024,981	610,564	70,262,097	-	3,000,000	2,534	99,658	15,118	3,117,310	8.89%	(3,000,000)		
8/1/2015	75,000,000	99,711	3,920,894	594,774	70,384,621	-	3,000,000	2,647	104,087	15,789	3,122,523	8.89%	(3,000,000)		
2/1/2016	75,000,000	96,946	3,812,181	578,283	70,512,589	-	3,000,000	2,765	108,713	16,491	3,127,968	8.89%	(3,000,000)		

EXHIBIT NO.___(TKW-9)
SHEET 1 OF 11

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
8.0% Debenture, Due 8/1/2026

														Effective Rate
													Internal Rate of Return =	8.89%
		Unamortized Balance						Amortization of						
Semi-Annual Payment	Outstanding Principal	Debt Expense	Reacquired Debt Expense	Discount	Carrying Value	Redemption	Interest Expense	Debt Expense	Reacquired Debt Expense	Discount	Total Expense	Annual Cost	Cash Flows	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
8/1/2016	75,000,000	94,059	3,698,637	561,059	70,646,245	-	3,000,000	2,887	113,544	17,224	3,133,656	8.89%	(3,000,000)	
2/1/2017	75,000,000	91,043	3,580,047	543,070	70,785,840	-	3,000,000	3,016	118,590	17,989	3,139,595	8.89%	(3,000,000)	
8/1/2017	75,000,000	87,893	3,456,187	524,281	70,931,639	-	3,000,000	3,150	123,860	18,789	3,145,799	8.89%	(3,000,000)	
2/1/2018	75,000,000	84,603	3,326,822	504,657	71,083,918	-	3,000,000	3,290	129,365	19,624	3,152,279	8.89%	(3,000,000)	
8/1/2018	75,000,000	81,167	3,191,708	484,162	71,242,964	-	3,000,000	3,436	135,114	20,496	3,159,046	8.89%	(3,000,000)	
2/1/2019	75,000,000	77,578	3,050,589	462,755	71,409,078	-	3,000,000	3,589	141,119	21,407	3,166,114	8.89%	(3,000,000)	
8/1/2019	75,000,000	73,830	2,903,199	440,397	71,582,574	-	3,000,000	3,748	147,390	22,358	3,173,496	8.89%	(3,000,000)	
2/1/2020	75,000,000	69,915	2,749,259	417,045	71,763,781	-	3,000,000	3,915	153,940	23,352	3,181,207	8.89%	(3,000,000)	
8/1/2020	75,000,000	65,827	2,588,477	392,655	71,953,041	-	3,000,000	4,089	160,782	24,390	3,189,260	8.89%	(3,000,000)	
2/1/2021	75,000,000	61,556	2,420,551	367,182	72,150,712	-	3,000,000	4,270	167,927	25,473	3,197,671	8.89%	(3,000,000)	
8/1/2021	75,000,000	57,096	2,245,161	340,576	72,357,167	-	3,000,000	4,460	175,390	26,605	3,206,455	8.89%	(3,000,000)	
2/1/2022	75,000,000	52,437	2,061,977	312,789	72,572,797	-	3,000,000	4,658	183,184	27,788	3,215,631	8.89%	(3,000,000)	
8/1/2022	75,000,000	47,572	1,870,652	283,766	72,798,011	-	3,000,000	4,866	191,325	29,023	3,225,213	8.89%	(3,000,000)	
2/1/2023	75,000,000	42,490	1,670,824	253,453	73,033,233	-	3,000,000	5,082	199,828	30,313	3,235,222	8.89%	(3,000,000)	
8/1/2023	75,000,000	37,182	1,462,115	221,794	73,278,909	-	3,000,000	5,308	208,708	31,660	3,245,676	8.89%	(3,000,000)	
2/1/2024	75,000,000	31,639	1,244,132	188,727	73,535,502	-	3,000,000	5,543	217,984	33,067	3,256,594	8.89%	(3,000,000)	
8/1/2024	75,000,000	25,849	1,016,461	154,191	73,803,499	-	3,000,000	5,790	227,671	34,536	3,267,997	8.89%	(3,000,000)	
2/1/2025	75,000,000	19,802	778,672	118,120	74,083,407	-	3,000,000	6,047	237,789	36,071	3,279,907	8.89%	(3,000,000)	
8/1/2025	75,000,000	13,486	530,315	80,445	74,375,753	-	3,000,000	6,316	248,357	37,674	3,292,346	8.89%	(3,000,000)	
2/1/2026	75,000,000	6,890	270,922	41,097	74,681,092	-	3,000,000	6,597	259,394	39,348	3,305,339	8.89%	(3,000,000)	
8/1/2026	75,000,000	-	-	-	75,000,000	75,000,000	3,000,000	6,890	270,922	41,097	3,318,908	8.89%	(78,000,000)	
						$ 75,000,000	$ 180,000,000	$ 150,000	$ 5,898,405	$ 894,750	$ 186,943,155			

EXHIBIT NO.___(TKW-9)
SHEET 2 OF 11

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
8.375 % Notes Due 2011

														Effective Rate
													Internal Rate of Return =	8.6098%
		Unamortized Balance						Amortization of						
Semi-Annual Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Net Proceeds	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Annual Cost	Cash Flows	
2/13/2001	$ 200,000,000	$ 0	$ 2,818,000	$ 288,784	$ 196,893,216	$ 0	$ 0		$ 0	$ 0	$ 0		$ 196,893,216	
8/15/2001	200,000,000	0	2,726,322	279,389	196,994,289	0	8,375,000	0	91,678	9,395	8,476,073	8.61%	(8,375,000)	
2/15/2002	200,000,000	0	2,630,697	269,589	197,099,713	0	8,375,000	0	95,625	9,799	8,480,424	8.61%	(8,375,000)	
8/15/2002	200,000,000	0	2,530,956	259,368	197,209,676	0	8,375,000	0	99,741	10,221	8,484,962	8.61%	(8,375,000)	
2/15/2003	200,000,000	0	2,426,921	248,707	197,324,372	0	8,375,000	0	104,035	10,661	8,489,696	8.61%	(8,375,000)	
8/15/2003	200,000,000	0	2,318,408	237,586	197,444,006	0	8,375,000	0	108,514	11,120	8,494,634	8.61%	(8,375,000)	
2/15/2004	200,000,000	0	2,205,223	225,987	197,568,790	0	8,375,000	0	113,185	11,599	8,499,784	8.61%	(8,375,000)	
8/15/2004	200,000,000	0	2,087,166	213,889	197,698,945	0	8,375,000	0	118,057	12,098	8,505,156	8.61%	(8,375,000)	
2/15/2005	200,000,000	0	1,964,026	201,270	197,834,704	0	8,375,000	0	123,140	12,619	8,510,759	8.61%	(8,375,000)	
8/15/2005	200,000,000	0	1,835,585	188,108	197,976,307	0	8,375,000	0	128,441	13,162	8,516,603	8.61%	(8,375,000)	
2/15/2006	200,000,000	0	1,701,615	174,379	198,124,006	0	8,375,000	0	133,970	13,729	8,522,699	8.61%	(8,375,000)	
8/15/2006	200,000,000	0	1,561,878	160,058	198,278,064	0	8,375,000	0	139,737	14,320	8,529,057	8.61%	(8,375,000)	
2/15/2007	200,000,000	0	1,416,125	145,122	198,438,753	0	8,375,000	0	145,753	14,936	8,535,689	8.61%	(8,375,000)	
8/15/2007	200,000,000	0	1,264,098	129,543	198,606,360	0	8,375,000	0	152,027	15,579	8,542,607	8.61%	(8,375,000)	
2/15/2008	200,000,000	0	1,105,526	113,292	198,781,182	0	8,375,000	0	158,572	16,250	8,549,822	8.61%	(8,375,000)	
8/15/2008	200,000,000	0	940,127	96,343	198,963,530	0	8,375,000	0	165,398	16,950	8,557,348	8.61%	(8,375,000)	
2/15/2009	200,000,000	0	767,609	78,663	199,153,728	0	8,375,000	0	172,519	17,679	8,565,198	8.61%	(8,375,000)	
8/15/2009	200,000,000	0	587,663	60,223	199,352,114	0	8,375,000	0	179,945	18,440	8,573,386	8.61%	(8,375,000)	
2/15/2010	200,000,000	0	399,971	40,988	199,559,040	0	8,375,000	0	187,692	19,234	8,581,926	8.61%	(8,375,000)	
8/15/2010	200,000,000	0	204,200	20,926	199,774,874	0	8,375,000	0	195,772	20,062	8,590,834	8.61%	(8,375,000)	
2/15/2011	200,000,000	0	0	0	200,000,000	200,000,000	8,375,000	0	204,200	20,926	8,600,126	8.61%	(208,375,000)	
						$ 200,000,000	$ 167,500,000	$ 0	$ 2,818,000	$ 288,784	$ 170,606,784			

EXHIBIT NO.___(TKW-9)
SHEET 3 OF 11

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.625% New Debenture, Due May 15, 2012

														Effective Rate
													Internal Rate of Return =	7.79%
		Unamortized Balance						Amortization of						
Semi-Annual Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Net Proceeds	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Annual Cost	Cash Flows	
5/15/2002	$ 200,000,000	$ 0	$ 2,052,000	$ 270,042	$ 197,677,958	$ 0	$ 0		$ 0	$ 0	$ 0		$ 197,677,958	
11/15/2002	200,000,000	0	1,982,352	260,876	197,756,772	0	7,625,000	0	69,648	9,166	7,703,814	7.79%	(7,625,000)	
6/15/2003	200,000,000	0	1,909,989	251,354	197,838,657	0	7,625,000	0	72,363	9,523	7,706,885	7.79%	(7,625,000)	
11/15/2003	200,000,000	0	1,834,806	241,460	197,923,734	0	7,625,000	0	75,183	9,894	7,710,077	7.79%	(7,625,000)	
5/15/2004	200,000,000	0	1,756,694	231,180	198,012,126	0	7,625,000	0	78,113	10,280	7,713,392	7.79%	(7,625,000)	
11/15/2004	200,000,000	0	1,675,537	220,500	198,103,963	0	7,625,000	0	81,157	10,680	7,716,837	7.79%	(7,625,000)	
5/15/2005	200,000,000	0	1,591,217	209,403	198,199,379	0	7,625,000	0	84,320	11,096	7,720,416	7.79%	(7,625,000)	
11/15/2005	200,000,000	0	1,503,612	197,874	198,298,514	0	7,625,000	0	87,606	11,529	7,724,135	7.79%	(7,625,000)	
5/15/2006	200,000,000	0	1,412,592	185,896	198,401,512	0	7,625,000	0	91,020	11,978	7,727,998	7.79%	(7,625,000)	
11/15/2006	200,000,000	0	1,318,025	173,451	198,508,524	0	7,625,000	0	94,567	12,445	7,732,012	7.79%	(7,625,000)	
5/15/2007	200,000,000	0	1,219,772	160,521	198,619,706	0	7,625,000	0	98,252	12,930	7,736,182	7.79%	(7,625,000)	
11/15/2007	200,000,000	0	1,117,691	147,087	198,735,222	0	7,625,000	0	102,082	13,434	7,740,515	7.79%	(7,625,000)	
5/15/2008	200,000,000	0	1,011,631	133,130	198,855,239	0	7,625,000	0	106,060	13,957	7,745,017	7.79%	(7,625,000)	
11/15/2008	200,000,000	0	901,438	118,629	198,979,933	0	7,625,000	0	110,193	14,501	7,749,694	7.79%	(7,625,000)	
5/15/2009	200,000,000	0	786,950	103,562	199,109,487	0	7,625,000	0	114,487	15,066	7,754,554	7.79%	(7,625,000)	
11/15/2009	200,000,000	0	668,001	87,909	199,244,090	0	7,625,000	0	118,949	15,654	7,759,603	7.79%	(7,625,000)	
5/15/2010	200,000,000	0	544,416	71,645	199,383,939	0	7,625,000	0	123,585	16,264	7,764,849	7.79%	(7,625,000)	
11/15/2010	200,000,000	0	416,015	54,747	199,529,238	0	7,625,000	0	128,401	16,898	7,770,299	7.79%	(7,625,000)	
5/15/2011	200,000,000	0	282,610	37,191	199,680,199	0	7,625,000	0	133,405	17,556	7,775,961	7.79%	(7,625,000)	
11/15/2011	200,000,000	0	144,006	18,951	199,837,043	0	7,625,000	0	138,604	18,240	7,781,844	7.79%	(7,625,000)	
5/15/2012	200,000,000	0	0	(0)	200,000,000	200,000,000	7,625,000	0	144,006	18,951	7,787,957	7.79%	(207,625,000)	
						$ 200,000,000	$ 152,500,000	$ 0	$ 2,052,000	$ 270,042	$ 154,822,042			

EXHIBIT NO.___(TKW-9)
SHEET 4 OF 11

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.59% Medium Term Note Series A, Due 1/17/2017

Internal Rate of Return = Effective Rate 7.68%

Semi-Annual Payment	Outstanding Principal	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Unamortized Balance: Debt Expense	Carrying Value	Redemption	Interest Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Amortization of: Debt Expense	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1/17/1997	$ 25,000,000	$ -	$ 187,500	$ 33,400	$ 24,779,100	$ -	$ -	$ -	$ -	$ -	$ 0		$ 24,779,100
4/1/1997	25,000,000	-	186,657	33,250	24,780,093	-	390,042	-	843	150.09	391,034	7.68%	(390,042)
10/1/1997	25,000,000	-	184,576	32,879	24,782,545	-	948,750	-	2,082	371	951,203	7.68%	(948,750)
4/1/1998	25,000,000	-	182,414	32,494	24,785,092	-	948,750	-	2,162	385	951,297	7.68%	(948,750)
10/1/1998	25,000,000	-	180,169	32,094	24,787,737	-	948,750	-	2,245	400	951,395	7.68%	(948,750)
4/1/1999	25,000,000	-	177,838	31,679	24,790,483	-	948,750	-	2,331	415	951,496	7.68%	(948,750)
10/1/1999	25,000,000	-	175,418	31,248	24,793,334	-	948,750	-	2,420	431	951,601	7.68%	(948,750)
4/1/2000	25,000,000	-	172,905	30,800	24,796,295	-	948,750	-	2,513	448	951,711	7.68%	(948,750)
10/1/2000	25,000,000	-	170,295	30,335	24,799,370	-	948,750	-	2,610	465	951,825	7.68%	(948,750)
4/1/2001	25,000,000	-	167,585	29,852	24,802,562	-	948,750	-	2,710	483	951,943	7.68%	(948,750)
10/1/2001	25,000,000	-	164,771	29,351	24,805,878	-	948,750	-	2,814	501	952,065	7.68%	(948,750)
4/1/2002	25,000,000	-	161,849	28,831	24,809,320	-	948,750	-	2,922	521	952,192	7.68%	(948,750)
10/1/2002	25,000,000	-	158,815	28,290	24,812,895	-	948,750	-	3,034	540	952,325	7.68%	(948,750)
4/1/2003	25,000,000	-	155,665	27,729	24,816,606	-	948,750	-	3,151	561	952,462	7.68%	(948,750)
10/1/2003	25,000,000	-	152,393	27,146	24,820,461	-	948,750	-	3,272	583	952,604	7.68%	(948,750)
4/1/2004	25,000,000	-	148,996	26,541	24,824,463	-	948,750	-	3,397	605	952,752	7.68%	(948,750)
10/1/2004	25,000,000	-	145,468	25,913	24,828,619	-	948,750	-	3,527	628	952,906	7.68%	(948,750)
4/1/2005	25,000,000	-	141,806	25,260	24,832,934	-	948,750	-	3,663	652	953,065	7.68%	(948,750)
10/1/2005	25,000,000	-	138,002	24,583	24,837,415	-	948,750	-	3,803	678	953,231	7.68%	(948,750)
4/1/2006	25,000,000	-	134,053	23,879	24,842,068	-	948,750	-	3,949	704	953,403	7.68%	(948,750)
10/1/2006	25,000,000	-	129,951	23,149	24,846,900	-	948,750	-	4,101	731	953,582	7.68%	(948,750)
4/1/2007	25,000,000	-	125,693	22,390	24,851,917	-	948,750	-	4,259	759	953,767	7.68%	(948,750)
10/1/2007	25,000,000	-	121,271	21,602	24,857,127	-	948,750	-	4,422	788	953,960	7.68%	(948,750)
4/1/2008	25,000,000	-	116,679	20,784	24,862,536	-	948,750	-	4,592	818	954,160	7.68%	(948,750)
10/1/2008	25,000,000	-	111,911	19,935	24,868,154	-	948,750	-	4,768	849	954,367	7.68%	(948,750)
4/1/2009	25,000,000	-	106,960	19,053	24,873,987	-	948,750	-	4,951	882	954,583	7.68%	(948,750)
10/1/2009	25,000,000	-	101,819	18,137	24,880,043	-	948,750	-	5,141	916	954,807	7.68%	(948,750)
4/1/2010	25,000,000	-	96,481	17,186	24,886,333	-	948,750	-	5,338	951	955,039	7.68%	(948,750)
10/1/2010	25,000,000	-	90,937	16,199	24,892,864	-	948,750	-	5,543	987	955,281	7.68%	(948,750)
4/1/2011	25,000,000	-	85,181	15,174	24,899,645	-	948,750	-	5,756	1,025	955,531	7.68%	(948,750)
10/1/2011	25,000,000	-	79,204	14,109	24,906,687	-	948,750	-	5,977	1,065	955,792	7.68%	(948,750)
4/1/2012	25,000,000	-	72,998	13,003	24,913,999	-	948,750	-	6,206	1,106	956,062	7.68%	(948,750)
10/1/2012	25,000,000	-	66,553	11,855	24,921,592	-	948,750	-	6,445	1,148	956,343	7.68%	(948,750)
4/1/2013	25,000,000	-	59,861	10,663	24,929,476	-	948,750	-	6,692	1,192	956,634	7.68%	(948,750)
10/1/2013	25,000,000	-	52,912	9,425	24,937,663	-	948,750	-	6,949	1,238	956,937	7.68%	(948,750)
4/1/2014	25,000,000	-	45,696	8,140	24,946,164	-	948,750	-	7,216	1,285	957,251	7.68%	(948,750)
10/1/2014	25,000,000	-	38,204	6,805	24,954,991	-	948,750	-	7,493	1,335	957,577	7.68%	(948,750)
4/1/2015	25,000,000	-	30,423	5,419	24,964,157	-	948,750	-	7,780	1,386	957,916	7.68%	(948,750)
10/1/2015	25,000,000	-	22,344	3,980	24,973,676	-	948,750	-	8,079	1,439	958,268	7.68%	(948,750)
4/1/2016	25,000,000	-	13,955	2,486	24,983,559	-	948,750	-	8,389	1,494	958,633	7.68%	(948,750)
10/1/2016	25,000,000	-	5,244	934	24,993,822	-	948,750	-	8,711	1,552	959,013	7.68%	(948,750)
1/17/2017	25,000,000	-	-	-	25,000,000	25,000,000	558,708	-	5,244	934	564,886	7.68%	(25,558,708)
						$ 25,000,000	$ 37,950,000	$ -	$ 187,500	$ 33,400	$ 38,170,900		

EXHIBIT NO.___(TKW-9)
SHEET 5 OF 11

Exhibit No. (TKW-9) MTN Series A 7.59

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.78% Medium Term Note Series A, Due 2/3/2022

Internal Rate of Return = Effective Rate 7.86%

Semi-Annual Payment	Outstanding Principal	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Unamortized Balance: Debt Expense	Carrying Value	Redemption	Interest Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Amortization of: Debt Expense	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
2/3/1997	$ 25,000,000	$ -	$ 187,500	$ 33,400	$ 24,779,100	$ -	$ -	$ -	$ -	$ -	$ -		$ 24,779,100
4/1/1997	25,000,000	-	187,096	33,328	24,779,576	-	313,361	-	404	72	313,837	7.86%	(313,361)
10/1/1997	25,000,000	-	185,825	33,102	24,781,073	-	972,500	-	1,271	226	973,997	7.86%	(972,500)
4/1/1998	25,000,000	-	184,504	32,866	24,782,629	-	972,500	-	1,321	235	974,056	7.86%	(972,500)
10/1/1998	25,000,000	-	183,132	32,622	24,784,246	-	972,500	-	1,373	244	974,117	7.86%	(972,500)
4/1/1999	25,000,000	-	181,705	32,368	24,785,927	-	972,500	-	1,426	254	974,181	7.86%	(972,500)
10/1/1999	25,000,000	-	180,223	32,104	24,787,673	-	972,500	-	1,483	264	974,247	7.86%	(972,500)
4/1/2000	25,000,000	-	178,682	31,829	24,789,489	-	972,500	-	1,541	274	974,315	7.86%	(972,500)
10/1/2000	25,000,000	-	177,081	31,544	24,791,375	-	972,500	-	1,601	285	974,387	7.86%	(972,500)
4/1/2001	25,000,000	-	175,416	31,248	24,793,336	-	972,500	-	1,664	296	974,461	7.86%	(972,500)
10/1/2001	25,000,000	-	173,687	30,939	24,795,374	-	972,500	-	1,730	308	974,538	7.86%	(972,500)
4/1/2002	25,000,000	-	171,889	30,619	24,797,492	-	972,500	-	1,798	320	974,618	7.86%	(972,500)
10/1/2002	25,000,000	-	170,021	30,286	24,799,693	-	972,500	-	1,868	333	974,701	7.86%	(972,500)
4/1/2003	25,000,000	-	168,079	29,940	24,801,981	-	972,500	-	1,942	346	974,788	7.86%	(972,500)
10/1/2003	25,000,000	-	166,061	29,581	24,804,359	-	972,500	-	2,018	360	974,878	7.86%	(972,500)
4/1/2004	25,000,000	-	163,963	29,207	24,806,830	-	972,500	-	2,097	374	974,971	7.86%	(972,500)
10/1/2004	25,000,000	-	161,783	28,819	24,809,398	-	972,500	-	2,180	388	975,068	7.86%	(972,500)
4/1/2005	25,000,000	-	159,518	28,415	24,812,067	-	972,500	-	2,266	404	975,169	7.86%	(972,500)
10/1/2005	25,000,000	-	157,163	27,996	24,814,841	-	972,500	-	2,355	419	975,274	7.86%	(972,500)
4/1/2006	25,000,000	-	154,716	27,560	24,817,724	-	972,500	-	2,447	436	975,383	7.86%	(972,500)
10/1/2006	25,000,000	-	152,172	27,107	24,820,721	-	972,500	-	2,543	453	975,496	7.86%	(972,500)
4/1/2007	25,000,000	-	149,529	26,636	24,823,835	-	972,500	-	2,643	471	975,614	7.86%	(972,500)
10/1/2007	25,000,000	-	146,782	26,147	24,827,072	-	972,500	-	2,747	489	975,737	7.86%	(972,500)
4/1/2008	25,000,000	-	143,926	25,638	24,830,436	-	972,500	-	2,855	509	975,864	7.86%	(972,500)
10/1/2008	25,000,000	-	140,959	25,109	24,833,932	-	972,500	-	2,968	529	975,996	7.86%	(972,500)
4/1/2009	25,000,000	-	137,875	24,560	24,837,565	-	972,500	-	3,084	549	976,134	7.86%	(972,500)
10/1/2009	25,000,000	-	134,669	23,989	24,841,342	-	972,500	-	3,205	571	976,276	7.86%	(972,500)
4/1/2010	25,000,000	-	131,338	23,396	24,845,266	-	972,500	-	3,331	593	976,425	7.86%	(972,500)
10/1/2010	25,000,000	-	127,876	22,779	24,849,345	-	972,500	-	3,462	617	976,579	7.86%	(972,500)
4/1/2011	25,000,000	-	124,277	22,138	24,853,585	-	972,500	-	3,598	641	976,739	7.86%	(972,500)
10/1/2011	25,000,000	-	120,537	21,472	24,857,991	-	972,500	-	3,740	666	976,906	7.86%	(972,500)
4/1/2012	25,000,000	-	116,651	20,779	24,862,570	-	972,500	-	3,887	692	977,079	7.86%	(972,500)
10/1/2012	25,000,000	-	112,611	20,060	24,867,329	-	972,500	-	4,040	720	977,259	7.86%	(972,500)
4/1/2013	25,000,000	-	108,413	19,312	24,872,275	-	972,500	-	4,198	748	977,446	7.86%	(972,500)
10/1/2013	25,000,000	-	104,049	18,535	24,877,416	-	972,500	-	4,363	777	977,641	7.86%	(972,500)
4/1/2014	25,000,000	-	99,514	17,727	24,882,759	-	972,500	-	4,535	808	977,843	7.86%	(972,500)
10/1/2014	25,000,000	-	94,801	16,887	24,888,312	-	972,500	-	4,713	840	978,053	7.86%	(972,500)
4/1/2015	25,000,000	-	89,903	16,015	24,894,083	-	972,500	-	4,898	873	978,271	7.86%	(972,500)
10/1/2015	25,000,000	-	84,812	15,108	24,900,080	-	972,500	-	5,091	907	978,498	7.86%	(972,500)
4/1/2016	25,000,000	-	79,521	14,165	24,906,314	-	972,500	-	5,291	943	978,734	7.86%	(972,500)
10/1/2016	25,000,000	-	74,022	13,186	24,912,793	-	972,500	-	5,499	980	978,979	7.86%	(972,500)
4/1/2017	25,000,000	-	68,306	12,168	24,919,526	-	972,500	-	5,715	1,018	979,233	7.86%	(972,500)
10/1/2017	25,000,000	-	62,367	11,110	24,926,524	-	972,500	-	5,940	1,058	979,498	7.86%	(972,500)
4/1/2018	25,000,000	-	56,193	10,010	24,933,797	-	972,500	-	6,173	1,100	979,773	7.86%	(972,500)
10/1/2018	25,000,000	-	49,777	8,867	24,941,356	-	972,500	-	6,416	1,143	980,059	7.86%	(972,500)
4/1/2019	25,000,000	-	43,109	7,679	24,949,212	-	972,500	-	6,668	1,188	980,356	7.86%	(972,500)
10/1/2019	25,000,000	-	36,179	6,445	24,957,377	-	972,500	-	6,930	1,235	980,665	7.86%	(972,500)
4/1/2020	25,000,000	-	28,976	5,162	24,965,862	-	972,500	-	7,203	1,283	980,986	7.86%	(972,500)
10/1/2020	25,000,000	-	21,490	3,828	24,974,681	-	972,500	-	7,486	1,333	981,319	7.86%	(972,500)
4/1/2021	25,000,000	-	13,710	2,442	24,983,847	-	972,500	-	7,780	1,386	981,666	7.86%	(972,500)
10/1/2021	25,000,000	-	5,624	1,002	24,993,374	-	972,500	-	8,086	1,440	982,026	7.86%	(972,500)
2/3/2022	25,000,000	-	-	-	25,000,000	25,000,000	659,139	-	5,624	1,002	665,765	7.86%	(25,659,139)
						$ 25,000,000	$ 48,625,000	$ -	$ 187,500	$ 33,400	$ 48,845,900		

EXHIBIT NO.___(TKW-9)
SHEET 6 OF 11

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.92% Medium Term Note, Due June 4, 2027

														Effective Rate
													Internal Rate of Return =	8.00%
		Unamortized Balance						Amortization of						
Semi-Annual Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Carrying Value	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Annual Cost	Cash Flows	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
6/4/1997	$ 25,000,000	$ -	$ 187,500	$ 45,761	$ 24,766,739	$ -	$ -	$ -	$ -	$ -	$ -		$ 24,766,739	
10/1/1997	25,000,000	-	186,988	45,636	24,767,375	-	643,500	-	512	125	644,137	8.00%	(643,500)	
4/1/1998	25,000,000	-	186,180	45,439	24,768,381	-	990,000	-	808	197	991,005	8.00%	(990,000)	
10/1/1998	25,000,000	-	185,340	45,234	24,769,426	-	990,000	-	840	205	991,045	8.00%	(990,000)	
4/1/1999	25,000,000	-	184,466	45,021	24,770,513	-	990,000	-	874	213	991,087	8.00%	(990,000)	
10/1/1999	25,000,000	-	183,557	44,799	24,771,644	-	990,000	-	909	222	991,131	8.00%	(990,000)	
4/1/2000	25,000,000	-	182,612	44,568	24,772,820	-	990,000	-	945	231	991,176	8.00%	(990,000)	
10/1/2000	25,000,000	-	181,629	44,329	24,774,043	-	990,000	-	983	240	991,223	8.00%	(990,000)	
4/1/2001	25,000,000	-	180,607	44,079	24,775,315	-	990,000	-	1,022	250	991,272	8.00%	(990,000)	
10/1/2001	25,000,000	-	179,543	43,819	24,776,637	-	990,000	-	1,063	260	991,323	8.00%	(990,000)	
4/1/2002	25,000,000	-	178,437	43,550	24,778,013	-	990,000	-	1,106	270	991,376	8.00%	(990,000)	
10/1/2002	25,000,000	-	177,287	43,269	24,779,444	-	990,000	-	1,150	281	991,431	8.00%	(990,000)	
4/1/2003	25,000,000	-	176,091	42,977	24,780,932	-	990,000	-	1,196	292	991,488	8.00%	(990,000)	
10/1/2003	25,000,000	-	174,847	42,673	24,782,479	-	990,000	-	1,244	304	991,548	8.00%	(990,000)	
4/1/2004	25,000,000	-	173,554	42,358	24,784,089	-	990,000	-	1,294	316	991,609	8.00%	(990,000)	
10/1/2004	25,000,000	-	172,208	42,029	24,785,763	-	990,000	-	1,346	328	991,674	8.00%	(990,000)	
4/1/2005	25,000,000	-	170,809	41,688	24,787,504	-	990,000	-	1,399	342	991,741	8.00%	(990,000)	
10/1/2005	25,000,000	-	169,353	41,333	24,789,314	-	990,000	-	1,455	355	991,811	8.00%	(990,000)	
4/1/2006	25,000,000	-	167,840	40,963	24,791,197	-	990,000	-	1,514	369	991,883	8.00%	(990,000)	
10/1/2006	25,000,000	-	166,266	40,579	24,793,155	-	990,000	-	1,574	384	991,958	8.00%	(990,000)	
4/1/2007	25,000,000	-	164,629	40,179	24,795,192	-	990,000	-	1,637	400	992,037	8.00%	(990,000)	
10/1/2007	25,000,000	-	162,926	39,764	24,797,310	-	990,000	-	1,703	416	992,118	8.00%	(990,000)	
4/1/2008	25,000,000	-	161,155	39,332	24,799,513	-	990,000	-	1,771	432	992,203	8.00%	(990,000)	
10/1/2008	25,000,000	-	159,314	38,882	24,801,804	-	990,000	-	1,842	449	992,291	8.00%	(990,000)	
4/1/2009	25,000,000	-	157,398	38,415	24,804,187	-	990,000	-	1,915	467	992,383	8.00%	(990,000)	
10/1/2009	25,000,000	-	155,407	37,929	24,806,665	-	990,000	-	1,992	486	992,478	8.00%	(990,000)	
4/1/2010	25,000,000	-	153,335	37,423	24,809,242	-	990,000	-	2,072	506	992,577	8.00%	(990,000)	
10/1/2010	25,000,000	-	151,180	36,897	24,811,922	-	990,000	-	2,154	526	992,680	8.00%	(990,000)	
4/1/2011	25,000,000	-	148,940	36,350	24,814,710	-	990,000	-	2,241	547	992,788	8.00%	(990,000)	
10/1/2011	25,000,000	-	146,609	35,782	24,817,609	-	990,000	-	2,330	569	992,899	8.00%	(990,000)	
4/1/2012	25,000,000	-	144,186	35,190	24,820,624	-	990,000	-	2,424	592	993,015	8.00%	(990,000)	
10/1/2012	25,000,000	-	141,665	34,575	24,823,760	-	990,000	-	2,521	615	993,136	8.00%	(990,000)	
4/1/2013	25,000,000	-	139,044	33,935	24,827,021	-	990,000	-	2,621	640	993,261	8.00%	(990,000)	
10/1/2013	25,000,000	-	136,317	33,270	24,830,413	-	990,000	-	2,726	665	993,392	8.00%	(990,000)	
4/1/2014	25,000,000	-	133,482	32,578	24,833,940	-	990,000	-	2,835	692	993,527	8.00%	(990,000)	
10/1/2014	25,000,000	-	130,533	31,858	24,837,609	-	990,000	-	2,949	720	993,669	8.00%	(990,000)	
4/1/2015	25,000,000	-	127,466	31,110	24,841,424	-	990,000	-	3,067	748	993,815	8.00%	(990,000)	
10/1/2015	25,000,000	-	124,277	30,331	24,845,392	-	990,000	-	3,190	778	993,968	8.00%	(990,000)	
4/1/2016	25,000,000	-	120,960	29,521	24,849,519	-	990,000	-	3,317	810	994,127	8.00%	(990,000)	
10/1/2016	25,000,000	-	117,510	28,679	24,853,811	-	990,000	-	3,450	842	994,292	8.00%	(990,000)	
4/1/2017	25,000,000	-	113,922	27,804	24,858,275	-	990,000	-	3,588	876	994,464	8.00%	(990,000)	
10/1/2017	25,000,000	-	110,190	26,893	24,862,917	-	990,000	-	3,732	911	994,642	8.00%	(990,000)	
4/1/2018	25,000,000	-	106,309	25,946	24,867,745	-	990,000	-	3,881	947	994,828	8.00%	(990,000)	
10/1/2018	25,000,000	-	102,273	24,961	24,872,766	-	990,000	-	4,036	985	995,021	8.00%	(990,000)	
4/1/2019	25,000,000	-	98,076	23,936	24,877,988	-	990,000	-	4,198	1,024	995,222	8.00%	(990,000)	
10/1/2019	25,000,000	-	93,710	22,871	24,883,419	-	990,000	-	4,366	1,065	995,431	8.00%	(990,000)	
4/1/2020	25,000,000	-	89,170	21,763	24,889,067	-	990,000	-	4,540	1,108	995,648	8.00%	(990,000)	
10/1/2020	25,000,000	-	84,448	20,610	24,894,942	-	990,000	-	4,722	1,152	995,874	8.00%	(990,000)	
4/1/2021	25,000,000	-	79,537	19,412	24,901,051	-	990,000	-	4,911	1,199	996,109	8.00%	(990,000)	
10/1/2021	25,000,000	-	74,430	18,165	24,907,405	-	990,000	-	5,107	1,246	996,354	8.00%	(990,000)	

EXHIBIT NO.___(TKW-9)
SHEET 7 OF 11

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.92% Medium Term Note, Due June 4, 2027

													Effective Rate
												Internal Rate of Return =	8.00%
		Unamortized Balance						Amortization of					
Semi-Annual Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Carrying Value	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
4/1/2022	25,000,000	-	69,118	16,869	24,914,013	-	990,000	-	5,312	1,296	996,608	8.00%	(990,000)
10/1/2022	25,000,000	-	63,594	15,521	24,920,885	-	990,000	-	5,524	1,348	996,872	8.00%	(990,000)
4/1/2023	25,000,000	-	57,849	14,119	24,928,033	-	990,000	-	5,745	1,402	997,147	8.00%	(990,000)
10/1/2023	25,000,000	-	51,873	12,660	24,935,466	-	990,000	-	5,975	1,458	997,433	8.00%	(990,000)
4/1/2024	25,000,000	-	45,659	11,144	24,943,197	-	990,000	-	6,214	1,517	997,731	8.00%	(990,000)
10/1/2024	25,000,000	-	39,196	9,566	24,951,237	-	990,000	-	6,463	1,577	998,040	8.00%	(990,000)
4/1/2025	25,000,000	-	32,475	7,926	24,959,599	-	990,000	-	6,721	1,640	998,362	8.00%	(990,000)
10/1/2025	25,000,000	-	25,485	6,220	24,968,296	-	990,000	-	6,990	1,706	998,696	8.00%	(990,000)
4/1/2026	25,000,000	-	18,214	4,445	24,977,340	-	990,000	-	7,270	1,774	999,044	8.00%	(990,000)
10/1/2026	25,000,000	-	10,653	2,600	24,986,747	-	990,000	-	7,561	1,845	999,406	8.00%	(990,000)
4/1/2027	25,000,000	-	2,790	681	24,996,529	-	990,000	-	7,864	1,919	999,783	8.00%	(990,000)
6/4/2027	25,000,000	-	-	-	25,000,000	25,000,000	346,500	-	2,790	681	349,971	8.00%	(25,346,500)
						$ 25,000,000	$ 59,400,000	$ -	$ 187,500	$ 45,761	$ 59,633,261		

EXHIBIT NO.___(TKW-9)
SHEET 8 OF 11

Exhibit No. ___(TKW-9) MTN Series A 7.92

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
6.89% Medium Term Note Series A, Due 9/24/07

														Effective Rate
													Internal Rate of Return =	7.00%
		Unamortized Balance						Amortization of						
Semi-Annual Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Carrying Value	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Cost	Cash Flows	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
9/23/1997	$ 17,500,000	$ -	$ 102,325	$ 40,200	$ 17,357,475	$ -	$ -	$ -	$ -	$ -	$ -		$ 17,357,475	
4/1/1998	17,500,000	-	98,547	38,715	17,362,738	-	629,669	-	3,778	1,484	634,932	7.00%	(629,669)	
10/1/1998	17,500,000	-	94,797	37,242	17,367,961	-	602,875	-	3,750	1,473	608,098	7.00%	(602,875)	
4/1/1999	17,500,000	-	90,916	35,717	17,373,367	-	602,875	-	3,881	1,525	608,281	7.00%	(602,875)	
10/1/1999	17,500,000	-	86,899	34,139	17,378,962	-	602,875	-	4,017	1,578	608,470	7.00%	(602,875)	
4/1/2000	17,500,000	-	82,741	32,506	17,384,753	-	602,875	-	4,158	1,633	608,666	7.00%	(602,875)	
10/1/2000	17,500,000	-	78,438	30,815	17,390,747	-	602,875	-	4,303	1,691	608,869	7.00%	(602,875)	
4/1/2001	17,500,000	-	73,984	29,065	17,396,951	-	602,875	-	4,454	1,750	609,079	7.00%	(602,875)	
10/1/2001	17,500,000	-	69,374	27,254	17,403,372	-	602,875	-	4,610	1,811	609,296	7.00%	(602,875)	
4/1/2002	17,500,000	-	64,602	25,380	17,410,018	-	602,875	-	4,772	1,875	609,521	7.00%	(602,875)	
10/1/2002	17,500,000	-	59,663	23,440	17,416,897	-	602,875	-	4,939	1,940	609,754	7.00%	(602,875)	
4/1/2003	17,500,000	-	54,552	21,431	17,424,017	-	602,875	-	5,112	2,008	609,995	7.00%	(602,875)	
10/1/2003	17,500,000	-	49,261	19,353	17,431,386	-	602,875	-	5,291	2,078	610,244	7.00%	(602,875)	
4/1/2004	17,500,000	-	43,785	17,202	17,439,013	-	602,875	-	5,476	2,151	610,502	7.00%	(602,875)	
10/1/2004	17,500,000	-	38,118	14,975	17,446,907	-	602,875	-	5,668	2,227	610,769	7.00%	(602,875)	
4/1/2005	17,500,000	-	32,251	12,670	17,455,078	-	602,875	-	5,866	2,305	611,046	7.00%	(602,875)	
10/1/2005	17,500,000	-	26,180	10,285	17,463,535	-	602,875	-	6,072	2,385	611,332	7.00%	(602,875)	
4/1/2006	17,500,000	-	19,895	7,816	17,472,288	-	602,875	-	6,284	2,469	611,628	7.00%	(602,875)	
10/1/2006	17,500,000	-	13,391	5,261	17,481,348	-	602,875	-	6,504	2,555	611,935	7.00%	(602,875)	
4/1/2007	17,500,000	-	6,659	2,616	17,490,725	-	602,875	-	6,732	2,645	612,252	7.00%	(602,875)	
9/24/2007	17,500,000	-	-	-	17,500,000	17,500,000	579,430	-	6,659	2,616	588,705	7.00%	(18,079,430)	
						$ 17,500,000	$ 12,060,849	$ -	$ 102,325	$ 40,200	$ 12,203,374			

EXHIBIT NO. ___ (TKW-9)
SHEET 9 OF 11

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
6.76% Medium Term Note Series A, Due 9/24/27
Put Date September 24, 2007

														Effective Rate
													Internal Rate of Return =	6.88%
		Unamortized Balance						Amortization of						
Semi-Annual Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Carrying Value	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Annual Cost	Cash Flows	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
9/23/1997	$ 7,500,000	$ -	$ 46,875	$ 17,228	$ 7,435,897	$ -	$ -	$ -	$ -	$ -	$ -		$ 7,435,897	
4/1/1998	7,500,000	-	45,133	16,588	7,438,279	-	264,767	-	1,742	640	267,149	6.88%	(264,767)	
10/1/1998	7,500,000	-	43,405	15,953	7,440,642	-	253,500	-	1,728	635	255,863	6.88%	(253,500)	
4/1/1999	7,500,000	-	41,618	15,296	7,443,086	-	253,500	-	1,787	657	255,944	6.88%	(253,500)	
10/1/1999	7,500,000	-	39,769	14,617	7,445,614	-	253,500	-	1,849	679	256,028	6.88%	(253,500)	
4/1/2000	7,500,000	-	37,857	13,914	7,448,229	-	253,500	-	1,912	703	256,115	6.88%	(253,500)	
10/1/2000	7,500,000	-	35,879	13,187	7,450,934	-	253,500	-	1,978	727	256,205	6.88%	(253,500)	
4/1/2001	7,500,000	-	33,833	12,435	7,453,732	-	253,500	-	2,046	752	256,298	6.88%	(253,500)	
10/1/2001	7,500,000	-	31,717	11,657	7,456,626	-	253,500	-	2,116	778	256,394	6.88%	(253,500)	
4/1/2002	7,500,000	-	29,527	10,853	7,459,620	-	253,500	-	2,189	805	256,494	6.88%	(253,500)	
10/1/2002	7,500,000	-	27,263	10,020	7,462,717	-	253,500	-	2,265	832	256,597	6.88%	(253,500)	
4/1/2003	7,500,000	-	24,920	9,159	7,465,920	-	253,500	-	2,342	861	256,703	6.88%	(253,500)	
10/1/2003	7,500,000	-	22,497	8,269	7,469,234	-	253,500	-	2,423	891	256,814	6.88%	(253,500)	
4/1/2004	7,500,000	-	19,991	7,348	7,472,661	-	253,500	-	2,506	921	256,928	6.88%	(253,500)	
10/1/2004	7,500,000	-	17,398	6,395	7,476,207	-	253,500	-	2,593	953	257,045	6.88%	(253,500)	
4/1/2005	7,500,000	-	14,717	5,409	7,479,874	-	253,500	-	2,682	986	257,167	6.88%	(253,500)	
10/1/2005	7,500,000	-	11,943	4,389	7,483,668	-	253,500	-	2,774	1,020	257,294	6.88%	(253,500)	
4/1/2006	7,500,000	-	9,073	3,335	7,487,592	-	253,500	-	2,869	1,055	257,424	6.88%	(253,500)	
10/1/2006	7,500,000	-	6,105	2,244	7,491,651	-	253,500	-	2,968	1,091	257,559	6.88%	(253,500)	
4/1/2007	7,500,000	-	3,035	1,115	7,495,850	-	253,500	-	3,070	1,128	257,699	6.88%	(253,500)	
9/24/2007	7,500,000	-	-	-	7,500,000	7,500,000	243,642	-	3,035	1,115	247,792	6.88%	(7,743,642)	
						$ 7,500,000	$ 5,071,408	$ -	$ 46,875	$ 17,228	$ 5,135,512			

EXHIBIT NO.___(TKW-9)
SHEET 10 OF 11

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
6.27% Medium Term Note Series A, Due 9/22/08

														Effective Rate
													Internal Rate of Return =	6.40%
		Unamortized Balance						Amortization of						
Semi-Annual Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Carrying Value	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Annual Cost	Cash Flows	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
9/24/1998	$ 25,000,000	$ -	$ 156,250	$ 79,928	$ 24,763,822	$ -	$ -	$ -	$ -	$ -	$ -		$ 24,763,822	
4/1/1999	25,000,000	-	150,331	76,900	24,772,769	-	814,229	-	5,919	3,028	823,177	6.40%	(814,229)	
10/1/1999	25,000,000	-	144,443	73,889	24,781,668	-	783,750	-	5,887	3,012	792,649	6.40%	(783,750)	
4/1/2000	25,000,000	-	138,368	70,781	24,790,852	-	783,750	-	6,076	3,108	792,933	6.40%	(783,750)	
10/1/2000	25,000,000	-	132,098	67,573	24,800,329	-	783,750	-	6,270	3,207	793,227	6.40%	(783,750)	
4/1/2001	25,000,000	-	125,627	64,263	24,810,109	-	783,750	-	6,471	3,310	793,531	6.40%	(783,750)	
10/1/2001	25,000,000	-	118,950	60,847	24,820,203	-	783,750	-	6,678	3,416	793,844	6.40%	(783,750)	
4/1/2002	25,000,000	-	112,058	57,322	24,830,619	-	783,750	-	6,891	3,525	794,166	6.40%	(783,750)	
10/1/2002	25,000,000	-	104,947	53,684	24,841,369	-	783,750	-	7,112	3,638	794,500	6.40%	(783,750)	
4/1/2003	25,000,000	-	97,607	49,930	24,852,463	-	783,750	-	7,339	3,754	794,844	6.40%	(783,750)	
10/1/2003	25,000,000	-	90,033	46,055	24,863,911	-	783,750	-	7,574	3,874	795,199	6.40%	(783,750)	
4/1/2004	25,000,000	-	82,217	42,057	24,875,726	-	783,750	-	7,817	3,998	795,565	6.40%	(783,750)	
10/1/2004	25,000,000	-	74,150	37,931	24,887,920	-	783,750	-	8,067	4,126	795,943	6.40%	(783,750)	
4/1/2005	25,000,000	-	65,825	33,672	24,900,503	-	783,750	-	8,325	4,258	796,333	6.40%	(783,750)	
10/1/2005	25,000,000	-	57,234	29,277	24,913,488	-	783,750	-	8,591	4,395	796,736	6.40%	(783,750)	
4/1/2006	25,000,000	-	48,368	24,742	24,926,890	-	783,750	-	8,866	4,535	797,151	6.40%	(783,750)	
10/1/2006	25,000,000	-	39,218	20,062	24,940,720	-	783,750	-	9,150	4,680	797,580	6.40%	(783,750)	
4/1/2007	25,000,000	-	29,776	15,232	24,954,992	-	783,750	-	9,442	4,830	798,023	6.40%	(783,750)	
10/1/2007	25,000,000	-	20,031	10,247	24,969,722	-	783,750	-	9,745	4,985	798,479	6.40%	(783,750)	
4/1/2008	25,000,000	-	9,975	5,103	24,984,922	-	783,750	-	10,056	5,144	798,951	6.40%	(783,750)	
9/22/2008	25,000,000	-	-	-	25,000,000	25,000,000	744,563	-	9,975	5,103	759,640	6.40%	(25,744,563)	
						$ 25,000,000	$ 15,666,292	$ -	$ 156,250	$ 79,928	$ 15,902,470			

EXHIBIT NO.___(TKW-9)
SHEET 11 OF 11

SOUTHWEST GAS CORPORATION
Effective Cost Calculation - $100 Million Term Facility/CP Facility
As of April 30, 2007

Line No.	Principal (a)	(b)	(c)	(d)	Annualized Interest (e)	Line No.
	Libor Loans	LIBOR	Spread	Rate[1]		
1	$ 31,000,000	5.32%	0.600%	5.92%	$ 1,860,770	1
	CP Notes	Discount Rate				
2	$ 23,011,000	5.61%			$ 1,290,347	2
	Credit Facility Fees					
3	Amortization Expense				$ 139,736	3
4	Annual Fee				12,500	4
5	Unused Commitment Fees-CP				29,163	5
6	Total Annualized Fees				$ 181,399	6
7	Total Annualized Fees and Interest (365 day basis)				$ 3,332,516	7
8	Unamortized Debt Expense - 04/30/2007				$ 558,943	8
9	CP Discount				282,858	9
10	Net Proceeds - 04/30/2007				$ 53,169,199	10
11	All-In Effective Rate				6.27%	11

Notes:
[1] Money Market Rate - 360 day basis

SOUTHWEST GAS CORPORATION
Effective Cost Calculation - Term Facility
Outstanding Loans at April 30, 2007

Line No.	Origination (a)	Maturity (b)	Principal (c)	Rate [1] (d)	One Day Interest (e)	Annualized Interest Rate [2] (f)	Annualized Interest (g)	Line No.
1	4/27/2007	5/4/2007	31,000,000	5.920%	5,098	6.00%	1,860,770	1
			31,000,000			6.00%	1,860,770	
	Credit Facility Fees							
3	One Time Arrangement Fee (5 Year Facility)				$ 70,000		$ 14,000	3
4	Annual Fee				12,500		12,500	4
5	Legal & Other Expense				596,428		119,286	5
6	Upfront Fees (5 Year Facility)				32,250		6,450	6
7	Total Annualized Fees				$ 711,178		152,236	7
8	Total Annualized Fees and Interest (365 day basis)						$ 2,013,006	8
9	Unamortized Debt Expense - 04/30/2007						$ 558,943	9
10	Net Proceeds						$ 30,441,057	10
11	All-In Effective Rate						6.61%	11

Notes
[1] Money Market Rate
[2] 365-Day Rate

EXHIBIT NO.___(TKW-10)
SHEET 2 OF 3

SOUTHWEST GAS CORPORATION
Effective Cost Calculation - Term Facility
Commercial Paper
Outstanding at April 30, 2007

Line No.	Issue Date (a)	Maturity Date (b)	Face Value [1] (c)	Net Proceeds [1] (d)	Discount Rate (e)	Discount [1] (f)	One Day Interest (g)	Annualized Interest [1] (h)	Line No.
1	3/7/2007	5/3/2007	3,000,000.00	2,973,685.00	5.54%	26,315.00	461.67	168,508.33	1
2	1/12/2007	5/4/2007	100,000.00	98,279.56	5.53%	1,720.44	15.36	5,606.81	2
3	4/23/2007	5/8/2007	1,050,000.00	1,047,598.13	5.49%	2,401.88	160.13	58,445.63	3
4	3/12/2007	5/11/2007	1,180,000.00	1,169,104.67	5.54%	10,895.33	181.59	66,279.94	4
5	1/19/2007	5/15/2007	1,000,000.00	982,181.11	5.53%	17,818.89	153.61	56,068.06	5
6	3/16/2007	5/15/2007	1,000,000.00	990,766.67	5.54%	9,233.33	153.89	56,169.44	6
7	3/19/2007	5/18/2007	850,000.00	842,151.67	5.54%	7,848.33	130.81	47,744.03	7
8	4/19/2007	5/29/2007	600,000.00	596,306.67	5.54%	3,693.33	92.33	33,701.67	8
9	3/8/2007	5/31/2007	255,000.00	251,709.65	5.53%	3,290.35	39.17	14,297.35	9
10	3/21/2007	5/31/2007	200,000.00	197,814.78	5.54%	2,185.22	30.78	11,233.89	10
11	4/30/2007	5/31/2007	250,000.00	248,807.36	5.54%	1,192.64	38.47	14,042.36	11
12	3/13/2007	6/6/2007	2,000,000.00	1,973,838.89	5.54%	26,161.11	307.78	112,338.89	12
13	3/23/2007	6/8/2007	250,000.00	247,037.64	5.54%	2,962.36	38.47	14,042.36	13
14	4/4/2007	6/15/2007	400,000.00	395,568.00	5.54%	4,432.00	61.56	22,467.78	14
15	3/16/2007	6/22/2007	560,000.00	551,585.07	5.52%	8,414.93	85.87	31,341.33	15
16	3/15/2007	6/25/2007	2,537,000.00	2,497,321.32	5.52%	39,678.68	389.01	141,987.43	16
17	3/5/2007	6/27/2007	300,000.00	294,765.50	5.51%	5,234.50	45.92	16,759.58	17
18	4/13/2007	6/27/2007	2,076,000.00	2,052,039.50	5.54%	23,960.50	319.47	116,607.77	18
19	3/29/2007	6/28/2007	200,000.00	197,209.33	5.52%	2,790.67	30.67	11,193.33	19
20	3/16/2007	6/29/2007	100,000.00	98,390.00	5.52%	1,610.00	15.33	5,596.67	20
21	4/9/2007	7/6/2007	300,000.00	295,937.33	5.54%	4,062.67	46.17	16,850.83	21
22	3/26/2007	7/13/2007	260,000.00	255,654.53	5.52%	4,345.47	39.87	14,551.33	22
23	4/18/2007	7/17/2007	700,000.00	690,322.50	5.53%	9,677.50	107.53	39,247.64	23
24	4/3/2007	7/19/2007	668,000.00	657,040.35	5.52%	10,959.65	102.43	37,385.73	24
25	4/23/2007	7/19/2007	650,000.00	641,297.58	5.54%	8,702.42	100.03	36,510.14	25
26	4/16/2007	7/26/2007	450,000.00	443,018.38	5.53%	6,981.63	69.13	25,230.63	26
27	4/11/2007	7/27/2007	250,000.00	245,890.90	5.53%	4,109.10	38.40	14,017.01	27
28	4/13/2007	7/31/2007	350,000.00	344,139.74	5.53%	5,860.26	53.76	19,623.82	28
29	4/16/2007	8/3/2007	475,000.00	467,046.78	5.53%	7,953.22	72.97	26,632.33	29
30	4/11/2007	8/9/2007	1,000,000.00	981,633.33	5.51%	18,366.67	153.06	55,865.28	30
31	Total		$ 23,011,000.00	$ 22,728,141.92	5.68%	$ 282,858.08		$ 1,290,347.39	31
	Credit Facility Fees								
32	Unused Commitment Fees		$ 23,011,000.00		0.125%		365	$ 29,163.25	32
33	Total Discount and Credit Facility Fees							$ 1,319,510.64	33
34	Net Proceeds							$ 22,728,141.92	34
35	All-In Effective Rate							5.81%	35

EXHIBIT NO.___(TKW-10)
SHEET 3 OF 3

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.7% Trust Originated Preferred Securities, Due September 15, 2043

Quarterly Payment	Outstanding Principal	Unamortized Balance			Net Proceeds	Redemption	Interest Expense	Amortization of			Total Expense	Cost	Effective Rate: Internal Rate of Return = 2.05%; Annual Effective Rate = 8.20%; Cash Flows
		Reacquired Debt Expense	Discount	Debt Expense				Reacquired Debt Expense	Discount	Debt Expense			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
8/25/2003	$ 100,000,000	$ 2,221,449	$ 3,150,000	$ 537,824	$ 94,090,727	$ 0	$ 0		$ 0	$ 0	$ 0		$ 94,090,727
9/30/2003	100,000,000	2,220,737	3,148,990	537,651	94,092,622	0	748,611	712	1,010	172	750,506	2.05%	(748,611)
12/31/2003	100,000,000	2,218,890	3,146,371	537,204	94,097,534	0	1,925,000	1,847	2,619	447	1,929,912	2.05%	(1,925,000)
3/31/2004	100,000,000	2,217,006	3,143,699	536,748	94,102,547	0	1,925,000	1,885	2,672	456	1,930,013	2.05%	(1,925,000)
6/30/2004	100,000,000	2,215,083	3,140,972	536,282	94,107,663	0	1,925,000	1,923	2,727	466	1,930,116	2.05%	(1,925,000)
9/30/2004	100,000,000	2,213,120	3,138,189	535,807	94,112,884	0	1,925,000	1,963	2,783	475	1,930,221	2.05%	(1,925,000)
12/31/2004	100,000,000	2,211,117	3,135,349	535,322	94,118,212	0	1,925,000	2,003	2,840	485	1,930,328	2.05%	(1,925,000)
3/31/2005	100,000,000	2,209,073	3,132,451	534,827	94,123,649	0	1,925,000	2,044	2,898	495	1,930,437	2.05%	(1,925,000)
6/30/2005	100,000,000	2,206,987	3,129,493	534,322	94,129,197	0	1,925,000	2,086	2,958	505	1,930,549	2.05%	(1,925,000)
9/30/2005	100,000,000	2,204,859	3,126,475	533,807	94,134,860	0	1,925,000	2,129	3,018	515	1,930,662	2.05%	(1,925,000)
12/31/2005	100,000,000	2,202,686	3,123,394	533,281	94,140,638	0	1,925,000	2,172	3,080	526	1,930,779	2.05%	(1,925,000)
3/31/2006	100,000,000	2,200,470	3,120,251	532,744	94,146,535	0	1,925,000	2,217	3,144	537	1,930,897	2.05%	(1,925,000)
6/30/2006	100,000,000	2,198,207	3,117,043	532,197	94,152,553	0	1,925,000	2,262	3,208	548	1,931,018	2.05%	(1,925,000)
9/30/2006	100,000,000	2,195,899	3,113,769	531,638	94,158,695	0	1,925,000	2,309	3,274	559	1,931,141	2.05%	(1,925,000)
12/31/2006	100,000,000	2,193,542	3,110,428	531,067	94,164,962	0	1,925,000	2,356	3,341	570	1,931,267	2.05%	(1,925,000)
3/31/2007	100,000,000	2,191,138	3,107,019	530,485	94,171,358	0	1,925,000	2,404	3,409	582	1,931,396	2.05%	(1,925,000)
6/30/2007	100,000,000	2,188,684	3,103,539	529,891	94,177,886	0	1,925,000	2,454	3,479	594	1,931,527	2.05%	(1,925,000)
9/30/2007	100,000,000	2,186,180	3,099,988	529,285	94,184,547	0	1,925,000	2,504	3,551	606	1,931,661	2.05%	(1,925,000)
12/31/2007	100,000,000	2,183,625	3,096,365	528,666	94,191,344	0	1,925,000	2,555	3,624	619	1,931,798	2.05%	(1,925,000)
3/31/2008	100,000,000	2,181,017	3,092,667	528,035	94,198,281	0	1,925,000	2,608	3,698	631	1,931,937	2.05%	(1,925,000)
6/30/2008	100,000,000	2,178,356	3,088,893	527,390	94,205,361	0	1,925,000	2,661	3,774	644	1,932,079	2.05%	(1,925,000)
9/30/2008	100,000,000	2,175,640	3,085,042	526,733	94,212,585	0	1,925,000	2,716	3,851	658	1,932,225	2.05%	(1,925,000)
12/31/2008	100,000,000	2,172,868	3,081,112	526,062	94,219,958	0	1,925,000	2,772	3,930	671	1,932,373	2.05%	(1,925,000)
3/31/2009	100,000,000	2,170,040	3,077,101	525,377	94,227,482	0	1,925,000	2,828	4,011	685	1,932,524	2.05%	(1,925,000)
6/30/2009	100,000,000	2,167,153	3,073,008	524,678	94,235,160	0	1,925,000	2,886	4,093	699	1,932,678	2.05%	(1,925,000)
9/30/2009	100,000,000	2,164,208	3,068,831	523,965	94,242,996	0	1,925,000	2,946	4,177	713	1,932,836	2.05%	(1,925,000)
12/31/2009	100,000,000	2,161,201	3,064,569	523,237	94,250,993	0	1,925,000	3,006	4,263	728	1,932,997	2.05%	(1,925,000)
3/31/2010	100,000,000	2,158,134	3,060,219	522,495	94,259,153	0	1,925,000	3,068	4,350	743	1,933,161	2.05%	(1,925,000)
6/30/2010	100,000,000	2,155,003	3,055,779	521,737	94,267,481	0	1,925,000	3,131	4,439	758	1,933,328	2.05%	(1,925,000)
9/30/2010	100,000,000	2,151,808	3,051,249	520,963	94,275,980	0	1,925,000	3,195	4,530	773	1,933,499	2.05%	(1,925,000)
12/31/2010	100,000,000	2,148,548	3,046,626	520,174	94,284,653	0	1,925,000	3,260	4,623	789	1,933,673	2.05%	(1,925,000)
3/31/2011	100,000,000	2,145,220	3,041,908	519,368	94,293,504	0	1,925,000	3,327	4,718	806	1,933,851	2.05%	(1,925,000)
6/30/2011	100,000,000	2,141,825	3,037,093	518,546	94,302,536	0	1,925,000	3,396	4,815	822	1,934,032	2.05%	(1,925,000)
9/30/2011	100,000,000	2,138,360	3,032,179	517,707	94,311,754	0	1,925,000	3,465	4,914	839	1,934,218	2.05%	(1,925,000)
12/31/2011	100,000,000	2,134,823	3,027,165	516,851	94,321,161	0	1,925,000	3,536	5,014	856	1,934,407	2.05%	(1,925,000)
3/31/2012	100,000,000	2,131,215	3,022,048	515,977	94,330,761	0	1,925,000	3,609	5,117	874	1,934,600	2.05%	(1,925,000)
6/30/2012	100,000,000	2,127,532	3,016,825	515,086	94,340,557	0	1,925,000	3,683	5,222	892	1,934,797	2.05%	(1,925,000)
9/30/2012	100,000,000	2,123,773	3,011,496	514,176	94,350,555	0	1,925,000	3,758	5,329	910	1,934,998	2.05%	(1,925,000)
12/31/2012	100,000,000	2,119,938	3,006,057	513,247	94,360,757	0	1,925,000	3,835	5,439	929	1,935,203	2.05%	(1,925,000)
3/31/2013	100,000,000	2,116,024	3,000,507	512,300	94,371,169	0	1,925,000	3,914	5,550	948	1,935,412	2.05%	(1,925,000)
6/30/2013	100,000,000	2,112,030	2,994,843	511,332	94,381,795	-	1,925,000	3,994	5,664	967	1,935,625	2.05%	(1,925,000)
9/30/2013	100,000,000	2,107,953	2,989,063	510,346	94,392,638	0	1,925,000	4,076	5,780	987	1,935,843	2.05%	(1,925,000)
12/31/2013	100,000,000	2,103,793	2,983,164	509,338	94,403,704	0	1,925,000	4,160	5,899	1,007	1,936,066	2.05%	(1,925,000)
3/31/2014	100,000,000	2,099,548	2,977,145	508,311	94,414,997	0	1,925,000	4,245	6,020	1,028	1,936,293	2.05%	(1,925,000)
6/30/2014	100,000,000	2,095,216	2,971,001	507,262	94,426,521	0	1,925,000	4,332	6,143	1,049	1,936,524	2.05%	(1,925,000)
9/30/2014	100,000,000	2,090,795	2,964,732	506,191	94,438,282	0	1,925,000	4,421	6,269	1,070	1,936,761	2.05%	(1,925,000)
12/31/2014	100,000,000	2,086,283	2,958,334	505,099	94,450,284	0	1,925,000	4,512	6,398	1,092	1,937,002	2.05%	(1,925,000)
3/31/2015	100,000,000	2,081,678	2,951,805	503,984	94,462,532	0	1,925,000	4,604	6,529	1,115	1,937,248	2.05%	(1,925,000)
6/30/2015	100,000,000	2,076,980	2,945,143	502,847	94,475,031	0	1,925,000	4,699	6,663	1,138	1,937,499	2.05%	(1,925,000)
9/30/2015	100,000,000	2,072,184	2,938,343	501,686	94,487,787	0	1,925,000	4,795	6,800	1,161	1,937,756	2.05%	(1,925,000)

EXHIBIT NO.___(TKW-11)
SHEET 1 OF 4

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.7% Trust Originated Preferred Securities, Due September 15, 2043

Effective Rate: 2.05%
Internal Rate of Return = 2.05%
Annual Effective Rate = 8.20%

Quarterly Payment	Outstanding Principal	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Unamortized Balance: Debt Expense	Net Proceeds	Redemption	Interest Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Amortization of: Debt Expense	Total Expense	Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
12/31/2015	100,000,000	2,067,291	2,931,404	500,501	94,500,804	0	1,925,000	4,894	6,939	1,185	1,938,017	2.05%	(1,925,000)
3/31/2016	100,000,000	2,062,297	2,924,323	499,292	94,514,089	0	1,925,000	4,994	7,081	1,209	1,938,284	2.05%	(1,925,000)
6/30/2016	100,000,000	2,057,200	2,917,096	498,058	94,527,646	0	1,925,000	5,096	7,227	1,234	1,938,557	2.05%	(1,925,000)
9/30/2016	100,000,000	2,052,000	2,909,721	496,799	94,541,480	0	1,925,000	5,201	7,375	1,259	1,938,835	2.05%	(1,925,000)
12/31/2016	100,000,000	2,046,692	2,902,195	495,514	94,555,599	0	1,925,000	5,308	7,526	1,285	1,939,119	2.05%	(1,925,000)
3/31/2017	100,000,000	2,041,276	2,894,515	494,203	94,570,007	0	1,925,000	5,416	7,680	1,311	1,939,408	2.05%	(1,925,000)
6/30/2017	100,000,000	2,035,748	2,886,677	492,864	94,584,711	0	1,925,000	5,528	7,838	1,338	1,939,704	2.05%	(1,925,000)
9/30/2017	100,000,000	2,030,107	2,878,678	491,499	94,599,716	0	1,925,000	5,641	7,999	1,366	1,940,005	2.05%	(1,925,000)
12/31/2017	100,000,000	2,024,350	2,870,515	490,105	94,615,030	0	1,925,000	5,757	8,163	1,394	1,940,313	2.05%	(1,925,000)
3/31/2018	100,000,000	2,018,476	2,862,185	488,683	94,630,657	0	1,925,000	5,875	8,330	1,422	1,940,627	2.05%	(1,925,000)
6/30/2018	100,000,000	2,012,481	2,853,684	487,231	94,646,604	0	1,925,000	5,995	8,501	1,451	1,940,948	2.05%	(1,925,000)
9/30/2018	100,000,000	2,006,363	2,845,008	485,750	94,662,879	0	1,925,000	6,118	8,675	1,481	1,941,275	2.05%	(1,925,000)
12/31/2018	100,000,000	2,000,119	2,836,155	484,238	94,679,488	0	1,925,000	6,244	8,853	1,512	1,941,609	2.05%	(1,925,000)
3/31/2019	100,000,000	1,993,747	2,827,120	482,696	94,696,437	0	1,925,000	6,372	9,035	1,543	1,941,949	2.05%	(1,925,000)
6/30/2019	100,000,000	1,987,245	2,817,899	481,122	94,713,734	0	1,925,000	6,502	9,220	1,574	1,942,297	2.05%	(1,925,000)
9/30/2019	100,000,000	1,980,609	2,808,490	479,515	94,731,386	0	1,925,000	6,636	9,409	1,607	1,942,652	2.05%	(1,925,000)
12/31/2019	100,000,000	1,973,837	2,798,888	477,875	94,749,400	0	1,925,000	6,772	9,602	1,640	1,943,014	2.05%	(1,925,000)
3/31/2020	100,000,000	1,966,927	2,789,088	476,202	94,767,783	0	1,925,000	6,911	9,799	1,673	1,943,383	2.05%	(1,925,000)
6/30/2020	100,000,000	1,959,874	2,779,088	474,495	94,786,543	0	1,925,000	7,052	10,000	1,707	1,943,760	2.05%	(1,925,000)
9/30/2020	100,000,000	1,952,677	2,768,882	472,752	94,805,688	0	1,925,000	7,197	10,205	1,742	1,944,145	2.05%	(1,925,000)
12/31/2020	100,000,000	1,945,332	2,758,468	470,974	94,825,226	0	1,925,000	7,345	10,415	1,778	1,944,538	2.05%	(1,925,000)
3/31/2021	100,000,000	1,937,837	2,747,839	469,160	94,845,165	0	1,925,000	7,495	10,628	1,815	1,944,939	2.05%	(1,925,000)
6/30/2021	100,000,000	1,930,188	2,736,993	467,308	94,865,512	0	1,925,000	7,649	10,846	1,852	1,945,347	2.05%	(1,925,000)
9/30/2021	100,000,000	1,922,382	2,725,924	465,418	94,886,277	0	1,925,000	7,806	11,069	1,890	1,945,765	2.05%	(1,925,000)
12/31/2021	100,000,000	1,914,415	2,714,628	463,489	94,907,468	0	1,925,000	7,966	11,296	1,929	1,946,191	2.05%	(1,925,000)
3/31/2022	100,000,000	1,906,286	2,703,100	461,521	94,929,093	0	1,925,000	8,130	11,528	1,968	1,946,625	2.05%	(1,925,000)
6/30/2022	100,000,000	1,897,990	2,691,336	459,512	94,951,162	0	1,925,000	8,296	11,764	2,009	1,947,069	2.05%	(1,925,000)
9/30/2022	100,000,000	1,889,523	2,679,331	457,463	94,973,683	0	1,925,000	8,466	12,005	2,050	1,947,522	2.05%	(1,925,000)
12/31/2022	100,000,000	1,880,883	2,667,079	455,371	94,996,667	0	1,925,000	8,640	12,252	2,092	1,947,983	2.05%	(1,925,000)
3/31/2023	100,000,000	1,872,066	2,654,576	453,236	95,020,122	0	1,925,000	8,817	12,503	2,135	1,948,455	2.05%	(1,925,000)
6/30/2023	100,000,000	1,863,068	2,641,817	451,058	95,044,058	0	1,925,000	8,998	12,759	2,178	1,948,936	2.05%	(1,925,000)
9/30/2023	100,000,000	1,853,885	2,628,796	448,834	95,068,485	0	1,925,000	9,183	13,021	2,223	1,949,427	2.05%	(1,925,000)
12/31/2023	100,000,000	1,844,514	2,615,508	446,566	95,093,412	0	1,925,000	9,371	13,288	2,269	1,949,928	2.05%	(1,925,000)
3/31/2024	100,000,000	1,834,951	2,601,947	444,250	95,118,852	0	1,925,000	9,563	13,561	2,315	1,950,439	2.05%	(1,925,000)
6/30/2024	100,000,000	1,825,191	2,588,109	441,888	95,144,813	0	1,925,000	9,759	13,839	2,363	1,950,961	2.05%	(1,925,000)
9/30/2024	100,000,000	1,815,232	2,573,986	439,476	95,171,306	0	1,925,000	9,960	14,123	2,411	1,951,493	2.05%	(1,925,000)
12/31/2024	100,000,000	1,805,068	2,559,574	437,016	95,198,343	0	1,925,000	10,164	14,412	2,461	1,952,037	2.05%	(1,925,000)
3/31/2025	100,000,000	1,794,695	2,544,866	434,504	95,225,934	0	1,925,000	10,372	14,708	2,511	1,952,591	2.05%	(1,925,000)
6/30/2025	100,000,000	1,784,110	2,529,856	431,942	95,254,092	0	1,925,000	10,585	15,010	2,563	1,953,157	2.05%	(1,925,000)
9/30/2025	100,000,000	1,773,308	2,514,539	429,326	95,282,827	0	1,925,000	10,802	15,317	2,615	1,953,735	2.05%	(1,925,000)
12/31/2025	100,000,000	1,762,284	2,498,907	426,657	95,312,151	0	1,925,000	11,024	15,632	2,669	1,954,324	2.05%	(1,925,000)
3/31/2026	100,000,000	1,751,035	2,482,955	423,934	95,342,077	0	1,925,000	11,250	15,952	2,724	1,954,926	2.05%	(1,925,000)
6/30/2026	100,000,000	1,739,554	2,466,676	421,154	95,372,616	0	1,925,000	11,481	16,279	2,780	1,955,540	2.05%	(1,925,000)
9/30/2026	100,000,000	1,727,838	2,450,062	418,318	95,403,782	0	1,925,000	11,716	16,613	2,837	1,956,166	2.05%	(1,925,000)
12/31/2026	100,000,000	1,715,882	2,433,108	415,423	95,435,587	0	1,925,000	11,956	16,954	2,895	1,956,805	2.05%	(1,925,000)
3/31/2027	100,000,000	1,703,680	2,415,806	412,469	95,468,045	0	1,925,000	12,202	17,302	2,954	1,957,457	2.05%	(1,925,000)
6/30/2027	100,000,000	1,691,228	2,398,150	409,454	95,501,168	0	1,925,000	12,452	17,657	3,015	1,958,123	2.05%	(1,925,000)
9/30/2027	100,000,000	1,678,521	2,380,131	406,378	95,534,970	0	1,925,000	12,707	18,019	3,076	1,958,803	2.05%	(1,925,000)
12/31/2027	100,000,000	1,665,553	2,361,743	403,238	95,569,466	0	1,925,000	12,968	18,388	3,140	1,959,496	2.05%	(1,925,000)
3/31/2028	100,000,000	1,652,319	2,342,977	400,034	95,604,670	0	1,925,000	13,234	18,766	3,204	1,960,203	2.05%	(1,925,000)

EXHIBIT NO.___(TKW-11)
SHEET 2 OF 4

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.7% Trust Originated Preferred Securities, Due September 15, 2043

													Effective Rate
											Internal Rate of Return =		2.05%
		Unamortized Balance						Amortization of			Annual Effective Rate =		8.20%
Quarterly Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Net Proceeds	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
6/30/2028	100,000,000	1,638,814	2,323,827	396,765	95,640,595	0	1,925,000	13,505	19,150	3,270	1,960,925	2.05%	(1,925,000)
9/30/2028	100,000,000	1,625,031	2,304,283	393,428	95,677,257	0	1,925,000	13,782	19,543	3,337	1,961,662	2.05%	(1,925,000)
12/31/2028	100,000,000	1,610,966	2,284,339	390,023	95,714,672	0	1,925,000	14,065	19,944	3,405	1,962,414	2.05%	(1,925,000)
3/31/2029	100,000,000	1,596,613	2,263,986	386,548	95,752,854	0	1,925,000	14,354	20,353	3,475	1,963,182	2.05%	(1,925,000)
6/30/2029	100,000,000	1,581,965	2,243,215	383,001	95,791,818	0	1,925,000	14,648	20,771	3,546	1,963,965	2.05%	(1,925,000)
9/30/2029	100,000,000	1,567,017	2,222,019	379,382	95,831,582	0	1,925,000	14,948	21,197	3,619	1,964,764	2.05%	(1,925,000)
12/31/2029	100,000,000	1,551,762	2,200,387	375,689	95,872,162	0	1,925,000	15,255	21,631	3,693	1,965,580	2.05%	(1,925,000)
3/31/2030	100,000,000	1,536,194	2,178,312	371,920	95,913,574	0	1,925,000	15,568	22,075	3,769	1,966,412	2.05%	(1,925,000)
6/30/2030	100,000,000	1,520,307	2,155,784	368,074	95,955,835	0	1,925,000	15,887	22,528	3,846	1,967,261	2.05%	(1,925,000)
9/30/2030	100,000,000	1,504,094	2,132,794	364,148	95,998,964	0	1,925,000	16,213	22,990	3,925	1,968,128	2.05%	(1,925,000)
12/31/2030	100,000,000	1,487,548	2,109,333	360,142	96,042,976	0	1,925,000	16,546	23,461	4,006	1,969,013	2.05%	(1,925,000)
3/31/2031	100,000,000	1,470,663	2,085,390	356,055	96,087,892	0	1,925,000	16,885	23,943	4,088	1,969,916	2.05%	(1,925,000)
6/30/2031	100,000,000	1,453,432	2,060,957	351,883	96,133,729	0	1,925,000	17,231	24,434	4,172	1,970,837	2.05%	(1,925,000)
9/30/2031	100,000,000	1,435,847	2,036,022	347,625	96,180,505	0	1,925,000	17,585	24,935	4,257	1,971,777	2.05%	(1,925,000)
12/31/2031	100,000,000	1,417,902	2,010,575	343,281	96,228,242	0	1,925,000	17,945	25,446	4,345	1,972,736	2.05%	(1,925,000)
3/31/2032	100,000,000	1,399,589	1,984,607	338,847	96,276,957	0	1,925,000	18,313	25,968	4,434	1,973,715	2.05%	(1,925,000)
6/30/2032	100,000,000	1,380,900	1,958,106	334,322	96,326,672	0	1,925,000	18,689	26,501	4,525	1,974,715	2.05%	(1,925,000)
9/30/2032	100,000,000	1,361,827	1,931,062	329,705	96,377,406	0	1,925,000	19,072	27,044	4,618	1,975,734	2.05%	(1,925,000)
12/31/2032	100,000,000	1,342,364	1,903,463	324,993	96,429,181	0	1,925,000	19,464	27,599	4,712	1,976,775	2.05%	(1,925,000)
3/31/2033	100,000,000	1,322,501	1,875,297	320,184	96,482,018	0	1,925,000	19,863	28,165	4,809	1,977,837	2.05%	(1,925,000)
6/30/2033	100,000,000	1,302,231	1,846,554	315,276	96,535,938	0	1,925,000	20,270	28,743	4,908	1,978,921	2.05%	(1,925,000)
9/30/2033	100,000,000	1,281,545	1,817,222	310,268	96,590,965	0	1,925,000	20,686	29,332	5,008	1,980,027	2.05%	(1,925,000)
12/31/2033	100,000,000	1,260,435	1,787,288	305,157	96,647,120	0	1,925,000	21,110	29,934	5,111	1,981,155	2.05%	(1,925,000)
3/31/2034	100,000,000	1,238,892	1,756,740	299,942	96,704,427	0	1,925,000	21,543	30,548	5,216	1,982,307	2.05%	(1,925,000)
6/30/2034	100,000,000	1,216,907	1,725,565	294,619	96,762,909	0	1,925,000	21,985	31,175	5,323	1,983,482	2.05%	(1,925,000)
9/30/2034	100,000,000	1,194,471	1,693,751	289,187	96,822,591	0	1,925,000	22,436	31,814	5,432	1,984,682	2.05%	(1,925,000)
12/31/2034	100,000,000	1,171,574	1,661,284	283,644	96,883,497	0	1,925,000	22,896	32,467	5,543	1,985,906	2.05%	(1,925,000)
3/31/2035	100,000,000	1,148,209	1,628,152	277,987	96,945,653	0	1,925,000	23,366	33,133	5,657	1,987,155	2.05%	(1,925,000)
6/30/2035	100,000,000	1,124,364	1,594,340	272,214	97,009,083	0	1,925,000	23,845	33,812	5,773	1,988,430	2.05%	(1,925,000)
9/30/2035	100,000,000	1,100,030	1,559,834	266,322	97,073,814	0	1,925,000	24,334	34,506	5,891	1,989,731	2.05%	(1,925,000)
12/31/2035	100,000,000	1,075,196	1,524,621	260,310	97,139,873	0	1,925,000	24,833	35,213	6,012	1,991,059	2.05%	(1,925,000)
3/31/2036	100,000,000	1,049,854	1,488,685	254,175	97,207,286	0	1,925,000	25,343	35,936	6,136	1,992,414	2.05%	(1,925,000)
6/30/2036	100,000,000	1,023,991	1,452,013	247,913	97,276,083	0	1,925,000	25,862	36,673	6,261	1,993,796	2.05%	(1,925,000)
9/30/2036	100,000,000	997,599	1,414,588	241,523	97,346,290	0	1,925,000	26,393	37,425	6,390	1,995,207	2.05%	(1,925,000)
12/31/2036	100,000,000	970,664	1,376,396	235,002	97,417,938	0	1,925,000	26,934	38,192	6,521	1,996,647	2.05%	(1,925,000)
3/31/2037	100,000,000	943,178	1,337,420	228,348	97,491,055	0	1,925,000	27,487	38,976	6,655	1,998,117	2.05%	(1,925,000)
6/30/2037	100,000,000	915,128	1,297,645	221,557	97,565,671	0	1,925,000	28,050	39,775	6,791	1,999,617	2.05%	(1,925,000)
9/30/2037	100,000,000	886,502	1,257,053	214,626	97,641,818	0	1,925,000	28,626	40,591	6,930	2,001,147	2.05%	(1,925,000)
12/31/2037	100,000,000	857,289	1,215,630	207,554	97,719,527	0	1,925,000	29,213	41,424	7,073	2,002,709	2.05%	(1,925,000)
3/31/2038	100,000,000	827,477	1,173,357	200,336	97,798,830	0	1,925,000	29,812	42,273	7,218	2,004,303	2.05%	(1,925,000)
6/30/2038	100,000,000	797,054	1,130,216	192,970	97,879,760	0	1,925,000	30,423	43,140	7,366	2,005,929	2.05%	(1,925,000)
9/30/2038	100,000,000	766,006	1,086,191	185,454	97,962,349	0	1,925,000	31,047	44,025	7,517	2,007,589	2.05%	(1,925,000)
12/31/2038	100,000,000	734,322	1,041,263	177,783	98,046,632	0	1,925,000	31,684	44,928	7,671	2,009,283	2.05%	(1,925,000)
3/31/2039	100,000,000	701,988	995,414	169,955	98,132,644	0	1,925,000	32,334	45,850	7,828	2,011,012	2.05%	(1,925,000)
6/30/2039	100,000,000	668,990	948,624	161,966	98,220,420	0	1,925,000	32,997	46,790	7,989	2,012,776	2.05%	(1,925,000)
9/30/2039	100,000,000	635,316	900,874	153,813	98,309,997	0	1,925,000	33,674	47,750	8,153	2,014,577	2.05%	(1,925,000)
12/31/2039	100,000,000	600,951	852,145	145,493	98,401,411	0	1,925,000	34,365	48,729	8,320	2,016,414	2.05%	(1,925,000)
3/31/2040	100,000,000	565,882	802,416	137,003	98,494,700	0	1,925,000	35,070	49,729	8,491	2,018,289	2.05%	(1,925,000)
6/30/2040	100,000,000	530,093	751,668	128,338	98,589,902	0	1,925,000	35,789	50,749	8,665	2,020,202	2.05%	(1,925,000)
9/30/2040	100,000,000	493,570	699,878	119,496	98,687,057	0	1,925,000	36,523	51,789	8,842	2,022,155	2.05%	(1,925,000)

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.7% Trust Originated Preferred Securities, Due September 15, 2043

													Effective Rate
											Internal Rate of Return =		2.05%
		Unamortized Balance						Amortization of			Annual Effective Rate =		8.20%
Quarterly Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Net Proceeds	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
12/31/2040	100,000,000	456,297	647,026	110,472	98,786,204	0	1,925,000	37,272	52,852	9,024	2,024,148	2.05%	(1,925,000)
3/31/2041	100,000,000	418,261	593,091	101,263	98,887,386	0	1,925,000	38,037	53,936	9,209	2,026,181	2.05%	(1,925,000)
6/30/2041	100,000,000	379,444	538,049	91,865	98,990,642	0	1,925,000	38,817	55,042	9,398	2,028,257	2.05%	(1,925,000)
9/30/2041	100,000,000	339,831	481,878	82,275	99,096,017	0	1,925,000	39,613	56,171	9,590	2,030,374	2.05%	(1,925,000)
12/31/2041	100,000,000	299,405	424,555	72,487	99,203,552	0	1,925,000	40,425	57,323	9,787	2,032,536	2.05%	(1,925,000)
3/31/2042	100,000,000	258,151	366,056	62,500	99,313,294	0	1,925,000	41,255	58,499	9,988	2,034,741	2.05%	(1,925,000)
6/30/2042	100,000,000	216,050	306,357	52,307	99,425,286	0	1,925,000	42,101	59,699	10,193	2,036,992	2.05%	(1,925,000)
9/30/2042	100,000,000	173,086	245,434	41,905	99,539,575	0	1,925,000	42,964	60,923	10,402	2,039,289	2.05%	(1,925,000)
12/31/2042	100,000,000	129,240	183,262	31,290	99,656,209	0	1,925,000	43,846	62,173	10,615	2,041,633	2.05%	(1,925,000)
3/31/2043	100,000,000	84,495	119,814	20,457	99,775,234	0	1,925,000	44,745	63,448	10,833	2,044,026	2.05%	(1,925,000)
6/30/2043	100,000,000	38,833	55,064	9,402	99,896,701	0	1,925,000	45,663	64,749	11,055	2,046,467	2.05%	(1,925,000)
9/15/2043	100,000,000	(0)	(0)	0	100,000,000	100,000,000	1,604,167	38,833	55,065	9,402	1,707,465	2.05%	(101,604,167)
						$ 100,000,000	308,427,778	$ 2,221,449	$ 3,150,000	$ 537,824	$ 314,337,051		

EXHIBIT NO.___(TKW-11)
SHEET 4 OF 4

Volume III
Testimony
6

BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

CONCERNING

COMMON EQUITY COST RATE

RE: SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-___

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BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY

OF

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PRINCIPAL & DIRECTOR
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RE: SOUTHWEST GAS CORPORATION

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

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
FRANK J. HANLEY

I. INTRODUCTION

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, Mt. Laurel, New Jersey 08054.

Q. 2 Please summarize your educational background and professional experience.

A. 2 I have testified as an expert witness on rate of return and related financial issues before 33 state public utility commissions including the Arizona Corporation Commission, the District of Columbia Public Service Commission, the Public Services Commission of the Territory of the U.S. Virgin Islands, and the Federal Energy Regulatory Commission. I have also testified before local and county regulatory bodies, an arbitration panel, a U.S. Bankruptcy Court, the U.S. Tax Court and a state district court. I have appeared on behalf of investor-owned companies, municipalities, and state public utility commissions. The details of these appearances, as well as my educational background, are shown in Appendix A supplementing this testimony.

Q. 3 What is the purpose of your testimony?

A. 3 The purpose of my testimony is to provide evidence on behalf of Southwest Gas Corporation (Southwest or the Company) in the form of a study of the common

equity cost rate which it should be afforded an opportunity to earn on the common equity financed portion of its Arizona jurisdictional rate base and to support the reasonableness of the use of a hypothetical regulatory capital structure consisting of 51.00% long-term debt, 4.00% preferred equity and 45.00% common equity capital sponsored by Southwest witness Theodore K. Wood.

Q. 4 What is your recommended common equity cost rate?

A. 4 It is 11.25% if the requested 45.00% common equity ratio is approved. My recommended common equity cost rate would be higher if applicable to a lower common equity ratio due to a greater degree of financial risk.

Q. 5 Have you prepared exhibits which support your recommended common equity cost rates as well as the reasonableness of the requested capital structure and the resultant overall costs of capital?

A. 5 Yes, they have been marked for identification as Exhibits __ (FJH-1) through (FJH-14).

Q. 6 What is the resultant requested overall cost of capital utilizing your recommended common equity cost rate and the requested regulatory capital structure as well as the debt and preferred equity cost rates sponsored by Mr. Wood?

A. 6 As shown on Exhibit__(FJH-1), Sheet 1, it is 9.45% if the requested tariff tools are authorized.

II. SUMMARY

Q. 7 Please summarize your testimony.

A. 7 My summarization is divided into five sections as follows: (1) Southwest's Greater Risk, (2) Capital Structure, (3) Common Equity Cost Rate, (4) Reasonableness Check and (5) Conclusion.

A. Southwest's Greater Risk

Southwest is more risky than the average gas distribution company (LDC), as evidenced by its bottom of investment grade bond ratings by Moody's and Standard & Poor's (S&P) and its earned returns on common equity which have been substantially below those of comparable LDCs. Southwest's substandard earnings levels resulted in the inability to increase its common dividend for 13 years, that is, from the Spring of 1994 until the Spring of 2007. Nonetheless, extraordinary measures taken by management enabled the Company to maintain its high quality service.

In drawing conclusions about Southwest, it is important to do so in the context of comparison to other similar LDCs, such as a group of eight LDCs covered in Value Line's Gas Distribution Industry. Based on bond ratings and S&P business profiles, it is clear that Southwest is more risky than the proxy group of eight Value Line LDCs as illustrated in the following table:

	Bond Ratings and Business Profile		
	Moody's	S&P	
	Bond Rating	Bond Rating	Business Profile
Southwest	Baa3	BBB-	3.0
Proxy Group of Eight Value Line LDCs	A3	A	2.3

Source: Exhibit__(FJH-10), Sheet 2 of 9.

In addition, Southwest's higher risk attributes relative to the proxy group are as follows:

(1) The following table shows that Southwest's Arizona jurisdiction has experienced a totally substandard level of returns on its common equity investment, which was so low as to be below the yield on Moody's Baa rated public utility bonds in nine out of the ten years and averaged 141 basis points below the average yield on Baa rated public utility bonds over the ten-year period (7.13% - 5.72% = 1.41%);

Rates of Return
Earned on Book Common Equity 1997-2006

	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	Avg.
Southwest Gas	10.15%	6.02%	8.50%	5.60%	6.65%	5.79%	6.32%	6.89%	9.75%	2.87%	6.85%
Southwest Gas - Arizona Jurisdiction	5.99	(0.50)	4.18	4.10	7.23	7.39	5.65	7.18	12.93	3.08	5.72
Yield on Moody's Baa Rated P.U. Bonds	6.32	5.93	6.40	6.84	8.02	8.03	8.36	7.88	7.26	7.95	7.13
Proxy Group of Eight Value Line LDCs	12.52	12.33	11.25	11.88	12.29	13.55	10.66	12.34	11.26	12.78	11.83

Source: Exhibit__(FJH-1), Sheet 5 of 5

(2) Southwest's rapid growth and related essential capital expenditures for infrastructure development;

(3) Approximately ninety percent of the Company's gas distribution business is subject to historical ratemaking paradigms which exacerbate regulatory lag when combined with significant infrastructure development; and

(4) The loss of substantial net income attributable to the vagaries of the weather and declining per customer usage and the related unrealized operating margins as indicated below:

Susceptibility to the Impact of Weather
and Declining Per Customer Usage

	Tariff Mechanisms of Protection
Southwest	Arizona – None California – Margin Tracker Balancing Account Nevada – Innovative Weather Rate Design
Proxy Group of Eight Value Line LDCs	6 of 8 have some form of Revenue Normalization Decoupling Mechanism 7 of 8 have weather normalization adjustment clauses and/or other innovative weather rate design or some form of revenue decoupling mechanism

Source: Exhibit__(FJH-1), Sheet 4 of 5

All of the foregoing is reflected in Southwest's bottom of investment grade bond ratings (Moody's Baa3 and S&P's BBB-) as well as an assigned business profile of 3.0 by S&P which indicates even greater risk vis-à-vis the proxy group which has an average assigned business profile of 2.3. A bond/credit rating at the bottom of investment grade means greater credit risk which in turn means greater cost to customers and greater risk to common shareholders, as the next downward rating change would be to below investment grade.

B. Capital Structure

Southwest made substantial progress in increasing its common equity ratio. As Mr. Wood explains in his testimony, the Company not only reached a 40% common equity ratio since the Commission's Order in the last rate case, but achieved a common equity ratio of 42.9% at April 30, 2007. Mr. Wood further explains how the Company accomplished this significant improvement in its common equity ratio.

The recommended capital structure containing a 45% target common equity is about equal to the average ratio of approximately 45 percent, based on total capital employed including short-term debt maintained by the proxy group of eight Value Line LDCs as shown on Exhibit__ (FJH-4), Sheet 1 of 3. However, the requested target ratio of 45% is considerably less than the approximately 52-53% maintained on average by the proxy group in 2006 and for the five years then ended based on permanent capital employed, i.e., excluding short-term debt, also shown on Exhibit__(FJH-4), Sheets 1 and 3.

Based on S&P's financial metrics as to bond rating and business profile, as shown on Exhibit__(FJH-2), Sheet 14, it can be determined that the requested target capital structure, in concert with the requested tariff changes which will go a long way toward increasing stability of authorized operating margins, will afford the Company a reasonable opportunity over time to achieve an A bond rating. For an A bond rating and a business profile of "3", S&P requires total equity in the range of 45-50% (the complement of total debt range of 50-55%). The requested 4% preferred equity equates to approximately 1.6% common equity equivalent as

represented to Southwest by S&P (40% of 4%). Thus, 1.6% plus the target common equity ratio of 45% equals 46.6%, which is within the range specified by S&P.

C. Common Equity Cost Rate

The Efficient Market Hypothesis (EMH) is the foundation of modern investment theory. It tells us that investors (except those who illegally use insider information) take into account all publicly-available information which is then fully reflected in securities' prices. Common sense affirms this proposition to be true as the markets constantly reflect the processing of new information. Inasmuch as the financial literature discusses multiple cost of common equity models – and actually encourages their use – it is logical to assume that investors rely upon multiple models and avoid exclusive reliance upon any single cost of common equity model. Consequently, consideration must be given to the four principal cost of common equity models which are discussed in the literature: the Discounted Cash Flow Model (DCF), the Risk Premium Model (RPM), the Capital Asset Pricing Model (CAPM) and the Comparable Earnings Model (CEM). In the manner which I utilize them, all of them are market-based.

Although there are a number of forms of the DCF model which can be used, I rely upon the constant growth form. Forms of the model such as two- or three-stage growth models are inappropriate for mature LDCs that are not facing transition to a fully competitive environment.

The growth in the DCF model is a substitute for expected growth in market price (capital) appreciation. Analysts' growth forecasts in earnings per share (EPS) have significant impact on market prices. Even casual observers of the market are

aware that it is the expectation of earnings that is the primary driver of market prices. Thus, the use of analysts' forecasted growth in EPS is the best proxy for growth in market price.

DCF cost rates tend to understate investors' required rate of return when market values exceed the book values of the common stocks of utility companies, and vice versa. Consequently, the DCF cost rates for Southwest and the proxy group are not indicative of investors' required rate of return when those market-based cost rates are applied to a lower book value, i.e., the common equity financed portion of an original cost rate base.

As a result of my analyses and consideration of all of the cost of common equity models and other pertinent information, I conclude that a common equity cost rate of 11.25% is applicable to Southwest's proposed 45% common equity ratio.

The results of the financial models for Southwest and the proxy group both result in an 11% equity cost rate, as shown on Sheet 2, Line 5 of Exhibit __ (FJH-1). However, the adverse impact of weather and declining usage per customer on Southwest's revenues and earnings and the lack of rate design mechanisms to minimize or obviate the same, has made Southwest more risky vis-à-vis the proxy group and has resulted in bottom of investment grade bond ratings and a more risky S&P business profile. For these reasons, a common equity cost rate of 11.00% based on Southwest's own data is counter-intuitive, i.e., understated vis-à-vis a similar cost rate of 11.00% applicable to the considerably less risky proxy group which has an S&P bond rating of A and an average business profile of "2.3" (versus Southwest's BBB- bond rating and business profile of "3.0"). Therefore, I provide far greater

weight to the cost rate of 11.00% for the less risky proxy group. However, that cost rate must be adjusted upward so that the cost rate derived from the proxy group will be applicable to Southwest, which is more risky. As shown on Sheet 2, Line 6 of Exhibit__(FJH-1), such adjustment is 0.31%, or 31 basis points. Another reason I provide far greater weight to the cost rate results for the proxy group is that the landmark Hope and Bluefield cases (see cites infra) require the use of comparable firms. The use of a number of comparable firms, i.e., proxy group, adds reliability to the conclusions reached and lessens the likelihood of inadvertent reliance upon data derived from extraordinary circumstances of a single company which often affects indicators of common equity cost rate. Consequently, after observing common equity cost rate results (Sheet 2, Line 7 of Exhibit__(FJH-1)) of 11.00% for Southwest and 11.31% for the proxy group, I conclude that a cost rate of 11.25% is applicable to Southwest's requested 45% common equity.

D. Reasonableness Check

As shown by the information contained in Exhibit__(FJH-14), regulatory awards made to gas distribution companies in fully litigated cases during the period April 1, 2006 through March 31, 2007 averaged 10.48% relative to a common equity ratio of 45.92%. Those companies that received the awards, on average, had a debt/credit rating of A. Thus, these data indicate that my recommended common equity cost rates are reasonable when it is considered that Southwest has bond ratings of Moody's Baa3 and S&P's BBB-, both of which are at the bottom of investment grade. In addition, when it is also considered that Southwest has had neither a weather normalization adjustment clause (WNC) nor any type of revenue decoupling

mechanism (RDM) to protect against the impact of weather on its earnings, and declining per customer usage, my recommendation(s) are reasonable. As shown on Exhibit__(FJH-14), the average equity risk premium over A rated utility bonds in all of the fully litigated cases was 459 basis points, or 4.59 percentage points (4.59%). As will be shown herein, the prospective yield on A rated utility bonds is 6.60%, thereby indicating a cost rate of 11.19% (6.60% + 4.59%) applicable to a less risky LDC whose debt credit rating is A, which supports the reasonableness of my recommendation for Southwest, whose debt is rated Baa3/BBB-, as discussed supra.

E. Conclusion

The foregoing summary demonstrates that the requested regulatory capital structure, which includes a 45% common equity ratio, the requested tariff mechanisms, and the 11.25% common equity cost rate, are reasonable and should be approved.

III. GENERAL PRINCIPLES

Q. 8 What general principles have you considered in arriving at your recommended common equity cost rate of 11.25%?

A. 8 In unregulated industries, competition is the principal determinant in establishing the price of the product or service. For price-regulated utilities, the regulatory process becomes the substitute for the missing competition; however, the natural gas distribution business has become increasingly competitive. Investors reflect their awareness of the increased competition in the market prices they pay for securities. Analyses based on companies whose securities are traded is essential when evaluating capital structure and its component cost rates. The common equity cost

rate should be adequate enough to fulfill investors' requirements and assure that the utility will be able to fulfill its obligations to its customers. A utility's obligation to serve requires a level of earnings sufficient to maintain the integrity of presently invested capital and permit the attraction of needed new capital at a reasonable cost in competition with other comparable-risk seekers of capital. These standards for a fair rate of return have been established by the U.S. Supreme Court in the Hope[1] and Bluefield[2] cases.

IV. BUSINESS RISK

Q. 9 Please define business risk and explain why it is important to the determination of a fair rate of return.

A. 9 Business risk is a collective term encompassing all of the diversifiable risks of an enterprise except financial risk. Business risk is important to the determination of a fair rate of return because the greater the level of risk, the greater the rate of return demanded by investors consistent with the basic financial precept of risk and return.

Q. 10 Are there any extraordinary business risks which affect Southwest?

A. 10 Yes. Southwest faces many of the same risks as other LDCs in today's increasingly competitive environment. These risks include the threat of bypass; uncertainty associated with the unbundling of services behind the city-gate; increased competition from, among others, gas marketers, interstate pipelines and electric utilities through integrated resource plans, and industry mergers and acquisitions. In addition, Southwest has the potential for significant revenue and earnings volatility

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1 Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

2 Bluefield Water Works Improvement Co. v. Public Serv. Comm'n, 262 U.S. 679 (1922).

(classic signs of greater business risk) due to its lack of protection from the vagaries of weather, declining per customer usage and a rate of customer growth which is among the highest in the nation.

In contrast to Southwest's total exposure to the vagaries of weather and declining per customer usage, almost all of my proxy group companies have degrees of protection from these factors. Of the proxy group of eight Value Line LDCs, seven have either a WNC and/or some type of innovative rate design or revenue decoupling mechanism (Sheet 4 of Exhibit__(FJH-1)).

The extraordinarily low achieved rates of earnings on the common equity financed portion of the total Arizona rate base is apparent by comparison to the achieved rates of earnings on book common equity of the proxy group of eight Value Line LDCs. I chose to make such comparison beginning with 1997, the first full year without PriMerit Bank being part of Southwest, in order to obviate controversy. The comparative rates are shown on Exhibit__(FJH-1), Sheet 5. As shown, the proxy group achieved an average ROE over the ten-year period of 11.83% while Southwest achieved an average of only 6.85% and the Arizona jurisdiction earned only 5.72% on average over the ten-year period, both of which were lower than the average yield on Moody's Baa rated public utility bonds during the same period.

The inordinately low achieved ROEs have been a major factor in Southwest's bottom of investment grade bond rating. The inadequate achieved ROEs are attributable to lower than average authorized ROEs exacerbated by the inability to earn them.

V. FINANCIAL RISK

Q. 11 Please define financial risk and explain why it is important to the determination of a fair rate of return.

A. 11 Financial risk is the additional risk created by the introduction of debt into the capital structure. Standard & Poor's (S&P) corporate bond rating criteria is contained in Exhibit__(FJH-2), which consists of 15 sheets. Sheet 14 contains S&P's target financial metrics for ten levels of business profiles at different bond ratings with "1" considered the lowest risk and "10" the highest risk.

Q. 12 Are bond ratings a good measure of investment risk?

A. 12 Yes. Similar bond ratings reflect similar combined business and financial risks. Although the specific business or financial risks may differ between companies, the same bond rating indicates that the combined risks are similar because the bond rating process recognizes diversifiable business and financial risks. S&P expressly states that the bond rating process encompasses a qualitative analysis of business and financial risks (Sheets 3 through 9 of Exhibit__(FJH-2)). Differences in risk may still exist between companies with the same bond rating and are reflected in S&P's assigned business profile, i.e., the higher the assigned number (e.g., "1" through "10"), the greater the risk, and vice versa. The riskier the assigned business profile, the more stringent the financial metrics. It is noteworthy that Southwest's S&P bond rating is "BBB-" and has an assigned business profile of "3.0" in contrast to the average company in the proxy group (which will be discussed infra) which has an average S&P bond rating of "A" and a less risky business profile of "2.3".

Although there is no perfect proxy by which one can differentiate common

equity risk between companies, the bond rating provides excellent insight because it is the result of a thorough and comprehensive analysis of all diversifiable investment risks.

VI. SOUTHWEST GAS CORPORATION

Q. 13 Have you reviewed financial data for Southwest?

A. 13 Yes. Southwest is principally engaged in natural gas operations providing distribution service in Arizona, Nevada and California as well as transportation service through Southwest's wholly-owned pipeline subsidiary, Paiute Pipeline Company. At calendar year-end 2006, Southwest served nearly 1.8 million customers. Customer growth has been about 6% in Nevada and 4% in Arizona, well above the national average.

I have shown Southwest's capitalization and financial statistics for the years 2002-2006, inclusive on Sheet 1 of Exhibit__(FJH-3). Notes relevant to Sheet 1 are shown on Sheet 2. As shown on Sheet 1, Southwest's average achieved rate of earnings on book common equity during the 2002-2006 period was just 7.38% and its average market/book ratio was 132.83%, while the average dividend payout ratio was 63.30%.

VII. PROXY GROUP

Q. 14 You previously mentioned that you also observe the market data for a proxy group of LDCs in order to gain insight into a market-based common equity cost rate for Southwest. Please explain how you selected the proxy group of eight Value Line LDCs.

A. 14 The basis of selection was to include those gas distribution companies: 1) which are

included in Value Line Investment Survey's (Standard Edition) – Natural Gas (Distribution) Industry; 2) which have actively traded common stock; 3) which have not cut or omitted their common stock dividend during the five calendar years ending 2006 and up to the time of the preparation of this direct testimony; 4) which at the time of the preparation of this testimony had not announced any merger or acquisition plans; 5) which in 2006 had at least 50% of operating revenues and at least 50% of net operating income derived from gas distribution operations; and 6) which are included in S&P's Compustat PC Plus Research Insight Data Base.

Southwest was not included because it is the Company at issue in this proceeding and is analyzed by itself. As discussed supra, Southwest's indicated common equity cost rates are counter-intuitive vis-à-vis the greater reliability of the use of a proxy group of eight comparable, albeit less risky, gas distribution companies.

The financial profile of the eight companies is summarized in Exhibit__(FJH-4).

Q. 15 Please describe Exhibit__(FJH-4).

A. 15 Exhibit__(FJH-4) contains average comparative capitalization and financial statistics for the proxy group of eight Value Line LDCs for the years 2002 through 2006. It consists of three sheets. Sheet 1 contains a summary of the comparative financial data for the years 2002-2006. Sheet 2 contains notes relevant to Sheet 1, as well as the selection criteria and identity of the individual companies in the proxy group. Sheet 3 contains the capital structure ratios based upon permanent capital for each company as well as group averages by year and company/group averages for the five

years.

As shown on Sheet 1, during the five-year period ending 2006, the achieved average earnings rate on book common equity (ROE) and market/book ratio were 11.99% and 178.20%, respectively, while the average dividend payout ratio was 69.50%.

VIII. CAPITAL STRUCTURE

Q. 16 Do you believe the target capital structure ratios requested by Southwest and supported by Mr. Wood are reasonable?

A. 16 Yes. I believe that the requested target capital structure ratios consisting of 51% long-term debt, 4% preferred equity and 45% common equity are reasonable. A 45% common equity ratio is similar to the average ratios maintained by the proxy group of eight Value Line LDCs including short-term debt but much less than the approximate 53% common equity which they maintain based on total permanent capital, i.e., excluding short-term debt.

If the requested target capital structure ratios are utilized, they will afford Southwest the opportunity over time to obtain a higher S&P bond/credit rating of A. Those ratios fit within the S&P debt to equity financial metric for an A bond/credit rating with a business profile of "3". Of course, other financial metrics will also need to be achieved consistently over time. Given Southwest's proven susceptibility to the adverse impacts of weather and declining per customer usage on revenues and earnings, approval of the requested tariff tools is critical to alleviating this susceptibility and to provide Southwest the opportunity to achieve S&P's financial metrics as well as Moody's relatively new metrics for the gas distribution industry.

It is most important that Southwest have the opportunity to upgrade its bond/credit ratings as the next downward change from Baa3/BBB- will be to below investment grade, i.e., Ba1 and BB+, which would be disastrous for any utility but especially so for Southwest, which is one of the fastest growing LDCs in the U.S. As such, it is imperative that Southwest have access to the capital markets at all times on a reasonable cost basis.

Moody's[3] has stated:

> LDCs that have, or soon expect to have, RD (revenue decoupling) stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in face of adversity. *This difference between those companies that have RD and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident.* (italics added for emphasis)
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> In attempting to grapple with the conservation issue, LDCs are in fact, having to dispel the notion that their fixed charges should be recovered from volumetric sales of gas. *As the fixed charges appear year in and year out regardless of gas usage, the volumetric approach to cost recovery for operating a gas distribution system is a faulty equation which needs to be rectified in ratemaking.* (italics added for emphasis)

IX. COMMON EQUITY COST RATE MODELS

A. The Efficient Market Hypothesis (EMH)

Q. 17 Are all of the models you employ market-based?

A. 17 Yes. The DCF model is market-based as current market prices are employed. The Risk Premium Model (RPM) is market-based as the current and expected bond

[3] Moody's Investors Service – Global Credit Research June 2006 – Special Comment – Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings, pp. 1, 4.

ratings and yields reflect the market's assessment of risk. To the extent betas are used to determine equity risk premium, the market's assessment is reflected because betas are derived from regression analyses of market prices. The Capital Asset Pricing Model (CAPM) model is market-based for much the same reason as the RPM except that the yield on U.S. Government Treasury Bonds is used in lieu of company-specific bond yields. My application of the Comparable Earnings Model (CEM) is also market-based because the selection process of comparable risk domestic, non-price regulated, companies is based upon statistics which result from regression analyses of market prices. All of the models are, therefore, based upon the Efficient Market Hypothesis (EMH).

Q. 18 Please describe the conceptual basis of the EMH.

A. 18 The EMH is the cornerstone of modern investment theory. It was pioneered by Eugene F. Fama[4] in 1970. An efficient market is one in which security prices at all times reflect all the relevant information at that time. An efficient market implies that prices adjust instantaneously to the arrival of new information and that the process therefore reflects the intrinsic fundamental economic value of a security.[5]

The essential components of the EMH are:

1. Investors are rational and will invest in assets which provide the highest expected return for a particular level of risk.

2. Current market prices reflect all publicly available information.

3. Returns are independent in that today's market returns are unrelated to yesterday's returns as that information has already been processed.

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4 Fama, Eugene F., "Efficient Capital Markets: A Review of Theory and Empirical Work", Journal of Finance, May 1970, pp. 383-417.

5 Morin, Roger A., "New Regulatory Finance", Public Utilities Reports, Inc., 2006, pp. 279-281.

4. The markets follow a random walk, i.e., the probability distribution of expected returns approximates the normal bell curve.

Brealey and Myers[6] state:

> When economists say that the security market is 'efficient", they are not talking about whether the filing is up to date or whether desktops are tidy. They mean that information is widely and cheaply available to investors and that all relevant and ascertainable information is already reflected in security prices.

There are three forms of the EMH, namely:

1. The "weak" form asserts that all past market prices and data are fully reflected in securities prices. In other words, technical analysis cannot enable an investor to "outperform the market".

2. The "semistrong" form asserts that all publicly available information is fully reflected in securities prices. In other words, fundamental analysis cannot enable an investor to "outperform the market".

3. The "strong" form asserts that all information, both public and private, is fully reflected in securities prices. In other words, even insider information cannot enable an investor to "outperform the market".

The "semistrong" form is generally held as true because the illegal use of insider information can enable an investor to "beat the market" and earn excessive returns, thereby disproving the "strong" form.

Q. 19 Please explain the applicability of the EMH to your determination of common equity cost rate.

A. 19 Common sense affirms the conceptual basis of the EMH as described above. In practical terms, this means that market prices paid for securities reflect all relevant information available to investors and that no degree of sophistication and/or analysis can enable investors to consistently outperform the market. Consequently,

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6 Brealey, R.A. and Myers, S.C., "Principles of Corporate Finance". McGraw-Hill Publications, Inc., 1996, pp. 323-324.

it confirms that all perceived risks are taken into account by investors in the prices they pay which reflect the information inexpensively or freely available such as bond ratings; analyses of the rating agencies and financial analysts, and the various methodologies employed to determine common equity cost rate as discussed in the academic and financial literature. Thus, in an attempt to emulate investors' actions, it is necessary to take into account the results of multiple cost of common equity models.

Q. 20 Is there specific support in the academic and financial literature for the need to rely upon multiple cost of common equity models in arriving at a recommended common equity cost rate?

A. 20 Yes. For example, Phillips[7] states:

> Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. *For these reasons, the DCF model 'suggests a degree of precision which is in fact not present' and leaves 'wide room for controversy and argument about the level of k'.* (italics added) (p. 396)
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> *Despite the difficulty of measuring relative risk, the comparable earnings standard is no harder to apply than is the market-determined standard. The DCF method, to illustrate, requires a subjective determination of the growth rate the market is contemplating. Moreover, as Leventhal has argued: 'Unless the utility is permitted to earn a return comparable to that available elsewhere on similar risk, it will not be able in the long run to attract capital'.* (italics added) (p. 398)

Also, Morin[8] states:

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7 Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, 1993, Public Utility Reports, Inc., Arlington, VA, pp. 396, 398.

8 Id., at pp. 428, 430-431.

Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate a theory. *The inability of the DCF model to account for changes in relative market valuation, discussed below, is a vivid example of the potential shortcomings of the DCF model when applied to a given company.* Similarly, the inability of the CAPM to account for variables that affect security returns other than beta tarnishes its use. (italics added)

No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. (Morin, p. 428)

* * *

The financial literature supports the use of multiple methods. Professor Eugene Brigham, a widely respected scholar and finance academician, asserts:[1](footnote omitted)

> Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) method, and (3) the bond-yield-plus-risk-premium approach. These methods are not mutually exclusive – no method dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand.

Another prominent finance scholar, Professor Stewart Myers, in an early pioneering article on regulatory finance, stated:[2](footnote omitted)

> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.

> Reliance on multiple tests recognizes that no single methodology produces a precise definitive estimate of the cost of equity. As stated in Bonbright, Danielsen, and Kamerschen (1988), '*no single or group test or technique is conclusive.*' Only a fool discards relevant evidence. (italics in original) (Morin, p. 430)
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> * * *
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> While it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. Sole reliance on the DCF model ignores the capital market evidence and financial theory formalized in the CAPM and other risk premium methods. The DCF model is one of many tools to be employed in conjunction with other methods to estimate the cost of equity. *It is not a superior methodology that supplants other financial theory and market evidence. The broad usage of the DCF methodology in regulatory proceedings in contrast to its virtual disappearance in academic textbooks does not make it superior to other methods. The same is true of the Risk Premium and CAPM methodologies.* (italics added) (Morin, p. 431)

In view of the foregoing, it is clear that investors are aware of all of the models including comparable earnings. The EMH requires the assumption that investors use them all.

B. Discounted Cash Flow Model (DCF)

1. Theoretical Basis

Q. 21 What is the theoretical basis of the DCF model?

A. 21 DCF theory is based upon finding the present value of an expected future stream of net cash flows during the investment holding period discounted at the cost of capital, or the capitalization rate. The theory suggests that an investor buys a stock for an expected total return rate which is expected to be derived from cash flows in the form of dividends and appreciation in market price, i.e., the expected growth rate.

Thus, the dividend yield on market price plus a growth rate equals the capitalization rate. The capitalization rate is the total return rate expected by investors.

Q. 22 Please comment on the applicability of the DCF model in establishing the cost rate of common equity capital for Southwest.

A. 22 As discussed supra, it is necessary to determine common equity cost rates based on the utility proxy group and Southwest and adjust those cost rates upward to reflect Southwest's and the Arizona jurisdictions' greater investment risk, respectively. The proxy group has less investment risk than Southwest, reflected in better bond ratings, i.e., Moody's A3 and S&P's A versus Southwest's Moody's Baa3 and S&P's BBB-. In addition, the proxy group has a lower, i.e., less risky average S&P business profile of 2.3 versus Southwest's 3.0.

The DCF model has a tendency to mis-specify investors' required return rate when the market value of common stock differs significantly from its book value, as will be discussed infra in detail. Market values and book values of common stocks are seldom at unity. For example, the average market values of companies in the LDC proxy group have been well in excess of their book values. As shown on Sheet 1 of Exhibit__(FJH-4), the average company in the proxy group of eight Value Line LDCs sold at 186.27% of its book value in 2006.

A market-based DCF cost rate will result in a total annual dollar return on book common equity equal to the total annual dollar return expected by investors only when market and book values are equal. A DCF cost rate produces the investor-required return on the market value, the application of which to a lower book value will result in a lower return in dollars. There are many macroeconomic

factors which influence market values because, as explained infra, regulatory allowed earnings can only influence market values but cannot control them.

2. Applicability of a Market-Based Common Equity Cost Rate to a Book Value Rate Base

Q. 23 Are the market prices of public utilities' stocks influenced by factors beyond the influence of the regulatory process?

A. 23 Yes. For example, Phillips[9] states:

> *Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.'* (italics added)

In addition, Bonbright[10] states:

> *In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market. In short, market prices are beyond the control, though not beyond the influence of rate regulation.* (italics added)

Q. 24 Because market prices are beyond the control of rate regulation, does a DCF cost rate reflect investors' required rate of return when applied to a book value which differs from its market value?

A. 24 No. Under the DCF model, the rate of return investors require is related to the price paid for a stock. Thus, market price is the basis upon which investors formulate their required rate of return. A regulated utility (under the traditional rate base/rate of

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9 Id., p. 395.

10 James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, 1998, Public Utilities Reports, Inc., Arlington, VA, p. 334.

return paradigm) is limited to earning on its net book value (depreciated original cost) rate base. Market values diverge from book values for many reasons unrelated to allowed and/or achieved rates of earnings on book common equity (ROEs). Thus, when market values depart from book values, a market-based DCF cost rate applied to the book value of common equity will not reflect investors' expected common equity cost rate based on market prices. This is true because there are many macroeconomic factors which influence the demand for, and hence the market prices of, common stocks in addition to company-specific earnings per share (EPS) and dividends per share (DPS). Consequently, a market-based DCF cost rate applied to the book value per share will either overstate investors' required common equity cost rate when market value is less than book value or understate investors' required common equity cost rate when market value is above book value. In the late 1970's and early 1980's, when interest rates were extraordinarily high and the market-to-book ratios of utilities averaged below unity, i.e., one, the DCF model overstated investors' required common equity cost rate.

Some regulatory commissions have recognized the tendency of DCF cost rates to understate investors' required rates of return when the market-to-book ratio is in excess of one (see cites infra). In recent years, as well as currently, with relatively low interest rates and utility market-to-book ratios consistently averaging well above one, the DCF model typically understates investors' required common equity cost rate. For this reason, throughout more than 30 years as a rate of return witness, I have consistently recommended the use of multiple common equity cost

rate models in the application of expert judgment in forming a recommendation as to a utility's common equity cost rate.

Q. 25 Can you demonstrate how a market-based DCF cost rate either understates or overstates investors' required rate of return on book common equity when the market value of common equity is above or below its book value, respectively?

A. 25 Yes. Exhibit__(FJH-5) demonstrates how a market-based DCF cost rate applied to a significantly different book value will either understate or overstate investors' required return rate on market price.

Investors require a rate of return on their investment which is the market price they pay for a stock. The hypothetical illustration on Exhibit__(FJH-5) demonstrates that the expected market-based rate of return is either under-achieved or over-achieved. In the first hypothetical example (refer to columns 1 and 2), market price is 80% in excess of its book value and investors expect a total return rate of 10.00% on market price, based on a growth rate of 6.00% and a dividend yield of 4.00%. As shown, when the 10.00% return rate is applied to the book value, which is only 55.54% of the market value, or $13.33, the opportunity for total annual return is only $1.333 on book value (10.00% x $13.33) and not $2.40 (10.00% return on $24 market value). With an annual dividend of $0.96, there is an opportunity to earn only $0.373 in growth which is just 1.55% on the $24 market price in contrast to the 6.00% growth rate in market price expected by investors. Conversely, if market value is less than book value (refer to columns 1 and 3), a market-based DCF cost rate when applied to a greater book value will result in an overstatement of investors' required rate of return related to the book value of common equity.

The Pennsylvania PUC recognized this tendency by utilizing an adjusted DCF cost rate. It did so in re: Aqua Pennsylvania Water Company (R-00038805) in its Order entered August 8, 2004 and also in Pennsylvania Power & Light Company (R-00049255) in its Order entered December 22, 2004. In the December Order, the PA PUC stated:

> We find it reasonable that a financial risk adjustment, as proposed by PPL, is necessary to compensate PPL for the mismatched application of a market-based cost of common equity to a book value common equity ratio. The adjustment is necessary because the DCF method produces the investor-required return based on the current market price, not the return on the book value capitalization.

The Indiana Utility Regulatory Commission (IURC) also recognized the tendency of the DCF model to understate the cost of equity when market value exceeds book value[11]:

> In determining a common equity cost rate, we must again recognize the tendency of the traditional DCF model, . . . to understate the cost of common equity. As the Commission stated in Indiana-Mich. Power Co. (BPU 8/24/90), Cause No. 38728, 116 PUR 4th 1, 17-18, *"the unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible, and therefore, requires an upward adjustment based largely on the expert witness's judgement."* (italics added)

And, in its June 17, 1994 Final Decision and Order in Re U.S. West Communications, Docket No. RPU-93-9, the Iowa Utilities Board stated:[12]

> While the Board has relied in the past on the DCF model, in *Iowa Electric Light and Power Company*, Docket No. RPU-89-9, "Final Decision and Order" (October 15, 1990), the Board stated: *'[T]he DCF model may understate the return on equity in some circumstances. This is particularly true when the market is relatively*

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11 Re: Indiana-American Water Company, Inc., Cause No. 39595, 150 PUR4th at 167-168.

12 Re: U.S. West Communications, Inc., Docket No. RPU-93-9, 152 PUR4th at 459.

volatile and the company in question has a market-to-book ratio in excess of one." Those conditions exist in this case and the Board will not rely on the DCF return. (Consumer Advocate Ex. 367, See Tr. 2208, 2250, 2277, 2283-2284). *The DCF approach underestimates the cost of equity needed to assure capital attraction during this time of market uncertainty and volatility. The Board will, therefore, give preference to the risk premium approach.* (italics added)

3. Constant Growth Model

Q. 26 Please explain the form of the DCF model you employ and why?

A. 26 I utilize the constant growth form of the model because it is by far the most widely utilized in public utility rate regulation. I believe it is widely utilized because most utilities are in a mature state, i.e., they are not in transition from one phase of growth to another. For example, a starting company will go through various phases of growth until it reaches maturity. Most utilities that are not transitioning from a regulated monopoly to a competitive environment are in the mature stage. Thus, there is no basis for using multi-stage growth DCF models. Moreover, for investors, long-term is really five years because five years is the maximum length of analysts' projections. Further, there is no empirical evidence which confirms that the rate of growth would change to some arbitrary rate(s), e.g., the long-term growth rate in gross domestic product. Consequently, in the instant matter, the constant growth model is most appropriate.

4. Application of the DCF Model

a. Dividend Yield

Q. 27 What unadjusted dividend yields do you utilize and why?

A. 27 The recent volatility of the stock market confirms that spot prices should not be relied on exclusively. Conversely, reliance on too long of a historical period would

not be representative of the future due to an increasingly competitive environment in the energy industries as well as a volatile stock market. Consequently, I rely on an average of recent spot prices on June 25, 2007 and average of the high and low market prices for the months of April and May 2007 as shown by company/group on Exhibit__(FJH-7). The average unadjusted dividend yields are 2.34% for Southwest and 3.76% for the proxy group of eight Value Line LDCs, respectively, as shown on Exhibit__(FJH-6), Column 1. Details are shown by company on Exhibit__(FJH-7).

b. Discrete Adjustment of Dividend Yield

Q. 28 Please explain the adjustments for discrete growth in dividends as shown in Column 2 of Exhibit__(FJH-6).

A. 28 Because dividends are paid quarterly, or periodically, as opposed to continuously (daily), an adjustment must be made. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

Since companies tend to increase their quarterly dividend at different times of the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the D_1 expression, or $D_{1/2}$. This is a conservative approach so as not to overstate the dividend yield as it should be representative of the next twelve-month period. Therefore, the actual average dividend yields in Column 1 of Exhibit__(FJH-6) were adjusted upward to reflect one-half the growth rates shown in Column 4. The resultant adjusted dividend yields are 2.42% for Southwest and 3.84% for the proxy group of eight Value Line LDCs as shown in Column 3 of Exhibit__(FJH-6).

c. DCF Growth Rates

Q. 29 Please explain the basis of the growth rates used in your constant growth DCF model, as shown in Column 4 of Exhibit__(FJH-6).

A. 29 It is shown on Exhibit__(FJH-8), that on average, individuals own about 25% of the common shares of Southwest and 39% of the common shares of the companies in the proxy group. Individual investors are likely to rely on information provided by securities' analysts which provide greater valuable insight into prospective growth in earnings per share value than do reliance upon historical accounting measures of growth. Analysts' forecasts, which incorporate historical information, are readily available from Value Line and other sources such as ThomsonFN FirstCall, the latter readily available on the internet at no cost, which provides, in most instances, the estimates of a number of analysts. While investors are influenced by short-term earnings growth such as forecasts for the next 12 months, I believe that they are more influenced by the longer term five-year forecasts. Five years typically is the longest future period for which analysts' forecasts are available. The use of a long-term period such as five years is more consistent with the long-term investment horizon implicit in common stocks than single 12-month growth rates. It is clear that EPS growth rate expectations, although they do not fully account for changes in market value, are the most significant of all accounting measures of value. It should be evident, even to the casual market observer, that the market reacts favorably when EPS expectations are met or exceeded and unfavorably when they are not.

In view of the foregoing, I rely upon the average projected long-term growth rate in EPS from Value Line and ThomsonFN First Call as shown in Column 4 of Exhibit__(FJH-6) and detailed by company and average for the proxy group on

Sheet 1 of Exhibit__(FJH-9). As shown on Sheet 1 of Exhibit__(FJH-9), Southwest's average growth rate is 6.75% while that of the proxy group is 4.51%. Sheets 2 through 10 of Exhibit__(FJH-9) contain the most recent Value Line Investment Survey for Southwest and the eight companies in the proxy group.

5. Conclusion of DCF Cost Rate

Q. 30 Please summarize the cost rates derived from your application of the constant growth DCF model to Southwest and the proxy group.

A. 30 As shown in Column 5 of Exhibit__(FJH-6), the DCF cost rates are 9.17% for Southwest AND 8.35% for the proxy group. However, for the reasons discussed supra, and by comparison to the cost rates derived from application of the other cost of common equity models and the reality check of regulatory awards to LDCs discussed infra, those cost rates understate the rates required by investors. For the reasons discussed infra, only a DCF cost rate of 9.92% is considered, as shown in Column 6 of Exhibit__(FJH-6).

Q. 31 Please explain the reason for the difference between the indicated DCF return rates in Column 5 and the "recommended" DCF return rate of 9.92% in Column 6 of Exhibit__(FJH-6).

A. 31 As mentioned supra, I have utilized regulatory awarded ROEs to LDCs during the 12 months ended March 31, 2007 as a reality check of reasonableness. That information will also be discussed infra in connection with Exhibit__(FJH-14). As shown therein, the lowest regulatory awarded ROE was 9.60% in July 2006 to Central Hudson Gas & Electric by the New York PSC.

Consequently, it is not reasonable to assume that DCF cost rates which are below 9.60% are in any way representative of the cost rates required by investors – and certainly are below those they would expect. Moreover, in the Central Hudson case (the 9.60%), the New York Public Service Commission utilized a future test year; approved a three-year gas rate settlement with an earnings sharing mechanism that does not begin until the return on equity exceeds 10.60%.

In view of the foregoing, I do not consider those DCF cost rates below 9.60% because they are not indicative of any reasonable investor required or expected return on common equity investment in an LDC. Thus, only the two DCF cost rates shown in Column 6 of Exhibit__(FJH-6) are somewhat reasonable. The need to consider and reject so many DCF cost rates highlights the problems associated with the application of the DCF model discussed supra.

C. The Risk Premium Model (RPM)

1. Theoretical Basis

Q. 32 Please describe the theoretical basis of the RPM.

A. 32 The RPM is based upon the theory that the cost of common equity capital is greater than the prospective company-specific cost rate for long-term debt capital. In other words, the cost of common equity is the expected cost rate for long-term debt capital plus a premium to compensate common shareholders for the added risk of being unsecured and last-in-line in any claim on the corporation's assets and earnings.

Q. 33 Some analysts state that the RPM is another form of the CAPM. Do you agree?

A. 33 Generally yes, but there is a very significant distinction between the two models. The RPM and CAPM both add a "risk premium" to an interest rate. However, the

beta approach to the determination of an equity risk premium in the RPM should not be confused with the CAPM. Beta is a measure of systematic, non-diversifiable, market risk which is usually a much smaller percentage of total investment risk, the sum of both diversifiable and non-diversifiable risks. Diversifiable risks, i.e., unsystematic or company-specific risks, are reflected in the RPM because the prospective company-specific long-term bond yield is the result of a bond rating process which includes an assessment of all diversifiable business and financial risks. This reality is verifiable by reading S&P's description of its bond rating process which is contained in Exhibit__(FJH-2), at Sheets 3 through 9. In contrast, the use of a U.S. Government Security as the risk-free rate of return in the CAPM, by definition, reflects no diversifiable company-specific risk. Clearly, the RPM and CAPM, are two separate and distinct cost of common equity models, a fact recognized in the financial literature.

Q. 34 Please describe your RPM analysis.

A. 34 It is shown in Exhibit__(FJH-10). As can be gleaned from Sheet 1, the projected bond yield on Moody's A rated utility bonds is estimated to be 6.60%. As explained in Notes 3 and 4 on Sheet 1 of Exhibit__(FJH-10), an adjustment of 0.40% is required to be made to the 6.60% yield on A rated public utility bonds to reflect Southwest's Moody's bond rating of Baa3 and an adjustment of 0.09% is required to be made to the 6.60% yield on A rated public utility bonds because the proxy group has an average Moody's bond rating of A3. Consequently, the resultant expected average bond yields are 7.00% for Southwest and 6.69% for the proxy group. I then calculated the equity risk premiums applicable to Southwest and the proxy group.

The sum of the prospective bond yields and equity risk premiums equal the RPM-derived common equity cost rates applicable to Southwest and the proxy group.

2. Estimation of Expected Bond Yield

Q. 35 Please explain the basis of the expected bond yields of 7.00% applicable to Southwest and 6.69% applicable to the proxy group.

A. 35 *Because the cost of common equity is prospective, the prospective yield on similarly-rated long-term debt is appropriate.* The average Moody's bond ratings (as well as S&P's bond ratings and business profiles) for Southwest and each company in the proxy group as well as group averages are shown on Exhibit__(FJH-10), Sheet 2. They are Baa3/BBB-/"3.0" for Southwest and the averages for the proxy group are A3/A/"2.3", respectively. I relied upon the consensus forecasts of about 50 economists of the expected yields on Moody's Aaa rated corporate bonds for the six calendar quarters ending with the fourth calendar quarter of 2008 as derived from the July 1, 2007 Blue Chip Financial Forecasts (Sheet 7 of Exhibit__(FJH-10). As shown on Line 1, Sheet 1 of Exhibit__(FJH-10), the average expected yield on Aaa-rated corporate bonds is 6.07%. It is necessary to adjust that average yield to be equivalent to the average bond rating of the proxy group and Southwest, which is accomplished through the adjustments on Lines 2 and 4 of Exhibit__(FJH-10), Sheet 1 and explained in Notes 2 through 4 on the same Sheet 1. Accordingly, the average prospective yields are 7.00% applicable to Southwest and 6.69% applicable to the proxy group. It is then necessary to estimate the equity risk premium applicable to each of those prospective bond yields.

3. Estimation of the Equity Risk Premium

Q. 36 Please explain the basis of the equity risk premiums you determined to be applicable to Southwest and the proxy group.

A. 36 I evaluated the results of two different historical equity risk premium studies, as well as Value Line's forecasted total annual return on the market over the prospective yield on high grade corporate bonds. These analyses are summarized on Sheet 5 of Exhibit__(FJH-10). As shown on Line 3 of Sheet 5, the average equity risk premiums are 3.86% applicable to Southwest and 4.27% applicable to the proxy group. The average equity risk premiums are the average of the arithmetic mean historical and the projected market equity risk premiums allocated to Southwest and the proxy group by the use of beta and the average of holding period returns of S&P's Public Utility Index, 1928-2005, inclusive, adjusted to reflect the premium applicable to the respective bond rating of Southwest and to the average bond rating of the proxy group.

Q. 37 Please explain the basis of the equity risk premiums shown on Line 1, Sheet 5 of Exhibit__(FJH-10).

A. 37 Equity risk premiums determined through the application of the beta approach are meaningful because the betas were derived from regression analyses of the market prices of common stocks over a recent five-year period. The market prices reflect investors' expectations over a long-term future investment horizon. Consequently, beta is a meaningful measure of prospective risk relative to the market as a whole and thus is a logical means by which to allocate a relative share of the total market equity risk premium to a specific company or a proxy group.

The average total market equity risk premium utilized was 4.87% as shown on Sheet 6, Line 7 of Exhibit__(FJH-10). It is based upon an average of the long-term average historical equity risk premium of 6.20% and the forecasted market equity risk premium of 3.53% as shown on Sheet 6, Lines 3 and 6, respectively, of Exhibit__(FJH-10).

To derive the historical market equity risk premium, I used the most recent Morningstar (formerly Ibbotson Associates) data on holding period returns for the S&P 500 Composite Index and the average historical yield on Aaa and Aa corporate bonds for the period 1926-2006. The use of holding period returns over a very long period of time is useful in the application of the beta approach. Morningstar, in its Valuation Edition – 2007 Yearbook, provides sound reasoning why the use of a long-term historical time period is appropriate to estimate the expected equity risk premium. They demonstrate empirically through tests of serial correlation that equity risk premia are random. They also demonstrate and explain why the arbitrary use of shorter time periods distorts the results of estimated long-term average market equity risk premia. Moreover, the arbitrary use of shorter time periods is contrary to the long-term randomness of equity risk premia. Consequently, the use of a long-term average equity risk premium provides stability in contrast to the volatility associated with the arbitrary use of shorter historical time periods. Moreover, the use of a long-term average is consistent with the long-term investment horizon implicit in the cost of common equity capital as exemplified by the premise of infinity in the standard DCF model used in rate regulation. Morningstar's full explanation of why the use of the long-term average

equity risk premium is appropriate is provided at Sheets 5 through 8 of Exhibit__(FJH-11).

In view of the foregoing and all of Morningstar's comments contained in Exhibit__(FJH-11), it is clear that the arbitrary selection of shorter historical periods would be highly suspect. Such periods would likely contain the 1987 stock market crash, the collapse of the Soviet Union, the two wars with Iraq, extraordinary inflation rates and other significant events. Therefore, the arbitrary use of shorter historical time periods is unlikely to be representative of the amount of change which could occur over a long period of time in the future (the presumed long-term holding period for common stocks as is implicit in the various cost of equity models). Thus, the use of a very long past period to estimate the equity risk premium is consistent with the long-term investment horizon for utilities' common stocks. Consequently, the use of the long-term past to estimate equity risk premium is critical to proper estimation of the long-term future. The arithmetic mean of those long-term historical total return rates on the market as a whole is the appropriate mean for use in estimating the cost of capital because it provides essential insight into the potential variance of expected returns. A full explanation by Morningstar of why the arithmetic mean must be used when discounting future cash flows for estimating the cost of capital is contained in Sheets 2 through 4 of Exhibit__(FJH-11).

Historical total returns and equity risk premiums differ in size and direction over time. It is precisely for this reason that the arithmetic mean is important. The arithmetic mean provides insight into the variance and standard deviation of returns.

The prospect for, and degree of, variance provides the insight required by investors to estimate risk when contemplating making an investment. Insight into variance can only be obtained by the use of the arithmetic mean of historical returns. Absent valuable insight into the potential variance of returns, there can be no meaningful evaluation of prospective risk. *If investors relied upon the geometric mean of historical returns, they would have no insight into the potential variance of future returns because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, critical to risk analysis.*

The basis of the historical market equity risk premium of 6.20% is detailed in Lines 1 through 3, Sheet 6 of Exhibit__(FJH-10).

Q. 38 Why do you also utilize a forecasted equity risk premium?

A. 38 The long-term historical arithmetic average market equity risk premium is the most likely to be experienced over a long-term prospective period. Also, a prospective element is contained in the use of beta because *beta is derived from market prices which reflect expectations of the future. Secondly, beta is also utilized in conjunction with the prospective yield on A rated public utility bonds.* Consequently, it is also appropriate to view the current potential for market price appreciation in the current market environment. Investors would certainly have knowledge of Value Line's forecasted market appreciation and dividend yield on its market universe and consider it along with long-term historical market returns. Because the potential for growth in the DCF model is market price appreciation, in

estimating the equity risk premium by use of the RPM model, it is also appropriate to take into account the forecasted equity risk premium.

The basis of the forecasted market equity risk premium of 3.53% is detailed in Lines 4 through 6, Sheet 6 of Exhibit__(FJH-10). The average of the historical and projected market equity risk premiums is 4.87%, as shown on Line 7, Sheet 6 of Exhibit__(FJH-10).

As shown on Line 9, Sheet 6 of Exhibit__(FJH-10), application of Southwest's beta and the average beta of the proxy group to the average market equity risk premium of 4.87% results in an equity risk premium of 4.14% for Southwest and 4.29% for the proxy group of eight Value Line LDCs.

Q. 39 Please describe the derivation of the equity risk premia shown on Line 2, Sheet 5 of Exhibit__(FJH-10).

A. 39 For the reasons described supra by Morningstar, an analysis was performed, under my direction and supervision, of the arithmetic mean long-term historical holding period returns applicable to public utilities, i.e., the S&P Public Utility Index for the period 1928-2005, inclusive. The long-term average provides a good basis for future expectations as all types of events are included, even "unusual" ones. The analysis is summarized on Sheet 8 of Exhibit__(FJH-10). After the adjustment necessary to reflect the average equity risk premium applicable to Moody's Baa3 rated public utility bonds for Southwest, as shown on Line 2a, and A3 rated public utility bonds for the proxy group, as shown on Line 2b of Exhibit__(FJH-10), Sheet 8, the resultant adjusted equity risk premia are 3.58% for Southwest and 4.24% for the proxy group.

Q. 40 What equity risk premia are applicable to Southwest and the proxy group?

A. 40 The resultant equity risk premia are 3.86% for Southwest, 4.27% for the proxy group of eight Value Line LDCs based on an average of Lines 1 and 2 on Exhibit__(FJH-10), Sheet 5 and shown on Line 3 of the same Sheet 5, as well as on Line 6, Sheet 1 of Exhibit__(FJH-10).

4. Conclusion of RPM Cost Rates

Q. 41 What are the resultant RPM cost rates applicable to Southwest and the proxy group?

A. 41 As shown on Exhibit__(FJH-10), Sheet 1, Line 7, they are 10.86% applicable to Southwest and 10.96% applicable to the proxy group.

5. The RPM Does Not Presume a Constant Equity Risk Premium

Q. 42 Does the RPM assume a constant equity risk premium?

A. 42 No. The equity risk premium determined under the RPM varies inversely with interest rate changes since the prospective bond yield is subtracted from the estimated market return. Common sense affirms this to be so, due to common stock investors' expectation of greater returns during periods of declining interest rates and vice versa. In a sense, the equity risk premium is no different than the "g", or growth component, in the DCF model. The growth component "g" in a DCF cost rate calculated today, will invariably differ in subsequent time periods due to the availability of different growth rate data, thereby confirming the reality that the "g" in the DCF model does change, even though it is presumed to be theoretically constant. In that regard, there is no difference between the RPM and DCF models, i.e., both models assume an expectationally constant equity risk premium and growth rate, respectively, but in actuality *both* change regularly.

As Morin[13] states with regard to the DCF model:

> It is not necessary that g be constant year after year to make the model valid. *The growth rate may vary randomly around some average expected value. Random variations around trend are perfectly acceptable, as long as the mean expected growth is constant. The growth rate must be 'expectationally constant' to use formal statistical jargon.* (italics added)

The foregoing confirms that the RPM is similar to the DCF model in the sense that both models contain the assumption of an "expectationally constant" risk premium and growth rate, respectively, despite the fact that each varies randomly around its mean. The mean referred to is the *arithmetic mean*, thereby indirectly *confirming that only the arithmetic mean is appropriate to use when estimating the cost of capital as discussed supra.*

D. The Capital Asset Pricing Model (CAPM)

1. Theoretical Basis

Q. 43 Please explain the theoretical basis of the CAPM.

A. 43 The CAPM defines risk as the covariability of a security's returns with the market's returns. This covariability is measured by beta ("β"), an index measure of an individual security's variability relative to the market. A beta less than 1.0 indicates lower variability than the market and a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market, or unsystematic, risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. The model presumes that

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[13] Id., p. 256.

investors require compensation for risks that cannot be eliminated through diversification. Systematic risks are caused by socioeconomic events that affect the returns on all assets. In essence, the model is applied by adding a risk-free rate of return to a market risk premium. The market risk premium is adjusted proportionally to reflect the systematic risk of the individual security relative to the market as measured by beta.

The **traditional CAPM** is expressed as:

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

Where R_s = Return rate on the common stock
R_f = Risk-free rate of return
R_m = Return rate on the market as a whole
β = Adjusted beta (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have confirmed its validity. These tests measured the extent to which security returns and betas are related as predicted by the CAPM.

The **empirical CAPM (ECAPM)**, discussed by Morin, reflects the reality that the empirical Security Market Line (SML), described by the traditional CAPM, is not as steeply sloped as the predicted SML. An empirical study by Morin[14] indicates that the ECAPM should be expressed as:

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[14] Typical of the empirical evidence on the validity of the CAPM is a study by Morin (1989) who found that the relationship between the expected return on a security and beta over the period 1926-1984 was given by:

$$\text{Return} = 0.0829 + 0.0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6% and that the market risk premium was 8% during the period of study, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, or ¼ of 8%, and that the slope of the relationship is close to ¾ of 8%. Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x(R_M - R_F) + (1 - x)\beta(R_M - R_F)$$

Where x is a fraction to a be determined empirically. The value of x that best explains the observed relationship Return = $0.0829 + 0.0520\,\beta$ is between 0..25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

$$K = RF + 0.25(RM - RF) + 0.75\beta(RM - RF)^{15}$$

Morin[16] further states:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend [sic], an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary.

Therefore, the ECAPM is a return adjustment, i.e., a y-axis adjustment and does not increase the adjusted beta, which is an x-axis adjustment that accounts for regression bias.

As a result of the foregoing, I apply both versions of the model (CAPM and ECAPM) which are contained in Exhibit__(FJH-12), consisting of 3 Sheets.

2. Risk-Free Rate of Return

Q. 44 Please describe your selection of a risk-free rate of return.

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15 Id., at pp. 189-190.
16 Id., at p. 191.

A. 44 My applications of the CAPM and the ECAPM reflect a risk-free rate of 5.33%. It is based upon the average consensus forecast of the reporting economists in the July 1, 2007 issue of Blue Chip Financial Forecasts for the yields on 30-year U.S. Treasury Notes for the six quarters ending with the fourth calendar quarter 2008, as shown in Note 2 on Sheet 3 of Exhibit__(FJH-12).

Q. 45 Why is the average prospective yield on 30-year U.S. Treasury Notes appropriate for use as the risk-free rate?

A. 45 The yield on 30-year T-Notes is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on public utility bonds and more closely matches the long-term investment horizon inherent in utilities' common stocks. Moreover, it is consistent with the long-term investment horizon, which is presumed to be infinite, in the standard DCF model employed in proceedings such as these. In addition, Morningstar[17] states:

> A common choice for the nominal riskless rate is the yield on a U.S. Treasury Security. The ability of the U.S. government to create money to fulfill its debt obligations under virtually any scenario makes U.S. Treasury securities practically default-free. While interest rate changes cause government obligations to fluctuate in price, investors face essentially no default risk as to either coupon payment or return of principal.
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> * * *
>
> The horizon of the chosen Treasury security should match the horizon of whatever is being valued. *When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond.* Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-

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17 Stocks, Bonds, Bills and Inflation: 2007 Yearbook – Valuation Edition, Morningstar, Chicago, IL, p. 59.

year Treasury note would not be appropriate since the company will continue to exist beyond those five years. (italics added)

In summary, the average expected yield on 30-year Treasury Notes is the appropriate proxy for the risk-free rate in the CAPM because it is almost risk-free and has a long-term investment horizon consistent with utilities' common stocks (not individual investors) and is thus consistent with the infinite investment horizon which is an assumption of the standard constant growth DCF model.

3. Market Equity Risk Premium

Q. 46 Please explain the basis for your estimation of the expected market equity risk premium.

A. 46 I estimate investors' expected total return rate based on an average of forecasted and long-term historical return rates from which I subtract the risk-free rate. The result is a market equity risk premium, some proportion of which must be allocated to Southwest and the proxy group. I make the allocation of the market equity risk premium through the use of beta because beta is a measure of the risk of a security relative to the entire market.

The basis of the projected market equity risk premium is explained in detail in Note 1, Sheet 3 of Exhibit__(FJH-12). The 3-5 year total market appreciation projection, when converted to an annual rate plus the market's average dividend yield, equals a forecasted total annual return rate of 9.60%. The long-term historical total annual arithmetic mean return rate of 12.30% on the market of large company stocks is from Table 2-1 of Stocks, Bonds, Bills and Inflation: Valuation Edition – 2007 Yearbook. The relevant risk-free rate was deducted from the total

market return rate. For example, from the Value Line projected total market return of 9.60%, the forecasted average risk-free rate of 5.33% was deducted indicating a forecasted market risk premium of 4.27%. From the Morningstar arithmetic mean long-term historical total return rate of 12.30%, the long-term historical income return rate on long-term U.S. Government Securities of 5.20% was deducted indicating an historical equity risk premium of 7.10%. Thus, the average of the projected and historical total market risk premiums of 4.27% and 7.10%, respectively, is 5.685%, rounded to 5.69%.

4. Conclusion of CAPM Cost Rates

Q. 47 What are the results of your applications of the CAPM and ECAPM?

A. 47 The results are shown on Exhibit__(FJH-12), Sheet 1 and the details are shown by company on Sheet 2.

I rely upon the average of both the CAPM and ECAPM cost rates. As shown on Line 3, Sheet 1 of Exhibit__(FJH-12), they are 10.28% for Southwest and 10.50% for the proxy group.

E. The Comparable Earnings Model (CEM)

1. Theoretical Basis

Q. 48 Please describe the theoretical basis of the CEM.

A. 48 The comparable earnings standard recognizes the fundamental economic concept of opportunity cost. This concept states that the cost of using any resource – land, labor and/or capital – for a specific purpose is the return that could have been earned in the next best alternative use. The opportunity cost to an investor in a utility's common stock is what that capital would yield in an alternative investment of similar risk.

The opportunity cost principle is consistent with one of the fundamental principles of utility price regulation, i.e., it is intended to act as a surrogate for the competition of the marketplace.

The problem in using returns on book equity (the ROEs) of non-price regulated companies is determining whether such companies are similar in risk to the price-regulated utility. The ROEs of other similar, price-regulated firms should not be relied upon because they reflect the results of regulatory awards which may not be indicative of what could have been earned in a competitive market. Moreover, to use such returns as a primary method to establish a cost of equity would be an exercise in circularity. Consequently, application of the CEM is most appropriately implemented by examining the ROEs of similar risk, domestic, non-price regulated firms.

In a more competitive environment for energy utilities, the concept of observing the rates of earnings on book equity, or net worth, of comparable risk non-price regulated firms has greater relevance than ever despite a long regulatory history for the use of the comparable earnings method. Moreover, the use of ROEs of comparable non-price regulated firms is appropriate because:

(1) Under the rate base/rate of return paradigm, the rate of return (including the rate of return on common equity) is applied to a rate base measured at original (i.e., book) cost;

(2) As discussed supra, many factors influence market prices other than company-specific EPS and/or DPS. Thus, when market values differ from their book values, market-based DCF cost rates either understate

or overstate the rates of earnings required on book equity (i.e., the common equity financed portion of an original cost rate base); and

(3) As also discussed supra, regulatory decisions can influence but cannot control market prices.

2. Application of the CEM

Q. 49 Please explain your CEM methodology.

A. 49 My CEM methodology is set forth in Exhibit__(FJH-13), which consists of four sheets. Sheets 1 and 2 contain the relevant data for the domestic, non-price regulated companies which are comparable in risk to Southwest and the proxy group, respectively. Sheets 3 and 4 contain the notes relative to Sheets 1 and 2.

It is critical to the application of the CEM to select proxy groups of non-price regulated companies which are similar in total risk to the price-regulated utilities, i.e., Southwest and the proxy group of LDCs. In each proxy group, the comparable non-price regulated firms should be broad-based in order to obviate individual company-specific aberrations. Utilities should be eliminated to avoid circularity since the rates of return on their book common equity are substantially influenced by the rate determinations of their respective regulatory commissions, many of which are the result of negotiated settlements and are not truly market-based cost rates.

3. Selection of Market-Based Companies of Similar Risk

Q. 50 Is your application of the CEM market-based?

A. 50 Yes. My application of the CEM is market-based because the selection of the comparable non-price regulated firms is based upon statistics derived from the market prices paid by investors. Specifically, I rely upon the betas and related

statistics derived from Value Line regression analyses of weekly market prices over the most recent 260 weeks (five years). The bases of selection resulted in proxy groups of domestic, non-price regulated firms comparable to Southwest and the proxy group. The average company in each proxy group of non-price regulated companies is comparable to Southwest and the proxy group of LDCs, respectively. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in the selection of the non-price regulated firms were:

1. They are covered by Value Line Investment Survey (Standard Edition).
2. They are domestic, non-price regulated companies, i.e., non-utilities.
3. Their betas lie within plus or minus two standard deviations of the unadjusted betas of Southwest and proxy group of LDCs, respectively.
4. The residual standard errors of the regressions lie within plus or minus two standard deviations of the average residual standard error of the regression for Southwest and the proxy group of LDCs, respectively.

Betas are a measure of market, or systematic, risk. The standard errors of the regressions were used to measure each firm's company-specific risk (diversifiable, unsystematic risk). The standard errors of the regressions measure the extent to which events specific to a company affect its stock price. *Because market prices reflect investors' perceptions of total risk, all risk which is not systematic market risk (beta) is reflected in the standard error of the regression which is a measure of total non-systematic risk which is diversifiable. In essence, companies which have similar betas and standard errors of the regressions have similar total investment*

risk, i.e., the sum of non-diversifiable market risk and diversifiable company-specific risk. The betas and standard errors result from regression analyses of market prices which reflect all perceived risks consistent with the EMH. Consequently, the use of those regression statistics results in proxy groups of non-price regulated domestic firms which are similar in total investment risk to Southwest and the proxy group of LDCs. The use of two standard deviations captures 95.50% of the distribution of unadjusted betas and standard errors, thereby assuring comparability of total risk.

Q. 51 Please discuss the projected ROEs of the 23 domestic, non-price regulated companies, comparable in total risk to Southwest, as shown on Sheet 1 of Exhibit__(FJH-13).

A. 51 After assuring comparability through the use of betas and standard errors as discussed supra, I reviewed Value Line's five-year projected ROEs for the companies in the group and performed a test (Student's T-Statistic) to assure that I would not rely upon any ROE(s) that were statistical outliers. As a result, one observation in the group was found to be a statistical outlier.

The mean projected ROE, after exclusion of that determined to be a statistical outlier per the T-test, is 13.98%. However, I also rely upon the elimination of ROEs 20.0% or higher and those below 9.60%. I eliminated those 20.0% or higher because it is unlikely that any gas distribution utility would be awarded an opportunity to earn such a rate of return on common equity. Conversely, I also eliminated ROEs below 9.60% which was the lowest ROE awarded to gas distribution operations of a combination electric and gas company by any state commission during the period

April 1, 2006 through March 31, 2007. Eliminating all ROEs of 20.00% or higher and those below 9.60% also resulted in the elimination of the statistical outlier.

Q. 52 Did you utilize the same procedures to select the 34 non-price regulated companies similar in total risk to the proxy group of LDCs?

A. 52 Yes, I did. I also utilized the same parameters for forming my CEM opinion of cost rate.

4. Conclusion of CEM Cost Rates

Q. 53 What are the indicated CEM cost rates?

A. 53 As shown on Sheets 1 and 2 of Exhibit__(FJH-13), my conclusion, based upon Value Line five-year projected ROEs, 13.42% is applicable to Southwest and 13.88% applicable to the proxy group of eight Value Line LDCs.

X. CONCLUSION OF COMMON EQUITY COST RATE

A. Conclusion of Common Equity Cost Rate Must be Based on the Application of Multiple Models and Consideration of all Risks

Q. 54 Please summarize why, in your opinion, the conclusion of common equity cost rate must be determined from the results of the application of multiple cost of common equity models.

A. 54 As discussed supra, the EMH and common sense mandate the use of multiple market-based cost of common equity models. All of the models I utilized are market-based.

1. The DCF Model utilizes market prices paid by investors.

2. The RPM utilizes the expected market yield on company-specific long-term debt and the equity risk premium based upon an expectation of the market equity risk premium.

3. The CAPM and ECAPM utilize total market returns, and betas which result from each individual stock's market price movement relative to the market.

4. The CEM is based upon the selection of comparable risk, non-price regulated domestic companies selected through the use of statistics derived from regression analyses of market prices paid by investors.

Investors are aware of all of the cost of common equity models in use and discussed in the financial literature. Therefore, belief in the EMH requires all of them be taken into account.

Q. 55 What is your recommended common equity cost rate?

A. 55 My recommended common equity cost rate is 11.25% applicable to Southwest's common equity ratio of 45.00%. This rate is based on the application of all four cost of common equity models to Southwest and the proxy group of LDCs. I gave much more weight to the proxy group than I did to Southwest. I gave much less weight to Southwest's cost rates because they are counter-intuitive. Southwest is clearly more risky by any objective measure. Its debt is rated a full bond rating lower compared to the proxy group, based on Moody's bond ratings, i.e., Baa3 versus A3; and one and one-third rating grades lower based on S&P's bond ratings, i.e., BBB- versus A. Also, based on S&P's assigned business profiles, Southwest is more risky at "3.0" versus "2.3" for the proxy group. (Bond ratings and business profiles are shown on Sheet 2 of Exhibit__(FJH-10)). Moreover, Southwest's comparative financial performance based on achieved ROEs 1997-2006 shows that Southwest has grossly underperformed vis-à-vis the proxy group and even to a greater extent in Arizona, as discussed supra re Sheet 5 of Exhibit__(FJH-1). In view of lower individual models' cost rates for Southwest, versus the proxy group's cost rate (as shown on Sheet 2 of

Exhibit__(FJH-1)) and the recent average awards to LDCs by various state regulatory commissions as discussed supra and infra, it is clear that Southwest's cost rates are counter-intuitive and contrary to the risk/return principle. Consequently, I give significantly greater weight to the cost rates of the proxy group which require the addition of an additional cost element in order to reflect Southwest's greater investment risk.

Q. 56 On Line 5, Sheet 2 of Exhibit__(FJH-1), you show a common equity cost rate before investment risk adjustments, of 11.00% for the proxy group. Please explain.

A. 56 For the proxy group, I gave considerably greater weight, albeit non-specific, to the results of the risk premiums and CAPM models of 10.96% and 10.50%, as they are closer to each other and in line with average regulatory awarded ROE in litigated LDC cases during the twelve months ended March 31, 2007 of 10.48%, as will be discussed infra regarding Exhibit__(FJH-14). Southwest's risk premium and CAPM cost rates are, as explained supra, counter-intuitive, i.e., lower than the proxy group when they should be higher, consistent with the risk/return principle. Consequently, a cost rate of 11.00% is conservatively appropriate. However, an upward adjustment is required for the proxy group cost rate of 11.00% because Southwest is more risky based upon essentially all diversifiable measures of risk including bond rating differential versus the proxy group.

Q. 57 Please explain the investment risk adjustment you made, as shown on Line 6, Sheet 2 of Exhibit__(FJH-1).

A. 57 An upward adjustment to the proxy group's 11.00% cost rate is required for it to be applicable to Southwest because of the higher average bond rating of the proxy

group (i.e., Moody's A3 vs. Baa3 for Southwest). The higher average bond rating reflects the proxy group's superior achieved rates of earnings on common equity capital attributable in part to a much better chance of achieving the allowed ROEs because of protection against the vagaries of weather and declining per customer usage.

An upward adjustment of 0.31% (explained in Note 5, Sheet 3 of Exhibit__(FJH-1)) is necessary to reflect Southwest's lower Moody's bond rating of Baa3 vis-à-vis the higher average Moody's bond rating of A3 for the proxy group. Bond rating differences alone do not reflect the fact that effectively, most of the companies in the proxy group have protection against the vagaries of weather and declining per customer usage, either through weather normalization clauses, some type of revenue decoupling mechanism or other innovative rate design meant to alleviate those problems. In Arizona, Southwest has not had any protection against the impact of the vagaries of weather and declining per customer usage on revenues, earnings and cash flows. That lack of protection surely is a significant factor in Southwest's more risky S&P assigned business profile of "3" versus an average "2.3" for the proxy group. The adjustment on Line 6 of Exhibit__(FJH-1), Sheet 2 reflects only the difference in bond rating but not Southwest's more risky business profile which directly impacts common shareholders' risks. I made no attempt to reflect Southwest's additional risk attributable to its higher business profile. Approval of the requested tariff tools will put the Company on a level playing field with the proxy group. Consequently, after the adjustment of 0.31%, the indicated cost rate applicable to Southwest based upon the proxy group is 11.31%. As

discussed supra, I provide substantial weight to the 11.31% cost rate derived from the proxy group, because Southwest's cost rates are counter-intuitive as they are contrary to the basic risk/return principle of finance. As a result, my recommended common equity cost rate is 11.25%, assuming approval of the requested 45% common equity ratio and tariff tools.

Q. 58 Have you included any provision for flotation costs in your recommended common equity cost rate of 11.25%?

A. 58 No. As indicated in Mr. Wood's testimony, the substantial increases in common equity between August 31, 2004 and April 30, 2007 are attributable to shares issued through the Dividend Reinvestment and Stock Purchase Plan to Employee Investment Plan, Management Incentive Plan and Stock Incentive Plan, the Equity Shelf Program and through an increase in retained earnings. Because a majority of new shares issued were through various employee plans, I have been conservative and made no adjustment to the common equity cost rate to recognize flotation costs.

XI. REASONABLENESS CHECK

Q. 59 Have you performed a check to ascertain whether your recommended common equity cost rate of 11.25% is reasonable?

A. 59 Yes. On Exhibit__(FJH-14), I show a summary of regulatory awards made to gas distribution companies by state regulatory commissions during the period twelve months ended March 31, 2007. As shown, the average authorized rate of return on common equity was 10.38% relative to a 46.76% common equity ratio for all awards, including those resulting from settlements. The average award for all fully litigated cases was 10.48% relative to a 45.92% common equity ratio. I note that

Southwest's requested hypothetical 45.00% common equity ratio is remarkably similar to the averages discussed supra, namely 46.76% and 45.92%.

As can be seen on Exhibit__(FJH-14), the average awarded ROE of 10.48% in a litigated case represented an average equity risk premium of 459 basis points (based upon the differences between the authorized ROE and the yield on Moody's A rated public utility bonds prior to the Order). As shown, with an expected yield on A rated public utility bonds of 6.60%, a common equity cost rate of 11.19% (6.60% + 4.59%) is indicated. Of course, Southwest's bond/credit rating is Moody's Baa3 and S&P's BBB- and its prospective bond yield is 7.00% as shown on Line 5, Sheet 1 of Exhibit__(FJH-10), which indicates a cost rate of 11.59% (7.00% + 4.59%). This range of 11.19% - 11.59% confirms the reasonableness of my recommended common equity cost rate of 11.25%.

XII. ADDITIONAL CONSIDERATIONS

Q. 60 Are there additional factors the Commission should consider when authorizing a fair rate of return, including common equity cost rate, for Southwest?

A. 60 Yes. It is important Southwest be afforded a reasonable opportunity to improve its bond/credit ratings from Moody's Baa3 and S&P's BBB-, which are at the bottom of investment grade bond ratings. Another downgrade of even one rating notch would put the rating(s) below investment grade, i.e., into the Ba/BB category. A below investment grade rating would be disastrous as it would impede the Company's access to the capital markets and make capital extremely more costly, if it can be obtained at all. A public utility must have the ability to access the capital markets on a reasonable cost basis at all times because of its obligation to serve customers at all

times, not just when it is convenient to do so. Southwest, as one of the fastest growing LDCs in the U.S., has an even more pronounced obligation to meet the demands of both new and existing customers. If its bond/credit ratings fell below investment grade, not only would capital cost more, but it might not be available. For example, during the late 1970s and early 1980s, when capital costs were extraordinarily high and capital was scarce, many companies, both regulated and non-regulated, were unsuccessful in raising capital (or all of the capital required) if they were not of investment grade quality. Consequently, Southwest must be able to access the capital markets at all times on a reasonable basis, even during extraordinarily difficult, high interest rate, markets such as the late 1970s and early 1980s. This can best be accomplished by:

- Allowing an ROE commensurate with Southwest's risk and affording it a reasonable opportunity to actually earn it; and
- Approving the requested tariff tools which will afford protection against the adverse impact of the vagaries of the weather and declining per customer usage on revenues, earnings, and cash flows, thereby enhancing the ability to earn the authorized ROE.

If the foregoing occurs, I believe that the financial community will respond favorably which will be reflected in improved bond/credit ratings and lessening of business risk profile which will result in lower capital costs.

Q. 61 Does that conclude your direct testimony?

A. 61 Yes, it does.

APPENDIX A

PROFESSIONAL QUALIFICATIONS

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

PROFESSIONAL QUALIFICATIONS OF FRANK J. HANLEY

EDUCATIONAL BACKGROUND

I am a graduate of Drexel University where I received a Bachelor of Science Degree from the College of Business Administration. The principal courses required for this Degree include accounting, economics, finance and other related courses. I am also Certified by the Society of Utility and Regulatory Financial Analysts, formerly the National Society of Rate of Return Analysts, as a Rate of Return Analyst (CRRA).

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I have appeared as a guest speaker before an annual convention of the Mid-American Cable Television Association in Kansas City, Missouri and as a guest panelist on the small water companies' operation seminar of the National Association of Water Companies' 77th Annual Convention in Hollywood, Florida. I addressed the Second Annual Seminar on Regulation of Water Utilities sponsored by N.A.R.U.C., at the University of South Florida's St. Petersburg campus. I have spoken on fair rate of return to the Third and Fourth Annual Utilities Conferences, as well as the special conference on the cost of capital in El Paso, Texas sponsored by New Mexico State University. In 1983 I also made a presentation on the Cost of Capital in Atlantic City, New Jersey, at a seminar co-sponsored by Temple University. I have also addressed the Public Utility Law Section of the American Bar Association's Third Institute on Fundamentals of Ratemaking which was held in Washington, D.C. and I addressed a Conference on Cable Television sponsored by The University of Texas School of Law at Austin, Texas. Also, I addressed a meeting of the New England Water Works Association at Boxborough, Massachusetts, on the subject of Enterprise Financing. In addition, I was a speaker and mock witness in three different Utility Workshops for Attorneys sponsored by the Financial Accounting Institute held in Boston and Washington, D.C. I also was on a panel at the 23rd Financial Forum sponsored by the National Society of Rate of Return Analysts. The topic was Rate of Return Determination in the Diversified and/or Partially Deregulated Environment. I addressed the 83rd Annual Meeting of the Pennsylvania Gas Association in Hershey, PA. My topic was

the Cost of Capital Implications of Demand Side Management. In June 1993, I lectured on the cost of capital at the American Gas Association's Gas Rate Fundamentals Course. In October 1993, I was a guest speaker at the University of Wisconsin's Center for Public Utilities -- my topic was "Diversification and Corporate Restructuring in the Electric Utility Industry - Trends and Cost of Capital Implications." In October 1994, I was a guest speaker on a panel at the Fourteenth Annual Electric & Natural Gas Conference in Atlanta, Ga., sponsored by the Bonbright Utilities Center of the University of Georgia and the Georgia Public Service Commission. The panel topic was "Responses to Competition and Incentive Rates." In October 1994, I was a guest speaker on a panel at a conference and workshop called "Navigating the Shoals of Cable Rate Regulation" sponsored by EXNET in Washington, D.C. The panel topic was "Rate of Return." Also, in March 1995, I was a guest speaker on a panel at a conference entitled, "Current Issues Challenging the Regulatory Process" sponsored by New Mexico State University - Center for Public Utilities. My panel topic concerned the electric industry and was titled, "Impact of a Competitive Structure on the Financial Markets". In May 1995, I was a guest speaker at the 87th Annual Meeting of the Pennsylvania Gas Association in Hershey, PA. My topic was "The Pennsylvania Economy and Utility Regulation: Impact on Industry, Consumers and Investors." In May 1996, I was on a panel at the 28th Financial Forum of the Society of Utility and Regulatory Financial Analysts. The panel's topic was "Revisiting the Risk Premium Approach" and was held in Richmond, Virginia. From 1996 through 2005, I participated as an instructor in 2-3 seminars per year on the "Basics of Regulation" (and the ratemaking process in a changing environment) and also in a program called "A Step Beyond

the Basics", all sponsored by New Mexico State University's Center for Public Utilities and NARUC. In March 2002, I was a guest speaker before the Rate and Strategic Issues Committee of the American Gas Association in St. Petersburg, Florida. My topic was Rate of Return Strategies. In December 2002, I was a guest speaker at a seminar entitled, "Service Innovations and Revenue Enhancements for the Energy Distribution Business" sponsored by the American Gas Association in Washington, DC. My topic was "The Impact of Volatile Energy Markets on Rate of Return Strategies". In February 2003, I spoke at the Rutgers University-Camden, NJ M.B.A. Speaker Series. I addressed M.B.A. students and interested faculty on the role of the expert witness in the public utility ratemaking process. In November 2003 and 2004, by invitation, I was a Guest Professor at Rutgers University–Camden for classes of undergraduate finance students, and managerial accounting students, respectively. In October 2006, I made a presentation entitled "Mergers & Acquisitions: A Regulatory Perspective" at the Bonbright Center Electric and Natural Gas Conference at the University of Georgia.

BEFORE THE

ARIZONA CORPORATION COMMISSION

EXHIBIT

TO ACCOMPANY THE

DIRECT TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

CONCERNING

COMMON EQUITY COST RATE

RE: SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-___

Southwest Gas Corporation
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of Frank J. Hanley

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Southwest Gas Corporation
Summary of Cost of Capital and Fair Rate of Return
Based Upon a Hypothetical Regulatory Capital Structure

Assuming Approval of the Requested Tariff Tools

Type of Capital	Ratios (1)	Cost Rate	Weighted Cost Rate
Long-Term Debt	51.00	7.96 (1)	4.06
Preferred Equity	4.00	8.20 (1)	0.33
Common Equity	45.00	11.25 (2)	5.06
Total	100.00 %		9.45 %

Notes:

(1) FromSchedule D-1, Sheet 1 of 1
(2) Based upon informed judgment from the entire study, the principal results of which are summarized on Sheet 2 of this Exhbit.

Southwest Gas Corporation
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Southwest Gas Corporation	Proxy Group of Eight Value Line Gas Distribution Companies
1.	Discounted Cash Flow Model (1)	NMF %	9.92 %
2.	Risk Premium Model (2)	10.86	10.96
3.	Capital Asset Pricing Model (3)	10.28	10.50
4.	Comparable Earnings Analysis (4)	13.42	13.88
5.	Indicated Common Equity Cost Rate before Investment Risk Adjustments	11.00 %	11.00 %
6.	Investment Risk Adjustment Due to Southwest Gas Corporation's Lower Bond Rating	--	0.31 (5)
7.	Common Equity Cost Rate after Investment Risk Adjustment	11.00 %	11.31 %
8.	Recommendation	11.25%	

NMF = Not Meaningful

See Sheet 3 for notes.

Southwest Gas Corporation
Brief Summary of Common Equity Cost Rate

Notes:

(1) From Sheet 1 of Exhibit No. ___ (FJH-6).

(2) From Sheet 1 of Exhibit No. ___ (FJH-10).

(3) From Sheet 1 of Exhibit No. ___ (FJH-12).

(4) From Sheets 1 and 2 of Exhibit No. ___ (FJH-14).

(5) The 11.00% indicated common equity cost rate based upon the proxy group of eight LDCs is applicable to the average A3 Moody's bond rating of the group. As explained in Mr. Hanley's direct testimony, Southwest Gas Corporation has greater relative risk than the eight LDCs as evidenced by the Company's Baa3 Moody's bond rating. Therefore, an indication of the magnitude of the investment risk adjustment is based upon the yield spread between A3 and Baa3 rated public utility bonds. The investment risk adjustment of 0.31% equals two-thirds of the average spread between A and Baa rated public utility bonds of 26 basis points plus one-third of the estimated average spread between Baa and Ba rated public utility bonds of 43 basis points (from Sheet 4 of Exhibit ___ (FJH-10)), (0.31% = (2/3 * 0.26%) + (1/3 * 0.43%) = 0.17% + 0.14% = 0.31%).

Southwest Gas Corporation
Revenue Decoupling Mechanisms, Alternative Regulation Plans and Weather Normalization Adjustment Clauses
for Southwest Gas Corporation and the Proxy Group of Eight Value Line Gas Distribution Companies

Companies	Revenue Normalization Decoupling Mechanisms			Alternative Regulation Plans (ARPS), Performance Based Ratemaking Mechanisms (PBRs) and other Alternative Programs			Weather Normalization Adjustment Clauses (WNAs) and other Weather Innovative Rate Designs		
	Does company have it?	Type	State	Does company have it?	Type	State	Does company have it?	Type	State
Southwest Gas Corporation	Yes (1)	Margin Tracker Balancing Account	California	No	—	—	Yes (1) Yes (1)	No WNA, but Margin Tracker Balancing Account. No WNA, but Innovative Weather Rate Design.	California Nevada
AGL Resources Inc.	Yes	Straight Fixed Variable Rate Design (SVF)	Georgia	Yes	PBR	Virginia	Yes	WNA	New Jersey Tennessee Virginia
Atmos Energy Corporation	Yes	Straight Fixed Variable Rate Design (SVF)	Missouri	Yes	PBR PBR ESM GCI	Georgia Kentucky Mississippi Tennessee	Yes	WNA WNA WNA WNA WNA WNA WNA	Georgia Kansas Kentucky Mississippi Tennessee Texas Virginia
The Laclede Group, Inc.	No	—	—	No	—	—	Yes (2)	No WNA, but Innovative Weather Rate Design.	Missouri
NICOR Inc.	No	—	—	No	—	—	No	—	—
Northwest Natural Gas Company	Yes	Conservation Adjustment Decoupling Mechanism (CADM)	Oregon	No	—	—	Yes	WNA	Oregon
Piedmont Natural Gas Co., Inc.	Yes (3)	Customer Utilization Tracker (CUT)	North Carolina	Yes Yes	Rate Tracking Factor (RTF) Gas Cost Incentive Mechanism (GCI)	North Carolina Tennessee	Yes (3) Yes Yes	Customer Utilization Tracker (CUT). WNA WNA	North Carolina South Carolina Tennessee
South Jersey Industries, Inc.	Yes (4)	Conservation and Usage Adjustment Mechanism (CUA)	New Jersey	No	—	—	Yes (4)	Conservation Usage and Adjustment mechanism (CUA).	New Jersey
WGL Holding, Inc.	Yes (5)	Revenue Normalization Adjustment mechanism (RNA)	Maryland	No	—	—	Yes (5)	Revenue Normalization Adjustment mechanism (RNA)	Maryland

Notes:

(1) Southwest Gas Corporation does not have a WNA. However, the company uses different mechanisms to reduce fluctuations in customer's bills due to colder or warmer than average weather. In California, the Public Utilities Commission authorized a margin tracker balancing account in April 2004 that mitigates margin volatility due to weather and other usage variations. In Nevada, the Public Utilities Commission approved certain rate design improvements in September 2004 to mitigate weather variations, including an increase in the monthly basic service charge and the use of declining block rates.

(2) The Laclede Group does not have a WNA. However, the company has an innovative weather mitigation rate design that lessens the impact of weather volatility on Laclede Gas Company's customers during the peak cold months of December through March, and reduces the impact of weather, to a lesser extent, during the months of November and April.

(3) Until September 2006, Piedmont Natural Gas Company had a WNA Clause in the state of North Carolina. However, on September 14, 2006, the North Carolina Utilities Commission adopted a settlement reached by the Company and the North Carolina Attorney General on July 18, 2006, regarding the company's Customer Utilization Tracker (CUT). The CUT is a mechanism that decouples the recovery of authorized margins from sales levels. The CUT applies to changes in sales levels caused by any factor.

(4) On October 12, 2006, the New Jersey Board of Public Utilities approved a three-year pilot energy conservation program and revenue decoupling mechanism that had been proposed by South Jersey Gas Company (SJG). Under the programs, SJG will implement enhanced customer education and energy conservation programs. In place of the existing weather normalization clause, the company will implement a conservation and usage adjustment mechanism (CUA) mechanism that is designed to remove impact on company earnings and revenue of sales fluctuations due to weather variations and customer participation in the conservation program.

(5) In August 2005, Washington Gas Light Company received approval from the Public Service Commission of Maryland to implement a Revenue Normalization Adjustment mechanism (RNA). The RNA is a billing adjustment mechanism that is designed to stabilize the level of distribution charge revenues received from Maryland customers as a result of deviations in customer usage caused by variations in weather from normal levels and other matters such as conservation.

Source of Information: Company Annual Forms 10-K and Quarterly Forms 10-Q
Regulatory Research Associates, Inc., An SNL Energy Company
AGA Rate Service, Published by AUS Utility Reports

Exhibit___(FJH-1)
Sheet 4 of 5

Southwest Gas Corporation
Comparison of Return on Average Book Common Equity for the Years 1997 through 2006 (1) for
Southwest Gas Corporation, the Arizona Jurisdiction
and the Proxy Group of Eight Gas distribution Companies

	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	10 YEAR AVERAGE
Southwest Gas Corporation	10.15 %	6.02 %	8.50 %	5.60 %	6.65 %	5.79 %	6.32 %	6.89 %	9.75 %	2.87 %	6.85 %
Arizona Jurisdiction (2)	5.99 %	(0.50) %	4.18 %	4.10 %	7.23 %	7.39 %	5.65 %	7.18 %	12.93 %	3.08 %	5.72 %
Average Annual Yields, "Baa" Public Utility Bonds	6.32 %	5.93 %	6.40 %	6.64 %	8.02 %	8.03 %	8.36 %	7.88 %	7.26 %	7.95 %	7.13
Proxy Group of Eight Gas distribution Companies											
AGL Resources Inc.	13.64 %	13.36 %	13.13 %	16.39 %	14.91 %	13.76 %	11.09 %	11.31 %	12.63 %	12.66 %	
Atmos Energy Corp.	9.09	9.93	8.66	11.11	10.31	11.49	9.33	4.74	15.83	10.00	
The Laclede Group, Inc.	12.74	11.09	11.01	11.83	7.76	10.64	9.15	9.63	10.96	13.18	
NICOR Inc.	15.24	17.47	9.99	14.79	17.84	17.25	6.21	16.05	15.45	17.30	
Northwest Natural Gas Co.	10.69	10.07	9.41	9.24	8.73	10.38	10.29	10.08	8.35	11.34	
Piedmont Natural Gas Co., Inc.	11.00	11.65	12.82	12.19	10.82	12.04	12.57	12.25	13.74	13.42	
South Jersey Industries, Inc.	17.32	13.21	13.36	12.90	12.84	12.73	12.75	12.40	8.08	10.65	
WGL Holdings, Inc.	10.43	11.85	11.56	14.18	5.03	10.99	11.93	10.44	11.25	14.06	
Average	12.52 %	12.33 %	11.25 %	12.83 %	11.03 %	12.41 %	10.42 %	10.86 %	11.78 %	12.83 %	11.83 %

Notes: (1) Calculated as income available for common equity before extraordinary items divided by the average of the beginning and ending total common equity for each year.
(2) Company provided.

Source of Information: Standard & Poor's Compustat Services, Inc., PC Plus Research Insight Data Base.
Company Annual Forms 10K and / or Quarterly Forms 10Q

Exhibit___(FJH-1)
Sheet 5 of 5

Standard & Poor's Ratings Services

Standard & Poor's CORPORATE RATINGS CRITERIA

STANDARD & POOR'S

CORPORATE RATINGS CRITERIA

Dear Reader,

This volume updates the 1994 edition of *Corporate Finance Criteria*. There are several new chapters, covering our recently introduced Bank Loan Ratings, criteria for "notching" junior obligations, and the role of cyclicality in ratings. Naturally, the ratio medians have been brought up to date.

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Solomon B. Samson
Chairman, Corporate Ratings Criteria Committee

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Utilities

The utilities rating methodology encompasses two basic components: business risk analysis and financial analysis. Evaluation of industry characteristics, the utility's position within that industry, its regulation, and its management provides the context for assessing a firm's financial condition.

Historical analysis is a tool for identifying strengths and weaknesses, and provides a starting point for evaluating financial condition. Business position assessment is the qualitative measure of a utility's fundamental creditworthiness. It focuses on the forces that will shape the utilities' future.

Utilities' credit analysis factors

Business risk	Financial risk
• Markets and service area economy	• Earnings protection
• Competitive position	• Capital structure
• Operations	• Cash flow adequacy
• Regulation	• Financial flexibility/capital attraction
• Management	
• Fuel, power, and water supply	
• Asset concentration	

The credit analysis of utilities is quickly evolving, as utilities are treated less as regulated monopolies and more as entities faced with a host of challengers in a competitive environment. Marketplace dynamics are supplanting the power of regulation, making it critically important to reduce costs and/or market new services in order to thwart competitors' inroads.

Markets and service area economy

Assessing service territory begins with the economic and demographic evaluation of the area in which the utility has its franchise. Strength of long-term demand for the product is examined from a macroeconomic perspective. This enables Standard & Poor's to evaluate the affordability of rates and the staying power of demand.

Standard & Poor's tries to discern any secular consumption trends and, more importantly, the reasons for them. Specific items examined include the size and growth rate of the market, strength of the franchise, historical and projected sales growth, income levels and trends in population, employment, and per capita income. A utility with a healthy economy and customer base—as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment—will have a greater capacity to support its operations.

For electric and gas utilities, distribution by customer class is scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed cautiously, since a utility may have significant exposure to cyclical volatility. Alternatively, a large residential component yields a stable and more predictable revenue stream. The largest utility customers are identified to determine their importance to the bottom line and assess the risk of their loss and potential adverse effect on the utility's financial position. Credit concerns arise when individual customers represent more than 5% of revenues. The company or industry may play a significant role in the overall economic base of the service area. Moreover, large customers may turn to cogeneration or alternative power supplies to meet their energy needs, potentially leading to reduced cash flow for the utility (even in cases where a large customer pays discounted rates and is not a profitable account for the utility). Customer concentration is less significant for water and telecommunication utilities.

Competitive position

As competitive pressures have intensified in the utilities industry, Standard & Poor's analysis has deepened to include a more thorough review of competitive position.

Electric utility competition

For electric utilities, competitive factors examined include: percentage of firm wholesale revenues that are most vulnerable to competition; industrial load concentration; exposure of key customers to alternative suppliers; commercial concentrations; rates for various customer classes; rate design and flexibility; production costs, both marginal and fixed; the regional capacity situation; and transmission constraints. A regional focus is evident, but high costs and rates relative to national averages are also of significant concern because of the potential for electricity substitutes over time.

Mounting competition in the electric utility industry derives from excess generating capacity, lower barriers to entering the electric generating business, and marginal costs that are below embedded costs. Standard & Poor's has already witnessed declining prices in wholesale markets, as *de facto* retail competition is already being seen in several parts of the country. Standard & Poor's believes that over the coming years more and more customers will want and demand lower prices. Initial concerns focus on the largest industrial loads, but other customer classes will be increasingly vulnerable. Competition will not necessar-

ily be driven by legislation. Other pressures will arise from global competition and improving technologies, whether it be the declining cost of incremental generation or advances in transmission capacity or substitute energy sources like the fuel cell. It is impossible to say precisely when wide-open retail competition will occur; this will be evolutionary. However, significantly greater competition in retail markets is inevitable.

Gas utility competition

Similarly, gas utilities are analyzed with regard to their competitive standing in the three major areas of demand: residential, commercial, and industrial. Although regulated as holders of monopoly power, natural gas utilities have for some time been actively competing for energy market share with fuel oil, electricity, coal, solar, wood, etc. The long-term staying power of market demand for natural gas cannot be taken for granted. In fact, as the electric utility industry restructures and reduces costs, electric power will become more cost competitive and threaten certain gas markets. In addition, independent gas marketers have made greater inroads behind the city gate and are competing for large gas users. Moreover, the recent trend by state regulators to unbundle utility services is creating opportunities for outsiders to market niche products. Distributors still have the upper hand, but those who do not reduce and control costs, and thus rates, could find competition even more difficult.

Natural gas pipelines are judged to carry a somewhat higher business risk than distribution companies because they face competition in every one of their markets. To the extent a pipeline serves utilities versus industrial end users, its stability is greater. Over the next five years, pipeline competition will heat up since many service contracts with customers are expiring. Most distributor or end-use customers are looking to reduce pipeline costs and are working to improve their load factor to do so. Thus, pipelines will likely find it difficult to recontract all capacity in coming years. Being the pipeline of choice is a function of attractive transportation rates, diversity and quality of services provided, and capacity available in each particular market. In all cases though, periodic discounting of rates to retain customers will occur and put pressure on profitability.

Water utility competition

As the last true utility monopoly, water utilities face very little competition and there is currently no challenge to the continuation of franchise areas. The only exceptions have been cases where investor-owned water companies have been subject to condemnation and municipalization because of poor service or political motivations. In that regard, Standard & Poor's pays close attention to costs and rates in relation to neighboring utilities and national averages. (In contrast, the privatization of public water facilities has begun, albeit at a slower pace than anticipated. This is occurring mostly in the form of operating contracts and public/private partnerships, and not in asset transfers. This trend should continue as cities look for ways to balance their tight budgets.) Also, water utilities are not fully immune to the forces of competition; in a few instances wholesale customers can access more than one supplier.

Telephone competition

The Telecommunications Act of 1996 accelerates the continuing challenge to the local exchange companies' (LECs) century-old monopoly in the local loop. Competitive access providers (CAPs), both facilities-based and resellers, are aggressively pursuing customers, generally targeting metropolitan areas, and promising lower rates and better service.

Most long-distance calls are still originated and terminated on the local telephone company network. To complete such a call, the long-distance provider (including AT&T, MCI, Sprint and a host of smaller interexchange carriers or "IXCs") must pay the local telephone company a steep "access" fee to compensate the local phone company for the use of its local network. CAPs, in contrast, build or lease facilities that directly connect customers to their long-distance carrier, bypassing the local telephone company and avoiding access fees, and thereby can offer lower long-distance rates. But the LECs are not standing still; they are combating the loss of business to CAPs by lowering access fees, thereby reducing the economic incentive for a high usage long-distance customer to use a CAP. LECs are attempting to make up for the loss of revenues from lower access fees by increasing basic local service rates (or at least not lowering them), since basic service is far less subject to competition. LECs are improving operating efficiency and marketing high margin, value-added new services. Additionally, in the wake of the Telecommunications Act, LECs will capture at least some of the inter-LATA long-distance market. As a result of these initiatives, LECs continue to rebuild themselves—from the traditional utility monopoly to leaner, more marketing oriented organizations.

While LECs, and indeed all segments of the telecommunications sector, face increasing competition, there are favorable industry factors that tend to offset heightened business risk and auger for overall ratings stability for most LECs. Importantly, telecommunications is a declining-cost business. With increased deployment of fiber optics, the cost of transport has fallen dramatically and digital switching hardware and software have yielded more capable, trouble-free and cost-efficient networks. As a result, the cost of network maintenance has dropped sharply, as illustrated by the ratio of employees per 10,000 access lines, an oft cited measurement of efficiency. Ratios as low as 25 employees per 10,000 lines are being seen, down from the typical 40 or more employees per 10,000 ratio of only a few years ago.

In addition, networks are far more capable. They are increasingly digitally switched and able to accommodate high-speed communications. The infrastructure needed to accommodate switched broadband services will be built into telephone networks over the next few years. These advanced networks will enable telephone companies to look to a greater variety of high-margin, value-added serv-

ices. In addition to those current services such as call waiting or caller ID, the delivery of hundreds of broadcast and interactive video channels will be possible. While these services offer the potential of new revenue streams, they will simultaneously present a formidable challenge. LECs will be entering the new (to them) arena of multimedia entertainment and will have to develop expertise in marketing and entertainment programming acumen; such skills stand in sharp contrast to LECs' traditional strengths in engineering and customer service.

Operations

Standard & Poor's focuses on the nature of operations from the perspective of cost, reliability, and quality of service. Here, emphasis is placed on those areas that require management attention in terms of time or money and which, if unresolved, may lead to political, regulatory, or competitive problems.

Operations of electric utilities

For electrics, the status of utility plant investment is reviewed with regard to generating plant availability and utilization, and also for compliance with existing and contemplated environmental and other regulatory standards. The record of plant outages, equivalent availability, load factors, heat rates, and capacity factors are examined. Also important is efficiency, as defined by total megawatt hour per employee and customers per employee. Transmission interconnections are evaluated in terms of the number of utilities to which the utility in question has access, the cost structures and available generating capacity of these other utilities, and the price paid for wholesale power.

Because of mounting competition and the substantial escalation in decommissioning estimates, significant weight is given to the operation of nuclear facilities. Nuclear plants are becoming more vulnerable to high production costs that make their rates uneconomic. Significant asset concentration may expose the utility to poor performance, unscheduled outages or premature shutdowns, and large deferrals or regulatory assets that may need to be written off for the utility to remain competitive. Also, nuclear facilities tend to represent significant portions of their operators' generating capability and assets. The loss of a productive nuclear unit from both power supply and rate base can interrupt the revenue stream and create substantial additional costs for repairs and improvements and replacement power. The ability to keep these stations running smoothly and economically directly influences the ability to meet electric demand, the stability of revenues and costs, and, by extension, the ability to maintain adequate creditworthiness. Thus, economic operation, safe operation, and long-term operation are examined in depth. Specifically, emphasis is placed on operation and maintenance costs, busbar costs, fuel costs, refueling outages, forced outages, plant statistics, NRC evaluations, the potential need for repairs, operating licenses, decommissioning estimates and amounts held in external trusts, spent fuel storage capacity, and management's nuclear experience. In essence, favorable nuclear operations offer significant opportunities but, if a nuclear unit runs poorly or not at all, the attendant risks can be great.

Operations of gas utilities

For gas pipeline and distribution companies, the degree of plant utilization, the physical condition of the mains and lines, adequacy of storage to meet seasonal needs, "lost and unaccounted for" gas levels, and per-unit nongas operating and construction costs are important factors. Efficiency statistics such as load factor, operating costs per customer, and operating income per employee are also evaluated in comparison to other utilities and the industry as a whole.

Operations of water utilities

As a group, water utilities are continually upgrading their physical plant to satisfy regulations and to develop additional supply. Over the next decade, water systems will increasingly face the task of maintaining compliance, as drinking water regulations change and infrastructure ages. Given that the Safe Drinking Water Act was authorized in 1974, the first generation of treatment plants built to conform with these rules are almost 20 years old. Additionally, because the focus during this period was on satisfying environmental standards, deferred maintenance of distribution systems has been common, especially in older urban areas. The increasing cost of supplying treated water argues against the high level of unaccounted for water witnessed in the industry. Consequently, Standard & Poor's anticipates capital plans for rebuilding distribution lines and major renewal and replacement efforts aimed at treatment plants.

Operations of telephone companies

For telephone companies, cost-of-service analysis focuses on plant capability and measures of efficiency and quality of service. Plant capability is ascertained by looking at such parameters as percentage of digitally switched lines; fiber optic deployment, in particular in those portions of the plant key to network survival; and the degree of broadband capacity fiber and coaxial deployment and broadband switching capacity. Efficiency measures include operating margins, the ratio of employees per 10,000 access lines, and the extent of network and operations consolidation. Quality of service encompasses examination of quantitative measures, such as trouble reports and repeat service calls, as well as an assessment of qualitative factors, that may include service quality goals mandated by regulators.

Regulation

Regulatory rate-setting actions are reviewed on a case-by-case basis with regard to the potential effect on creditworthiness. Regulators' authorizing high rates of return is of little value unless the returns are earnable. Furthermore, allowing high returns based on noncash items does not benefit bondholders. Also, to be viewed positively, regulatory treatment should allow consistent performance from

period to period, given the importance of financial stability as a rating consideration.

The utility group meets frequently with commission and staff members, both at Standard & Poor's offices and at commission headquarters, demonstrating the importance Standard & Poor's places on the regulatory arena for credit quality evaluation. Input from these meetings and from review of rate orders and their impact weigh heavily in Standard & Poor's analysis.

Standard & Poor's does not "rate" regulatory commissions. State commissions typically regulate a number of diverse industries, and regulatory approaches to different types of companies often differ within a single regulatory jurisdiction. This makes it all but impossible to develop inclusive "ratings" for regulators.

Standard & Poor's evaluation of regulation also encompasses the administrative, judicial, and legislative processes involved in state and federal regulation. These can affect rate-setting activities and other aspects of the business, such as competitive entry, environmental and safety rules, facility siting, and securities sales.

As the utility industry faces an increasingly deregulated environment, alternatives to traditional rate-making are becoming more critical to the ability of utilities to effectively compete, maintain earnings power, and sustain creditor protection. Thus, Standard & Poor's focuses on whether regulators, both state and federal, will help or hinder utilities as they are exposed to greater competition. There is much that regulators can do, from allocating costs to more captive customers to allowing pricing flexibility—and sometimes just stepping out of the way.

Under traditional rate-making, rates and earnings are tied to the amount of invested capital and the cost of capital. This can sometimes reward companies more for justifying costs than for containing them. Moreover, most current regulatory policies do not permit utilities to be flexible when responding to competitive pressures of a deregulated market. Lack of flexible tariffs for electric utilities may lure large customers to wheel cheaper power from other sources.

In general, a regulatory jurisdiction is viewed favorably if it permits earning a return based on the ability to sustain rates at competitive levels. In addition to performance-based rewards or penalties, flexible plans could include market-based rates, price caps, index-based prices, and rates premised on the value of customer service. Such rates more closely mirror the competitive environment that utilities are confronting.

Electric industry regulation

The ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract is also important in the electric industry. (While contracting at reduced rates constrains financial performance, it lessens the potential adverse impact in the event of retail wheeling. Since revenue losses associated with this strategy are not likely to be recovered from ratepayers, utilities must control costs well enough to remain competitive if they are to sustain current levels of bondholder protection.)

Natural gas industry regulation

In the gas industry, too, several state commission policies weigh heavily in the evaluation of regulatory support. Examples include stabilization mechanisms to adjust revenues for changes in weather or the economy, rate and service unbundling decisions, revenue and cost allocation between sales and transportation customers, flexible industrial rates, and the general supportiveness of construction costs and gas purchases.

Water industry regulation

In all water utility activities, federal and state environmental regulations continue to play a critical role. The legislative timetable to effect the 1986 amendments to the Safe Drinking Water Act of 1974 was quite aggressive. But environmental standards-setting has actually slowed over the past couple of years due largely to increasing sentiment that the stringent, costly standards have not been justified on the basis of public health. A moratorium on the promulgation of significant new environmental rules is anticipated.

Telecommunications industry regulation

Despite the advances in telecommunications deregulation, analysis of regulation of telephone operators will continue to be a key rating determinant for the foreseeable future. The method of regulation may be either classic rate-based rate of return or some form of price cap mechanism. The most important factor is to assess whether the regulatory framework—no matter which type—provides sufficient financial incentive to encourage the rated company to maintain its quality of service and to upgrade its plant to accommodate new services while facing increasing competition from wireless operators and cable television companies.

Where regulators do still set tariffs based on an authorized return, Standard & Poor's strives to explore with regulators their view of the rate-of-return components that can materially impact reported versus regulatory earnings. Specifically these include the allowable base upon which the authorized return can be earned, allowable expenses, and the authorized return. Since regulatory oversight runs the gamut from strict, adversarial relationships with the regulated operating companies to highly supportive postures, Standard & Poor's probes beyond the apparent regulatory environment to ascertain the actual impact of regulation on the rated company.

Management

Evaluating the management of a utility is of paramount importance to the analytical process since management's abilities and decisions affect all areas of a company's operations. While regulation, the economy, and other outside factors can influence results, it is ultimately the quality of management that determines the success of a company.

With emerging competition, utility management will be more closely scrutinized by Standard & Poor's and will become an increasingly critical component of the credit evaluation. Management strategies can be the key determinant in differentiating utilities and in establishing where companies lie on the business position spectrum. It is imperative that managements be adaptable, aggressive, and proactive if their utilities are to be viable in the future; this is especially important for utilities that are currently uncompetitive.

The assessment of management is accomplished through meetings, conversations, and reviews of company plans. It is based on such factors as tenure, industry experience, grasp of industry issues, knowledge of customers and their needs, knowledge of competitors, accounting and financing practices, and commitment to credit quality. Management's ability and willingness to develop workable strategies to address their systems' needs, to deal with the competitive pressures of free market, to execute reasonable and effective long-term plans, and to be proactive in leading their utilities into the future are assessed. Management quality is also indicated by thoughtful balancing of public and private priorities, a record of credibility, and effective communication with the public, regulatory bodies, and the financial community. Boards of directors will receive ever more attention with respect to their role in setting appropriate management incentives.

With competition the watchword, Standard & Poor's also focuses on management's efforts to enhance financial condition. Management can bolster bondholder protection by taking any number of discretionary actions, such as selling common equity, lowering the common dividend payout, and paying down debt. Also important for the electric industry will be creativity in entering into strategic alliances and working partnerships that improve efficiency, such as central dispatching for a number of utilities or locking up at-risk customers through long-term contracts or expanded flexible pricing agreements. Proactive management teams will also seek alternatives to traditional rate-base, rate-of-return rate-making, move to adopt higher depreciation rates for generating facilities, segment customers by individual market preferences, and attempt to create superior service organizations.

In general, management's ability to respond to mounting competition and changes in the utility industry in a swift and appropriate manner will be necessary to maintain credit health.

Fuel, power, and water supply

Assessment of present and prospective fuel and power supply is critical to every electric utility analysis, while gauging the long-term natural gas supply position for gas pipeline and distribution companies and the water resources of a water utility is equally important. There is no similar analytical category for telephone utilities.

Electric utilities

For electric utilities emphasis is placed on generating reserve margins, fuel mix, fuel contract terms, demand-side management techniques, and purchased power arrangements. The adequacy of generating margins is examined nationally, regionally, and for each individual company. However, the reserve margin picture is muddied by the imprecise nature of peak-load growth forecasting, and also supply uncertainty relating to such things as Canadian capacity availability and potential plant shutdowns due to age, new NRC rules, acid rain remedies, fuel shortages, problems associated with nontraditional technologies, and so forth. Even apparently ample reserves may not be what they seem. Moreover, the quality of capacity is just as important as the size of reserves. Companies' reserve requirements differ, depending upon individual operating characteristics.

Fuel diversity provides flexibility in a changing environment. Supply disruptions and price hikes can raise rates and ignite political and regulatory pressures that ultimately lead to erosion in financial performance. Thus, the ability to alter generating sources and take advantage of lower cost fuels is viewed favorably.

Dependence on any single fuel means exposure to that fuel's problems: electric utilities that rely on oil or gas face the potential for shortages and rapid price increases; utilities that own nuclear generating facilities face escalating costs for decommissioning; and coal-fired capacity entails environmental problems stemming from concerns over acid rain and the "greenhouse effect."

Buying power from neighboring utilities, qualifying facility projects, or independent power producers may be the best choice for a utility that faces increasing electricity demand. There has been a growing reliance on purchased power arrangements as an alternative to new plant construction. This can be an important advantage, since the purchasing utility avoids potential construction cost overruns as well as risking substantial capital. Also, utilities can avoid the financial risks typical of a multiyear construction program that are caused by regulatory lag and prudence reviews. Furthermore, purchased power may enhance supply flexibility, fuel resource diversity, and maximize load factors. Utilities that plan to meet demand projections with a portfolio of supply-side options also may be better able to adapt to future growth uncertainties. Notwithstanding the benefits of purchasing, such a strategy has risks associated with it. By entering into a firm long-term purchased power contract that contains a fixed-cost component, utilities can incur substantial market, operating, regulatory, and financial risks. Moreover, regulatory treatment of purchased power removes any upside potential that might help offset the risks. Utilities are not compensated through incentive rate-making; rather, purchased power is recovered dollar-for-dollar as an operating expense.

To analyze the financial impact of purchased power, Standard & Poor's first calculates the net present value of future annual capacity payments (discounted at 10%). This represents a potential debt equivalent—the off-balance-sheet obligation that a utility incurs when it enters into a long-term purchased power contract. However, Standard

& Poor's adds to the utility's balance sheet only a portion of this amount, recognizing that such a contractual arrangement is not entirely the equivalent of debt. What percentage is added is a function of Standard & Poor's qualitative analysis of the specific contract and the extent to which market, operating, and regulatory risks are borne by the utility (the risk factor). For unconditional, take-or-pay contracts, the risk factor range is from 40%-80%, with the average hovering around 60%. A lower risk factor is typically assigned for system purchases from coal-fired utilities and a higher risk factor is usually designated for unit-specific nuclear purchases. The range for take-and-pay performance obligations is between 10%-50%.

Gas utilities

For gas distribution utilities, long-term supply adequacy obviously is critical, but the supply role has become even more important in credit analysis since the Federal Energy Regulatory Commission's Order 636 eliminated the interstate pipeline merchant business. This thrust gas supply responsibilities squarely on local gas distributors. Standard & Poor's has always believed distributor management has the expertise and wherewithal to perform the job well, but the risks are significant since gas costs are such a large percentage of total utility costs. In that regard, it is important for utilities to get preapprovals of supply plans by state regulators or at least keep the staff and commissioners well informed. To minimize risks, a well-run program would diversify gas sources among different producers or marketers, different gas basins in the U.S. and Canada, and different pipeline routes. Also, purchase contracts should be firm, with minimal take-or-pay provisions, and have prices tied to an industry index. A modest percentage of fixed-price gas is not unreasonable. Contracts, whether of gas purchases or pipeline capacity, should be intermediate term. Staggering contract expirations (preferably annually) provides an opportunity to be an active market player. A modest degree of reliance on spot purchases provides flexibility, as does the use of market-based storage. Gas storage and on-property gas resources such as liquefied natural gas or propane air are effective peak-day and peak-season supply management tools.

Since pipeline companies no longer buy and sell natural gas and are just common carriers, connections with varied reserve basins and many wells within those basins are of great importance. Diversity of sources helps offset the risks arising from the natural production declines eventually experienced by all reserve basins and individual wells. Moreover, such diversity can enhance a pipeline's attractiveness as a transporter of natural gas to distributors and end users seeking to buy the most economical gas available for their needs.

Water utilities

Nearly all water systems throughout the U.S. have ample long-term water supplies. Yet to gain comfort, Standard & Poor's assesses the production capability of treatment plants and the ability to pump water from underground aquifers in relation to the usage demands from consumers. Having adequate treated water storage facilities has become important in recent years and has helped many systems meet demands during peak summer periods. Of interest is whether the resources are owned by the utility or purchased from other utilities or local authorities. Owning properties with water rights provides more supply security. This is especially so in states like California where water allocations are being reduced, particularly since recent droughts and environmental issues have created alarm. Since the primary cost for water companies is treatment, it makes little difference whether raw water is owned or bought. In fact, compliance with federal and state water regulations is very high, and the overall cost to deliver treated water to consumers remains relatively affordable.

Asset concentration in the electric utility industry

In the electric industry, Standard & Poor's follows the operations of major generating facilities to assess if they are well managed or troubled. Significant dependence on one generating facility or a large financial investment in a single asset suggests high risk. The size or magnitude of a particular asset relative to total generation, net plant in service, and common equity is evaluated. Where substantial asset concentration exists, the financial profile of a company may experience wide swings depending on the asset's performance. Heavy asset concentration is most prevalent among utilities with costly nuclear units.

Earnings protection

In this category, pretax cash income coverage of all interest charges is the primary ratio. For this calculation, allowance for funds used during construction (AFUDC) is removed from income and interest expense. AFUDC and other such noncash items do not provide any protection for bondholders. To identify total interest expense, the analyst reclassifies certain operating expenses. The interest component of various off-balance-sheet obligations, such as leases and some purchased-power contracts, is included in interest expense. This provides the most direct indication of a utility's ability to service its debt burden.

While considerable emphasis in assessing credit protection is placed on coverage ratios, this measure does not provide the entire earnings protection picture. Also important are a company's earned returns on both equity and capital, measures that highlight a firm's earnings performance. Consideration is given to the interaction of embedded costs, financial leverage, and pretax return on capital.

Capital structure

Analyzing debt leverage goes beyond the balance sheet and covers quasi-debt items and elements of hidden financial leverage. Noncapitalized leases (including sale/leaseback obligations), debt guarantees, receivables financing, and purchased-power contracts are all considered debt equivalents and are reflected as debt in calculating capital

structure ratios. By making debt level adjustments, the analyst can compare the degree of leverage used by each utility company.

Furthermore, assets are examined to identify undervalued or overvalued items. Assets of questionable value are discounted to more accurately evaluate asset protection.

Some firms use short-term debt as a permanent piece of their capital structure. Short-term debt also is considered part of permanent capital when it is used as a bridge to permanent financing. Seasonal, self-liquidating debt is excluded from the permanent debt amount, but this situation is rare—with the exception of certain gas utilities. Given the long life of almost all utility assets, short-term debt may expose these companies to interest-rate volatility, remarketing risk, bank line backup risk, and regulatory exposure that cannot be readily offset. The lower cost of shorter-term obligations (assuming a positively sloped yield curve) is a positive factor that partially mitigates the risk of interest-rate variability. As a rule of thumb, a level of short-term debt that exceeds 10% of total capital is cause for concern.

Similarly, if floating-rate debt and preferred stock constitute over one-third of total debt plus preferred stock, this level is viewed as unusually high and may be cause for concern. It might also indicate that management is aggressive in its financial policies.

A layer of preferred stock in the capital structure is usually viewed as equity—since dividends are discretionary and the subordinated claim on assets provides a cushion for providers of debt capital. A preferred component of up to 10% is typically viewed as a permanent wedge in the capital structure of utilities. However, as rate-of-return regulation is phased out, preferred stock may be viewed by utilities—as many industrial firms would—as a temporary option for companies that are not current taxpayers that do not benefit from the tax deductibility of interest. Even now, floating-rate preferred and money market perpetual preferred are problematic; a rise in the rate due to deteriorating credit quality tends to induce a company to take out such preferred stock with debt. Structures that convey tax deductibility to preferred stock have become very popular and do generally afford such financings with equity treatment.

Cash flow adequacy

Cash flow adequacy relates to a company's ability to generate funds internally relative to its needs. It is a basic component of credit analysis because it takes cash to pay expenses, fund capital spending, pay dividends, and make interest and principal payments. Since both common and preferred dividend payments are important to maintain capital market access, Standard & Poor's looks at cash flow measures both before and after dividends are paid.

To determine cash flow adequacy, several quantitative relationships are examined. Emphasis is placed on cash flow relative to debt, debt service requirements, and capital spending. Cash flow adequacy is evaluated with respect to a firm's ability to meet all fixed charges, including capacity payments under purchased-power contracts. Despite the conditional nature of some contracts, the purchaser is obligated to pay a minimum capacity charge. The ratio used is funds from operations plus interest and capacity payments divided by interest plus capacity payments.

Financial flexibility/capital attraction

Financing flexibility incorporates a utility's financing needs, plans, and alternatives, as well as its flexibility to accomplish its financing program under stress without damaging creditworthiness. External funding capability complements internal cash flow. Especially since utilities are so capital intensive, a firm's ability to tap capital markets on an ongoing basis must be considered. Debt capacity reflects all the earlier elements: earnings protection, debt leverage, and cash flow adequacy. Market access at reasonable rates is restricted if a reasonable capital structure is not maintained and the company's financial prospects dim. The analyst also reviews indenture restrictions and the impact of additional debt on covenant tests.

Standard & Poor's assesses a company's capacity and willingness to issue common equity. This is affected by various factors, including the market-to-book ratio, dividend policy, and any regulatory restrictions regarding the composition of the capital structure.

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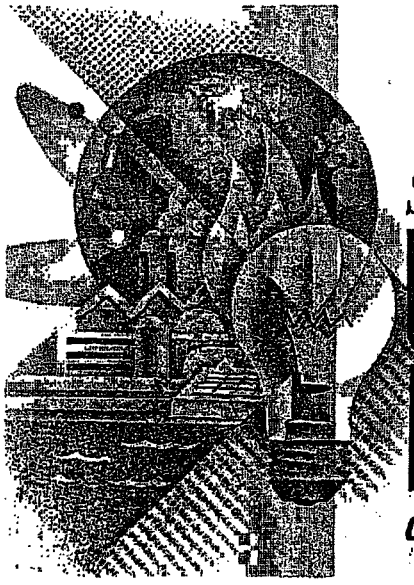

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STANDARD &POOR'S

New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised

Standard & Poor's Ratings Services has assigned new business profile scores to U.S. utility and power companies to better reflect the relative business risk among companies in the sector. Standard & Poor's also has revised its published risk-adjusted financial guidelines. The new business scores and financial guidelines do not represent a change to Standard & Poor's ratings criteria or methodology, and no ratings changes are anticipated from the new business profile scores or revised financial guidelines.

New Business Profile Scores and Revised Financial Guidelines

Standard & Poor's has always monitored changes in the industry and altered its business risk assessments accordingly. This is the first time since the 10-point business profile scale for U.S. investor-owned utilities was implemented that a comprehensive assessment of the benefits and the application of the methodology has been made. The principal purpose was to determine if the methodology continues to provide meaningful differentiation of business risk. The review indicated that while business profile scoring continues to provide analytical benefits, the complete range of the 10-point scale was not being utilized to the fullest extent.

Standard & Poor's has also revised the key financial guidelines that it uses as an integral part of evaluating the credit quality of U.S. utility and power companies. These guidelines were last updated in June 1999. The financial guidelines for three principal ratios (funds from operations (FFO) interest coverage, FFO to total debt, and total debt to total capital) have been broadened so as to be more flexible. Pretax interest cov-

Chart 1

Distribution of Business Profile Scores

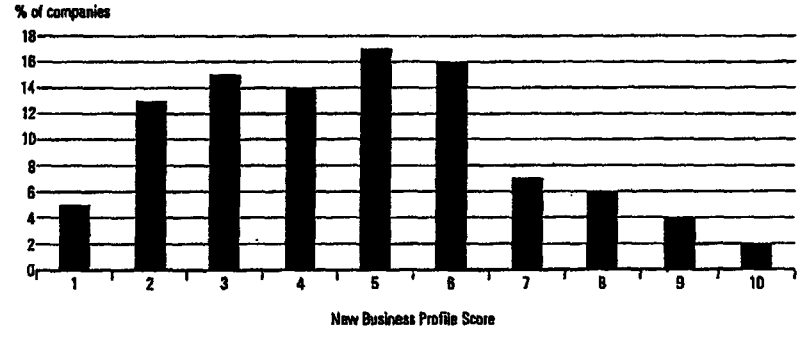
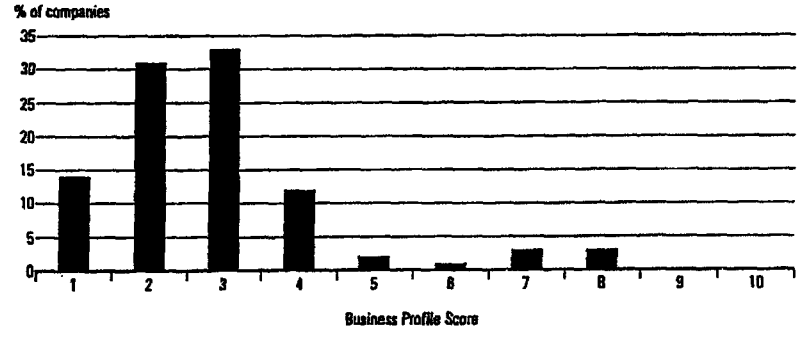


Chart 2

Transmission and Distribution—Water, Gas, and Electric



erage as a key credit ratio was eliminated.

Finally, Standard & Poor's has segmented the utility and power industry into sub-sectors based on the dominant corporate strategy that a company is pursuing. Standard & Poor's has published a new U.S. utility and power company ranking list that reflects these sub-sectors.

There are numerous benefits to the reassessment. Fuller utilization of the entire 10-point scale provides a superior relative ranking of qualitative business risk. A revision of the financial guidelines supports the goal of not causing rating changes from the recalibration of the business profiles. Classification of companies by sub-sectors will ensure greater comparability and consistency in ratings. The use of industry segmentation will also allow more in-depth statistical analysis of ratings distributions and rating changes.

The reassessment does not represent a change to Standard & Poor's criteria or methodology for determining ratings for utility and power companies. Each business profile score should be considered as the assignment of a new score; these scores do not represent improvement or deterioration in our assessment of an individual company's business risk relative to the previously assigned score. The financial guidelines continue to be risk-adjusted based on historical utility and industrial medians. Segmentation into industry sub-sectors does not imply that specific company characteristics will not weigh heavily into the assignment of a company's business profile score.

Results

Previously, 83% of U.S. utility and power business profile scores fell between '3' and '6', which clearly does not reflect the risk differentiation that exists in the utility and power industry today. Since the 10-point scale was introduced, the industry has transformed into a much less homogenous industry, where the divergence of business risk—particularly regarding management, strategy, and degree of competitive market exposure—has created a much wider spectrum of risk profiles. Yet over the same period, business profile scores actually converged more tightly around a median score of '4'. The new business pro-

Chart 3

Transmission Only—Electric, Gas, and Other

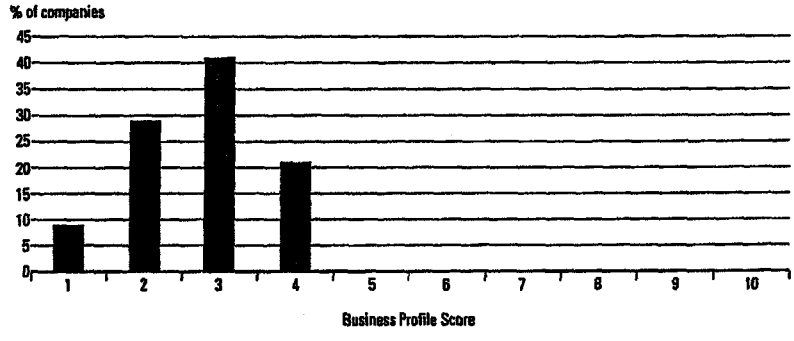
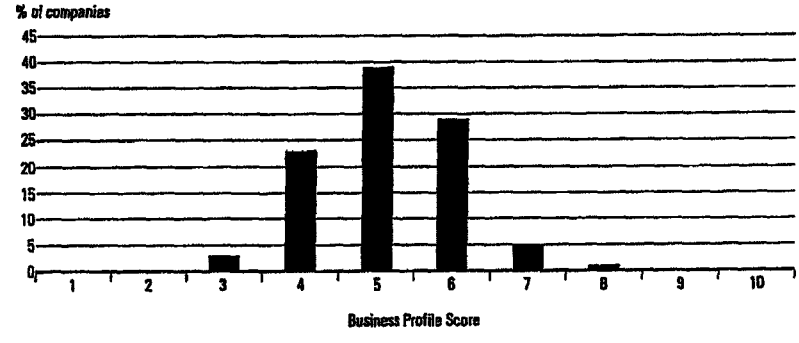


Chart 4

Integrated Electric, Gas, and Combination Utilities



file scores, as of June 2, are shown in Chart 1. The overall median business profile score is now '5'.

Table 1 contains the revised financial guidelines. It is important to emphasize that these metrics are only guidelines associated with expectations for various rating levels. Although credit ratio analysis is an important part of the ratings process, these three statistics are by no means the only critical financial measures that Standard & Poor's uses in its analytical process. We also analyze a wide array of financial ratios that do not have published guidelines for each rating category.

Again, ratings analysis is not driven solely by these financial ratios, nor has it ever been. In fact, the new financial guidelines that Standard & Poor's is incorporating for the specified rating categories reinforce the analytical framework whereby other factors can outweigh the achievement of otherwise acceptable financial ratios. These factors include:

- Effectiveness of liability and liquidity management;
- Analysis of internal funding sources;
- Return on invested capital;
- The execution record of stated business strategies;
- Accuracy of projected performance versus actual results, as well as the trend;
- Assessment of management's financial policies and attitude toward credit; and
- Corporate governance practices.

Charts 2 through 6 show business profile scores broken out by industry sub-sector. The five industry sub-sectors are:

- Transmission and distribution—Water, gas, and electric;
- Transmission only—Electric, gas, and other;
- Integrated electric, gas, and combination utilities;
- Diversified energy and diversified nonenergy; and
- Energy merchant/power developer/trading and marketing companies.

The average business profile scores for transmission and distribution companies and transmission-only companies are lower on the scale than the previous averages, while the average business profile scores for integrated utilities, diversified energy, and energy merchants and developers are higher.

Chart 5

Diversified Energy and Diversified Non-Energy

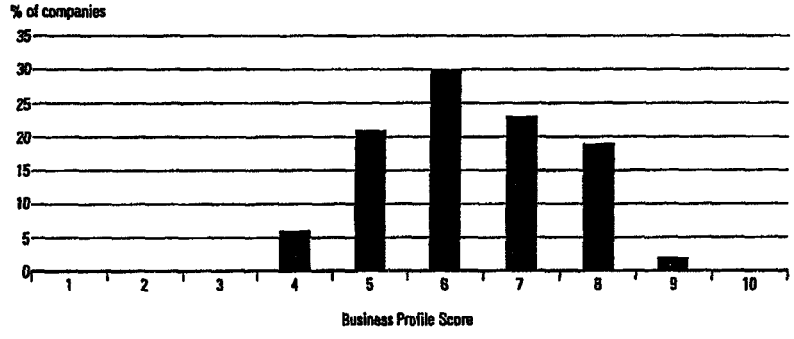
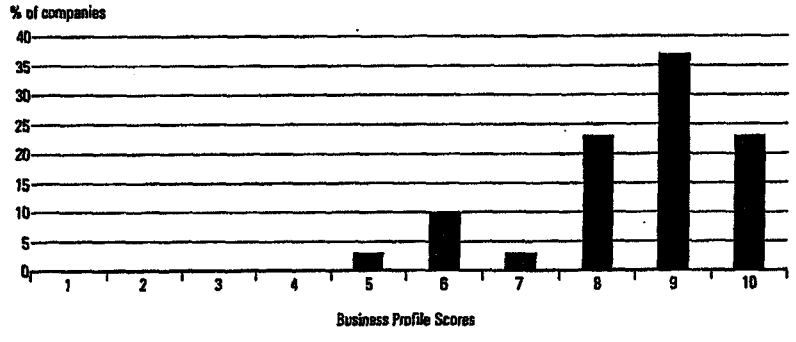


Chart 6

Energy Merchant/Developers/Trading and Marketing



See pages 16 to 19 for the company ranking list of business profile scores segmented by industry sub-sector and ranked in order of credit rating, outlook, business profile score, and relative strength.

Business Profile Score Methodology

Standard & Poor's methodology of determining corporate utility business risk is anchored in the assessment of certain specific characteristics that define the sector. We assign business profile scores to each of the rated companies in the utility and power sector on a 10-point scale, where '1' represents the lowest risk and '10' the highest risk. Business profile scores are assigned to all rated utility and power companies, whether they are holding companies, subsidiaries, or stand-alone corporations. For operating subsidiaries and stand-alone companies, the score is a bottom-up assessment. Scores for families of companies are a composite of the operating subsidiaries' scores. The actual credit rating of a company is analyzed, in part, by comparing the business profile score with the risk-adjusted financial guidelines.

For most companies, business profile scores are assessed using five categories; specifically, regulation, markets, operations, competitiveness, and management. The emphasis placed on each category may be influenced by the

Table 1

Revised Financial Guidelines

Funds from operations/interest coverage (x)

Business Profile	AA		A		BBB		BB	
1	3	2.5	2.5	1.5	1.5	1		
2	4	3	3	2	2	1		
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1
4	5	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6	5.2	5.2	4.2	4.2	3	3	2
7	8	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9			10	7	7	4	4	2.8
10			11	8	8	5	5	3

Funds from operation/total debt (%)

Business Profile	AA		A		BBB		BB	
1	20	15	15	10	10	5		
2	25	20	20	12	12	8		
3	30	25	25	15	15	10	10	5
4	35	28	28	20	20	12	12	8
5	40	30	30	22	22	15	15	10
6	45	35	35	28	28	18	18	12
7	55	45	45	30	30	20	20	15
8	70	55	55	40	40	25	25	15
9			65	45	45	30	30	20
10			70	55	55	40	40	25

Total debt/total capital (%)

Business Profile	AA		A		BBB		BB	
1	48	55	55	60	60	70		
2	45	52	52	58	58	68		
3	42	50	50	55	55	65	65	70
4	38	45	45	52	52	62	62	68
5	35	42	42	50	50	60	60	65
6	32	40	40	48	48	58	58	62
7	30	38	38	45	45	55	55	60
8	25	35	35	42	42	52	52	58
9			32	40	40	50	50	55
10			25	35	35	48	48	52

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dominant strategy of the company or other factors. For example, for a regulated transmission and distribution company, regulation may account for 30% to 40% of the business profile score because regulation can be the single-most important credit driver for this type of company. Conversely, competition, which may not exist for a transmission and distribution company, would provide a much lower proportion (e.g., 5% to 15%) of the business profile score.

For certain types of companies, such as power generators, power developers, oil and gas exploration and production companies, or nonenergy-related holdings, where these five components may not be appropriate, Standard & Poor's will use other, more appropriate methodologies. Some of these companies are assigned business profile scores that are useful only for relative ranking purposes.

As noted above, the business profile score for a parent or holding company is a composite of the business profile scores of its individual subsidiary companies. Again, Standard & Poor's does not apply rigid guidelines for determining the proportion or weighting that each subsidiary represents in the overall business profile score. Instead, it is determined based on a number of factors. Standard & Poor's will analyze each subsidiary's contribution to FFO, forecast capital expenditures, liquidity requirements, and other parameters, including the extent to which one subsidiary has higher growth. The weighting is determined case-by-case. ■

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SOUTHWEST GAS CORPORATION
CAPITALIZATION AND FINANCIAL STATISTICS (1)
2002 - 2006, INCLUSIVE

	2006	2005	2004	2003	2002	
			(MILLIONS OF DOLLARS)			
CAPITALIZATION STATISTICS						
AMOUNT OF CAPITAL EMPLOYED						
TOTAL PERMANENT CAPITAL	$2,315.324	$2,159.248	$1,998.433	$1,858.066	$1,757.020	
SHORT-TERM DEBT	$0.000	$24.000	$100.000	$52.000	$53.000	
TOTAL CAPITAL EMPLOYED	$2,315.324	$2,183.248	$2,098.433	$1,910.066	$1,810.020	
INDICATED AVERAGE CAPITAL COST RATES (2)						
TOTAL DEBT	6.67 %	6.40 %	6.47 %	6.73 %	6.92 %	
PREFERRED STOCK						
						5 YEAR AVERAGE
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	61.07 %	65.21 %	64.69 %	66.07 %	66.07 %	64.62 %
PREFERRED STOCK	0.00	0.00	0.00	0.00	0.00	0.00
COMMON EQUITY	38.93	34.79	35.31	33.93	33.93	35.38
TOTAL	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT-TERM	61.07 %	65.60 %	66.37 %	66.99 %	67.06 %	65.42 %
PREFERRED STOCK	0.00	0.00	0.00	0.00	0.00	0.00
COMMON EQUITY	38.93	34.40	33.63	33.01	32.94	34.58
TOTAL	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
FINANCIAL STATISTICS						
FINANCIAL RATIOS - MARKET BASED						
EARNINGS / PRICE RATIO	6.32 %	4.46 %	6.76 %	5.31 %	6.12 %	5.79 %
MARKET / AVERAGE BOOK RATIO	160.91	134.80	126.74	118.21	123.51	132.83
DIVIDEND YIELD	2.51	3.18	3.44	3.87	3.77	3.35
DIVIDEND PAYOUT RATIO	40.54	72.44	51.71	81.22	70.59	63.30
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	10.15 %	6.02 %	8.50 %	5.60 %	6.65 %	7.38 %
FUNDS FROM OPERATIONS / INTEREST COVERAGE (3)	3.58 x	3.28 x	3.79 x	3.57 x	2.68 x	3.38 x
FUNDS FROM OPERATIONS / TOTAL DEBT (4)	17.35 %	14.38 %	17.31 %	16.84 %	11.85 %	15.55 %
TOTAL DEBT / TOTAL CAPITAL	61.07 %	65.60 %	66.37 %	66.99 %	67.06 %	65.42 %

See page 2 for notes.

Exhibit___(FJH-3)
Sheet 1 of 2

Southwest Gas Corporation
Capitalization and Financial Statistics
2002-2006, Inclusive

Notes:

(1) All capitalization and financial statistics are based upon financial statements as originally reported in each year.

(2) Computed by relating actual long-term debt interest booked to average of beginning and ending long-term debt or reported to be outstanding.

(3) Coverages - excluding all AFUDC represent the number of times available earnings, excluding all AFUDC, cover fixed charges.

(4) Sinking Fund Requirements for Corning Natural Gas Corporation were obtained from Company Annual Forms 10-K.

Source of Information: Standard & Poor's Compustat Services, Inc, PC Plus / Research Insight Database

PROXY GROUP OF EIGHT VALUE LINE GAS DISTRIBUTION COMPANIES
CAPITALIZATION AND FINANCIAL STATISTICS (1)
2002 - 2006, INCLUSIVE

	2006	2005	2004	2003	2002	
			(MILLIONS OF DOLLARS)			
CAPITALIZATION STATISTICS						
AMOUNT OF CAPITAL EMPLOYED						
TOTAL PERMANENT CAPITAL	$1,814.938	$1,745.823	$1,481.120	$1,221.674	$1,110.558	
SHORT-TERM DEBT	$265.099	$224.599	$161.914	$267.240	$173.091	
TOTAL CAPITAL EMPLOYED	$2,080.037	$1,970.422	$1,643.034	$1,488.913	$1,283.649	
INDICATED AVERAGE CAPITAL COST RATES (2)						
TOTAL DEBT	6.03 %	5.96 %	5.41 %	5.54 %	6.10 %	
PREFERRED STOCK	4.80	4.78	4.82	5.58	5.99	
CAPITAL STRUCTURE RATIOS						5 YEAR AVERAGE
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	46.67 %	46.95 %	46.45 %	47.41 %	50.05 %	47.50 %
PREFERRED STOCK	0.40	0.40	0.43	0.30	0.45	0.40
COMMON EQUITY	52.93	52.65	53.12	52.29	49.50	52.10
TOTAL	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT-TERM	54.17 %	53.52 %	51.89 %	57.21 %	56.94 %	54.75 %
PREFERRED STOCK	0.36	0.37	0.40	0.26	0.41	0.36
COMMON EQUITY	45.47	46.11	47.71	42.53	42.65	44.89
TOTAL	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
FINANCIAL STATISTICS						
FINANCIAL RATIOS - MARKET BASED						
EARNINGS / PRICE RATIO	6.73 %	6.46 %	6.38 %	7.53 %	6.54 %	6.73 %
MARKET / AVERAGE BOOK RATIO	186.27	189.06	179.46	170.48	165.72	178.20
DIVIDEND YIELD	4.03	4.01	4.17	4.90	5.34	4.49
DIVIDEND PAYOUT RATIO	61.36	62.60	70.55	65.89	87.12	69.50
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	12.52 %	12.33 %	11.25 %	12.83 %	11.03 %	11.99 %
FUNDS FROM OPERATIONS / INTEREST COVERAGE (3)	4.48 X	4.44 X	5.22 X	5.62 X	4.62 X	4.88 X
FUNDS FROM OPERATIONS / TOTAL DEBT (4)	20.21 %	18.88 %	22.76 %	22.45 %	20.89 %	21.04 %
TOTAL DEBT / TOTAL CAPITAL	54.17 %	53.52 %	51.89 %	57.21 %	56.94 %	54.75 %

See Page 2 for notes.

Exhibit___(FJH-4)
Sheet 1 of 3

Proxy Group of Eight Value Line Gas Distribution Companies
Capitalization and Financial Statistics
2002-2006, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.

(2) Computed by relating actual long-term debt interest or preferred stock dividends booked to average of beginning and ending long-term debt or preferred stock reported to be outstanding.

(3) Funds from operations (sum of net income, depreciation, amortization, netdeferred income tax and investment tax credits, less total AFUDC) plus interest charges divided by interest charges.

(4) Funds from operations (as defined in Note 3) as a percentage of total debt.

Selection Criteria:

The basis of selection was to include those domestic gas distribution companies: 1) which are included in Value Line Investment Survey (Standard Edition) – Natural Gas (Distribution) Industry; 2) which have actively traded common stock; 3) which have not cut or omitted their cash common stock dividends during the five calendar years ending 2006 or through the time of the preparation of Mr. Hanley's accompanying direct testimony; 4) which derived at least 50% of their 2006 operating revenues from natural gas distribution operations; 5) which derived at least 50% of their 2006 net operating income from natural gas distribution operations; 6) which at the time of the preparation of Mr. Hanley's direct testimony, had not publicly announced that they were being acquired by or merged into another company; and 7) which are included in S&P's Compustat PC Plus/Research Insight Database. Although Southwest Gas Corporation met these criteria, it has been excluded from the proxy group as it is the Company for whom rates are beingset in the current proceeding.

The following nine companies met the above criteria:
AGL Resources Inc.
Atmos Energy Corporation
The Laclede Group, Inc.
NICOR Inc.
Northwest Natural Gas Company
Piedmont Natural Gas Company, Inc.
South Jersey Industries, Inc.
WGL Holdings, Inc.

Source of Information: Standard & Poor's Compustat Services, Inc., PC Plus / Research Insight Database
Annual Reports to Shareholders and / or Forms 10K

Capital Structure Based upon Total Permanent Capital for
the Proxy Group of Eight Value Line Gas Distribution Companies
for the Years 2002 through 2006

	2006	2005	2004	2003	2002	5 YEAR AVERAGE
AGL Resources Inc.						
Long-Term Debt	49.56 %	51.24 %	53.32 %	52.22 %	59.06 %	53.08 %
Preferred Stock	1.28	1.20	1.18	0.00	0.00	0.73
Common Equity	49.16	47.56	45.50	47.78	40.94	46.19
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Atmos Energy Corp.						
Long-Term Debt	56.99 %	57.71 %	43.35 %	50.45 %	54.71 %	52.64 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	43.01	42.29	56.65	49.55	45.29	47.36
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
The Laclede Group, Inc.						
Long-Term Debt	49.50 %	50.87 %	53.17 %	50.35 %	49.78 %	50.73 %
Preferred Stock	0.12	0.13	0.16	0.21	0.22	0.17
Common Equity	50.38	49.00	46.67	49.44	50.00	49.10
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
NICOR Inc.						
Long-Term Debt	36.34 %	39.80 %	39.89 %	39.70 %	40.38 %	39.22 %
Preferred Stock	0.00	0.00	0.00	0.00	0.35	0.07
Common Equity	63.66	60.20	60.11	60.30	59.27	60.71
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Northwest Natural Gas Co.						
Long-Term Debt	47.69 %	47.43 %	46.75 %	49.70 %	48.67 %	48.05 %
Preferred Stock	0.00	0.00	0.00	0.00	0.86	0.17
Common Equity	52.31	52.57	53.25	50.30	50.47	51.78
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Piedmont Natural Gas Co., Inc.						
Long-Term Debt	48.30 %	42.74 %	43.57 %	42.30 %	46.33 %	44.65 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	51.70	57.26	56.43	57.70	53.67	55.35
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
South Jersey Industries, Inc.						
Long-Term Debt	44.83 %	45.08 %	49.11 %	51.17 %	54.23 %	48.88 %
Preferred Stock	0.06	0.06	0.28	0.28	0.32	0.20
Common Equity	55.11	54.86	50.61	48.55	45.45	50.92
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
WGL Holdings, Inc.						
Long-Term Debt	40.14 %	40.75 %	42.47 %	43.40 %	47.20 %	42.79 %
Preferred Stock	1.78	1.81	1.84	1.88	1.87	1.84
Common Equity	58.08	57.44	55.69	54.72	50.93	55.37
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Proxy Group of Eight Value Line Gas Distribution Companies						
Long-Term Debt	46.67 %	46.95 %	46.45 %	47.41 %	50.05 %	47.51 %
Preferred Stock	0.40	0.40	0.43	0.30	0.45	0.40
Common Equity	52.93	52.65	53.12	52.29	49.50	52.10
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Source of Information: Standard & Poor's Compustat Services, Inc , PC Plus / Research Insight Data Base
Company Annual Forms 10K (Sinking Fund Requirements)

Southwest Gas Corporation
Hypothetical Example of the Inadequacy of
A DCF Return Rate Related to Book Value
When Market Value Is Greater / Less than Book Value

Line No.		1 Market Value	2 Book Value with Market to Book Ratio of 180%	3 Book Value with Market to Book Ratio of 80%
1.	Per Share	$ 24.000	$ 13.33	$ 30.00
2.	DCF Cost Rate (1)	10.00%	10.00%	10.00%
3.	Return in Dollars	$ 2.400	$ 1.333	$ 3.000
4.	Dividends (2)	$ 0.960	$ 0.960	$ 0.960
5.	Growth in Dollars	$ 1.440	$ 0.373	$ 2.040
6.	Return on Market Value	10.00%	5.55% (3)	12.50% (4)
7.	Rate of Growth on Market Value	6.00% (5)	1.55% (6)	8.50% (7)

Notes:
(1) Comprised of 4.0% dividend yield and 6.0%% growth.
(2) $24.00 * 4.0% yield = $0.960.
(3) $1.333 / $24.00 market value = 5.55%.
(4) $3.000 / $24.00 market value = 12.50%.
(5) Expected rate of growth per market based DCF model.
(6) Actual rate of growth when DCF cost rate is applied to book value ($1.333 possible earnings - $0.960 dividends = $0.373 for growth / $24.00 market value = 1.55%).
(7) Actual rate of growth when DCF cost rate is applied to book value ($3.000 possible earnings - $0.960 dividends = $2.040 for growth / $24.00 market value = 8.50%).

Southwest Gas Corporation
Indicated Common Equity Cost Rate through the use
of the Discounted Cash Flow Model for
Southwest Gas Corporation
the Proxy Group of Eight Value Line Gas distribution Companies and

	1 Dividend Yield (1)	2 Dividend Growth Component (2)	3 Adjusted Dividend Yield (3)	4 Growth Rate (4)	5 Indicated DCF Return Rate (5)	6 "Recommended" DCF Return Rate (6)
Southwest Gas Corp.	2.34 %	0.08 %	2.42 %	6.75 %	9.17 %	-- %
Proxy Group of Eight Value Line Gas Distribution Companies						
AGL Resources Inc.	3.90 %	0.07 %	3.97 %	3.80 %	7.77 %	-- %
Atmos Energy Corp.	4.09	0.12	4.21	5.69	9.90	9.90
The Laclede Group, Inc.	4.66	0.05	4.71	2.00	6.71	--
NICOR Inc.	3.90	0.09	3.99	4.55	8.54	--
Northwest Natural Gas Co	2.99	0.08	3.07	5.67	8.74	--
Piedmont Natural Gas Co., Inc.	3.84	0.08	3.92	4.38	8.30	--
South Jersey Industries, Inc.	2.60	0.09	2.69	7.25	9.94	9.94
WGL Holdings, Inc.	4.10	0.06	4.16	2.75	6.91	--
Average	3.76 %	0.08 %	3.84 %	4.51 %	8.35 %	9.92 %

Notes:
(1) From Exhibit (FJH-7).
(2) This reflects a growth rate component equal to one-half the average projected five-year growth rate in EPS (from Sheet 1 of Exhibit (FJH-9) x Line No. 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Southwest Gas Corp., 2.34% x (1/2 x 6.75%) = 0.08%.
(3) Column 1 + Column 2.
(4) From Sheet 1 of Exhibit (FJH-9)
(5) Column 3 + Column 4.
(6) Includes only those indicated common equity cost rates which are greater than 9.60% (the lowest rate awarded to a gas distribution utility during the twelve months ended March 2007, from Exhibit 14) as fully explained in Mr. Hanley's accompanying direct testimony.

Southwest Gas Corporation
Derivation of Dividend Yield for Use in the
Discounted Cash Flow Model

	Dividend Yield			
		Average Based Upon Average High / Low Market Prices (2)		Average Dividend Yield (3)
	Spot (6/25/07) (1)	May 2007	April 2007	
Southwest Gas Corp.	2.55 %	2.24 %	2.22 %	2.34 %
Proxy Group of Eight Value Line Gas Distribution Companies				
AGL Resources Inc.	4.11 %	3.84 %	3.76 %	3.90 %
Atmos Energy Corp.	4.29	3.93	4.04	4.09
The Laclede Group, Inc.	4.68	4.67	4.62	4.66
NICOR Inc.	4.27	3.78	3.64	3.90
Northwest Natural Gas Co.	3.12	2.93	2.93	2.99
Piedmont Natural Gas Co., Inc.	4.04	3.76	3.72	3.84
South Jersey Industries, Inc.	2.79	2.47	2.53	2.60
WGL Holdings, Inc.	4.25	3.94	4.12	4.10
Average	3.94 %	3.67 %	3.67 %	3.76 %

Notes:
(1) The spot dividend yield is the current annualized dividend per share divided by the spot market price on 6/25/07.
(2) The average dividend yield was computed by relating the indicated annualized dividend rate and market price on the last trading day of each of the two months ended May 2007.
(3) Equal weight has been given to the spot, April 2007 and May 2007 dividend yields.

Source of Information: Standard & Poor's Compustat Services, Inc., PC Plus/Research Insight Data Base
http://finance.yahoo.com

Southwest Gas Corporation
Current Institutional Holdings (1) and Individual Holdings (2)
for the Proxy Group of Eight Gas Value Line Distribution Companies and

	1 June 2007 Percentage of Institutional Holdings	2 June 2007 Percentage of Individual Holdings (1)
Southwest Gas Corp.	75.5 %	24.5 %
Proxy Group of Eight Gas Value Line Distribution Companies		
AGL Resources Inc.	65.4 %	34.6 %
Atmos Energy Corp.	63.8	36.2
The Laclede Group, Inc.	49.0	51.0
NICOR Inc.	81.7	18.3
Northwest Natural Gas Co.	54.9	45.1
Piedmont Natural Gas Co., Inc.	45.9	54.1
South Jersey Industries, Inc.	58.9	41.1
WGL Holdings, Inc.	68.5	31.5
Average	61.0 %	39.0 %

(1) (1 - column 1).

Source of Information: reuters.com - updated June 25, 2007

Southwest Gas Corporation
Development of Projected Growth for Use in the Discounted Cash Flow Model

	1	2		3
	Value Line Projected 2010-'12 Growth Rate in EPS (1)	Thomson FN / First Call Projected Median Five-Year Growth Rate EPS	No. of Estimates	Average Projected Five-Year Growth Rate in EPS (2)
Southwest Gas Corp.	9.00 %	4.50 %	[2]	6.75 %
Proxy Group of Eight Value Line Gas Distribution Companies				
AGL Resources Inc.	3.50 %	4.10 %	[5]	3.80 %
Atmos Energy Corp.	6.00	5.38	[4]	5.69
The Laclede Group, Inc.	2.00	NA	--	2.00
NICOR Inc.	4.50	4.60	[3]	4.55
Northwest Natural Gas Co.	6.50	4.83	[3]	5.67
Piedmont Natural Gas Co., Inc.	4.00	4.75	[2]	4.38
South Jersey Industries, Inc.	NMF	7.25	[4]	7.25
WGL Holdings, Inc.	2.00	3.50	[2]	2.75
Average	4.07 %	4.92 %		4.51 %

NMF No Meaningful Figure

Notes: (1) From Sheets 2 through 10 of this Exhibit.
(2) Average of Columns 1 and 2.

Source of Information: Value Line Investment Survey, (Standard Edition), June 15, 2007
ThomsonFN First Call Earnings, thomsonfn.com, updated June 23, 2007

SOUTHWEST GAS NYSE-SWX

RECENT PRICE 37.29 | P/E RATIO 17.3 (Trailing: 18.3 Median: 19.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 2.3% | VALUE LINE

TIMELINESS 4 Lowered 5/11/07
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 6/8/07
BETA .85 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+60%)	14%
Low	40	(+5%)	4%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	1	0	1	0	0	0	0	1
Options	2	5	2	1	8	2	3	0	3
to Sell	2	5	2	1	8	4	3	0	5

Institutional Decisions

	3Q2006	4Q2006	1Q2007
to Buy	82	82	92
to Sell	46	60	65
Hld's(000)	29038	29706	30129

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
	24.99	25.93	25.68	26.16	23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	52.90	55.70	Revenues per sh [A]	58.95
	1.53	3.34	3.24	5.09	2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	6.07	6.25	6.45	"Cash Flow" per sh	6.95
	d.76	.81	.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	2.15	2.30	Earnings per sh [A B]	2.70
	.88	.70	.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.86	Div'ds Decl'd per sh [C=]	.90
	3.76	5.02	5.43	6.64	6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	8.50	9.10	Cap'l Spending per sh	9.45
	15.88	15.99	15.96	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.65	22.75	Book Value per sh	25.25
	20.60	20.60	21.00	21.28	24.47	26.73	27.38	30.41	30.99	31.71	32.49	33.29	34.23	35.79	39.33	41.77	43.00	44.00	Common Shs Outst'g [D]	47.50
	--	16.6	26.5	14.0	NMF	69.3	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.5	15.9	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	18.0
	--	1.01	1.57	.92	NMF	4.34	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86			Relative P/E Ratio	1.20
	7.0%	5.2%	4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%			Avg Ann'l Div'd Yield	1.9%
							732.0	917.3	936.9	1034.1	1396.7	1320.9	1231.0	1477.1	1714.3	2024.7	2275	2450	Revenues ($mill) [A]	2800
							20.8	47.5	39.3	38.3	37.2	38.6	38.5	58.9	48.1	81.1	90.0	100	Net Profit ($mill)	125
							29.2%	43.4%	35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	29.7%	34.7%	35.0%	35.0%	Income Tax Rate	35.0%
							2.8%	5.2%	4.2%	3.7%	2.7%	2.8%	3.1%	4.0%	2.8%	4.0%	4.0%	4.1%	Net Profit Margin	4.5%
							63.5%	60.2%	60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	63.8%	60.6%	57.1%	57.4%	Long-Term Debt Ratio	53.8%
							31.5%	35.3%	35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	42.9%	42.6%	Common Equity Ratio	46.2%
							1224.7	1349.3	1424.7	1489.9	1417.6	1748.3	1851.6	1988.6	2076.0	2287.8	2275	2350	Total Capital ($mill)	2600
							1360.3	1459.4	1561.1	1686.1	1825.6	1979.5	2176.7	2336.0	2489.1	2668.1	2890	3000	Net Plant ($mill)	3500
							3.9%	5.8%	4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	4.3%	5.6%	6.0%	6.0%	Return on Total Cap'l	6.5%
							4.7%	8.9%	7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	6.4%	9.0%	9.0%	10.0%	Return on Shr. Equity	10.5%
							5.4%	10.0%	7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	9.0%	9.0%	10.0%	Return on Com Equity	10.5%
							NMF	5.0%	2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	2.2%	5.3%	5.5%	6.5%	Retained to Com Eq	7.0%
							107%	50%	64%	67%	71%	70%	72%	49%	65%	41%	41%	37%	All Div'ds to Net Prof	33%

CAPITAL STRUCTURE as of 3/31/07

Total Debt $1338.2 mill. Due in 5 Yrs $225.0 mill.
LT Debt $1310.7 mill. LT Interest $93.0 mill.
(Total interest coverage: 3.3x)

Pension Assets-12/06 $413.5 mill.
Oblig. $534.9 mill.

Pfd Stock None

Common Stock 42,159,705 shs as of 5/1/07

MARKET CAP: $1.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	3/31/07
Cash Assets	29.6	18.8	54.0
Other	513.1	482.8	396.4
Current Assets	542.7	501.6	450.4
Accts Payable	259.5	265.7	191.1
Debt Due	107.2	27.5	27.5
Other	254.3	202.9	288.6
Current Liab.	621.0	496.1	507.2
Fix. Chg. Cov.	167%	220%	234%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	6.0%	4.5%	5.0%
"Cash Flow"	4.5%	4.0%	3.5%
Earnings	12.0%	6.0%	9.0%
Dividends	--	--	1.5%
Book Value	3.0%	3.5%	4.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	473.4	278.7	264.5	460.5	1477.1
2005	542.9	361.1	313.3	497.0	1714.3
2006	676.9	430.9	351.8	565.1	2024.7
2007	793.7	480	400	601.3	2275
2008	850	500	450	650	2450

Calendar	EARNINGS PER SHARE [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1.18	d.24	d.51	1.23	1.66
2005	.88	d.07	d.43	.87	1.25
2006	1.11	.02	d.26	1.11	1.98
2007	1.17	.05	d.20	1.13	2.15
2008	1.22	.05	d.15	1.18	2.30

Calendar	QUARTERLY DIVIDENDS PAID [C=] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.205	.205	.205	.205	.82
2004	.205	.205	.205	.205	.82
2005	.205	.205	.205	.205	.82
2006	.205	.205	.205	.205	.82
2007	.205	.215			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approx. 1.8 million customers in sections of Arizona, Nevada, and California '06 margin mix: resid. and small commercial, 85%; large commercial and industrial, 6%; transportation, 9% Total throughput: 2.4 billion therms Principal suppliers: El Paso Natural Gas Co. and Northwest Pipeline Corp. Acquired gas utility assets from Arizona Public Service in 1984. Sold PriMerit Bank (acq. in '86) in 7/96. Has about 4,902 employees. Officers & Directors own 1.4% of common stock (3/07 Proxy). Chairman: LeRoy Hanneman. Chief Executive Officer: Jeffrey W. Shaw. Incorporated: California. Address: 5241 Spring Mountain Rd., Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com

Southwest Gas posted solid first-quarter performance. The top line advanced roughly 17%. The comparison benefited from three full months of rate relief in Arizona, which had originally become effective March 1, 2006. These results are also a reflection of closer-to-normal weather, compared to the warmer temperatures experienced in the first quarter of 2006. In addition, Southwest Gas benefited from a rising customer base, as the company has added 62,000 meters during the past year, for growth of about 4%. Operating expenses were considerably higher, primarily as a result of an increase in the cost of gas sold, which jumped approximately 24%. The bottom-line tally came in at $1.17, a moderate improvement from the prior year's period. Comparisons should remain favorable in the coming quarters. We expect revenues and share earnings will increase about 12% and 9%, respectively, for full-year 2007.

We are mildly optimistic about the company's growth prospects. We believe the increased focus on securing rate relief and improving rate design will continue to benefit SWX going forward. This factor is important, as Southwest Gas depends upon such approved revenue increases to help cope with higher natural gas prices. We anticipate continued growth in the customer base, as well. However, the company is not without risk. As Southwest continues to expand, it is likely to incur increased operating costs. Insufficient, or lagging, rate relief could also hurt profitability. The possibility of warmer-than-usual weather during the winter months is another caveat.

The company has increased its dividend by almost 5%. Starting with the June payout, the quarterly dividend is now $0.215 per share. We find this move encouraging. Nonetheless, the stock's dividend yield of 2.3% remains below the industry average.

Shares of Southwest Gas are ranked 4 (Below Average) for Timeliness. We anticipate that revenues and share earnings will advance at a moderate clip over the pull to 2010-2012. However, this appears to be reflected in the current quotation, and total return potential is unexciting for this timeframe.

Michael F. Napoli, CPA *June 15, 2007*

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	65

(A) Incl. income for PriMerit Bank on the equity basis through 1994. (B) Based on avg. shares outstand. thru '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Incl. asset writedown: '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Next egs. report due in August. (C) Dividends historically paid early March, June, September, December. = Div'd reinvest. plan avail. (D) In millions.

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AGL RESOURCES NYSE-ATG

RECENT PRICE 42.34 | P/E RATIO 15.1 (Trailing: 16.2 Median: 14.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 4 Lowered 8/11/06
SAFETY 2 New 7/27/90
TECHNICAL 3 Raised 2/23/07
BETA .95 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	10%
Low	40	(-5%)	3%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	0
Options	0	1	0	0	3	6	0	1	0
to Sell	0	2	0	0	4	1	0	0	0

Institutional Decisions

	3Q2006	4Q2006	1Q2007
to Buy	95	113	121
to Sell	102	78	89
Hld's(000)	49525	50305	49321

	High:	22.0	21.6	23.4	23.4	23.2	24.5	25.0	29.3	33.7	39.3	40.1	44.7
	Low:	17.1	17.8	17.7	15.8	15.5	19.0	17.3	21.9	26.5	32.0	34.4	38.2

LEGENDS
1.50 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 12/95
Options: Yes
Shaded area indicates recession

Target Price Range 2010 | 2011 | 2012

% TOT. RETURN 5/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	21.3	22.2
3 yr.	69.9	56.5
5 yr.	128.5	97.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
20.26	20.43	22.73	23.59	19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	34.95	35.45	Revenues per sh [A]	38.75
2.07	2.31	2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.62	4.80	5.00	"Cash Flow" per sh	5.55
1.04	1.13	1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.62	2.06	2.28	2.48	2.72	2.80	2.90	Earnings per sh [A B]	3.10
1.02	1.03	1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.84	Div'ds Decl'd per sh [C]	1.80
2.85	2.74	2.49	2.37	2.17	2.37	2.59	2.05	2.51	2.82	2.83	3.30	2.45	3.44	3.44	3.26	3.35	3.30	Cap'l Spending per sh	3.45
9.42	9.70	9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.55	21.50	Book Value per sh [D]	22.50
47.57	48.69	49.72	50.86	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	78.00	79.00	Common Shs Outst'g [E]	80.00
15.3	15.5	17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	15.0
.98	.94	1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73			Relative P/E Ratio	1.00
6.4%	5.9%	5.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%			Avg Ann'l Div'd Yield	3.9%
1287.6	1338.6	1068.6	607.4	1049.3	868.9	983.7	1832.0	2718.0	2621.0	2725	2800	Revenues ($mill) [A]	3100
76.6	80.6	52.1	71.1	82.3	103.0	132.4	153.0	193.0	212.0	220	230	Net Profit ($mill)	250
37.9%	32.5%	33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	37.8%	38.0%	38.0%	Income Tax Rate	38.0%
5.9%	6.0%	4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	8.1%	8.1%	8.2%	Net Profit Margin	8.1%
48.7%	47.5%	45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	50.2%	49.3%	49.3%	Long-Term Debt Ratio	49.2%
45.9%	47.1%	49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	50.7%	50.7%	Common Equity Ratio	50.8%
1356.4	1388.4	1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	3231.0	3315	3350	Total Capital ($mill)	3540
1496.6	1534.0	1598.9	1637.5	2058.9	2104.2	2352.4	3178.0	3271.0	3436.0	3550	3700	Net Plant ($mill)	4000
7.3%	7.6%	5.7%	7.4%	6.5%	8.1%	6.9%	6.3%	7.9%	8.0%	8.0%	8.5%	Return on Total Cap'l	8.5%
11.0%	11.1%	7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	13.0%	13.5%	Return on Shr. Equity	14.0%
11.3%	12.3%	7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	13.0%	13.5%	Return on Com Equity	14.0%
3.2%	4.4%	NMF	3.2%	4.2%	7.0%	6.6%	5.6%	6.2%	6.3%	5.5%	6.0%	Retained to Com Eq	6.0%
74%	64%	101%	72%	65%	52%	53%	49%	52%	52%	58%	56%	All Div'ds to Net Prof	58%

CAPITAL STRUCTURE as of 3/31/07
Total Debt $1734.0 mill. Due in 5 Yrs $411.0 mill.
LT Debt $1623.0 mill. LT Interest $100.0 mill.

(Total interest coverage: 3.7x)
Leases, Uncapitalized Annual rentals $32.0 mill.

Pension Assets-12/06 $375.0 mill.
Oblig. $454.0 mill.

Pfd Stock None
Common Stock 77,794,028 shs.
as of 4/25/07

MARKET CAP: $3.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	3/31/07
Cash Assets	30.0	20.0	29.0
Other	2002.0	1802.0	1365.0
Current Assets	2032.0	1822.0	1394.0
Accts Payable	264.0	213.0	160.0
Debt Due	522.0	539.0	111.0
Other	1153.0	875.0	830.0
Current Liab.	1939.0	1627.0	1101.0
Fix. Chg. Cov.	442%	397%	384%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	3.5%	13.5%	4.0%
"Cash Flow"	5.5%	7.0%	5.5%
Earnings	7.0%	15.0%	3.5%
Dividends	2.5%	4.0%	5.5%
Book Value	6.5%	10.5%	2.5%

Calendar	QUARTERLY REVENUES ($ mill.) [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	651	294	262	625	1832
2005	908	430	387	993	2718
2006	1044	436	434	707	2621
2007	973	480	455	817	2725
2008	1000	500	470	830	2800

Calendar	EARNINGS PER SHARE [A B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1.00	.33	.31	.64	2.28
2005	1.14	.30	.19	.85	2.48
2006	1.41	.25	.46	.60	2.72
2007	1.30	.35	.50	.65	2.80
2008	1.40	.35	.45	.70	2.90

Calendar	QUARTERLY DIVIDENDS PAID [C] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.27	.28	.28	.28	1.11
2004	.28	.29	.29	.29	1.15
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37	.37	1.48
2007	.41	.41			

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia (primarily Atlanta), Virginia, and in southern Tennessee. Also engaged in nonregulated natural gas marketing and other, allied services. Also wholesales and retails propane. Nonregulated subsidiaries: Georgia Natural Gas Services markets natural gas at retail. Acq. Virginia Natural Gas, 10/00. Sold Utilipro, 3/01. Off./dir. own less than 1.0% of common; Barclays Global Investors, 5.0% (3/07 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: 10 Peachtree Place N.E., Atlanta, GA 30309. Tel.: 404-584-4000. Internet: www.aglresources.com.

AGL Resources posted solid results for the first quarter, although revenues and share earnings came in somewhat below the record-high numbers achieved in the prior year's period. Performance was supported by the Retail Energy Operations segment, where operating earnings increased about 17%. This business experienced increased customer usage during the quarter. The addition of the Ohio retail market that SouthStar Energy Services entered last summer also boosted performance. (AGL owns a 70% noncontrolling interest in SouthStar.) In addition, the company benefited from a lower cost of gas during the recent interim. However, operating earnings declined considerably in the Wholesale Services business, which experienced lower commercial activity and mark-to-market losses following an increase in NYMEX natural gas prices.

We anticipate a moderate top-line advance in the current year. The company has reaffirmed its share-net guidance of $2.75-$2.85 for 2007, assuming normal weather and average volatility in natural gas prices. Our projection remains at the midpoint of this range. This modest growth ought to continue in the following year, as well.

Subsidiary Golden Triangle Storage has plans to build a $180 million natural gas storage facility. This proposed facility should provide 12 billion cubic feet of working gas capacity following completion of the first phase. Located at the Spindletop salt dome in Beaumont, Texas, it will connect with six pipelines serving diverse markets with counter-seasonal demand. Construction is scheduled to begin next year, with the facility becoming operational in 2011.

Shares of AGL are ranked 4 (Below Average) for Timeliness. We anticipate modest growth in revenues and earnings per share over the pull to 2010-2012. This appears to be reflected in the current quotation, and appreciation potential is unexciting for this timeframe. On the bright side, the company recently increased its dividend by over 10%. Income-oriented investors may find the 3.9% dividend yield enticing. In addition, this good-quality issue has superior marks for Safety and Price Stability.

Michael F. Napoli, CPA *June 15, 2007*

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	75

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(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, ($0.83); '99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07). Next earnings report due early August.
(C) Dividends historically paid early March, June, Sept. and Dec. ■ Div'd reinvest. plan available.
(D) Includes intangibles. At 3/31/07: $420 million, $5.40/share.
(E) In millions, adjusted for stock split.

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ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 32.12 | P/E RATIO 16.2 (Trailing: 14.6 / Median: 16.0) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 7/28/06
SAFETY 2 Raised 12/16/05
TECHNICAL 4 Lowered 5/25/07
BETA .80 (1.00 = Market)

2010-12 PROJECTIONS

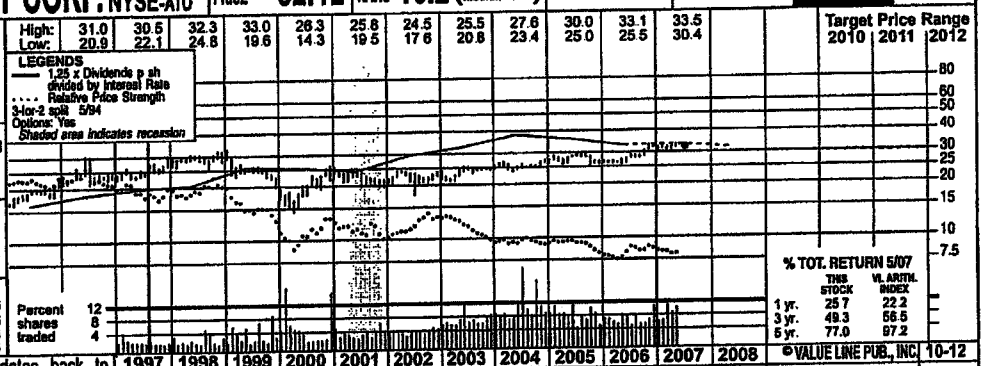
	Price	Gain	Ann'l Total Return
High	40	(+25%)	9%
Low	30	(-5%)	3%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	3Q2006	4Q2006	1Q2007
to Buy	102	90	115
to Sell	67	88	84
Hld's(000)	46293	48572	53926



Target Price Range 2010 | 2011 | 2012
80 60 50 40 30 25 20 15 10 7.5

% TOT. RETURN 5/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	25.7	22.2
3 yr.	49.3	56.5
5 yr.	77.0	97.2

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

CAPITAL STRUCTURE as of 3/31/07
Total Debt $2181.5 mill. Due in 5 Yrs $1450.0 mill.
LT Debt $1878.3 mill. LT Interest $115.0 mill.
(LT Interest earned: 2.9x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $16.0 mill.
Pfd Stock None
Pension Assets-9/06 $362.7 mill. Oblig. $326.5 mill.
Common Stock 88,806,235 shs. as of 4/25/07
MARKET CAP: $2.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	3/31/07
Cash Assets	40.1	75.8	176.3
Other	1224.3	1041.7	1253.1
Current Assets	1264.4	1117.5	1429.4
Accts Payable	461.3	345.1	665.2
Debt Due	148.1	385.6	303.2
Other	503.4	388.5	421.4
Current Liab.	1112.8	1119.2	1389.8
Fix. Chg. Cov.	395%	408%	415%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.5%	17.0%	3.5%
"Cash Flow"	4.0%	5.0%	4.5%
Earnings	3.5%	10.0%	6.0%
Dividends	3.0%	2.0%	1.5%
Book Value	6.5%	8.5%	4.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	763.6	1117.5	546.1	492.8	2920.0
2005	1371.0	1687.8	909.9	1004.6	4973.3
2006	2283.8	2033.8	863.2	971.6	6152.4
2007	1802.6	2075.6	*900*	*961.8*	*5540*
2008	*1450*	*1450*	*1450*	*1450*	*5800*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	.57	1.12	.09	d.11	1.58
2005	.79	1.11	.06	d.21	1.72
2006	.88	1.10	d.22	.25	2.00
2007	.97	1.20	*d.06*	*d.11*	*2.00*
2008	*.95*	*1.15*	*.08*	*d.08*	*2.10*

Calendar	QUARTERLY DIVIDENDS PAID C Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.30	.30	.30	.305	1.21
2004	.305	.305	.305	.31	1.23
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315	.32	1.27
2007	.32	.32			

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
	30.59	27.90	22.09	26.61	35.36	22.82	54.39	46.50	61.75	75.27	*61.90*	*62.70*	Revenues per sh A	*74.75*
	2.85	3.38	2.62	3.01	3.03	3.39	3.23	2.91	3.90	4.26	*4.20*	*4.30*	"Cash Flow" per sh	*4.75*
	1.34	1.84	.81	1.03	1.47	1.45	1.71	1.58	1.72	2.00	*2.00*	*2.10*	Earnings per sh A B	*2.50*
	1.01	1.06	1.10	1.14	1.16	1.18	1.20	1.22	1.24	1.26	*1.28*	*1.30*	Div'ds Decl'd per sh C■	*1.35*
	4.13	4.44	3.53	2.36	2.77	3.17	3.10	3.03	4.14	5.20	*5.00*	*5.30*	Cap'l Spending per sh	*6.60*
	11.04	12.21	12.09	12.28	14.31	13.75	16.66	18.05	19.90	20.16	*22.45*	*21.75*	Book Value per sh	*25.20*
	29.64	30.40	31.25	31.95	40.79	41.68	51.48	62.80	80.54	81.74	*89.50*	*92.50*	Common Shs Outst'g D	*107.00*
	17.9	15.4	33.0	18.9	15.6	15.2	13.4	15.9	16.1	13.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.0*
	1.03	.80	1.88	1.23	.80	.83	.76	.84	.86	.73			Relative P/E Ratio	*.95*
	4.2%	3.7%	4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%			Avg Ann'l Div'd Yield	*3.9%*
	906.8	848.2	690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	*5540*	*5800*	Revenues ($mill) A	*8000*
	39.2	55.3	25.0	32.2	56.1	59.7	79.5	86.2	135.8	162.3	*180*	*195*	Net Profit ($mill)	*270*
	37.5%	36.5%	35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	*39.0%*	*39.0%*	Income Tax Rate	*40.5%*
	4.9%	6.5%	3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	*3.2%*	*3.4%*	Net Profit Margin	*3.4%*
	48.1%	51.8%	50.0%	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	*48.0%*	*50.0%*	Long-Term Debt Ratio	*51.0%*
	51.9%	48.2%	50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	*52.0%*	*50.0%*	Common Equity Ratio	*49.0%*
	630.2	769.7	755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	3828.5	*4070*	*4230*	Total Capital ($mill)	*5750*
	849.1	917.9	965.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	3629.2	*3850*	*4150*	Net Plant ($mill)	*5300*
	8.3%	9.0%	5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	6.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
	12.0%	14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.9%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
	12.0%	14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.9%	*8.5%*	*9.0%*	Return on Com Equity	*9.5%*
	3.9%	6.3%	NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	3.6%	*3.0%*	*3.5%*	Retained to Com Eq	*4.5%*
	67%	58%	NMF	112%	79%	82%	70%	77%	73%	63%	*64%*	*62%*	All Div'ds to Net Prof	*54%*

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2006 gas volumes: 272 MMcf. Breakdown: 53% residential; 32% commercial; 10% industrial; and 5% other. 2006 depreciation rate 3.6%. Has around 4,600 employees. Officers and directors own approximately 1.9% of common stock (12/06 Proxy). Chairman and Chief Executive Officer: Robert W. Best. Incorporated: Texas. Address: P.O. Box 650205, Dallas, Texas 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy Corporation generated healthy bottom-line growth during the first half of fiscal 2007 (ends September 30th). The core utility unit enjoyed a 9% increase in throughput, plus benefits from the implementation of weather-normalization mechanisms for the Mid-Tex and Louisiana operations. Furthermore, margins for the natural gas marketing segment widened nicely, partially because of efforts to capture more favorable arbitrage opportunities with regard to storage activities. Meanwhile, the pipeline business reaped the rewards of the North Side Loop and other projects that were completed last year, and there was a healthy rise in asset management fees.

Nevertheless, we believe that share net will be flat for the year as a whole. The fourth-quarter comparison may be quite difficult, given that our fiscal 2006 figure excludes an $0.18-a-share charge for the impairment of irrigation properties in the West Texas Division. Furthermore, the public offering of 6.3 million common shares last December will dilute earnings per share by around a nickel. Lastly, the effective income tax rate has been higher.

The company stands to register steady, albeit measured, profit gains out to 2010-2012. With utility operations in 12 states, Atmos is not dependent on the economy or rate commissions in any one region of the country. What's more, the non-utility businesses, contributing between 15% and 35% of net income historically, possess decent overall prospects. (During 2006, the company expanded into natural gas gathering, which fits nicely with the pipeline unit.) In the present corporate configuration, share net could advance between 5% and 7% annually over the 3- to 5-year timeframe.

Income-oriented investors may find the dividend yield appealing. And it seems that more moderate increases in the distribution are likely. Earnings coverage should remain strong.

But long-term total-return potential is limited, since these good-quality shares are already trading within our 2010-2012 Target Price Range. And for the coming year, the equity is ranked to just approximate the broader market averages.

Frederick L. Harris, III *June 15, 2007*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '97, d53¢; '99, d23¢; '00, 12¢; '03, d17¢; '06, d18¢. Next egs. rpt. due early Aug. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions, adjusted for stock splits. (E) Qtrs may not add due to change in shrs outstanding. (F) ATO completed United Cities merger 7/97.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	70

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LACLEDE GROUP NYSE-LG

RECENT PRICE 31.27 | P/E RATIO 15.3 (Trailing: 16.8 Median: 15.0) | RELATIVE P/E RATIO 0.78 | DIV'D YLD 4.9% | VALUE LINE

TIMELINESS 5 Lowered 1/19/07
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Raised 6/15/07
BETA .90 (1.00 = Market)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	24.9	28.6	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3	37.5	36.0	
Low:	20.0	20.3	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9	29.1	29.3	

Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+45%)	13%
Low	30	(-5%)	4%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	1	0	4	1	0	1	0
to Sell	0	0	1	0	4	1	0	1	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	60	54	64
to Sell	47	52	38
Hld's(000)	10115	9986	10381

% TOT. RETURN 5/07

	THIS STOCK	VL ARITH. INDEX
1 yr	-3.2	22.2
3 yr	31.0	56.5
5 yr.	61.1	97.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
28.10	26.83	32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	*85.60*	*87.25*	Revenues per sh	*110.00*
2.37	2.32	2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	*3.70*	*4.00*	"Cash Flow" per sh	*5.00*
1.28	1.17	1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	*1.90*	*2.00*	Earnings per sh A B	*2.35*
1.20	1.20	1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	*1.45*	*1.49*	Div'ds Decl'd per sh C ■	*1.60*
2.46	2.87	2.82	2.50	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	*2.85*	*3.05*	Cap'l Spending per sh	*3.80*
11.83	11.79	12.19	12.44	13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	*20.70*	*20.90*	Book Value per sh D	*24.50*
15.59	15.59	15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	*21.50*	*22.00*	Common Shs Outst'g E	*25.00*
12.5	15.8	13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	18.2	13.6	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*16.0*
.80	.96	.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	*estimates*		Relative P/E Ratio	*1.05*
7.5%	6.5%	5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%			Avg Ann'l Div'd Yield	*4.3%%*
						602.8	547.2	491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	1997.6	*1840*	*1920*	Revenues ($mill) A	*2750*
						32.5	27.9	26.9	26.0	30.5	22.4	34.6	36.1	40.1	50.5	*41.0*	*44.0*	Net Profit ($mill)	*60.0*
						36.1%	35.6%	35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	*35.5%*	*35.5%*	Income Tax Rate	*35.5%*
						5.4%	5.1%	5.5%	4.6%	3.0%	3.0%	3.3%	2.8%	2.5%	2.5%	*2.2%*	*2.3%*	Net Profit Margin	*2.2%*
						38.0%	40.9%	41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	49.5%	*47.0%*	*48.0%*	Long-Term Debt Ratio	*49.0%*
						61.6%	58.6%	57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	*53.0%*	*52.0%*	Common Equity Ratio	*51.0%*
						406.8	438.0	488.6	519.2	574.1	546.6	605.0	737.4	707.9	798.9	*840*	*890*	Total Capital ($mill)	*1200*
						467.6	490.6	519.4	575.4	602.5	594.4	621.2	646.9	679.5	763.8	*815*	*865*	Net Plant ($mill)	*1150*
						9.7%	8.1%	7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	7.6%	8.4%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
						12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
						12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	*9.0%*	*9.5%*	Return on Com Equity	*10.0%*
						3.9%	1.8%	1.0%	.2%	1.8%	NMF	3.1%	2.7%	3.1%	5.1%	*2.0%*	*2.5%*	Retained to Com Eq	*3.5%*
						70%	83%	89%	98%	83%	113%	74%	73%	72%	58%	*78%*	*75%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 3/31/07
Total Debt $512.7 mill. Due in 5 Yrs $275.0 mill.
LT Debt $355.5 mill LT Interest $20.0 mill
(Total interest coverage: 3.1x)

Leases, Uncapitalized Annual rentals $.9 mill
Pension Assets-9/06 $246.1 mill.
Oblig. $282.1 mill.

Pfd Stock $.6 mill. Pfd Div'd $.05 mill.
Common Stock 21,601,259 shs. as of 4/27/07

MARKET CAP: $675 million (Small Cap)

CURRENT POSITION ($MILL.)	2005	2006	3/31/07
Cash Assets	6.0	50.8	35.5
Other	418.1	409.0	432.8
Current Assets	424.1	459.8	468.3
Accts Payable	138.4	103.3	143.8
Debt Due	110.7	207.5	157.2
Other	116.5	120.1	105.0
Current Liab.	365.6	430.9	406.0
Fix. Chg. Cov.	293%	285%	280%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	10.0%	16.0%	5.5%
"Cash Flow"	1.0%	3.0%	7.0%
Earnings	3.0%	6.5%	2.0%
Dividends	1.0%	.5%	2.5%
Book Value	3.0%	3.5%	5.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	332.6	475.0	245.1	197.6	1250.3
2005	442.5	576.5	311.3	266.7	1597.0
2006	689.2	708.8	330.6	269.0	1997.6
2007	539.6	700.8	*345*	*254.6*	*1840*
2008	*480*	*480*	*480*	*480*	*1920*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	.87	1.12	.19	d.28	1.82
2005	.79	1.06	.29	d.24	1.90
2006	1.23	1.05	.13	d.04	2.37
2007	.89	.97	*.15*	*d.11*	*1.90*
2008	*1.03*	*1.07*	*.20*	*d.30*	*2.00*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.335	.335	.335	.335	1.34
2004	.335	.34	.34	.34	1.36
2005	.34	.345	.345	.345	1.38
2006	.345	.355	.355	.355	1.41
2007	.365	.365			

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 631,000 customers. Purchased SM&P for approximately $43 million (1/02). Therms sold and transported in fiscal 2006: 1.02 mill. Revenue mix for regulated operations: residential, 60%; commercial and industrial, 25%; transportation, 1%; other, 14%. Has around 3,880 employees. Officers and directors own approximately 7.0% of common shares (1/07 proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.lacledegas.com.

Earnings for Laclede Group's core natural gas subsidiary, Laclede Gas, have been down thus far in fiscal 2007 (ends September 30th). That is attributable, in part, to lower income from entities outside the service territory. Heightened operation and maintenance expenses have also hurt. Unfortunately, it seems that these negative trends will persist for a while.

The two main non-regulated segments are also struggling. The performance of Laclede Energy Resources (LER) has not been as strong as last year, when margins were substantially higher as the result of supply/demand imbalances arising from the 2005 Gulf Coast hurricanes. Meanwhile, SM&P Utility Resources continues to be weighed down by expenses from expansionary initiatives, although its longer-term performance should benefit nicely. That said,

Consolidated share net could plunge 20%, to $1.90 a share, in fiscal 2007. But it's important to mention that the comparison is quite difficult, given LER's exceptional showing last year. The bottom line stands to rise to $2.00 a share in fiscal 2008, assuming some improvement in business conditions.

Unspectacular operating results may be in store for the company out to 2010-2012. The customer base for Laclede Gas has expanded at a sluggish pace for some time, leading us to believe that internal growth here will remain moderate. Furthermore, there does not appear to be any major acquisitions on the horizon. Thus, annual share-net advances may only be in the mid-single-digit range over the 3- to 5-year horizon.

These good-quality shares offer an appealing dividend yield. Additional increases in the payout may be minimal, though, given that the regulated division operates in a mature area.

Long-term total-return possibilities are limited. That's because the stock is presently trading within our 2010-2012 Target Price Range, and we're assuming moderate increases in the dividend. Moreover, Laclede Group shares are ranked to underperform the year-ahead market, based on recent price and earnings momentum.

Frederick L. Harris, III *June 15, 2007*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Next earnings report due late July.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '06: $256.8 mill., $12.02/sh.
(E) In millions. Adjusted for stock split.
(F) Qtly. egs. may not sum due to change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	65

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NICOR, INC. NYSE-GAS

RECENT PRICE 45.84 | P/E RATIO 16.1 (Trailing: 15.7 Median: 15.5) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 4 Lowered 5/6/07
SAFETY 3 Lowered 6/17/05
TECHNICAL 4 Lowered 6/1/07
BETA 1.30 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+30%)	10%
Low	40	(-15%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	1	1	3	0	1	0	0	0	1
Options	0	2	0	0	2	0	0	2	0
to Sell	0	0	0	0	2	0	0	2	1

Institutional Decisions

	3Q2006	3Q2006	4Q2006
to Buy	98	83	124
to Sell	110	118	80
Hld's(000)	32450	32534	32939

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC	10-12
High:	37.1	42.9	44.4	42.9	43.9	42.4	49.0	39.3	39.7	43.0	49.9	53.7							Target Price Range 2010	2011	2012
Low:	25.4	30.0	37.1	31.2	29.4	34.0	17.3	23.7	32.0	35.5	38.7	44.5									
26.46	28.90	31.02	31.23	29.42	37.39	41.33	30.84	34.45	50.52	57.30	43.11	60.46	62.12	76.00	65.92	68.90	71.10	Revenues per sh			71.10
3.92	4.14	3.80	4.11	4.19	4.97	5.29	5.21	5.59	6.16	6.41	6.03	5.37	6.00	6.19	6.82	6.20	6.35	"Cash Flow" per sh			6.45
1.86	1.92	1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.29	3.03	2.85	2.90	Earnings per sh A			3.15
1.12	1.18	1.22	1.25	1.28	1.32	1.40	1.48	1.54	1.66	1.76	1.84	1.86	1.86	1.86	1.86	1.90	1.90	Div'ds Decl'd per sh B ■			2.00
3.65	3.12	2.62	3.34	3.12	2.42	2.34	2.67	3.28	3.48	4.18	4.37	4.12	4.32	4.57	4.17	4.45	4.45	Cap'l Spending per sh			4.45
12.28	12.78	13.05	13.26	13.67	14.74	15.43	15.97	16.80	15.56	16.39	16.55	17.13	18.99	18.36	19.43	20.45	21.45	Book Value per sh			24.40
57.30	55.77	53.96	51.54	50.30	49.49	48.22	47.51	46.89	45.49	44.40	44.01	44.04	44.10	44.18	44.90	45.00	45.00	Common Shs Outst'g C			45.00
11.5	11.6	14.1	12.5	13.1	12.5	14.2	17.6	14.6	11.9	12.8	13.1	15.8	15.9	17.3	15.0	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio			16.0
.73	.70	.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.84	.92	.81			Relative P/E Ratio			1.05
5.2%	5.3%	4.4%	4.8%	5.0%	4.4%	3.9%	3.6%	4.1%	4.7%	4.6%	4.9%	5.6%	5.3%	4.7%	4.3%			Avg Ann'l Div'd Yield			4.5%
1992.6	1465.1	1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	3357.6	2960.0	3100	3200	Revenues ($mill)			3200
124.3	111.1	121.9	136.4	136.3	128.0	93.1	98.1	101.1	128.3	130	130	Net Profit ($mill)			140
35.0%	34.4%	34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	26.3%	30.0%	31.0%	Income Tax Rate			33.0%
6.2%	7.6%	7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	4.3%	4.1%	4.1%	Net Profit Margin			4.4%
42.3%	42.1%	35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	36.3%	35.0%	34.0%	Long-Term Debt Ratio			31.0%
57.2%	57.4%	64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	65.0%	66.0%	Common Equity Ratio			69.0%
1300.6	1322.6	1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	1370.7	1420	1465	Total Capital ($mill)			1600
1735.8	1731.8	1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2659.1	2714.1	2850	2950	Net Plant ($mill)			3250
11.1%	9.9%	10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	10.9%	10.5%	10.5%	Return on Total Cap'l			10.0%
16.6%	14.5%	15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	14.7%	14.0%	13.5%	Return on Shr. Equity			13.0%
16.7%	14.6%	15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	14.7%	14.0%	14.0%	Return on Com Equity			13.0%
7.6%	5.4%	6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	5.2%	4.5%	4.5%	Retained to Com Eq			4.5%
55%	63%	60%	58%	58%	63%	88%	84%	81%	65%	66%	65%	All Div'ds to Net Prof			64%

% TOT. RETURN 5/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	19.4	22.2
3 yr.	62.1	56.5
5 yr.	25.0	97.2

CAPITAL STRUCTURE as of 3/31/07
Total Debt $595.1 mill. Due in 5 Yrs $550.0 mill.
LT Debt $498.1 mill. LT Interest $5.1 mill
(Total interest coverage: 4.6x)

Pension Assets-12/06 $432.3 mill. Oblig. $271.3 mill.

Pfd Stock $.6 mill. Pfd Div'd $2.0 mill.
(11,681 shares of 4.48% mandatorily redeemable preferred stock)
Common Stock 45,024,851 shares
as of 4/26/07
MARKET CAP: $2.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	3/31/07
Cash Assets	126.9	67.6	44.9
Other	1218.8	843.1	877.5
Current Assets	1345.7	910.7	922.4
Accts Payable	658.2	564.5	446.7
Debt Due	636.0	350.0	97.0
Other	328.7	227.9	573.2
Current Liab.	1622.9	1142.4	1116.9
Fix. Chg. Cov.	367%	NMF	46.9%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.5%	7.5%	0.5%
"Cash Flow"	3.5%	1.0%	0.5%
Earnings	1.5%	-3.0%	4.5%
Dividends	4.0%	2.5%	1.0%
Book Value	3.0%	2.5%	5.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1115.7	429.5	299.9	894.6	2739.7
2005	1179.9	484.4	236.0	1357.5	3257.8
2006	1319.4	451.3	351.1	838.2	2960.0
2007	1334.7	515.3	350	900	3100
2008	1350	525	375	950	3200

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.96	.44	d.26	1.08	2.22
2005	.98	.35	d.06	1.02	2.29
2006	.94	.41	.39	1.29	3.03
2007	.93	.43	.34	1.15	2.85
2008	.95	.45	.35	1.15	2.90

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.465	.465	.465	.465	1.86
2004	.465	.465	.465	.465	1.86
2005	.465	.465	.465	.465	1.86
2006	.465	.465	.465	.465	1.86
2007	.465	.465			

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.1 million customers in northern and western Illinois. 2006 gas delivered: 438.7 Bcf, incl. 206.0 Bcf from transportation. 2006 gas sales (232.7 bcf): residential, 80%; commercial, 18%; industrial, 2%. Principal supplying pipelines: Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested inland barging, 7/86; contract drilling, 9/86; oil and gas E&P, 6/93. Has about 3,900 employees. Off./dir. own about 1.7% of common stock (3/07 proxy). Chairman and CEO: Russ Strobel. Inc.: Illinois Address: 1844 Ferry Road, Naperville, Illinois 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor reported a slight decline in share net in its first quarter. The company posted earnings of $0.93 a share, compared with $0.94 a share in the same period of 2006. These results excluded a one-time benefit related to Nicor's reserve for its mercury inspection and repair program, as well as its mercury-related cost recoveries. The top line edged up slightly, by 1%, from the year-ago tally.

The company reiterated its earnings guidance for 2007. Nicor's new share-net range of $2.76-$2.96 reflects the benefit, totaling $0.11, mentioned above. Thus, management has maintained its earnings guidance for the remainder of 2007. All told, this year's results will likely be down from 2006, which benefited from a strong performance in wholesale natural gas marketing.

Base rates should stay near current levels for the foreseeable future. Nicor continues to work within previously agreed upon parameters. Moreover, the company does not have any rate cases pending with the Illinois Commerce Commission.

Nicor's strategy should boost results in 2008. Management appears focused on improving GAS' margins by cutting costs and better utilizing its resources. Thus, we anticipate the top and bottom lines will grow at a single-digit clip next year.

The company offers a solid dividend yield. Nicor returns a healthy 4.1% to investors, which is above the industry average. The company has consistently paid a dividend for numerous years, which may be of interest to income-oriented investors.

Nicor has below-average appreciation potential to 2010-2012. These shares are trading within our 3- to 5-year Target Price Range, which limits their appeal to investors with an eye on the future. Additionally, this stock is influenced by the unpredictable gas commodities market, which adds further volatility to Nicor's profile.

These shares are ranked to trail the broader market in the year ahead. Indeed, Nicor will likely struggle to match its performance in 2006. Therefore, most investors may want to remain on the sidelines until Nicor's overall operating environment improves.

Richard Gallagher *June 15, 2007*

(A) Based on primary earnings thru '96, then diluted. Excl. nonrecurring gains/(loss): '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.95); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢). Excl items from discontinued ops: '93, 4¢; '96, 30¢. Quarterly earnings may not sum to total due to rounding. Next egs. report due early August. (B) Dividends historically paid early February, May, August, November. ■ Dividend reinvestment plan available (C) In millions

Company's Financial Strength	A
Stock's Price Stability	50
Price Growth Persistence	40
Earnings Predictability	75

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N.W. NAT'L GAS NYSE-NWN

RECENT PRICE 49.21 | P/E RATIO 18.9 (Trailing: 19.1 / Median: 16.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Raised 2/23/07
SAFETY 1 Raised 3/18/05
TECHNICAL 3 Lowered 1/12/07
BETA .75 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	9%
Low	50	(Nil)	4%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	1	0	1	2	0	0	0
to Sell	0	0	1	0	1	2	0	0	1

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	77	66	75
to Sell	59	54	60
Hld's(000)	14328	14332	14381

High: 25.9 31.4 30.8 27.9 27.5 26.8 30.7 31.3 34.1 39.6 43.7 52.8
Low: 20.8 23.0 24.3 19.5 17.8 21.7 23.5 24.0 27.5 32.4 32.8 39.8

LEGENDS
1.10 x Dividends p sh divided by Interest Rate
Relative Price Strength
3-for-2 split 9/96
Options: Yes
Shaded area indicates recession

Target Price Range 2010 | 2011 | 2012
120 / 100 / 80 / 64 / 48 / 32 / 24 / 20 / 16 / 12 / 8

% TOT. RETURN 5/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	47.8	22.2
3 yr.	91.5	56.5
5 yr.	108.5	97.2

Percent shares traded 9 / 6 / 3

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
16.74	14.10	18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	*37.85*	*39.80*	Revenues per sh	*44.85*
2.57	3.25	3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.75	*5.15*	*5.20*	"Cash Flow" per sh	*5.90*
.67	.74	1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	*2.60*	*2.65*	Earnings per sh [A]	*3.10*
1.13	1.15	1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	*1.46*	*1.54*	Div'ds Decl'd per sh [B=]	*1.86*
3.56	3.73	3.61	4.23	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	*4.45*	*3.85*	Cap'l Spending per sh	*3.85*
12.23	12.41	13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.58	18.88	19.52	20.64	21.28	22.01	*23.20*	*24.20*	Book Value per sh	*27.35*
17.68	19.46	18.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	*27.00*	*27.00*	Common Shs Outst'g [C]	*29.00*
28.1	27.0	12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	16.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
1.79	1.64	.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.88			Relative P/E Ratio	*1.20*
5.9%	5.7%	5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%			Avg Ann'l Div'd Yield	*3.3%*
361.8	416.7	455.8	532.1	650.3	641.4	611.3	707.6	910.5	1013.2	*1025*	*1075*	Revenues ($mill)	*1300*
43.1	27.3	44.9	47.8	50.2	43.8	46.0	50.6	58.1	63.4	*70.5*	*71.5*	Net Profit ($mill)	*90.0*
32.9%	31.0%	35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	36.4%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
11.9%	6.6%	9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	6.3%	*6.5%*	*6.7%*	Net Profit Margin	*6.9%*
46.0%	45.0%	46.0%	45.1%	43.0%	47.5%	49.7%	46.0%	47.0%	46.3%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*48.0%*
49.0%	50.5%	49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	*53.0%*	*53.0%*	Common Equity Ratio	*52.0%*
748.0	815.6	861.5	887.8	880.5	937.3	1006.6	1052.5	1108.4	1116.5	*1150*	*1200*	Total Capital ($mill)	*1350*
827.5	894.7	895.9	934.0	965.0	995.6	1205.9	1318.4	1373.4	1425.1	*1485*	*1525*	Net Plant ($mill)	*1650*
7.4%	5.0%	6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	7.0%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
10.7%	6.1%	9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	10.6%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.5%*
11.0%	6.0%	9.8%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.6%	*11.0%*	*11.0%*	Return on Com Equity	*11.5%*
3.6%	NMF	2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	4.2%	*5.0%*	*5.0%*	Retained to Com Eq	*4.5%*
70%	118%	74%	70%	67%	79%	72%	69%	63%	60%	*56%*	*58%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 3/31/07
Total Debt $646.6 mill. Due in 5 Yrs $251.7 mill.
LT Debt $517.0 mill. LT Interest $31.0 mill.

(Total interest coverage: 3.4x)

Pension Assets-12/05 $236 mill.
Oblig. $269 mill.
Pfd Stock None

Common Stock 26,987,803 shs
as of 4/30/07
MARKET CAP $1.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	12/31/06	3/31/07
Cash Assets	7.1	5.8	5.1
Other	316.6	303.0	218.6
Current Assets	323.7	308.8	223.7
Accts Payable	135.3	113.6	92.2
Debt Due	134.7	129.6	15.0
Other	56.6	98.3	128.7
Current Liab.	326.6	341.5	235.9
Fx. Chg. Cov.	340%	349%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	6.5%	8.0%	*6.0%*
"Cash Flow"	2.0%	3.0%	*5.0%*
Earnings	2.0%	3.0%	*6.5%*
Dividends	1.0%	1.5%	*5.5%*
Book Value	4.0%	3.5%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	254.5	109.7	81.4	262.0	707.6
2005	308.7	153.7	106.7	341.4	910.5
2006	390.4	171.0	114.9	336.9	1013.2
2007	394.1	*175*	*110*	*345.9*	*1025*
2008	*410*	*185*	*120*	*360*	*1075*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1.24	d.03	d.30	.95	1.86
2005	1.44	.04	d.31	.94	2.11
2006	1.48	.07	d.35	1.15	2.35
2007	1.70	*.06*	*d.33*	*1.17*	*2.60*
2008	*1.69*	*.07*	*d.33*	*1.22*	*2.65*

Calendar	QUARTERLY DIVIDENDS PAID [B=] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.315	.315	.315	.325	1.27
2004	.325	.325	.325	.325	1.30
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345	.355	1.39
2007	.355	.355			

BUSINESS: Northwest Natural Gas Co. distributes natural gas at retail to 90 communities, 641,000 customers, in Oregon (90% of custs.) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 55%; commercial, 28%; industrial, gas transportation, and other, 17%. Employs 1,200. Fidelity owns 14.9% of shares; Snyder Cap'l, 8.7%; off./dir., 2.0% (4/07 proxy). CEO: Mark S. Dodson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural's first-quarter earnings got a big boost from gas hedging ... In Oregon, the company retains one-third of the difference, whether loss or gain, between its forecast and actual gas costs. (The cost of gas is all passed through to customers in Washington.) Hedging netted $9.8 million, pretax, in the March 2007 period, compared with $1.8 million in both the 2006 and 2005 first quarters. The difference amounted to $0.18 a share in 2007. First-quarter results also benefited from customer growth of 2.8%, colder weather than last year, and a bit lower bad-debt costs.

... but we don't look for similar gains over the balance of the year. At 2.8%, Northwest's customer growth remains at about twice the national average, but the housing slowdown is affecting the Portland area somewhat. Accordingly, that source of earnings growth is not likely to be as fruitful in 2007. Gas storage profits should rise a bit, as Northwest has expanded its Mist storage facility by around 7%. And the company's work-redesign program, now in its second year, will likely yield further gains, but we think they will just mitigate labor cost inflation.

Absent further gas hedging profits, earnings will probably not rise much in 2008. Customer growth will probably pick up a bit, after a slowdown in 2007. The work redesign program will probably be completed, outsourcing some activities and paring costs by some centralizing and automated meter reading. But no major project now in the works is due to come on stream by 2008. Still,

Earnings growth is likely to be above the industry average out to 2010-2012. The urban zoning boundary of Portland is scheduled to be extended to include some eastern suburbs over the next five years. When that happened west of the city in the 1990s, Northwest saw great customer growth, and a similar spurt is likely from the coming expansion. The likely opening of one or two liquefied natural gas plants in the company's territory should boost earnings, as well.

These neutrally ranked, top-quality shares are trading on the company's good prospects. But their dividend yield is now below the industry average.

Sigourney B. Romaine, CFA June 15, 2007

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	80

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06). Next earnings report due early August.
(B) Dividends historically paid in mid-February, mid-May, mid-August, and mid-November.
= Dividend reinvestment plan available.
(C) In millions, adjusted for stock split.

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PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE 26.10 | P/E RATIO 18.5 (Trailing: 20.6 Median: 17.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Raised 9/15/07
SAFETY 2 New 7/27/90
TECHNICAL 4 Lowered 5/25/07
BETA .80 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+55%)	14%
Low	30	(+15%)	7%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	10	1	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	2	0	0	0	0	1	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	85	68	79
to Sell	61	69	70
Hld's(000)	32936	33570	33589

	High:	12.9	18.2	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.8	28.4	27.5			Target Price Range 2010	2011	2012
	Low:	10.3	11.0	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.3	23.2	24.3					

LEGENDS
1.40 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 11/04
Options: No
Shaded area indicates recession

% TOT. RETURN 5/07

	THIS STOCK	VL ARITH. INDEX
1 yr	13.3	22.2
3 yr	45.2	56.5
5 yr	80.7	97.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
8.32	8.91	10.57	10.82	8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	27.10	28.50	Revenues per sh [A]	32.60
.78	1.07	1.14	1.13	1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.50	2.50	2.60	"Cash Flow" per sh	2.90
.44	.70	.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.27	1.40	1.45	Earnings per sh [B]	1.60
.44	.46	.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	Div'ds Decl'd per sh [C]	1.15
1.37	1.41	1.58	1.65	1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.95	2.05	Cap'l Spending per sh	2.30
4.83	5.13	5.45	5.68	6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	12.35	12.90	Book Value per sh [D]	14.45
49.46	51.59	52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.80	73.00	Common Shs Outst'g [E]	71.80
16.3	12.3	15.4	15.7	13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	15.6	17.9	19.4	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	22.0
1.04	.75	.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.02			Relative P/E Ratio	1.30
6.0%	5.3%	4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%			Avg Ann'l Div'd Yield	3.5%
775.5	765.3	686.5	830.4	1107.9	832.0	1220.8	1529.7	1761.1	1924.7	2000	2100	Revenues ($mill) [A]	2340
55.2	60.3	58.2	64.0	65.5	62.2	74.4	95.2	101.3	96.7	105	105	Net Profit ($mill)	115
39.1%	39.2%	39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	35.0%	35.0%	35.0%	Income Tax Rate	35.0%
7.1%	7.9%	8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	5.0%	5.2%	5.1%	Net Profit Margin	5.0%
47.6%	44.7%	46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	48.3%	48.5%	49.0%	Long-Term Debt Ratio	47.2%
52.4%	55.3%	53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	51.5%	51.0%	Common Equity Ratio	52.8%
800.8	829.3	914.7	978.4	1069.4	1051.6	1090.2	1514.9	1509.2	1708.0	1770	1845	Total Capital ($mill)	1970
941.7	990.8	1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	2075.0	2100	2150	Net Plant ($mill)	2350
8.9%	9.2%	8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	7.1%	7.0%	7.0%	Return on Total Cap'l	7.0%
13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.5%	11.5%	Return on Shr. Equity	11.5%
13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.5%	11.5%	Return on Com Equity	11.5%
4.6%	4.7%	3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.5%	Retained to Com Eq	3.5%
65%	65%	72%	71%	75%	83%	74%	66%	68%	74.6%	71%	71%	All Div'ds to Net Prof	69%

CAPITAL STRUCTURE as of 1/31/07
Total Debt $1057.5 mill. Due in 5 Yrs $150.0 mill.
LT Debt $825.0 mill. LT Interest $50.0 mill
(LT interest earned: 4.0x; total interest coverage: 4.0x)

Pension Assets-10/06 $211.9 mill. Oblig. $236.3 mill.

Pfd Stock None

Common Stock 74,599,552 shs.
as of 3/2/07
MARKET CAP: $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	1/31/07
Cash Assets	7.1	8.9	18.0
Other	497.8	467.1	598.4
Current Assets	504.9	476.0	616.4
Accts Payable	182.8	80.3	128.5
Debt Due	193.5	170.0	232.5
Other	152.3	150.1	156.0
Current Liab.	528.6	400.4	517.0
Fix. Chg. Cov.	271%	261%	300%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.5%	11.0%	6.0%
"Cash Flow"	7.0%	5.5%	3.0%
Earnings	5.5%	5.0%	4.0%
Dividends	5.5%	5.0%	4.0%
Book Value	6.5%	6.5%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2004	618.8	482.4	214.7	213.8	1529.7
2005	680.6	508.0	232.9	339.6	1761.1
2006	921.4	483.2	237.9	282.2	1924.7
2007	677.2	531.6	350	322.8	2000
2008	925	575	275	325	2100

Fiscal Year Ends	EARNINGS PER SHARE [A B F] Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2004	1.03	.54	d.11	d.21	1.27
2005	.93	.52	d.06	d.07	1.32
2006	.94	.57	d.16	d.08	1.27
2007	.94	.69	d.13	d.10	1.40
2008	.95	.60	d.06	d.04	1.45

Calendar	QUARTERLY DIVIDENDS PAID [C] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.20	.208	.208	.208	.82
2004	.208	.215	.215	.215	.85
2005	.215	.23	.23	.23	.91
2006	.23	.24	.24	.24	.95
2007	.25				

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 1,016,000 customers in North Carolina, South Carolina, and Tennessee. 2006 revenue mix: residential (44%), commercial (28%), industrial (11%), other (19%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 72.8% of revenues '06 deprec. rate: 3.5%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 2,051 employees. Officers & directors own less than 1% of common stock (1/07 proxy) Chairman, CEO, & President: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-731-4226. Internet: www.piedmontng.com

Piedmont Natural Gas posted a $0.12 year-to-year share-net gain in the fiscal second quarter (period ended April 30th). One factor affecting the bottom line is strong customer growth. So far this year we have seen growth of 2.2% over last year. Despite warmer weather earlier in the fiscal year the expansion of the customer base has boosted revenues, which has created operating leverage. Also, the lower cost of wholesale natural gas and reduced maintenance expenses has helped bolster operating profits. Finally, the company has been pursuing opportunities that have aided the earnings recovery. Its Automated Meter Reading (AMR) project in South Carolina is now operational. And, a similar endeavor in North Carolina was completed earlier this year. Both are likely to help streamline operations and enhance profitability.

Piedmont's joint venture, Hardy Storage Company, is now being stocked with natural gas. The facility should be up and running later this year, and recent improvements should allow the field to deliver natural gas as soon as November. Delivery capacity is projected to increase roughly 75% by the time the facility becomes fully developed in 2009. Firm long-term contracts have been established with several gas distribution companies, which should result in stable cash flows for Hardy. Piedmont will benefit from the underground storage asset as an affiliate and through the use of the facility as a customer.

The company continues to pass earnings on to investors through respectable dividends. During the first quarter, the directors raised the payout for the 29th consecutive year. The company boosted annual dividends by 5%, an increase of a nickel.

Shares of PNY offer about average appreciation potential over the 2010–2012 push. However, the dividend yield of approximately 4% may be appealing to income-oriented investors. This, coupled with the 5% discount offered through the dividend reinvestment plan should produce an attractive total return for patient investors. Also, conservative investors should note the stock's Above-Average Safety rank.

Bryan Fong *June 15, 2007*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early Aug
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. At 10/31/06: $11.3 million, 15¢/share.
(E) In millions, adjusted for stock splits.
(F) Quarters may not add to total due to change in shares outstanding

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	80

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SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 38.20 | P/E RATIO 16.6 (Trailing: 20.8 Median: 14.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 2.6% | VALUE LINE

TIMELINESS 3 Raised 3/9/07
SAFETY 2 Lowered 1/4/91
TECHNICAL 3 Lowered 1/26/07
BETA .70 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+30%)	9%
Low	35	(-10%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	2

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	64	50	58
to Sell	48	47	44
Hld's(000)	15700	15711	15668

High: 12.3 15.3 15.4 15.4 15.1 17.0 18.3 20.3 26.5 32.4 34.3 41.3
Low: 10.1 10.5 11.0 10.8 12.3 13.8 14.1 15.3 19.7 24.9 25.6 31.8

Target Price Range 2010 2011 2012

LEGENDS
1.05 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 7/05
Options: No
Shaded area indicates recession

% TOT. RETURN 5/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	49.3	22.2
3 yr.	103.8	56.5
5 yr.	165.7	97.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
15.10	16.67	17.03	17.45	16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.89	26.34	29.51	31.78	31.77	32.60	33.75	Revenues per sh	37.50
1.37	1.56	1.54	1.35	1.65	1.54	1.80	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	2.88	3.25	3.40	"Cash Flow" per sh	4.15
.64	.81	.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.30	2.45	Earnings per sh A	3.00
.71	.71	.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	.98	1.04	Div'ds Decl'd per sh B ■	1.20
2.17	1.69	1.87	1.93	2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	2.51	2.50	2.60	Cap'l Spending per sh	3.15
6.77	6.95	7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.15	16.40	Book Value per sh C	17.95
18.48	19.00	19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.78	28.98	29.33	29.75	30.50	Common Shs Outst'g D	32.00
14.5	13.2	15.8	16.1	12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	14.0
.93	.80	.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64			Relative P/E Ratio	.95
7.6%	6.6%	5.9%	7.4%	7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%			Avg Ann'l Div'd Yield	2.9%
348.6	450.2	392.5	515.9	837.3	505.1	696.8	819.1	921.0	931.4	970	1030	Revenues ($mill)	1200
18.4	13.8	22.0	24.7	26.8	29.4	34.6	43.0	48.6	54.0	65.0	70.0	Net Profit ($mill)	95.0
36.8%	46.2%	42.6%	43.1%	42.2%	41.4%	40.6%	40.9%	41.5%	41.1%	41.0%	40.5%	Income Tax Rate	40.0%
5.3%	3.1%	5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	5.8%	6.7%	6.8%	Net Profit Margin	7.9%
54.6%	57.3%	53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	44.9%	44.7%	43.9%	44.4%	Long-Term Debt Ratio	42.5%
35.8%	33.5%	37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	56.1%	55.6%	Common Equity Ratio	57.5%
387.1	401.1	405.9	443.5	516.2	512.5	608.4	675.0	710.3	801.1	855	900	Total Capital ($mill)	1000
456.5	504.3	533.3	562.2	607.0	668.6	748.3	799.9	877.3	920.0	960	1025	Net Plant ($mill)	1200
6.7%	5.3%	7.4%	7.4%	6.9%	7.5%	7.3%	7.9%	8.3%	7.9%	8.0%	9.0%	Return on Total Cap'l	11.0%
10.5%	8.1%	11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	12.4%	12.2%	13.5%	14.0%	Return on Shr. Equity	16.5%
13.3%	10.3%	14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	12.2%	13.5%	14.0%	Return on Com Equity	16.5%
2.1%	NMF	4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	6.2%	6.1%	7.5%	7.5%	Retained to Com Eq	10.0%
84%	112%	72%	67%	76%	62%	57%	52%	50%	50%	45%	45%	All Div'ds to Net Prof	40%

CAPITAL STRUCTURE as of 3/31/07
Total Debt $442.6 mill. Due in 5 Yrs $117.7 mill.
LT Debt $368.0 mill. LT Interest $22.0 mill
(Total interest coverage: 5.1x)

Pension Assets-12/06 $117.1 mill.
Oblig. $132.6 mill.

Pfd Stock none

Common Stock 29,465,942 common shs.
as of 5/1/07

MARKET CAP: $1.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	3/31/07
Cash Assets	4.9	7.9	13.9
Other	352.6	363.8	319.7
Current Assets	357.5	371.7	333.6
Accts Payable	179.0	101.6	111.7
Debt Due	149.7	197.0	64.6
Other	74.4	124.2	121.1
Current Liab.	403.1	422.8	317.4
Fix. Chg. Cov.	486%	527%	495%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	6.5%	4.5%	3.0%
"Cash Flow"	5.5%	6.5%	8.0%
Earnings	8.5%	9.5%	NMF
Dividends	2.0%	3.5%	5.5%
Book Value	6.0%	13.5%	4.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	307.6	136.5	129.5	245.5	819.1
2005	328.6	154.0	157.0	281.4	921.0
2006	372.6	153.8	154.7	250.3	931.4
2007	368.4	170	160	271.6	970
2008	390	190	170	280	1030

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.91	.15	.02	.50	1.58
2005	.96	.27	.09	.39	1.71
2006	1.06	.20	.51	.69	2.46
2007	1.30	.20	.30	.50	2.30
2008	1.25	.25	.35	.60	2.45

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	--	.193	.193	.395	.78
2004	--	.202	.202	.415	.82
2005	--	.213	.213	.438	.86
2006	--	.225	.225	.470	.92
2007	--	.245			

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 330,049 customers in New Jersey's southern counties, which covers 2,500 square miles and includes Atlantic City. Gas revenue mix '06: residential, 43%; commercial, 24%; cogeneration and electric generation, 3%; industrial, 30%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 611 employees. Off./dir. cntrl. 1.2% of com. shares; Dimensional Fund Advisors, 8.3%; Barclays, 6.0% (3/07 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com

Our share earnings figures for South Jersey Industries will now be based on the company's economic earnings, a non-GAAP measure that eliminates unrealized gains and losses from commodity derivative transactions. Investors should be advised that bottom-line figures from 2007 onward will not be directly comparable with those from prior years, although we'll discuss any notable differences. GAAP EPS will be disclosed in the footnotes. The switch better reflects basic trends.

The Utility business reported solid results for the first quarter. Performance was benefited by growth in the customer base and the implementation of the Conservation Incentive Program (discussed below). This was partially offset by increased interest and depreciation expense, compared to the prior year's period.

We are optimistic about the company's Conservation Incentive Program (CIP). This initiative allows subsidiary South Jersey Gas to promote energy conservation, while insulating itself from the negative impact of reduced customer usage. The CIP prevented the loss of $3.1 million in the first quarter by offsetting the effect of lower customer utilization. This program should continue to benefit SJI going forward.

The company has announced a new project for Marina Energy. Marina develops, owns, and operates on-site energy plants, which provide income streams as part of long-term contracts. The company recently announced that it will partner with DCO Energy to design, construct, own, and operate a thermal facility that will provide for the heating and cooling needs of Boyd Gaming's Echelon casino and resort project in Las Vegas. This $200 million facility will likely become operational in 2010.

These shares are neutrally ranked for Timeliness. This issue earns high marks for Price Stability and Earnings Predictability. We anticipate steady growth in share earnings to 2010-2012. The dividend ought to increase during this timeframe, as well. Nevertheless, at the present quotation, appreciation potential is unexciting. Moreover, the current dividend yield of 2.6% is below average for a gas utility.

Michael F. Napoli, CPA *June 15, 2007*

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

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(A) Based on avg. shs through 2006, economic earnings thereafter. GAAP EPS: Q1 2007, $0.92. Excl. nonrecur. gain: '01, $0.13. Excl gain (losses) from discont. ops : '95, $1.14; '97, ($0.24); '98, ($0.26); '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02). Next egs. report due early August. (B) Dividends paid early Apr., Jul., Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. regulatory assets. At 3/31/07: $220.0 mill., $7.48 per shr (D) In millions, adjusted for split.

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WGL HOLDINGS NYSE-WGL

RECENT PRICE 34.69 | P/E RATIO 17.3 (Trailing: 17.1 Median: 15.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Raised 5/25/07
SAFETY 1 Raised 4/2/93
TECHNICAL 4 Lowered 5/25/07
BETA .85 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(NII)	4%
Low	30	(-15%)	7%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	0
Options	1	6	0	1	6	1	0	0	0
to Sell	1	7	0	1	6	1	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	73	86	81
to Sell	78	73	68
Hld's(000)	29760	30043	30408

High:	25.0	31.4	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8	33.6	35.9
Low:	19.1	20.9	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0	30.4

LEGENDS
1.30 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 5/95
Options: No
Shaded area indicates recession

Target Price Range 2010 | 2011 | 2012

% TOT. RETURN 5/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	27.8	22.2
3 yr.	46.1	56.5
5 yr.	86.3	97.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
17.50	18.37	21.55	21.89	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	55.55	57.20	Revenues per sh [A]	62.40
2.04	2.17	2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.93	3.90	3.95	"Cash Flow" per sh	4.40
1.14	1.27	1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.11	1.94	1.98	2.10	Earnings per sh [B]	2.40
1.05	1.07	1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.34	1.36	1.40	Div'ds Decl'd per sh [C] [D]	1.52
2.05	2.17	2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	2.45	2.45	Cap'l Spending per sh	2.55
9.63	10.66	11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.28	19.40	20.65	Book Value per sh [D]	22.10
39.89	40.62	41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	48.91	48.92	Common Shs Outst'g [E]	49.00
12.8	13.6	15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	15.0
.82	.82	.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.81			Relative P/E Ratio	1.00
7.2%	6.2%	5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%			Avg Ann'l Div'd Yield	4.3%
1055.8	1040.6	972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	2637.9	2715	2800	Revenues ($mill) [A]	3060
82.0	68.6	68.8	84.6	89.9	55.7	112.3	98.0	104.8	95.1	95.0	100	Net Profit ($mill)	115
36.9%	35.6%	36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	39.0%	38.0%	38.0%	Income Tax Rate	38.0%
7.8%	6.6%	7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.6%	3.7%	3.7%	Net Profit Margin	3.8%
41.1%	40.3%	41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	38.5%	36.8%	36.1%	Long-Term Debt Ratio	33.7%
58.2%	57.1%	56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	61.5%	61.4%	62.1%	Common Equity Ratio	64.5%
1049.0	1084.8	1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1497.8	1550	1580	Total Capital ($mill)	1690
1217.1	1319.5	1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2068	2170	2280	Net Plant ($mill)	2640
9.3%	8.0%	7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	7.7%	7.5%	7.5%	Return on Total Cap'l	8.0%
13.3%	10.8%	9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	10.3%	10.0%	10.5%	Return on Shr. Equity	10.5%
13.7%	11.1%	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.2%	10.5%	10.5%	Return on Com Equity	10.5%
5.1%	2.5%	1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	3.1%	3.0%	3.0%	Retained to Com Eq	3.5%
63%	78%	82%	69%	67%	112%	56%	65%	62%	70%	69%	68%	All Div'ds to Net Prof	64%

CAPITAL STRUCTURE as of 3/31/07
Total Debt $778.0 mill. Due in 5 Yrs $290.0 mill.
LT Debt $605.1 mill. LT Interest $40.6 mill.
(LT interest earned: 4.8x; total interest coverage: 4.2x)
Pension Assets-9/06 $699.9 mill. Oblig. $697.4 mill.
Preferred Stock $28.2 mill. Pfd Div'd $1.3 mill.

Common Stock 49,224,499 shs. as of 4/30/07

MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	3/31/07
Cash Assets	4.8	4.4	92.8
Other	476.2	556.9	798.8
Current Assets	481.0	561.3	765.9
Accts Payable	204.9	208.5	312.0
Debt Due	91.0	238.4	172.9
Other	115.5	113.9	185.5
Current Liab.	411.4	560.8	670.4
Fix. Chg. Cov.	460%	465%	460%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.5%	14.5%	4.5%
"Cash Flow"	5.0%	6.5%	1.5%
Earnings	4.5%	6.0%	2.0%
Dividends	1.5%	1.5%	2.5%
Book Value	4.0%	3.0%	3.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	585.3	862.2	356.9	285.2	2089.6
2005	623.4	929.8	349.0	284.1	2186.3
2006	902.9	1064.5	346.9	323.6	2637.9
2007	732.9	1119.9	440	422.2	2715
2008	970	1040	390	400	2800

Fiscal Year Ends	EARNINGS PER SHARE [A] [B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	.81	1.62	d.08	d.37	1.98
2005	.88	1.63	d.17	d.23	2.11
2006	.93	1.17	d.01	d.15	1.94
2007	.92	1.28	.02	d.25	1.98
2008	.95	1.26	.04	d.15	2.10

Calendar	QUARTERLY DIVIDENDS PAID [C] [D] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.32	.325	.325	.325	1.30
2004	.325	.333	.333	.333	1.32
2005	.33	.33	.333	.333	1.33
2006	.333	.333	.338	.338	1.34
2007	.34	.34			

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,031,916 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century Inv. own 9.8% of common stock; Off./dir. less than 1% (1/07 proxy). Chmn & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Addr.: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wgiholdings.com

WGL Holdings' earnings will likely be little changed in fiscal 2007 (ends September 30th). Factors holding earnings in check this year include revenue normalization adjustment (RNA), which is a new rate designs that allows for a decreased affect on the bottom line. RMA would moderate some upside earnings potential. In turn, though, it should limit the downside as well. Second, management plans for continued infrastructure investments, such as two facilities in Maryland (discussed below). Finally, the company has been pursuing new rate cases in all three of its markets. That is, rate cases in Virginia, the District of Columbia and Maryland seeks a cumulative relief in rates of $71 million as well as the implementation of new rate designs.

The bottom line should start to advance in 2008. Thanks largely to benefits from price management initiatives namely the previously discussed RNA rate design recently introduced in Maryland, and pending rulings in D.C. and Virginia.

Washington Gas has minimized damages related to gas leaks at a distribution system in Cove Point, Maryland. The leaks were caused by decreased amounts of heavy hydrocarbons in liquefied natural gas (LNG), which shrunk rubber seals in pipe couplings. To prevent further leaks, WGL has included a gas conditioning facility to reintroduce heavy hydrocarbons in the form of hexane gas into the gas steam coming from the Cove Point plant. So far efforts have resulted in a considerable reduction in the number of leaks in the affected Prince George's county. Due to the successful results management has reduced the estimated cost of this project by 35%-40%.

WGL continues to ramp up capacity through the production of a Liquid Natural Gas peaking facility in Maryland. We think this will enable it to meet customers' peak day gas requirements at an operating cost that is about 25% less than alternatives, by the 2011-2012 winter heating season.

This equity offers a solid dividend yield of roughly 4%. Nevertheless the stock is trading within out Target Price Range and total return potential for the 2010–2012 time horizon is unattractive.

Bryan Fong *June 15, 2007*

(A) Fiscal years end Sept. 30th. (B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); discontinued operations: '06, (15¢). Next earnings report due late July. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available. (D) Includes deferred charges and intangibles. '06: $296.6 million, $6.07/sh. (E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	65

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

Line No.		Southwest Gas Corporation	Proxy Group of Eight Value Line Gas Distribution Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	6.07 %	6.07 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A Rated Public Utility Bonds	0.53 (2)	0.53 (2)
3.	Adjusted Prospective Yield on A Rated Public Utility Bonds	6.60 %	6.60 %
4.	Adjustment to Reflect Bond Rating Difference	0.40 (3)	0.09 (4)
5.	Adjusted Prospective Bond Yield	7.00 %	6.69 %
6.	Equity Risk Premium (5)	3.86	4.27
7.	Risk Premium Derived Common Equity Cost Rate	10.86 %	10.96 %

Notes:
(1) Derived in Note (4) on Sheet 6 of this Exhibit.
(2) The average yield spread of A rated public utility bonds over Aaa rated corporate bonds of 0.53% from Sheet 4 of this Exhibit.
(3) Tithe average spread between Moody's A and Baa rated public utility bond yields of 26 basis points plus one and one-third the estimated average yield spread of Baa over Ba rated public utility bonds to reflect Southwest Gas Corporation's Moody's bond rating of Baa3 as shown on Sheet 2 of this Exhibit. ((0.26% + (1/3 * 0.43%) = (0.26% + 0.14%) = 0.40% (from Sheet 4 of this Exhibit)).
(4) One-third the average spread between Moody's A and Baa rated public utility bond yields of 26 basis points to reflect the proxy group's average Moody's bond rating of A3 as shown on Sheet 2 of this Exhibit. ((1/3 X 0.26% = 0.087%, rounded to 0.09% (from Sheet 4 of this Exhibit)).
(5) From Sheet 5 of this Exhibit.

Southwest Gas Corporation
Comparison of Bond Ratings and Business profile
for Southwest Gas Corporation and
the Proxy Group of Eight Value Line Gas Distribution Companies

	May 2007 Moody's Bond Rating		May 2007 Standard & Poor's Bond Rating		Standard & Poor's Business Profile (2)
	Bond Rating	Numerical Weighting (1)	Bond Rating	Numerical Weighting (1)	
Southwest Gas Corp.	Baa3	10.0	BBB-	10.0	3.0 (9)
Proxy Group of Eight Value Line Gas Distribution Companies					
AGL Resources Inc. (3)	A3	7.0	A-	7.0	3.0
Atmos Energy Corp. (4)	Baa3	10.0	BBB	9.0	3.0
The Laclede Group, Inc. (5)	A3	7.0	A	6.0	3.0
NICOR Inc. (6)	A1	5.0	AA	3.0	2.0
Northwest Natural Gas Co.	A2	6.0	AA-	4.0	1.0
Piedmont Natural Gas Co., Inc.	A3	7.0	A	6.0	2.0
South Jersey Industries, Inc. (7)	Baa1	8.0	A	6.0	2.0
WGL Holdings, Inc. (8)	A2	6.0	AA-	4.0	2.0
Average	A3	7.0	A	5.6	2.3

Notes:
(1) From Sheet 3 of this Exhibit.
(2) From Standard & Poor's (S&P) Issuer Ranking: U.S. Utility And Power Companies, Strongest to Weakest, June 22, 2007.
(3) Moody's ratings are those of Atlanta Gas Light Co. S&P's ratings and business profile are a composite of those of Atlanta Gas Light Co. and Pivotal Utility Holdings (formerly NUI Utilities).
(4) Moody's ratings and S&P's business profile are those of Atmos Energy Corporation. S&P's ratings are a composite of those of Atmos Energy Corporation and United Cities Gas Company dba Atmos Energy Corporation.
(5) Ratings and business profile are those of Laclede Gas Company.
(6) Ratings and business profile are those of NICOR Gas Company.
(7) Ratings and business profile are those of South Jersey Natural Gas Company.
(8) Ratings and business profile are those of Washington Gas Light Company.
(9) Company advises that S&P Business Profile is 3.0

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

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

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

Moody's
Comparison of Interest Rate Trends
for the Two Months Ending April 2007 (1)

Years	Corporate Bonds Aaa Rated	Public Utility Bonds Aa Rated	Public Utility Bonds A Rated	Public Utility Bonds Baa Rated	Spread - Corporate v. Public Utility Bonds: Aa (Pub. Util.) over Aaa (Corp.)	Spread - Corporate v. Public Utility Bonds: A (Pub. Util.) over Aaa (Corp.)	Spread - Corporate v. Public Utility Bonds: Baa (Pub. Util.) over Aaa (Corp.)	Spread - Public Utility Bonds: A over Aa	Spread - Public Utility Bonds: Baa over A	Spread - Public Utility Bonds: Estimated Ba over Baa (3)
March-07	5.30 %	5.66 %	5.85 %	6.10 %	0.36 %	0.55 %	0.80 %	0.19 %	0.25 %	0.33 %
April-07	5.47	5.83	5.97	6.24	0.36 %	0.50 %	0.77 %	0.14 %	0.27 %	0.52
Average Spread (2)					0.36 %	0.53 %	0.79 %	0.17 %	0.26 %	0.43 %

Notes: (1) All yields are distributed yields.
(2) Equal weight has been given to the March 2007 and April 2007 spread.
(3) Estimated spread of Ba over Baa rated public utility bond yields calculated as (the spread of Baa over A rated public utility bond yields ÷ the spread of Aa over A rated public utilty bond yields) * (the spread of Baa over A rated public utility bonds).

Source of Information: Mergent Bond Record Monthly Update, May 2007, Vol. 74, No. 5

Exhibit ___(FJH-10)
Sheet 4 of 9

Southwest Gas Corporation
Judgment of Equity Risk Premium for
for Southwest Gas Corporation and
the Proxy Group of Eight Value Line Gas Distribution Companies

Line No.		Southwest Gas Corporation	Proxy Group of Eight Value Line Gas Distribution Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	4.14	4.29 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with:		
	A3 rated bonds (2)		4.24
	Baa3 rated bonds (2)	3.58	
3.	Average equity risk premium	3.86 %	4.27 %

Notes: (1) From Sheet 6 of this Exhibit.
(2) From Sheet 8 of this Exhibit.

Southwest Gas Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
for Southwest Gas Corporation and
the Proxy Group of Eight Value Line Gas Distribution Companies

Line No.		Southwest Gas Corporation	Proxy Group of Eight Value Line Gas
1.	*Arithmetic mean total return rate on the Standard & Poor's 500 Composite Index - 1926-2006 (1)*	12.30 %	12.30 %
2.	Arithmetic mean yield on Aaa and Aa Corporate Bonds 1926-2006 (2)	(6.10)	(6.10)
3.	*Historical Equity Risk Premium*	6.20 %	6.20 %
4.	Forecasted 3-5 year Total Annual Market Return (3)	9.60 %	9.60 %
5.	Prospective Yield an Aaa Rated Corporate Bonds (4)	(6.07)	(6.07)
6.	Forecasted Equity Risk Premium	3.53 %	3.53 %
7.	Average of Historical and Forecasted Equity Risk Premium (5)	4.87 %	4.87 %
8.	Adjusted Value Line Beta (6)	0.85	0.88
9.	Beta Adjusted Equity Risk Premium	4.14 %	4.29 %

Notes:
(1) From Stocks Bonds Bills and Inflation - Market Results for 1926-2006 - 2007 Yearbook Valuation Edition, Morningstar, Inc., 2007 Chicago, IL.

(2) From Moody's Industrial Manual and Mergent Bond Record Monthly Update.

(3) From Sheet 3 of Exhibit (FJH-12).

(4) Average forecast based upon six quarterly estimates of Aaa rated corporate bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated July 1, 2007 (see Sheet 7 of this Exhibit. The estimates are detailed below.

Third Quarter 2007	5.90 %
Fourth Quarter 2007	6.00
First Quarter 2008	6.10
Second Quarter 2008	6.10
Third Quarter 2008	6.10
Fourth Quarter 2008	6.20
Average	6.07 %

(5) Average of the Historical Equity Risk Premium of 6.20% from Line No. 3 and the Forecasted Equity Risk Premium of 3.53% from Line No. 6 ((6.20% + 43.53) / 2 = 4.865%, rounded to 4.87%).

(6) From Sheet 9 of this Exhibit.

Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

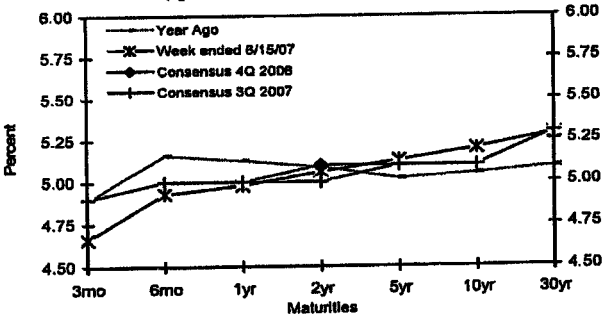
	History							Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Q	4Q	3Q	1Q	2Q	3Q	4Q
Interest Rates	Jun 15	June 8	Jun 1	May 25	May	Apr.	Mar.	2Q 2007*	2007	2007	2008	2008	2008	2008
Federal Funds Rate	5.26	5.24	5.28	5.24	5.25	5.25	5.26	*5.25*	5.2	5.2	5.2	5.1	5.1	5.1
Prime Rate	8.25	8.25	8.25	8.25	8.25	8.25	8.25	*8.25*	8.2	8.2	8.2	8.1	8.1	8.1
LIBOR, 3-mo.	5.36	5.36	5.36	5.36	5.35	5.35	5.35	*5.34*	5.4	5.4	5.3	5.3	5.3	5.2
Commercial Paper, 1-mo.	5.26	5.22	5.24	5.23	5.22	5.23	5.23	*5.23*	5.3	5.3	5.2	5.2	5.2	5.2
Treasury bill, 3-mo.	4.66	4.8	4.82	4.90	4.87	5.01	5.08	*4.87*	4.9	4.9	4.9	4.9	4.9	4.9
Treasury bill, 6-mo.	4.93	4.97	4.98	5.00	4.98	5.07	5.10	*5.00*	5.0	5.0	5.0	5.0	5.0	5.0
Treasury bill, 1 yr.	4.98	4.98	4.96	4.95	4.91	4.93	4.92	*4.94*	5.0	5.0	5.0	5.0	5.0	5.0
Treasury note, 2 yr.	5.06	4.99	4.92	4.84	4.77	4.67	4.57	*4.82*	5.0	5.1	5.1	5.0	5.1	5.1
Treasury note, 5 yr.	5.13	4.98	4.86	4.77	4.67	4.59	4.48	*4.77*	5.1	5.1	5.1	5.1	5.1	5.1
Treasury note, 10 yr.	5.20	5.02	4.90	4.84	4.75	4.69	4.56	*4.85*	5.1	5.2	5.2	5.2	5.3	5.3
Treasury note, 30 yr.	5.29	5.12	5.02	4.99	4.9	4.87	4.72	*4.99*	5.3	5.3	5.3	5.3	5.4	5.4
Corporate Aaa bond	5.89	5.67	5.58	5.55	5.47	5.47	5.30	*5.57*	5.9	6.0	6.1	6.1	6.1	6.2
Corporate Baa bond	6.79	6.62	6.51	6.47	6.39	6.39	6.27	*6.50*	6.8	6.9	7.0	7.0	7.1	7.1
State & Local bonds	4.64	4.54	4.41	4.38	4.31	4.26	4.15	*4.39*	4.7	4.7	4.8	4.8	4.8	4.8
Home mortgage rate	6.74	6.53	6.42	6.37	6.26	6.18	6.16	*6.36*	6.6	6.7	6.7	6.7	6.8	6.8

	History							Consensus Forecasts-Quarterly Avg.					
	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	4Q	3Q
Key Assumptions	2005	2005	2006	2006	2006	2006	2007	2007*	2007	2007	2008	2008	2008	2008
Major Currency Index	84.7	85.8	84.9	82.2	81.7	81.6	81.9	*79.3*	79.0	78.6	78.3	78.0	77.9	78.0
Real GDP	4.2	1.8	5.6	2.6	2.0	2.5	0.6	*3.1*	2.6	2.7	2.9	2.9	2.9	3.0
GDP Price Index	3.3	3.3	3.3	3.3	1.9	1.7	4.0	*3.1*	2.3	2.2	2.4	2.2	2.2	2.1
Consumer Price Index	5.5	3.5	1,8	5.1	3.0	-2.0	3.8	*5.2*	2.6	2.1	2.5	2.5	2.4	2.2

[1]Individual panel members' forecasts are on pages 4 through 9 Historical data for interest rates except LIBOR is from Federal Reserve Release (FRSR) H.15. LIBOR quotes available from *The Wall Street Journal*. Definitions reported here are same as those in FRSR H.15. Treasury yields are reported on a constant maturity basis Historical data for the U.S Federal Reserve Board's Major Currency Index is from FRSR H.10 and G 5 Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS). ***Interest rate data for 2Q 2007 based on historical data through the week ended June 15th. Data for 2Q 2007 Major Currency Index also is based on data through week ended June 15th. Figures for 2Q 2007 Real GDP, GDP Chained Price Index and Consumer Price Index are consensus forecasts based on a special question asked of the panel members this month.***

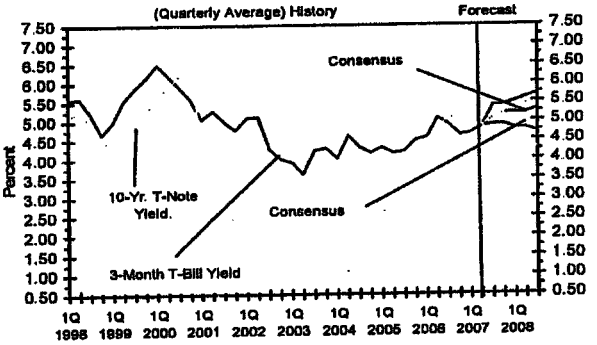
U.S. Treasury Yield Curve

Week ended June 15, 2007 and Year Ago vs.
3Q 2007 and 4Q 2008 Consensus forecasts



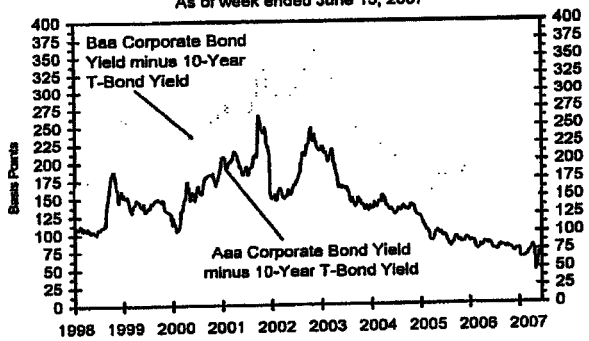
U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield

(Quarterly Average) History — Forecast



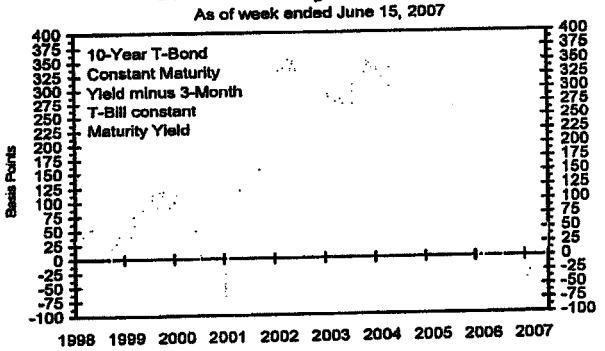
Corporate Bond Spreads

As of week ended June 15, 2007



U.S. Treasury Yield Curve

As of week ended June 15, 2007



Southwest Gas Corporation
Derivation of Mean Equity Risk Premium Based on a Study
Using Holding Period Returns of Public Utilities

Line No.			1 Southwest Gas Corporation AUS Consultants Risk Premium Study (1) 1928-2005	Proxy Group of Eight Value Line Gas Distribution Companies AUS Consultants Risk Premium Study (1) 1928-2005
Time Period				
1.		Arithmetic Mean Holding Period Returns (2): Standard & Poor's Public Utility Index	11.02 %	11.02 %
2.		Arithmetic Mean yield on:		
	A.	Baa rated Public Utility Bonds	(7.13)	
	B.	A rated Public Utility Bonds		(6.61)
3.		Adjustment to reflect Company or proxy group specific average Moody's bond rating	(0.31) (3)	(0.17) (4)
4.		Equity Risk Premium	3.58 %	4.24 %

Notes: (1) S&P Public Utility Index and Moody's Public Utility Bond Average Annual Yields, 1928-2005 (AUS Consultants, 2006).

(2) Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

(3) One-third the average 1928 - 2005 estimated spread between Baa and Ba rated Moody's public utility bond yields of 93 basis points to reflect Southwest Gas Corporation's Moody's bond rating of Baa3 as shown on Sheet 2 of this Exhibit. ((1/3 x 0.93% = 0.31%). (AUS Consultants, 2006).

(4) One-third the average 1928 - 2005 spread between A and Baa rated Moody's public utility bond yields of 52 basis points to reflect the proxy group's average Moody's bond rating of A3 as shown on page 2 of this Exhibit. ((1/3 x 0.52% = 0.17%). (AUS Consultants, 2006).

Southwest Gas Corporation
Value Line Adjusted Betas
for Southwest Gas Corporation and
the Proxy Group of Eight Value Line Gas Distribution Companies

	Value Line Adjusted Beta
Southwest Gas Corp.	0.85
Proxy Group of Eight Value Line Gas Distribution Companies	
AGL Resources Inc.	0.95
Atmos Energy Corp.	0.80
The Laclede Group, Inc.	0.90
NICOR Inc.	1.30
Northwest Natural Gas Co.	0.75
Piedmont Natural Gas Co., Inc.	0.80
South Jersey Industries, Inc.	0.70
WGL Holdings, Inc.	0.85
Average	0.88

Source of Information: Value Line Investment Survey, (Standard Edition)
June 15, 2007

Stocks, Bonds, Bills, and Inflation

Market Results for 1926–2006

2007 Yearbook
Valuation Edition

MORNINGSTAR®

For example, if bond yields rise unexpectedly, investors can receive a higher coupon payment from a newly issued bond than from the purchase of an outstanding bond with the former lower-coupon payment. The outstanding lower-coupon bond will thus fail to attract buyers, and its price will decrease, causing its yield to increase correspondingly, as its coupon payment remains the same. The newly priced outstanding bond will subsequently attract purchasers who will benefit from the shift in price and yield; however, those investors who already held the bond will suffer a capital loss due to the fall in price.

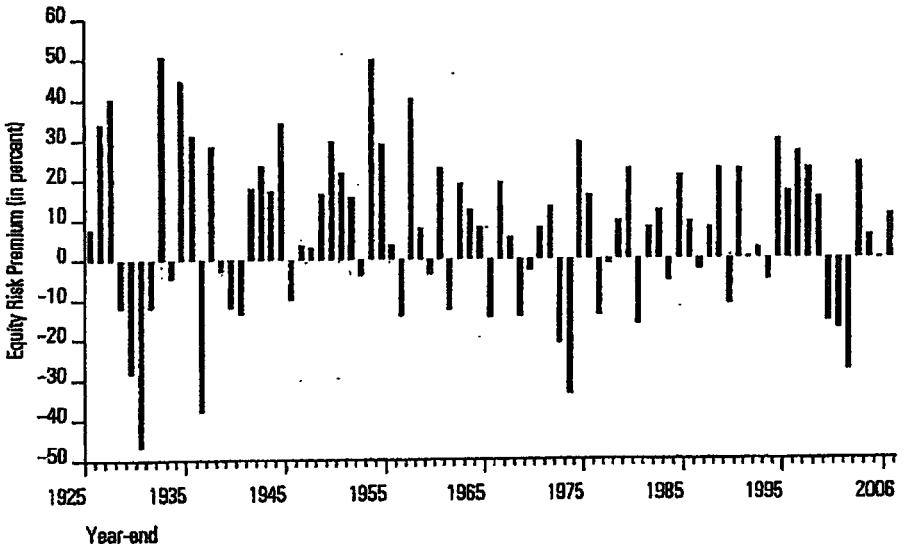
Anticipated changes in yields are assessed by the market and figured into the price of a bond. Future changes in yields that are not anticipated will cause the price of the bond to adjust accordingly. Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Arithmetic versus Geometric Means

The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

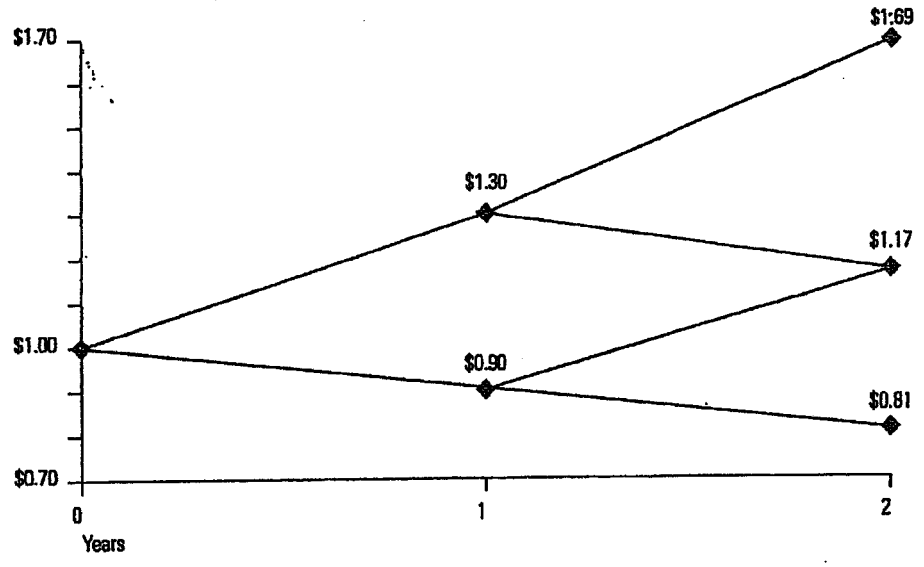
The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. Graph 5-3 shows the realized equity risk premium for each year based on the returns of the S&P 500 and the income return on long-term government bonds. (The actual, observed difference between the return on the stock market and the riskless rate is known as the realized equity risk premium.) There is considerable volatility in the year-by-year statistics. At times the realized equity risk premium is even negative.

Graph 5-3
Realized Equity Risk Premium Per Year
1926–2006



To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year: +30 percent and –10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-4.

Graph 5-4
Growth of Wealth Example



The most common outcome of $1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30)\times(1-0.10)]^{\frac{1}{2}}-1=0.082$$

However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

(0.25 × $1.69)	= $0.4225
+ (0.50 × $1.17)	= $0.5850
+ (0.25 × $0.81)	= $0.2025
Total	$1.2100

Therefore, $1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of $1.21 after 2 years is 10 percent, the arithmetic mean:

$$\$1\times(1+0.10)^2=\$1.21$$

The geometric mean, when compounded, results in the median of the distribution:

$$\$1\times(1+0.082)^2=\$1.17$$

The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

Appropriate Historical Time Period

The equity risk premium can be estimated using any historical time period. For the U.S., market data exists at least as far back as the late 1800s. Therefore, it is possible to estimate the equity risk premium using data that covers roughly the past 100 years.

Our equity risk premium covers the time period from 1926 to the present. The original data source for the time series comprising the equity risk premium is the Center for Research in Security Prices. CRSP chose to begin their analysis of market returns with 1926 for two main reasons. CRSP determined that the time period around 1926 was approximately when quality financial data became available. They also made a conscious effort to include the period of extreme market volatility from the late twenties and early thirties; 1926 was chosen because it includes one full business cycle of data before the market crash of 1929. These are the most basic reasons why our equity risk premium calculation window starts in 1926.

Implicit in using history to forecast the future is the assumption that investors' expectations for future outcomes conform to past results. This method assumes that the price of taking on risk changes only slowly, if at all, over time. This "future equals the past" assumption is most applicable to a random time-series variable. A time-series variable is random if its value in one period is independent of its value in other periods.

Does the Equity Risk Premium Revert to Its Mean over Time?

Some have argued that the estimate of the equity risk premium is upwardly biased since the stock market is currently priced high. In other words, since there have been several years with extraordinarily high market returns and realized equity risk premia, the expectation is that returns and realized equity risk premia will be lower in the future, bringing the average back to a normalized level. This argument relies on several studies that have tried to determine whether reversion to the mean exists in stock market prices and the equity risk premium.[3] Several academics contradict each other on this topic; moreover, the evidence supporting this argument is neither conclusive nor compelling enough to make such a strong assumption.

Our own empirical evidence suggests that the yearly difference between the stock market total return and the U.S. Treasury bond income return in any particular year is random. Graph 5-3, presented earlier, illustrates the randomness of the realized equity risk premium.

3 Fama, Eugene F., and Kenneth R. French. "Permanent and Temporary Components of Stock Prices," *Journal of Political Economy*, April 1988, pp. 246–273. Poterba, James M., and Lawrence H. Summers. "Mean Reversion in Stock Prices," *Journal of Financial Economics*, October 1988, pp. 27–59. Lo, Andrew W., and A. Craig MacKinlay. "Stock Market Prices Do Not Follow Random Walks: Evidence from a Simple Specification Test," *The Review of Financial Studies*, Spring 1988, pp. 41–66. Finnerty, John D., and Dean Leistikow. "The Behavior of Equity and Debt Risk Premiums: Are They Mean Reverting and Downward-Trending?" *The Journal of Portfolio Management*, Summer 1993, pp. 73–84. Ibbotson, Roger G., and Scott L. Lummer. "The Behavior of Equity and Debt Risk Premiums: Comment," *The Journal of Portfolio Management*, Summer 1994, pp. 98–100. Finnerty, John D., and Dean Leistikow. "The Behavior of Equity and Debt Risk Premiums: Reply to Comment," *The Journal of Portfolio Management*, Summer 1994, pp. 101–102.

A statistical measure of the randomness of a return series is its serial correlation. Serial correlation (or autocorrelation) is defined as the degree to which the return of a given series is related from period to period. A serial correlation near positive one indicates that returns are predictable from one period to the next period and are positively related. That is, the returns of one period are a good predictor of the returns in the next period. Conversely, a serial correlation near negative one indicates that the returns in one period are inversely related to those of the next period. A serial correlation near zero indicates that the returns are random or unpredictable from one period to the next. Table 5-3 contains the serial correlation of the market total returns, the realized long-horizon equity risk premium, and inflation.

Table 5-3
Interpretation of Annual Serial Correlations
1926–2006

Series	Serial Correlation	Interpretation
Large Company Stock Total Returns	0.03	Random
Equity Risk Premium	0.04	Random
Inflation Rates	0.65	Trend

The significance of this evidence is that the realized equity risk premium next year will not be dependent on the realized equity risk premium from this year. That is, there is no discernable pattern in the realized equity risk premium—it is virtually impossible to forecast next year's realized risk premium based on the premium of the previous year. For example, if this year's difference between the riskless rate and the return on the stock market is higher than last year's, that does not imply that next year's will be higher than this year's. It is as likely to be higher as it is lower. 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.

Table 5-4 also indicates that the equity risk premium varies considerably by decade. The complete decades ranged from a high of 17.9 percent in the 1950s to a low of 0.3 percent in the 1970s, however, thus far the 2000s have shown a –2.8 percent equity risk premium. This look at historical equity risk premium reveals no observable pattern.

Table 5-4
Long-Horizon Equity Risk Premium by Decade
1926–2006

1920s*	1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s**	1997-2006
17.6%	2.3%	8.0%	17.9%	4.2%	0.3%	7.9%	12.1%	–2.8%	4.5%

*Based on the period 1926–1929.

**Based on the period 2000–2006

Finnerty and Leistikow perform more econometrically sophisticated tests of mean reversion in the equity risk premium. Their tests demonstrate that—as we suspected from our simpler tests—the equity risk premium that was realized over 1926 to the present was almost perfectly free of mean reversion and had no statistically identifiable time trends.[4] Lo and MacKinlay conclude, "the rejection of the random walk for weekly returns does not support a mean-reverting model of asset prices."

Choosing an Appropriate Historical Period

The estimate of the equity risk premium depends on the length of the data series studied. A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns. When calculated using a long data series, the historical equity risk premium is relatively stable.[5] Furthermore, because an average of the realized equity risk premium is quite volatile when calculated using a short history, using a long series makes it less likely that the analyst can justify any number he or she wants. The magnitude of how shorter periods can affect the result will be explored later in this chapter.

Some analysts estimate the expected equity risk premium using a shorter, more recent time period on the basis that recent events are more likely to be repeated in the near future; furthermore, they believe that the 1920s, 1930s, and 1940s contain too many unusual events. This view is suspect because all periods contain "unusual" events. Some of the most unusual events of the last hundred years took place quite recently, including the inflation of the late 1970s and early 1980s, the October 1987 stock market crash, the collapse of the high-yield bond market, the major contraction and consolidation of the thrift industry, the collapse of the Soviet Union, the development of the European Economic Community, and the attacks of September 11, 2001.

It is even difficult for economists to predict the economic environment of the future. For example, if one were analyzing the stock market in 1987 before the crash, it would be statistically improbable to predict the impending short-term volatility without considering the stock market crash and market volatility of the 1929–1931 period.

Without an appreciation of the 1920s and 1930s, no one would believe that such events could happen. The 81-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to

4 Though the study performed by Finnerty and Leistikow demonstrates that the traditional equity risk premium exhibits no mean reversion or drift, they conclude that, "the processes generating these risk premiums are generally mean-reverting." This conclusion is completely unrelated to their statistical findings and has received some criticism. In addition to examining the traditional equity risk premia, Finnerty and Leistikow include analyses on "real" risk premia as well as separate risk premia for income and capital gains. In their comments on the study, Ibbotson and Lummer show that these "real" risk premia adjust for inflation twice, "creating variables with no economic content." In addition, separating income and capital gains does not shed light on the behavior of the risk premia as a whole.

5 This assertion is further corroborated by data presented in *Global Investing: The Professional's Guide to the World of Capital Markets* (by Roger G. Ibbotson and Gary P. Brinson and published by McGraw-Hill, New York). Ibbotson and Brinson constructed a stock market total return series back to 1790. Even with some uncertainty about the accuracy of the data before the mid-nineteenth century, the results are remarkable. The real (adjusted for inflation) returns that investors received during the three 50-year periods and one 51-year period between 1790 and 1990 did not differ greatly from one another (that is, in a statistically significant amount). Nor did the real returns differ greatly from the overall 201-year average. This finding implies that because real stock-market returns have been reasonably consistent over time, investors can use these past returns as reasonable bases for forming their expectations of future returns.

repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect "unusual" events to occur from time to time, and their return expectations reflect this.

A Look at the Historical Results

It is interesting to take a look at the realized returns and realized equity risk premium in the context of the above discussion. Table 5-5 shows the average stock market return and the average (arithmetic mean) realized long-horizon equity risk premium over various historical time periods. Similarly, Graph 5-5 shows the average (arithmetic mean) realized equity risk premium calculated through 2006 for different starting dates. The table and the graph both show that using a longer historical period provides a more stable estimate of the equity risk premium. The reason is that any unique period will not be weighted heavily in an average covering a longer historical period. It better represents the probability of these unique events occurring over a long period of time.

Table 5-5
Stock Market Return and Equity Risk Premium Over Time
1926–2006

Period Length	Period Dates	Large Company Stock Arithmetic Mean Total Return	Long-Horizon Equity Risk Premium
81 years	1926–2006	12.3%	7.1%
70 years	1937–2006	12.3%	6.7%
60 years	1947–2006	13.2%	7.1%
50 years	1957–2006	11.9%	5.2%
40 years	1967–2006	12.3%	4.8%
30 years	1977–2006	13.6%	5.8%
20 years	1987–2006	13.0%	6.4%
15 years	1992–2006	12.0%	6.0%
10 years	1997–2006	10.0%	4.5%
5 years	2002–2006	7.6%	2.7%

Looking carefully at Graph 5-5 will clarify this point. The graph shows the realized equity risk premium for a series of time periods through 2006, starting with 1926. In other words, the first value on the graph represents the average realized equity risk premium over the period 1926–2006. The next value on the graph represents the average realized equity risk premium over the period 1927–2006, and so on, with the last value representing the average over the most recent five years, 2002–2006. Concentrating on the left side of Graph 5-5, one notices that the realized equity risk premium, when measured over long periods of time, is relatively stable. In viewing the graph from left to right, moving from longer to shorter historical periods, one sees that the value of the realized equity risk premium begins to decline significantly. Why does this occur? The reason is that the severe bear market of 1973–1974 is receiving proportionately more weight in the shorter, more recent average. If you continue to follow the line to the right, however, you will also notice that when 1973 and 1974 fall out of the recent average, the realized equity risk premium jumps up by nearly 1.2 percent.

Southwest Gas Corporation
Indicated Common Equity Cost Rate Through Use of the
Capital Asset Pricing Model for
Southwest Gas Corporation and
the Proxy Group of Eight Value Line Gas Distribution Companies

No.		Southwest Gas Corporation	Proxy Group of Eight Value Line Gas Distribution
1.	Traditional Capital Asset Pricing Model Derived Company Equity Cost Rates (1)	10.17 %	10.49 %
2.	Empirical Capital Asset Pricing Model Derived Company Equity Cost Rate (1)	10.38 %	10.51 %
3.	CAPM Results	10.28 %	10.50 %

Notes: (1) Developed on Sheet 2 of this Exhibit.

Southwest Gas Corporation
Indicated Common Equity Cost Rate Through Use
of the Capital Asset Pricing Model

	Value Line Adjusted Beta	Company-Specific Risk Premium Based on Market Premium of 5.69% (1)	CAPM Result Including Risk-Free Rate of 5.33% (2)	Recommended CAPM Result (3)
Traditional Capital Asset Pricing Model (4)				
Southwest Gas Corp.	0.85	4.84 %	10.17 %	10.17 %
Proxy Group of Eight Value Line Gas Distribution Companies				
AGL Resources Inc.	0.95	5.41 %	10.74 %	10.74 %
Atmos Energy Corp.	0.80	4.55	9.88	9.88
The Laclede Group, Inc.	0.90	5.12	10.45	10.45
NICOR Inc.	1.30	7.40	12.73	12.73
Northwest Natural Gas Co.	0.75	4.27	9.60	9.60
Piedmont Natural Gas Co., Inc.	0.80	4.55	9.88	9.88
South Jersey Industries, Inc.	0.70	3.98	9.31	--
WGL Holdings, Inc.	0.85	4.84	10.17	10.17
Average	0.88	5.02 %	10.35 %	10.49 %
Empirical Capital Asset Pricing Model (5)				
Southwest Gas Corp.	0.85	5.05 %	10.38 %	10.38 %
Proxy Group of Eight Value Line Gas Distribution Companies				
AGL Resources Inc.	0.95	5.48 %	10.81 %	10.81 %
Atmos Energy Corp.	0.80	4.84	10.17	10.17
The Laclede Group, Inc.	0.90	5.26	10.59	10.59
NICOR Inc.	1.30	6.97	12.30	12.30
Northwest Natural Gas Co.	0.75	4.62	9.95	9.95
Piedmont Natural Gas Co., Inc.	0.80	4.84	10.17	10.17
South Jersey Industries, Inc.	0.70	4.41	9.74	9.74
WGL Holdings, Inc.	0.85	5.05	10.38	10.38
Average	0.88	5.18 %	10.51 %	10.51 %

See Sheet 3 for notes.

Southwest Gas Corporation
Development of the Market-Required Rate of Return on Common Equity Using the
Capital Asset Pricing Model for
Southwest Gas Corporation and
the Proxy Group of Eight Value Line Gas Distribution Companies
Adjusted to Reflect a Forecasted Risk-Free Rate and Market Return

Notes:

(1) From the two previous month-end (May '07 – June '07), as well as a recently available (June 29, 2007), Value Line Summary & Index, a forecasted 3-5 year total annual market return of 9.60% can be derived by averaging the May 2007, June 2007, and spot forecasted total 3-5 year total appreciation, converting it into an annual market appreciation and adding the Value Line average forecasted annual dividend yield.

The 3-5 year average total market appreciation of 36%, produces a four-year average annual return of 7.99% (($(1.36^{0.25})$ - 1)*100). When the average annual forecasted dividend yield of 1.61% is added, a total average market return of 9.60% (1.61% + 7.99%) is derived.

The average May 2007, June 2007 and spot forecasted total market return of 9.60% minus the risk-free rate of 5.33% (developed in Note 2) is 4.27% (9.60% - 5.33%). The Ibbotson Associates calculated market premium of 7.10% for the period 1926-2006 results from a total market return of 12.30% less the average income return on long-term U.S. Government Securities of 5.20% (12.30% - 5.20% = 7.10%). This is then averaged with the 4.27% Value Line market premium resulting in a 5.685%, rounded to 5.69% market premium. The 5.69% market premium is then multiplied by the beta in column 1 of Sheet 2 of this Exhibit.

(2) Average forecast based upon six quarterly estimates of 30-year Treasury Note yields per the consensus of nearly 50 economists reported in the Blue Chip Financial Forecasts dated July 1, 2007 (see Sheet 7 of Exhibit___(FJH-10). The estimates are detailed below:

	30-Year Treasury Note Yield
Third Quarter 2007	5.30%
Fourth Quarter 2007	5.30
First Quarter 2008	5.30
Second Quarter 2008	5.30
Third Quarter 2008	5.40
Fourth Quarter 2008	5.40
Average	5.33%

(3) Includes only those indicated common equity cost rates which are greater than 9.55% for reasons fully explained in Mr. Hanley's accompanying direct testimony.

(4) The traditional Capital Asset Pricing Model (CAPM) is applied using the following formula:

$R_S = R_F + \beta (R_M - R_F)$

Where R_S = Return rate of common stock
R_F = Risk Free Rate
β = Value Line Adjusted Beta
R_M = Return on the market as a whole

(5) The empirical CAPM is applied using the following formula:

$R_S = R_F + .25 (R_M - R_F) + .75 \beta (R_M - R_F)$

Where R_S = Return rate of common stock
R_F = Risk-Free Rate
β = Value Line Adjusted Beta
R_M = Return on the market as a whole

Source of Information: Value Line Summary & Index (Standard Edition)
Blue Chip Financial Forecasts, July 1, 2007
Value Line Investment Survey, June 15, 2007
Stocks, Bonds, Bills and Inflation– Market Results for 1926-2006 –
Valuation Edition 2007 Yearbook, Morningstar, Inc., Chicago, IL

Southwest Gas Corporaiton
Comparable Earnings Analysis
for a Proxy Group of Twenty-Three Non-Utility Companies Comparable to
Southwest Gas Corporaiton (1)

Proxy Group of Twenty-Three Non-Utility Companies Comparable to Southwest Gas Corporation (1)	Adj. Beta	Unadj. Beta	Standard Error of the Regression	5-Year Projected Rate of Return on Net Worth, Equity or Partners' Capital (2) Percent	Student's T-Test
Air Products & Chem.	0.95	0.86	2.1299	21.50 %	1.61
Allstate Corp.	0.90	0.78	2.0690	14.00	(0.13)
BOK Financial	0.90	0.82	2.1199	12.00	(0.59)
Bemis Co.	0.90	0.84	2.0646	13.50	(0.24)
Chevron Corp.	0.90	0.82	2.0979	18.50	0.92
City National Corp.	0.80	0.67	2.2257	15.50	0.22
Compass Bancshares	0.95	0.86	1.9176	15.50	0.22
Danaher Corp.	0.95	0.86	2.2117	12.00	(0.59)
Ecolab Inc.	0.80	0.68	2.1285	27.00 (6)	2.88
Exxon Mobil Corp.	0.90	0.80	2.0725	21.50	1.61
First Horizon National	0.95	0.88	2.2203	14.50	(0.01)
Gannett Co.	0.85	0.70	2.0446	11.00	(0.82)
Mercury General	0.90	0.78	2.1867	13.50	(0.24)
Old Nat'l Bancorp	0.80	0.65	2.0447	13.50	(0.24)
Protective Life	0.95	0.85	2.2237	10.50	(0.94)
Reinsurance Group	0.90	0.82	2.0891	10.50	(0.94)
Scripps (E.W.) 'A'	0.80	0.69	2.1521	12.50	(0.47)
Sigma-Aldrich	0.90	0.77	2.2097	18.50	0.92
Tootsie Roll Ind.	0.75	0.62	2.1315	10.00	(1.05)
Transatlantic Hldgs.	0.80	0.64	2.1720	11.00	(0.82)
Valspar Corp.	0.85	0.76	2.1707	13.50	(0.24)
Washington Federal	0.90	0.81	1.9170	15.00	0.11
Webster Fin'l	0.90	0.81	2.0271	9.50	(1.17)
Average for the Non-Utility Group	0.88	0.77	2.1142		
Southwest Gas Corporation	0.85	0.75 (3)	2.0519 (4)		
Mean				13.98 %	
Conclusion (5)				13.42 %	

See page 2 for notes.

Southwest Gas Corporation
Comparable Earnings Analysis
for a Proxy Group of Thirty-Four Non-Utility Companies Comparable to
the Proxy Group of Eight Value Line Gas Distribution Companies (7)

Proxy Group of Thirty-Four Non-Utility Companies Comparable to the Proxy Group of Eight Value Line Gas Distribution Companies (7)	Adj. Beta	Unadj. Beta	Standard Error of the Regression	5-Year Projected Rate of Return on Net Worth, Equity or Partners' Capital (2) Percent	Student's T-Test
3M Company	0.80	0.67	2.2583	26.50 % (8)	2.16
Air Products & Chem.	0.95	0.86	2.1299	21.50	1.23
Allstate Corp.	0.90	0.78	2.0690	14.00	(0.17)
AptarGroup	0.95	0.90	2.3049	10.50	(0.83)
BOK Financial	0.90	0.82	2.1199	12.00	(0.55)
Bemis Co.	0.90	0.84	2.0646	13.50	(0.27)
Buckeye Partners L.P.	0.80	0.66	2.2861	19.00	0.76
Chevron Corp	0.90	0.82	2.0979	18.50	0.67
City National Corp.	0.80	0.67	2.2257	15.50	0.11
Danaher Corp.	0.95	0.86	2.2117	12.00	(0.55)
Du Pont	0.95	0.90	2.1124	24.00	1.70
Ecolab Inc.	0.80	0.68	2.1285	27.00 (8)	2.26
Exxon Mobil Corp.	0.90	0.80	2.0725	21.50	1.23
Fifth Third Bancorp	0.90	0.81	2.2783	15.00	0.01
First Horizon National	0.95	0.88	2.2203	14.50	(0.08)
Gannett Co.	0.85	0.70	2.0446	11.00	(0.73)
Hudson City Bancorp	0.95	0.86	2.2946	10.00	(0.92)
Lee Enterprises	0.60	0.68	2.2978	7.50	(1.39)
Markel Corp.	0.80	0.66	2.2668	12.50	(0.45)
Mercury General	0.90	0.78	2.1867	13.50	(0.27)
New York Times	0.90	0.83	2.3134	20.50	1.04
Old Nat'l Bancorp	0.80	0.65	2.0447	13.50	(0.27)
Plum Creek Timber	0.95	0.86	2.2579	17.00	0.39
Praxair Inc.	0.95	0.89	1.9889	19.00	0.76
Protective Life	0.95	0.85	2.2237	10.50	(0.83)
Reinsurance Group	0.90	0.82	2.0891	10.50	(0.83)
SAFECO Corp.	0.85	0.71	2.2767	12.00	(0.55)
Scripps (E.W.) 'A'	0.80	0.69	2.1521	12.50	(0.45)
Sigma-Aldrich	0.90	0.77	2.2097	18.50	0.67
Sonoco Products	0.95	0.91	2.1003	17.00	0.39
UDR Inc	0.85	0.77	2.2800	2.50 (8)	(2.32)
Union Pacific	0.90	0.82	2.2342	11.50	(0.64)
Valspar Corp.	0.85	0.76	2.1707	13.50	(0.27)
Webster Fin'l	0.90	0.81	2.0271	9.50	(1.01)
Average for the Non-Utility Group	0.89	0.79	2.1776		
Average for the Proxy Group of Eight Value Line Gas Distribution Companies	0.88	0.78 (9)	2.1404 (10)		
Mean				14.56 %	
Conclusion (5)				13.88 %	

See page 2 for notes.

Southwest Gas Corporation
Comparable Earnings Analysis

Notes:

(1) The criteria for selection of the proxy group of twenty-three non-utility companies was that the non-utility companies be domestic and have a meaningful projected 2010 – 2012 rate of return on net worth or partners' capital as reported in Value Line Investment Survey (Standard Edition). The proxy group of twenty-three non-utility companies was selected based upon Southwest Gas Corporation's unadjusted beta range of 0.62 – 0.88 and standard error of the regression range of 1.8715 – 2.2323. These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression as detailed in Mr. Hanley's accompanying direct testimony. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and standard errors of the regression.

(2) 2010-2012.

(3) The standard deviation of Southwest Gas Corporation's unadjusted beta is 0.0644.

(4) The standard deviation of Southwest Gas Corporation's standard error of the regression is 0.0902. The standard deviation of the standard error of the regression is calculated as follows:

Standard Deviation of the Standard Error of the Regression =

$$\frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

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

$$\text{Thus, } 0.0902 = \frac{2.0519}{\sqrt{518}} = \frac{2.0519}{22.7596}$$

(5) Average of 5-year projected rates of return excluding those 20% and above as well as those below 9.60% for reasons fully explained in Mr. Hanley's testimony.

(6) The Student's T-statistic associated with this projected return exceeds 2.074 at the 95% level of confidence with twenty-two (22 = 23 observations –1) degrees of freedom. Therefore, it has been excluded, as an outlier, to arrive at a proper mean projected return as fully explained in the accompanying direct testimony.

(7) The criteria for selection of the proxy group of thirty-four non-utility companies was that the non-utility companies be domestic and have a meaningful projected 2010 – 2012 rate of return on net worth or partners' capital as reported in Value Line Investment Survey (Standard Edition). The proxy group of thirty-four non-utility companies was selected based upon the proxy group of eight Value Line gas distribution companies' unadjusted beta range of 0.65 – 0.91 and standard error of the regression range of 1.9524 – 2.3284. These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression as detailed in Mr. Hanley's accompanying direct testimony. Plus or minus

Southwest Gas Corporation
Comparable Earnings Analysis

two standard deviations captures 95.50% of the distribution of unadjusted betas and standard errors of the regression.

(8) The Student's T-statistic associated with this projected return exceeds 1.960 at the 95% level of confidence. Therefore, it has been excluded, as an outlier, to arrive at a proper mean projected return as fully explained in the accompanying direct testimony.

(9) The standard deviation of the proxy group of eight Value Line gas distribution companies' unadjusted beta is 0.0672.

(10) The standard deviation of the proxy group of eight Value Line gas distribution companies' standard error of the regression is 0.094 = (2.1404 / 22.7596).

Source of Information: Value Line, Inc., Proprietary database, June 15, 2007
Value Line Investment Survey (Standard Edition)

Southwest Gas Corporation
Authorized Returns on Common Equity and
Common Equity Ratios for Gas Distribution Companies
for the Twelve Months Ended March 2007

Company	1 Date	2 Jurisdiction	3 Authorized Return on Common Equity	4 Authorized Common Equity Ratio	5 Moody's A Rated Public Utility Bond Yields (9)	6 Spread between Authorized Return on Common Equity and Moody's A Rated Public Utility Bond Yields (10)
Sierra Pacific Power	04/26/06	NV	10.60 %	40.76 %	5.98 %	4.62 %
Atmos Energy Louisiana	05/25/06	LA	10.40 (1)	48.00 (2)	6.29	4.11
Central Hudson Gas & Electric	07/24/06	NY	9.60 (1, 5)	45.00	6.40	3.20
Kinder Morgan	09/20/06	WY	11.00 (1, 6)	43.56	6.37	4.63
Chesapeake Utilities	09/26/06	MD	10.75 (1)	53.00	6.20	4.55
Orange & Rockland Utilities	10/20/06	NY	9.80 (1, 5)	48.00	6.20	3.60
CenterPoint Energy Minnesota Gas	11/02/06	MN	9.71	46.14 (4)	6.00	3.71
Public Service Electric & Gas	11/09/06	NJ	10.00 (1, 7)	47.40	6.00	4.00
Consumers Energy	11/21/06	MI	11.00	36.06 (4, 8)	5.98	5.02
Puget Sound Energy	01/05/07	WA	10.40	44.00	5.80	4.60
SEMCO Energy Gas	01/09/07	MI	11.00 (1)	42.94 (8)	5.80	5.20
Wisconsin Public Service	01/11/07	WI	10.90	57.46	5.80	5.10
Wisconsin Power and Light	01/19/07	WI	10.80	54.13	5.80	5.00
Fitchburg Gas & Electric	01/26/07	MA	10.00 (1)	--	5.81	4.19
PPL Gas	02/08/07	PA	10.40	51.79 (2)	5.81	4.59
Connecticut Natural Gas	03/14/07	CT	10.10 (1)	53.60	5.96	4.14
Delmarva Power & Light	03/20/07	DE	10.25 (1)	46.90 (12)	5.96	4.29
Southern Union	03/22/07	MO	10.50	36.06	5.90	4.60
Atmos Energy	03/29/07	TX	10.00	47.90 (2)	5.90	4.10
Average			10.38 %	46.76 %	6.00 %	4.38 %
Average of Litigated Cases			10.48 %	45.92 %	5.89 %	4.59 %
Prospective Yield on A Rated Public Utility Bonds (11)					6.60 %	
Average Spread between Authorized Returns on Common Equity and Moody's A Rated Public Utility Bond Yields					4.59	
Reality Check Indicated Common Equity Cost Rate					11.19 %	

Notes:
(1) Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
(2) Hypothetical capital structure utilized.
(3) Estimated.
(4) Interim rates implemented prior to issuance of final order.
(5) Rate change implemented in multiple steps.
(6) While the rate increase was voted 9/20/06 and became effective 10/1/06, a final order was not issued until 12/4/06.
(7) Rate increase became effective 1/1/07.
(8) Capital structure includes cost-free items or tax credit balances at the overall rate of return.
(9) Actual A rated yield represents the yield of the previous month if the order was issued on or after the 21st of each month, or the yield of two months prior if the order was issued on or before the 20th of each month. For example, the yield for 11/2/06 is the A rated Public Utility yield for September 2006 and the yield for 4/26/07 is the A rated Public Utility yield for March 2007.
(10) Column 3 - Column 5.
(11) From Sheet 1 of Exhibit FJH-10.
(12) Commission adopted a stipulated PBR plan under which 75% of earnings above a 10.5% ROE flow to ratepayers

Source of Information:
Major Rate Case Decisions - January 2005 - December 2006, Published by Regulatory Research Associates, Inc., An SNL Energy Company
Regulatory Focus - Regulatory Study, Major Rate Case Decisions - January-March 2007, April 3 2007, Published by Regulatory Research Associates, Inc., An SNL Energy Company
Mergent Bond Record Monthly Update, May 2007, Vol. 74, No. 5

Volume III

Testimony

7

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-___

PREPARED DIRECT TESTIMONY

OF

JAMES L. CATTANACH

ON BEHALF OF

SOUTHWEST GAS CORPORATION

August 31, 2007

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Prepared Direct Testimony
Of
JAMES L. CATTANACH

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
JAMES L. CATTANACH

I. 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 By whom are you employed and in what capacity?

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) as Manager/Demand Planning in the Systems Planning Department.

Q. 3 Does Appendix A summarize your educational background and business experience?

A. 3 Yes, it does.

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

A. 4 Yes. I have testified before the Arizona Corporation Commission (Commission), the Public Utilities Commission of Nevada, the California Public Utilities Commission, and the Federal Energy Regulatory Commission.

Q. 5 Briefly describe the purpose of your prepared direct testimony in this proceeding.

A. 5 I sponsor testimony in support of Southwest's billing determinants (number of bills and therms) for the test period, and associated adjustments to the recorded number

of bills and therms. The billing determinants for the test period are set forth in Schedule H-2, Sheets 1 to 4 and are utilized in the development of revenues and proposed rates in Southwest's application.

I also present testimony that provides a description of the short- and long-term trends in residential consumption per customer that occurred in Southwest's Arizona rate jurisdiction.

II. VOLUME AND CUSTOMER ADJUSTMENTS

Q. 6 Please describe the methodology Southwest utilized to develop the billing determinants (number of bills and therms) for the test period.

A. 6 The billing determinants were developed by compiling the monthly recorded number of bills and therms by rate schedule for the 12-month period ended April 30, 2007, and making a number of adjustments to the recorded information.

Q. 7 Please describe the adjustments to Southwest's recorded number of bills and therms for the test year.

A. 7 Southwest made the following adjustments:

(1) Billing Adjustments;

(2) Volume Annualizations;

(3) Customer Reclassifications;

(4) Weather Normalization;

(5) Customer Annualizations; and

(6) Post Test Period Adjustments.

The details supporting the adjustments are shown in the

H-2 Workpapers.

Q. 8 Why have you made these adjustments to the recorded number of bills and therms for the test year?

A. 8 The purpose of the six adjustments is to ensure that Southwest's test period number of bills and volumes accurately reflect a full 12 months of consumption under normal weather conditions for the development of revenues and proposed rates.

Q. 9 Has Southwest made any changes to the methodology utilized to develop the billing determinants for the test period?

A. 9 No. Southwest has utilized the same methodology to develop the billing determinants for both its 2000 (Docket No. G-01551A-00-0309) and 2004 (Docket No. G-01551A-04-0876) general rate cases filed in Arizona and approved in Decision Nos. 64172 and 68487, respectively.

Q. 10 Please explain the purpose of Southwest's proposed "Billing Adjustments."

A. 10 After compiling recorded test year information, billing anomalies were investigated to ensure that the correct consumption level is reflected for each month in the test year. A majority of the corrections for Billing Adjustments involved restating the monthly consumption levels for customer bills to reflect actual monthly usage with no impact upon the total test period sales. This adjustment is necessary to ensure that the monthly adjusted volumes reflect an accurate portrayal of actual

test period consumption. Otherwise, distorted monthly values would affect the reliability of the regression analyses associated with the "Weather Normalization" adjustments, which are addressed later in my testimony.

Q. 11 Please explain Southwest's "Volume Annualization" adjustments.

A. 11 Upon completion of the process of correcting for Billing Adjustments, customer-specific Volume Annualization adjustments were performed to reflect a full year of consumption for each customer. This adjustment excludes residential and small commercial customer classes billed during April 2007, which are adjusted separately and addressed later in my testimony. This process involves estimating additional consumption for months during the test period for which a new customer was not on-line or was clearly in a start-up phase, as well as removing consumption attributable to specific customers who discontinued service during the test period.

Q. 12 Please outline the purpose of Southwest's "Customer Reclassification" adjustments.

A. 12 Southwest performed Customer Reclassification adjustments to ensure that customer-specific consumption reflected a full 12 months of usage under the correct rate schedule. Customer Reclassifications do not impact the overall number of bills or volumes for the test period.

Q. 13 Explain the purpose of Weather Normalization adjustments.

A. 13 Weather Normalization adjustments were performed to

accurately depict monthly test period volumes under normal weather conditions. To the extent that weather for the test year deviates from normal weather conditions, heat-sensitive consumption per customer must be adjusted to accurately represent monthly test period volumes under normal weather conditions.

For the test period, actual billing cycle heating degree days were approximately 0.6 percent warmer-than-normal in Tucson, and approximately 2.5 percent colder-than-normal in Phoenix. As a result of these deviations from normal weather, adjustments to test period volumes were computed to reflect anticipated volumes under normal weather conditions.

Weather Normalization adjustments were completed for the following rate schedules: single-family residential; multi-family residential; single-family low income residential; multi-family low income residential; special residential; the master-metered apartment, small commercial, armed forces and large commercial classes within the general service; the master-metered mobile home park; and weather-sensitive customers whose volumes are aggregated under a single transportation service agreement.

Q. 14 What heating degree day standard did Southwest utilize to weather normalize the heat-sensitive volumes for the test period?

A. 14 Southwest utilized a ten-year average (120 months ended

April 2007) of heating degree days to represent normal weather conditions. Southwest has consistently utilized ten-year average heating degree days to weather normalize test period volumes in every general rate case filed since 1986 (U-1551-86-300, U-1551-86-301, U-1551-89-102, U-1551-89-103, U-1551-90-322, U-1551-92-253, U-1551-93-272, U-1551-96-596, G-01551A-00-0309, G-01551A-04-0876).

Q. 15 Please explain Southwest's procedure for calculating the Weather Normalization adjustments.

A. 15 Southwest utilized regression analysis to quantify the relationships between actual monthly consumption per customer and weighted heating degree days for each heat-sensitive customer class. The monthly consumption per heating degree day factors (the regression coefficients) quantified in the regression analyses were then applied to monthly weighted heating degree day deviations from normal, to quantify the corresponding adjustments to consumption per customer.

Q. 16 Were there any other adjustments made to the number of bills or volumes for the test year under present rate schedules?

A. 16 Yes. "Customer Annualization" adjustments were computed for the residential rate schedules and small commercial customers within the small, medium, and large general service rate schedules.

Q. 17 What method was utilized to develop the Customer Annualization adjustments?

A. 17 Southwest utilized the same methodology adopted by the Commission in Decision Nos. 60352, 64172 and 68487. This Customer Annualization methodology was recommended by both Utilities Division Staff witness Michael L. Brosch and RUCO witness Marylee Diaz Cortez in Southwest's 1996 general rate case (Docket No. U-1551-96-596), and adopted in Decision No. 60352. This method captures the seasonal nature of test year customer growth by comparing the number of customers in the last month of the test year, April 2007, to the same month of the prior year, April 2006. The growth in customers is then prorated across the test period in declining intervals with 11/12ths of the adjustment in the first month of the test period (May 2006), 10/12ths in the second month (June 2006) and so forth. Adjustments to annualize volumes were made by multiplying the monthly customer additions by the respective monthly weather-adjusted average use per customer. Customer and volume adjustments are then added to the weather-normalized monthly bills and volumes to produce annualized test period monthly bills and volumes.

Q. 18 Why were the Customer Annualization adjustments only performed for the residential and small commercial customer classes?

A. 18 With the exception of the residential rate schedules and the small commercial class within the general service rate schedules, all other rate schedules were annualized by individual customers, based upon customer-specific

information. These customer-specific annualization adjustments were covered under the Volume Annualization adjustments previously discussed in my testimony. Because of the sheer magnitude of the residential and small commercial customer classes, which include thousands of billing records, tracking each individual's billing history to perform customer-specific billing or annualization adjustments was impractical. Accordingly, Customer Annualization adjustments were performed using the outlined methodology for the residential and small commercial customer classes.

Q. 19 Were any other adjustments required?

A. 19 Yes. "Post Test Period Adjustments" were made to the test period bills and volumes by rate schedules that reflect known and measurable changes that will occur after April 2007 for two of Southwest's largest customers. First, Eurofresh, which currently takes service on rate Schedule No. G-25(TE), executed an agreement to begin service under the Special Procurement Agreement provisions of Southwest's rate Schedule No. G-30. Eurofresh is expected to begin taking service under this agreement on September 1, 2007. Therefore, the test period bills and volumes for Eurofresh were reclassified from rate Schedule No. G-25(TE) to rate Schedule No. G-30. Second, Tucson Electric Power Company expressed its intent to bypass Southwest and take service directly from El Paso Natural Gas Company at its Sundt Generating Station.

Accordingly, the test period bills and volumes for the Sundt Generating Station have been removed from the rate case. Finally, bills and volumes for full-margin transportation customers were reclassified to their applicable sales rate schedules to reflect pricing for these customers at present rate schedules.

Q. 20 Please summarize the adjustments performed for the preparation of the billing determinants for the test period.

A. 20 The impact of each adjustment is reflected in the number of bills and volumes for the test period presented in Schedule H-2, Sheets 1 to 4. All of the adjustments were performed to ensure the accuracy and propriety of the number of bills and therms used to establish rates.

III. DECLINING RESIDENTIAL CONSUMPTION PER CUSTOMER

Q. 21 Describe the residential consumption per customer trend in Arizona.

A. 21 Southwest experienced significant declines in residential consumption per customer over the last 21 years.

Q. 22 Were the declines in residential consumption per customer reflected in the general rate cases Southwest filed over the last 21 years?

A. 22 Yes. Weather-normalized residential consumption per customer declined from 556 therms in the 1986 rate case (Docket Nos. U-1551-86-300, U-1551-86-301) to 332 therms in the current case. Between the 1986 and the 2007 rate cases, Southwest experienced a decline of 224 therms or

40.2 percent. Between Southwest's 2004 (Docket No. G-01551A-04-0876) and 2007 rate cases, weather-normalized residential consumption per customer dropped from 347 therms to 332 therms resulting in a decline of 15 therms or 4.3 percent. This equates to an approximate decline of 6 therms per year between Southwest's 2004 and 2007 rate cases. The declines in residential consumption per customer utilized in Southwest's general rate proceedings between 1986 and 2007 are graphically presented in Exhibit No.___(JLC-1).

Q. 23 Have you performed any other analysis that illustrates the significant declines in residential consumption per customer associated with Southwest's previous general rate cases?

A. 23 Yes, Southwest also examined the historical trend in residential baseload consumption per customer by examining residential consumption per customer for the month of August associated with each test year included in the historical rate case comparison. Because zero heating degree days are recorded during August in Tucson and Phoenix for each test year, August is an ideal month to analyze the historical trend in baseload consumption. Between the 1986 rate cases and the 2007 rate cases, August consumption per customer has declined from 16.4 therms to 9.6 therms, respectively. This is a decline of 6.8 therms or 41.5 percent between the 1986 and the 2007 rate cases. August baseload consumption per customer has

dropped four-tenths of a therm or 4 percent since the 2004 rate case. The significant downward trend in August consumption per customer is graphically depicted in attached Exhibit No.___(JLC-2). This analysis provides empirical support that declining residential consumption per customer is occurring with both space heating (seasonal) and baseload consumption.

Q. 24 What are the primary reasons that residential consumption per customer has declined over the last 21 years?

A. 24 The dramatic decline in residential consumption per customer occurred primarily because of continued improvements in dwelling and appliance efficiencies of Southwest's customer base. In fact, the relatively pronounced declines in residential consumption per customer that began in the 1990s roughly coincide with the implementation of the Energy Policy Act of 1992.

Q. 25 What roles have existing and new customers played in the decline of overall residential consumption per customer in Arizona?

A. 25 For new customers, their appliances and dwellings reflect efficiencies mandated by federal legislation, local building codes, and competition among builders to deliver a more energy efficient product. The resulting lower residential consumption per customer for new customers exerts downward pressure on overall residential consumption per customer. For existing customers, the turnover or replacement of older appliances with more

efficient, newer appliances contributes to the decline in overall consumption per customer. Southwest expects that a certain number of existing residential customers will adopt energy conservation practices related to the thermal integrity of their homes which results in lower overall residential consumption per customer. Therefore, the improved energy efficiencies of natural gas appliances and dwellings for both new customer additions and existing customers contributed to the overall decline in residential consumption per customer.

Q. 26 Is the significant downward trend in residential consumption per customer unique to Southwest's Arizona service areas?

A. 26 No. Southwest also experienced significant declines in residential consumption per customer in its Nevada and California service areas. In addition, the American Gas Association has performed studies that identify a national phenomenon of declining residential natural gas consumption per customer.

Q. 27 What do you anticipate in the way of future declines in residential consumption per customer?

A. 27 I expect overall residential consumption (weather normalized) to continue declining for the foreseeable future. A number of factors foreshadow further declines in residential consumption per customer. Consumers are increasingly encouraged to adopt energy conservation practices. For example, the Energy Policy Act of 2005

provides tax incentives for appliance manufacturers, consumers and home builders to pursue energy conservation. The continued emphasis on energy conservation to reduce energy-related household expenditures and the heightened interest in conservation measures and practices to mitigate CO_2 (carbon dioxide) emissions by residential dwellings into the atmosphere will contribute to the likelihood of this scenario. The issue of global warming and how consumers can participate in carbon abatement measures through reduced household energy consumption will be an important component of both state and federal energy policies in the future. It is also a reasonable hypothesis that home builders in Arizona will continue to pursue higher energy efficiencies in the new homes built in the future. In 2006, Arizona ranked second in the nation in terms of Energy Star-certified homes built. Furthermore, Southwest is currently implementing a number of new and expanded energy efficiency (demand-side management) programs which will have the effect of further lowering residential consumption per customer.

Q. 28 Please summarize the results of your research related to the phenomenon of declining residential consumption per customer in Arizona.

A. 28 The most recent data indicates residential consumption per customer in Arizona continues to decline. The structural change in residential natural gas consumption

per customer that occurred in the mid-1990s continues through the present. It is my belief that improvements in dwelling and appliance efficiencies and consumers' response to higher natural gas prices and bills by both existing and new customers contributed to the historical declines in residential consumption per customer and are expected to continue to have downward pressure on overall residential consumption per customer in the future.

Q. 29 Does this conclude your prepared direct testimony?

A. 29 Yes, it does.

SUMMARY OF QUALIFICATIONS
JAMES L. CATTANACH

I graduated from Utah State University, Logan, Utah, with a Bachelor of Science degree in Economics in 1983. Thereafter in 1990, I graduated from the University of Nevada, Las Vegas with a Master of Arts degree in Economics.

In 1984, I joined Southwest Gas Corporation as a Load Research Analyst in the Rate Department. In September 1985, I was promoted to the position of Economist in the Resource Planning Department. In November 1993, I was promoted to Senior Economist in the Revenue Requirements and Resource Planning Department. In August 2002, I was promoted to Supervisor in the Systems Planning Department. In July 2003, I was promoted to my current position as Manager/Demand Planning in the Systems Planning Department. I am responsible for the development of weather normalized billing determinants for rate cases, the development of short- and long-range demand forecasts for rate cases and systems planning, analysis and monitoring of the regional economy in each of Southwest's rate jurisdictions, assorted load research activities, and the ongoing review of weather normalization procedures and heating degree days. I supervise three analysts and two economists in the Systems Planning Department.

Since 1989, I have held the position of Adjunct Lecturer in the College of Business, Department of Economics, at the University of Nevada, Las Vegas. I currently teach an Applied Regression Analysis and Forecasting course each Fall and Spring Semester. I have previously taught courses in Business Statistics, Microeconomics, and Macroeconomics.

In addition to receiving my formal degrees in the study of Economics, I have attended seminars related to both public utility ratemaking and load forecasting. I am a member of the American Statistical Association, International Association for Energy Economics, National Association of Business Economics, National Association of Forensic Economics, Institute of Business Forecasting, and Southern Nevada Population Projection and Estimation Committee. I am also a contributing panel member of the Western Blue Chip Economic Forecast published by the Bank One Economic Outlook Center, W.P. Carey College of Business, Arizona State University. Between 1997 and 2000, I was an advising member of the Energy Economics Project Advisors Group, at The Gas Research Institute.

ARIZONA
RESIDENTIAL GAS SERVICE (G-5 & G-6)
ANNUAL RATE CASE CONSUMPTION PER CUSTOMER
1986 - 2007

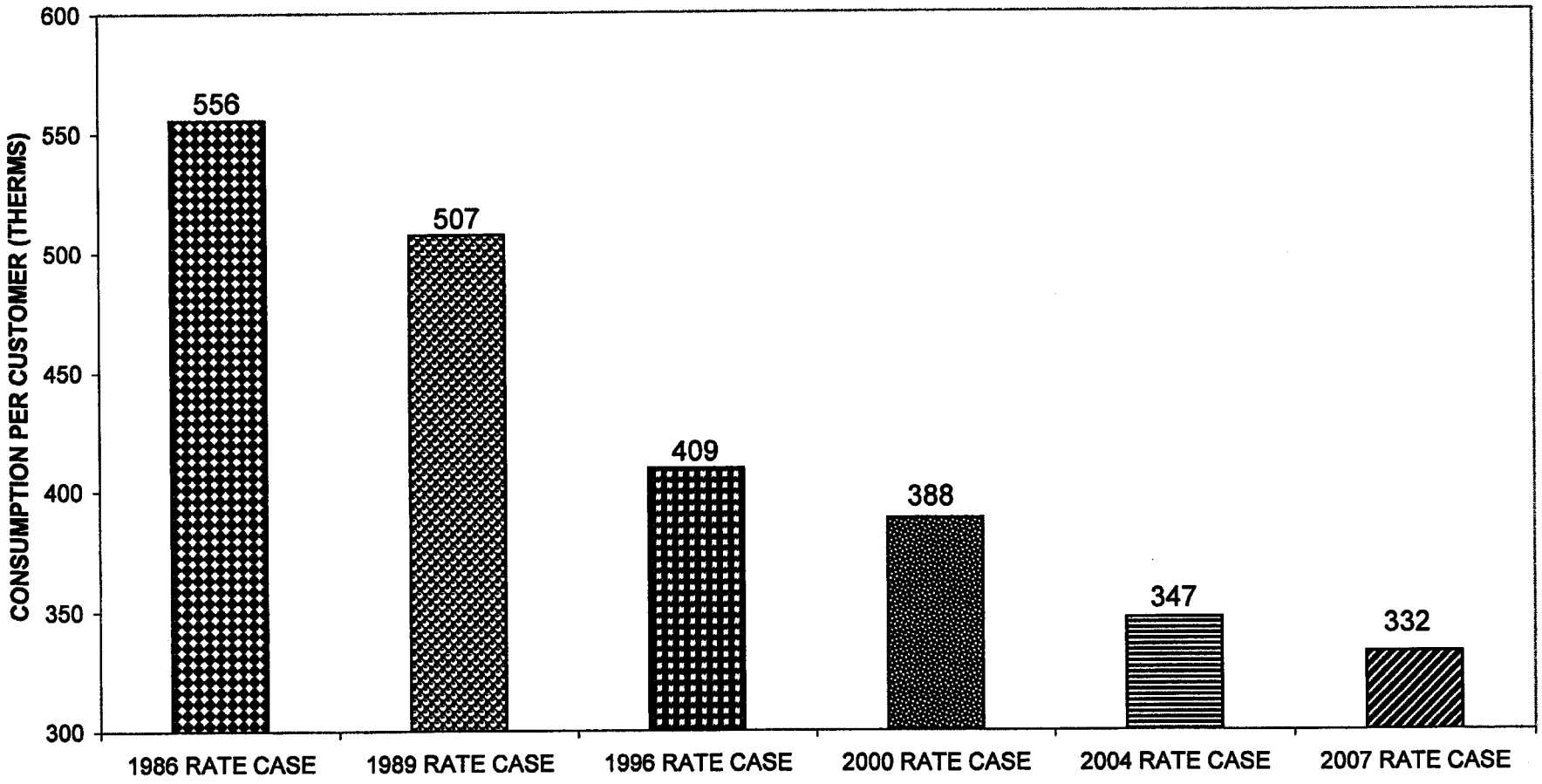

Exhibit No. ___(JLC-1)
Sheet 1 of 1

ARIZONA
RESIDENTIAL GAS SERVICE (G-5 & G-6)
AUGUST RATE CASE CONSUMPTION PER CUSTOMER
1986 - 2007

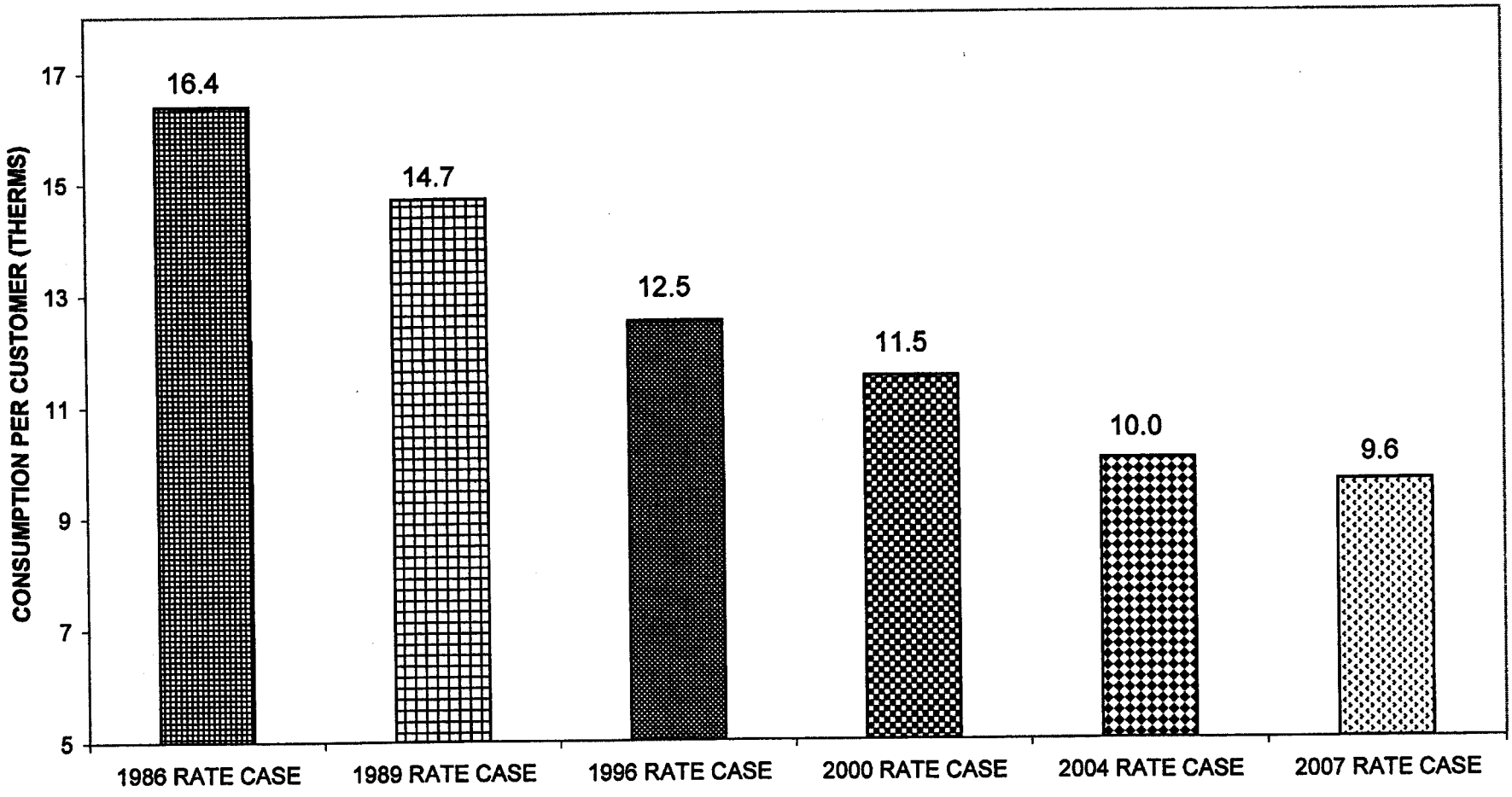

Exhibit No. ___(JLC-2)
Sheet 1 of 1

Volume III

Testimony

8

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

PREPARED DIRECT TESTIMONY
OF
FRANK J. MAGLIETTI, JR.

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
Prepared Direct Testimony
Of
FRANK J. MAGLIETTI, JR.

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
FRANK J. MAGLIETTI, JR.

I. 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 89150-0002.

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

A. 2 I am employed by Southwest Gas Corporation (Southwest) as Senior Specialist in the Pricing and Tariffs Department.

Q. 3 Please state your education background and business experience.

A. 3 My background and experience are reflected in Appendix A.

Q. 4 What is the purpose of your direct testimony?

A. 4 I sponsor Southwest's customer class cost of service study (CCOSS), an amendment to Southwest's Purchased Gas Cost Adjustment, and a ministerial tariff change to remove the references to Title Assignment Service in the Interstate Pipeline Capacity Services Provision of the tariff. I also sponsor several summary schedules identified in the Table of Contents for Volume II of the application.

II. CLASS COST OF SERVICE STUDY

Q. 5 What is the purpose of preparing a Class Cost of Service

Study (CCOSS)?

A. 5 The purpose of a CCOSS is to determine the cost of providing service to each customer class. The CCOSS provides the parties a tool to evaluate return on investment, or economics, of the service provided to each customer class.

Q. 6 Please explain the CCOSS methodology.

A. 6 The CCOSS apportions or "allocates" Southwest's rate base, operating costs and taxes to each of Southwest's customer classes based on various cost causation determinations. Subtracting operating costs from revenue for each class yields the net income by class of service. Net income divided by rate base produces the rate of return (ROR) for each rate class. The Company can then gauge the economics of providing service to various customer classes by determining whether customer class' revenues are sufficient to recover all expenses (O&M, A&G, depreciation and taxes) while still providing investors a sufficient enough return to continue attracting capital.

Q. 7 Please describe the costs factored into the CCOSS methodology?

A. 7 The following are apportioned or allocated via the CCOSS to each of Southwest's customer classes based on various cost causation determinations:

- Capital investment in facilities. These costs include the cost of meters, pipes, regulators, and

other equipment necessary to deliver natural gas to customers. Investment in these facilities comprises the majority of what is called "rate base" in the CCOSS;

- Operating and Maintenance (O&M) expenses. These costs are directly attributable to providing service in Arizona, such as the cost of materials and labor to maintain Southwest's mains, services, meters, the cost to read meters and to provide customer information and customer assistance;
- Administrative and General (A&G) expenses. These costs are not directly attributable to Southwest's Arizona operations, but nonetheless support those operations at a corporate level. These cost include the billing and accounting systems;
- Annual depreciation expenses. This includes the depreciation costs associated with Southwest's investment in facilities to serve customers; and
- State and federal income taxes.

Q. 8 How is the CCOSS used?

A. 8 The CCOSS is used as a tool to develop the proposed rate design, which is discussed more fully by Southwest witness Mr. Brooks Congdon.

Q. 9 Has Southwest changed the CCOSS methodology utilized in recent Arizona rate cases?

A. 9 No, the overall embedded CCOSS methodology and model are the same ones used by Southwest and supported by

Commission Staff in Southwest's last general rate case. However, in this case, Southwest changed how certain accounts (or costs) are allocated to each customer class to more correctly match how they are incurred on Southwest's system.

Q. 10 Please describe Southwest's proposed allocation changes and explain how they more appropriately allocate the costs.

A. 10 Southwest proposes the following modifications:

- Changing Southwest's calculation of the coincident peak demand (CP) allocation factor by basing the CP allocation factor on peak month throughput rather than a combination of three-day sustained peak data and peak month throughput used in the previous case. This change establishes consistency in the data used to develop the CP allocation factor;
- Changing the allocation for measuring and regulating station plant and expenses (accounts 378, 875 and 889) by apportioning these costs using distribution mains (allocation factor 2.2 in the CCOSS) instead of using throughput. Allocating these accounts using distribution mains more accurately reflects the actual use of these facilities;
- Finally, various components of "Other Revenues" are allocated separately based on the characteristics of each component, rather than as a single item, which more accurately reflects the cost.

III. PURCHASED GAS COST ADJUSTMENT (PGA)

Q. 11 Please briefly summarize Southwest's Monthly PGA process.

A. 11 Southwest's monthly gas cost adjustment mechanism has been in effect since June, 1999, and benefits Arizona customers by reducing the fluctuations in the cost of gas billed to customers. The monthly mechanism utilizes a twelve month rolling average of actual gas costs to calculate each month's rate. The original mechanism included a $0.07 per therm PGA bandwidth to limit the movement of the monthly PGA rate over a 12-month period. In other words, rates could not change by more than $0.07 upward from the lowest rate during the previous twelve months or $0.07 downward from the highest rate during the previous twelve months. The $0.07 per therm bandwidth was later raised to $0.10, and then further raised to the current $0.13.

Q. 12 How has the bandwidth limit on changes in the monthly gas cost affected Southwest's purchased gas cost adjustment mechanism?

A. 12 The bandwidth limit has had the desired effect on Arizona customers of "smoothing" rate changes so that no drastic changes occur from month-to-month. However, given increased price volatility in today's natural gas markets, the current $0.13 bandwidth has proven to be a relatively restrictive limit on monthly rate changes, and has had the negative effect of creating large balances in

Southwest's gas cost balancing account. Ironically smoothing month-to-month changes in PGA rates has resulted in the need to implement significant one time changes in Southwest's surcharge to recover under-collections in the gas cost balancing account. For example, the Commission approved Southwest's request for a surcharge of $0.11000 per therm effective January 31, 2006 to recover deferred gas costs.

Q. 13 How has the $0.13 per therm bandwidth affected the recovery of Southwest's deferred gas costs?

A. 13 Since its implementation in March 2006 through today, the $0.13 bandwidth has resulted in an additional amount of $24 million in deferred or under-recovered gas costs versus what would have occurred had no bandwidth been in place over the same time period.

Q. 14 Does Southwest have a proposal that will improve the current PGA methodology?

A. 14 Yes. Natural gas commodity prices change daily in the market, but the overall trend of gas costs has been upward since 1999. In June 1999, when Southwest's PGA mechanism, including a $0.07 per therm bandwidth limit on monthly changes, was implemented, the monthly Inside FERC index price at the Permian Basin was $.208 per therm. Therefore, the originally effective bandwidth was approximately 34 percent of the index price. In comparison, the Inside FERC index price at the Permian Basin for June 2007 was $.698 per therm, or over three

times the cost of gas in June 1999. During the same time period, the bandwidth only increased to $.13 per therm, which represents approximately 19 percent of current gas costs.

Southwest proposes to increase the bandwidth limit to $0.24 per therm so the bandwidth limit, as a percent of market gas prices, is restored to its original level. Changing the limit allows the monthly PGA rate to more closely follow the natural gas market, which results in more accurate price signals to customers and reduces the need for, and magnitude of, any surcharge rate adjustments in the future. Finally, the proposed change is in line with the percentage increases recommended by RUCO and Staff for UNS Gas' PGA bandwidth limit in that company's current rate case application.

Q. 15 Will increasing the $0.13 per therm bandwidth limit to $.0.24 per therm result in excessive month-to-month changes in Southwest's gas cost rate?

A. 15 No. Southwest's monthly gas cost calculation will still be based on a 12-month rolling average which smoothes out the peaks and valleys and therefore mitigates the effect of price volatility in the natural gas markets.

IV. MINISTERIAL TARIFF CHANGE

Q. 16 Please briefly describe the proposed ministerial change to Southwest's tariff.

A. 16 In addition to the rate design changes addressed by Southwest witness Mr. Brooks Congdon, Southwest proposes

to remove the references to Title Assignment Service in the Interstate Pipeline Capacity Services Provision of the tariff.

The Interstate Pipeline Capacity Services Provision currently contains a section on Title Assignment Service for operating agreements executed prior to April 1, 1993. Southwest no longer has any Title Assignment Operating Agreements executed prior to April 1, 1993. Therefore, Southwest proposes to eliminate the Title Assignment section of the schedule.

Q. 17 Please describe the schedules you are supporting.

A. 17 There are two schedules summarizing the results of the CCOSS at present and proposed rates. Schedule G-1 illustrates the rate of return on rate base at current rates by rate schedule. Schedule G-2 illustrates the rate of return on rate base at proposed rates by rate schedule.

Schedule A-1 and Schedules H-1 through H-4, which I am sponsoring, summarize the distribution of Southwest's proposed increase among customer classes and show the dollar and percentage change between Southwest's currently effective rates and its proposed rates. The sheets included in Schedule Nos. C-1 and C-2 quantify the differences in Southwest's recorded sales and revenue data and similar data annualized at adjusted test period bills and volumes. Schedule E-7 is a simple compilation

of recorded customer and sales data for three twelve-month periods prior to the test year in this case.

Q. 18 Does this conclude your prepared direct testimony?

A. 18 Yes, it does.

SUMMARY OF QUALIFICATIONS
FRANK J. MAGLIETTI, JR.

I graduated from Central Washington University in 1991 with a Bachelor of Science degree in Economics. I received a Master of Science in Economics from the University of Wyoming in 1994. I began my utility career as a utility rate analyst with the Washington Utilities and Transportation Commission in 1993. My career with Southwest began in 1997 as a rate analyst. I was subsequently promoted to a Specialist/Pricing and Tariffs in 1999, and was promoted to my current position as a Senior Specialist/Pricing and Tariffs in 2005.

I report to the Manager/Pricing and Tariffs. My primary responsibilities include the development of Class Cost of Service Studies and rate design, as well as other pricing and tariff analyses.

Volume III

Testimony

9

BEFORE THE
ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY
OF
RALPH E. MILLER

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

August 31, 2007

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Of
Prepared Direct Testimony
Of
RALPH E. MILLER

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Attachment A – Summary of Qualifications of Ralph E. Miller

Exhibit "1" – Joint Statement of the American Gas Association and the Natural Resources Defense Council

Exhibit "2" – Resolution on Gas and Electric Energy Efficiency

BEFORE THE ARIZONA CORPORATION COMMISSION

Direct Testimony
of
RALPH E. MILLER

A. Expert Witness Qualifications

Q. 1 Please state your name and business address.

A. 1 My name is Ralph E. Miller. My office is at 5502 Western Avenue, Chevy Chase, Maryland 20815.

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

A. 2 I am self-employed as an independent consulting economist.

Q. 3 Please summarize your professional qualifications.

A. 3 I am an economist specializing in the fields of utility regulation, industrial organization, and public policy towards business. I have more than thirty-five years of experience in public utility and related energy work, both as a consultant and in government. I am the author of several published reports and papers on public utility economics and energy matters, and I have testified in more than 30 different jurisdictions in a total of more than 300 public utility and other proceedings. I also have several additional years of experience in government and as a university teacher in antitrust, energy demand forecasting and supply analysis, and other areas of economics and energy.

Over the years, I have addressed almost all 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.

Attachment A to this testimony provides additional information about my education and professional experience.

Q. 4 Are you familiar with Southwest Gas Corporation (Southwest, or the Company)?

A. 4 Yes. I testified on rate design issues as a witness for the Commission Staff in Arizona in Southwest's 2000-2001 base rate case, Arizona C.C. Docket No. G-01551A-00-0309. In Nevada, I testified as a witness for the Company in its 2004 base rate case, Docket No. 04-3011. I also testified in Nevada as a witness for the Commission Staff in the 1991 investigation of Southwest's purchased gas costs, Docket Nos. 90-1109 and 90-1110, and on rate design in Southwest's 1982 base rate cases, Docket Nos. 82-398 and 82-399.

B. Introduction, Summary, and Conclusions

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

A. 5 The purpose is to describe and discuss the regulatory policy referred to as "revenue decoupling" and the benefits of revenue decoupling to Southwest and its customers.

Q. 6 What is revenue decoupling?

A. 6 Revenue decoupling is a rate design alternative to traditional rate design. Under traditional rate designs, a large fraction of a utility's non-gas cost recovery is achieved through volumetric rate components. Revenue decoupling breaks or weakens this linkage between a gas utility's non-gas revenues and its volumetric sales or total throughput. Full revenue

decoupling eliminates the linkage completely. Partial decoupling weakens the linkage but does not eliminate it.

Q. 7 Why is revenue decoupling important?

A. 7 Traditional rate designs hamper a company's ability to recover its authorized cost per customer because non-gas revenues vary with weather-related and other changes in use per customer. Traditional rate designs also penalize utilities for promoting economically efficient conservation. Full revenue decoupling is important because it solves these problems. It promotes a utility's financial health, while allowing the utility to aggressively promote economically efficient conservation with no attendant financial harm.

Q. 8 How does full revenue decoupling work?

A. 8 For gas distribution companies, full revenue decoupling typically involves a reconciliation between a utility's actual non-gas revenue per customer in each customer class and the allowed level of non-gas revenue per customer established in the utility's most recent base rate proceeding. If sales per customer increase and actual non-gas revenue per customer exceeds the allowed test year level, then the excess is returned to the affected customer class by a rate credit. If sales per customer decrease and actual non-gas revenue per customer is less than the allowed test year level, then the deficiency is recovered by a surcharge to the affected customer class.

Q. 9 Does full revenue decoupling guarantee that the utility will earn its authorized rate of return?

A. 9 No, it does not. The allowed level of test year non-gas revenue per customer is established in a base rate case. It is sufficient for the utility to recover its test year non-gas costs approved by the regulatory authority, including a reasonable return on invested capital. Full revenue decoupling only enables the utility to continue to recover that same test year level of non-gas revenue

per customer. If the utility's non-gas costs increase for any reason, including reasons that may be completely beyond the control of the utility, the money available for return on invested capital also decreases.

Q. 10 Are there other forms of revenue decoupling besides the full decoupling you described?

A. 10 Yes. For interstate pipelines, the FERC decoupled revenues from throughput when it adopted the straight fixed-variable (SFV) rate design in Order 636 in April 1992, but this form of full decoupling has not been widely adopted for gas distribution companies. On the other hand, several forms of partial revenue decoupling have been adopted in many states for gas distribution utilities. Among them are weather normalization, increased fixed monthly customer charges, and declining block rates.

Q. 11 Do you recommend full revenue decoupling?

A. 11 Yes. I support full revenue decoupling for three reasons. First, it removes a major obstacle to promoting the goals of energy conservation and efficiency. Second, it is fair to the utility, its shareholders and its customers. Third, it is likely to reduce the burden on the Commission's regulatory resources, because greater earnings stability is likely to reduce the frequency of Southwest's rate cases.

Q. 12 Can you summarize your recommendations regarding the regulatory policy of revenue decoupling for Southwest Gas' Arizona operations?

A. 12 I recommend the adoption of full revenue decoupling for Southwest's residential customers and all but its largest general service customers. The Company's proposed Revenue Decoupling Adjustment Provision (RDAP) and Weather Normalization Adjustment Provision (WNAP) together accomplish full revenue decoupling.

Q. 13 How is the remainder of your testimony organized to explain and support

your conclusions?

A. 13 First, I describe the broad support that revenue decoupling has achieved in the regulatory community. Second, I discuss why full decoupling is needed to promote energy conservation and efficiency. Third, I explain the weather normalization component of revenue decoupling. Finally, I discuss an alternative rate design that retains many of the features of traditional rate designs but also achieves partial revenue decoupling.

Q. 14 Is your testimony supported by exhibits?

A. 14 Yes. I selected Exhibit "1" and Exhibit "2" to support this testimony.

C. Revenue Decoupling Commands Broad Support

Q. 15 Is Southwest's request for full revenue decoupling a novel request?

A. 15 No, certainly not at the present time. The traditional use of volumetric rates to recover fixed costs that are independent of sales volume has been an issue for many years. As I mentioned earlier, the FERC adopted the straight fixed-variable (SFV) method of rate design for interstate pipelines in its Order 636 in April 1992. The SFV rate design would now be recognized as "full revenue decoupling", but that term did not come into widespread use until later. Within the past few years, there has been intense interest in full revenue decoupling for gas distribution utilities, and revenue decoupling attracts very broad support.

One of the early expressions of support for revenue decoupling was a Joint Statement of the American Gas Association (AGA) and the Natural Resources Defense Council (NRDC), which the AGA and NRDC submitted to NARUC in July 2004. The Joint Statement explained that traditional volumetric rates are a "significant financial disincentive for natural gas utilities to aggressively encourage their customers to use less gas", and it supported

"mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales." Exhibit "1" is a copy of this Joint Statement.

In a Resolution on Gas and Electric Energy Efficiency, adopted by the NARUC Board of Directors on July 14, 2004, the NARUC Board encourages State Commissions to review and consider the recommendations in the Joint Statement. Exhibit "2" is a copy of this NARUC resolution.

Q. 16 Have weather normalization and revenue decoupling been accepted in other jurisdictions?

A. 16 Yes. Within the past several years, there has been intense interest in other revenue decoupling measures and weather normalization, such as Southwest's proposed RDAP and WNAP, for gas distribution utilities. The support for these regulatory policies is very broad and many state regulatory commissions have adopted them.

Q. 17 Can you briefly describe other examples of the broad support for revenue decoupling?

A. 17 Yes. Recently, in June 2007, the State of Nevada adopted legislation to permit revenue decoupling. Senate Bill No. 437 amends the Nevada Regulatory Statute and requires the Nevada PUC to "remove the financial disincentives which discourage the public utility from supporting energy conservation, including . . . a mechanism . . . to ensure that the costs of the public utility for providing service are recovered without regard to the difference in the quantity of natural gas actually sold by the public utility . . . ."

Maryland adopted full revenue decoupling for its two large gas utilities, Baltimore Gas and Electric Company and Washington Gas Light Company. Their adopted decoupling mechanism is a rate adjustment (surcharge or credit) to recoup or refund all variations in non-gas revenue per

customer in each customer class. There is no distinction between weather-related changes and other variations in use per customer.

California adopted revenue decoupling more than 20 years ago, where it has long been recognized as an essential complement to that state's aggressive conservation programs.

More recently, revenue decoupling has also been adopted in several other states, often in conjunction with conservation programs. Among the states with full or essentially full revenue decoupling linked to conservation programs are Oregon, New Jersey, Missouri (for Atmos Energy), and Utah (for Questar Gas Company). Colorado, Indiana, Ohio, and Washington each adopted at least partial decoupling for one or more gas utilities, sometimes on a pilot or test basis. A few states, including North Dakota and Georgia, have allowed full decoupling in the form of straight fixed-variable (SFV) rate designs.

D. Full Revenue Decoupling, and its Relationship to Energy Conservation and Efficiency

Q. 18 You stated in your introduction that you support full revenue decoupling because it removes a major obstacle to promoting the goals of energy conservation and efficiency. What do you mean by the term "energy conservation and efficiency"?

A. 18 In this testimony, I use the term "conservation" to refer to any programs or actions that are designed to or have been successful in reducing natural gas usage. The concept of energy efficiency is a bit different, because it incorporates a recognition that reduced energy usage sometimes entails other costs. In a March 2007 report to Congress, the U.S. Department of Energy (DOE) defined "energy efficiency" as "using less energy to accomplish the same level of economic activity or amenity". New Mexico's

Efficient Use of Energy Act of 2005 defines "energy efficiency" as "measures, including energy conservation measures, . . . [intended] to result in a decrease in consumption of electricity and natural gas without reducing the amount or quality of energy services". These definitions are representative of what I mean when I refer to energy conservation and efficiency.

Q. 19 Are energy conservation and efficiency appropriate goals to be considered in utility regulation, including rate cases like the present proceeding?

A. 19 Yes, these goals are important in the regulation of gas and electric utilities for two reasons. First, gas and electric utility rates are the prices that the utilities' customers view when they (the customers) make decisions about their use of energy, and prices are an important influence on customer behavior. The pricing of gas and electric utility services thus influences the extent to which energy conservation and efficiency are achieved in the U.S. economy.

Consideration of these goals in the regulatory process is important because utilities are in a position to influence energy usage decisions, which affect energy conservation and efficiency. Utilities can do so through advertising, through promotional programs, and through other activities too closely tied to the provision of utility services to be conducted independently by third parties. Regulators seeking to promote energy conservation and efficiency should establish regulatory policies that encourage utilities to support the achievement of these goals.

Q. 20 How does full revenue decoupling relate to the goals of promoting energy conservation and efficiency?

A. 20 Traditional retail gas rate designs are inimical to these goals. As stated in the AGA and NRDC Joint Statement, traditional volumetric rate designs interfere with the promotion of energy conservation and efficiency because they result in a significant financial disincentive for gas utilities to aggressively promote

energy conservation and efficiency.

Traditional rate designs are adverse to energy conservation and efficiency because they impose a financial penalty on gas utilities whenever usage per customer decreases. Thus they create a financial disincentive for the utility to support any program that reduces customer usage, even if that program is an efficient use of resources for the economy as a whole. Under traditional rate designs, it is in the financial interest of a gas utility to instead promote increased customer usage. Full revenue decoupling breaks the linkage between usage per customer and the gas utility's revenues. By doing so, it removes the perverse financial incentive for gas utilities to refrain from promoting decreased gas use at a time when national, state, and regulatory policies are all directed at achieving energy conservation and efficiency.

Q. 21 How do traditional gas rate designs impose a financial penalty on a gas utility whenever usage per customer declines?

A. 21 Under traditional rate designs, a large fraction of a utility's non-gas revenues is obtained from "volumetric" charges, which depend upon gas usage. When usage per customer declines, the utility experiences a loss of non-gas revenue.

This loss of non-gas revenues under traditional rate designs is in stark contrast with the utility's non-gas costs, which do not change to any significant or appreciable extent with changes in sales volume. By reducing the utility's non-gas revenues in response to any decrease in usage per customer, traditional rate designs deprive the utility of the ability to recover its unchanging costs of providing service.

Q. 22 How does revenue decoupling address this problem?

A. 22 Full revenue decoupling breaks the linkage between a gas utility's non-gas revenues and its sales volume per customer and eliminates the financial

penalty imposed on the utility whenever usage per customer declines. Decoupling makes it possible for a utility to join in aggressive promotion of energy conservation and efficiency without harming itself financially.

Q. 23 Your analysis of revenue decoupling focuses on revenue per customer, not total revenue. If Southwest is experiencing rapid customer growth and therefore a growth in total revenue, does that revenue growth obviate the need for revenue decoupling to maintain revenues per customer?

A. 23 No, rapid growth in the number of customers is not a solution to the problems caused by traditional volumetric or throughput-based rate designs in an environment where sales per customer are decreasing. It is a mistake to view increasing total non-gas revenues that result from customer growth as offsetting the adverse effects of declining sales per customer on Southwest's ability to recover its cost of service under traditional volumetric rates.

New customers and new loads are sometimes said to "pay for themselves", but that means only that the revenues from the new customers are sufficient to cover the new and additional costs Southwest incurs to be able to serve those new customers. Even if new customers do pay for themselves, they do not pay for themselves and also for the revenues lost when existing customers decrease their gas usage.

E. Weather Normalization

Q. 24 What is weather normalization?

A. 24 Weather normalization is a regulatory procedure that adjusts the non-gas (or distribution) charges on customers' bills to reflect normal weather instead of actual weather which may be colder or warmer than normal.

In Southwest's proposed weather normalization provision, the adjustment is made each month to reflect the difference between actual and

normal weather in that month. This timing is similar to Southwest's current system of making small changes to the monthly gas cost, which has proven acceptable to customers. Other weather normalization procedures may apply the bill adjustment with a lag of one or two months or even an entire winter season.

Q. 25 How does weather normalization benefit customers?

A. 25 In a month that is colder than normal, most customers use more gas than they would if the weather were normal. The increased usage causes the customer's bill to increase, because the customer must pay the purchased gas charge for the increased usage. Under traditional rate designs, the customer must also pay increased non-gas charges for delivery of the increased usage volumes. A weather normalization adjustment offsets this further increase in the customer's bill, so the only additional charge in a colder than normal month is the purchased gas charge for the additional usage. Weather normalization thus offsets part of the increase in customer bills that occurs under traditional rate designs in colder than normal weather.

In months that are warmer than normal, the reverse occurs. Most customers use less gas than they would if the weather were normal. Under traditional rate design, the customer's bill decreases because the purchased gas charge and the non-gas charge are both applied to a smaller quantity of usage. With weather normalization, the decrease in non-gas charges is eliminated, and the bill decreases only by the amount of the purchased gas charge on the reduced usage.

Weather normalization moderates the fluctuation in the customer's bill that occurs when weather is colder than normal and when it is warmer than normal. In colder than normal months, the customer's bill increases less than it would under a traditional rate design, and in warmer than normal

months, it decreases less than it would under a traditional rate design.

Q. 26 How does weather normalization benefit utility companies?

A. 26 Weather normalization benefits utility companies because it eliminates the fluctuations in non-gas revenue that would otherwise occur whenever the actual weather is colder or warmer than the normal weather used for the test year to design the utility's rates.

Q. 27 Is weather normalization an accepted regulatory policy?

A. 27 Yes. Regulatory commissions in 25 states have adopted weather normalization procedures for one or more gas utilities under their jurisdiction.

Q. 28 How does weather normalization relate to full revenue decoupling?

A. 28 Weather normalization is a form of partial revenue decoupling. On a monthly basis, and even for an entire winter season, the difference between actual and normal weather may have a larger effect on gas usage than any other factor causing actual usage per customer to differ from test year usage per customer. Thus, weather normalization eliminates one of the major links between non-gas revenues and gas usage per customer, but has no effect on the linkage tying non-gas revenues under traditional rate designs to usage variations resulting from any other cause.

Q. 29 Is weather normalization appropriate for a utility that has a separate non-weather related revenue decoupling mechanism?

A. 29 Yes. With the exception of the SFV form of rate design, full revenue decoupling is a reconciliation mechanism, and it operates with a lag. Southwest's proposed "real-time" weather normalization adjusts customer bills to eliminate the non-gas revenue effect of the largest source of monthly and seasonal variations in customer usage, and it does so without any lag. Therefore, Southwest's proposed WNAP provides customers and the Company with an immediate benefit of reduced risk for variations in customer

bills due to the difference between actual and normal weather. It is also important to recognize that weather normalization decreases the magnitude of the rate adjustments needed to achieve full revenue decoupling because the revenue consequences of weather variations were already removed before the beginning of the full revenue decoupling procedure.

Q. 30 Why do you recommend weather normalization?

A. 30 I support the separate weather normalization component of full revenue decoupling because it reduces the revenue risks for Southwest and for Southwest's customers. Both sides benefit from comprehensive weather normalization, especially the "real-time" version proposed by Southwest in this proceeding.

F. Alternative Forms of Partial Revenue Decoupling

Q. 31 Earlier you recommended a policy of full revenue decoupling, including both a real-time adjustment to remove weather-related volatility from customer bills (Southwest's proposed WNAP) and a reconciliation and adjustment of non-gas revenues per customer for Southwest's residential and smaller general service customers (Southwest's proposed RDAP). Are there other approaches to revenue decoupling that the Commission might also consider?

A. 31 Yes. I believe that the Commission should consider other rate design changes, such as Southwest's proposal to integrate a declining block rate for non-gas charges with an inverted block rate for purchased gas cost. Company witness A. Brooks Congdon explains this rate design in his testimony. The important feature of this rate design is that the composite commodity charge for gas sales customers is a flat volumetric rate, but the offsetting block structures for the recovery of non-gas costs and gas costs provide Southwest with the partial decoupling effect of a declining block for its

non-gas charges. This rate design is an innovative way of combining the desirable pricing features of a flat commodity charge rate with the desirable decoupling effect of a declining block rate for the recovery of non-gas costs. This rate design was first adopted several years ago for Laclede Gas Company in Missouri, and I support its consideration and adoption here in Arizona.

Q. 32 Does this conclude your direct testimony?

A. 32 Yes.

Attachment A

Expert Witness Qualifications of Ralph E. Miller

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

A. 1 My name is Ralph E. Miller. I am self-employed as an independent consulting economist. My office is at 5502 Western Avenue, Chevy Chase, Maryland 20815.

Q. 2 Please describe your educational background.

A. 2 I did my undergraduate work at Harvard College, where I received the A.B. degree *summa cum laude* in mathematics in 1961, and I was elected to Phi Beta Kappa. I then went on to graduate work in economics at Harvard, where I received a Master's degree in 1963. I continued my graduate studies there until 1966, and I completed all of the course requirements for the Ph.D. degree, but not a doctoral dissertation.

Q. 3 What is your employment experience?

A. 3 I have been an independent consultant for more than twenty years. I also have ten years of experience as president or vice president of two different consulting firms specializing in public utility and energy matters. Before that, I spent three years in the federal government, where I 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). I was on the faculty of the University of California for three years, where I taught economics courses at both the graduate and undergraduate levels.

Q. 4 What is your experience in the area of utility rate design?

A. 4 I have been engaged in electric and gas utility rate design work for more than 30 years, and I have devoted much of my time to this field during this period. I am the author of several published reports on utility rate design, and I have been the invited leader of a workshop on class cost of service analysis at the National Regulatory Research Institute (NRRI). My utility rate design work includes class cost of service studies based on fully allocated embedded costs, marginal and avoided cost analysis, determination of customer class revenue responsibilities, tariff design, incentive rates and other alternative forms of rate regulation, and the analysis of ratemaking policy issues.

Q. 5 What is your experience in the specific area of gas rate design?

A. 5 Since 1981 I have testified on gas rate design in more than 20 proceedings involving gas local distribution companies (LDCs). Including collaboratives and roundtables as well as proceedings which were settled prior to hearing, I have worked on more than 30 gas rate design cases involving more than a dozen different LDCs in nine states. In the past ten years, my rate design work has included a consideration of unbundling and gas transportation, in addition to the more traditional class cost of service studies and class revenue responsibility issues. Even more recently, I have been focusing increasingly on ratemaking policy issues, including alternative forms of regulation and decoupling.

In Maryland I have testified on the traditional cost of service and class revenue responsibility issues in several Washington Gas Light Company and Baltimore Gas and Electric Company base rate cases, and I have been participating in the gas roundtables for these two and several smaller gas utilities. In Michigan I have testified on class cost of service, cost allocation, class revenue responsibilities, and gas transportation issues in several base rate cases. New Jersey and Pennsylvania are other states in

which I have testified on traditional class cost of service and rate design issues in several different proceedings. In addition, I have extensive experience with gas pipeline rate design and with unbundling and transportation issues at FERC, where I have testified in numerous pipeline rate cases and participated in several of the unbundling proceedings pursuant to FERC Order 636.

Exhibit "1"

AGA American Gas Association

NRDC
THE EARTH'S BEST DEFENSE

Joint Statement of the American Gas Association and the Natural Resources Defense Council

Submitted to the National Association of Regulatory Utility Commissioners
July 2004

The American Gas Association (AGA) and the Natural Resources Defense Council (NRDC) recognize the many benefits of using clean-burning natural gas efficiently to provide high quality energy services in all sectors of the economy. This statement identifies ways to promote both economic and environmental progress by removing barriers to natural gas distribution companies' investments in urgently needed and cost-effective resources and infrastructure.

NRDC and AGA agree on the importance of state Public Utility Commissions' consideration of innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility company customers, utility shareholders, and other stakeholders. Cost-effective opportunities abound to improve the efficiency of buildings and equipment in ways that promote the interests of both individual customers and entire utility systems, while improving environmental quality. For example, when energy supply and delivery systems are under stress, even relatively modest reductions in use can yield significant additional cost savings for all customers by relieving strong upward pressures on short-term prices.

NRDC and AGA also encourage state Commissions to support gas distribution company efforts to manage volatility in energy prices and reduce volatility risks for customers.

The Energy Efficiency Problem: Regulated Natural Gas Utilities are Penalized for Aggressively Promoting Energy Efficiency

Local natural gas distribution companies (gas utilities) have very high fixed costs. These fixed costs include the costs of maintaining system safety and reliability throughout the year, staffing customer service telephone lines 24 hours a day and doing what it takes each day of the year to ensure the safe and reliable delivery of natural gas to homes, schools, hospitals, retailers, factories and other customers.

Natural gas utilities typically purchase natural gas on behalf of their customers, and pass through the cost without markup. This means that natural gas utilities do not

profit from their acquisitions of natural gas to serve customer needs. The profit (authorized level of rate of return) comes from the rates utilities charge for transporting the natural gas to customers' homes and businesses.

The vast majority of the non-commodity costs of running a gas distribution utility are fixed and do not vary significantly from month to month. However, traditional utility rates do not reflect this reality. Traditional utility rates are designed to capture most of approved revenue requirements for fixed costs through volumetric retail sales of natural gas, so that a utility can recover these costs fully only if its customers consume a certain minimum amount of natural gas (these amounts are normally calculated in rate cases and generally are based on what customers consumed in the past). Thus, many states' rate structures offer – quite unintentionally – a significant financial disincentive for natural gas utilities to aggressively encourage their customers to use less natural gas, such as by providing financial incentives and education to promote energy-efficiency and conservation techniques.

When customers use less natural gas, utility profitability almost always suffers, because recovery of fixed costs is reduced in proportion to the reduction in sales. Thus, conservation may prevent the utility from recovering its authorized fixed costs and earning its state-allowed rate of return. In this important respect, traditional utility rate practices fail to align the interests of utility shareholders with those of utility customers and society as a whole. This need not be the case. Public utility commissions should consider utility rate proposals and other innovative programs that reward utilities for encouraging conservation and managing customer bills to avoid certain negative impacts associated with colder-than-normal weather. There are a number of ways to do this, and NRDC and AGA join in supporting mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales.[1] We also support performance-based incentives designed to allow utilities to share in independently verified savings associated with cost-effective energy efficiency programs.

Many states' rate structures also place utilities at risk for variations in customer usage based on variations in weather from a normal pattern. This variation can be both positive and negative. Utilities' allowed rate of return is premised on the

[1]For example, in 2003 the Oregon Public Utility Commission approved a "conservation tariff" for Northwest Natural Gas Company (NW Natural) "to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict." The conservation tariff seeks to do that by using modest periodic rate adjustments to "decouple" recovery of the utility's authorized fixed costs from unexpected fluctuations in retail sales. *See* Oregon PUC Order No. 02-634, *Stipulation Adopting Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization* (Sept. 12, 2003). In California, PG&E and other gas utilities have a long tradition of investment in energy efficiency services, including those targeting low-income households, and the PUC is now considering further expansion of these investments along with the creation of performance-based incentives tied to verified net savings. California also pioneered the use of modest periodic true-ups in rates to break the linkage between utilities' financial health and their retail gas sales, and has now restored this policy in the aftermath of an ill-fated industry restructuring experiment. Thus, in March 2004, Southwest Gas Company received an order that authorizes it to establish a margin tracker that will balance actual margin revenues to authorized levels.

expectation that weather will be normal, on average, and that customer use of gas will maintain a predictable pattern going forward. Proposals by utilities to decouple revenues from both conservation-induced usage changes and variations in weather from normal have sometimes been characterized as attempts to reduce utilities' risk of earning their authorized return. The result of these rate reforms, in this regulatory view, should be a lowered authorized return. But reducing authorized returns would penalize utilities for socially beneficial advocacy and action, including efforts to create mechanisms that minimize the volatility of customer bills.

Our shared objective is to give utilities real incentives to encourage conservation and energy efficiency. With properly designed programs, the benefits could be significant and widespread:

- Customers could save money by using less natural gas;
- Reduced overall use will help push down short-term prices at times when markets are under stress, reducing costs for all customers (whether or not they participate in the utility programs);
- Utilities would recover their costs and have a fair opportunity to earn their allowed return;
- State policies to encourage economic development could be enhanced by increased energy efficiency and lower business energy costs;
- State PUCs would be able to support larger state policy objectives as well as programs that reflect the public's desire to use energy efficiently and wisely.

In today's climate of rapidly changing natural gas prices, such reforms make good sense for consumers, shareholders, state governments, and the environment.

Natural Gas Consumers, Price Volatility and Resource Portfolio Management. Another area of concern shared by NRDC and AGA is the impact of natural gas price volatility on natural gas consumers, which can be exacerbated by limited diversification of utilities' resource portfolios. Today many of the nation's natural gas utilities find themselves relying on short-term markets for most of their gas needs, with either the encouragement or the acquiescence of their regulators. During much of the 1990's this approach was typically advantageous to consumers, as the market price of natural gas was generally low and did not fluctuate dramatically. As wholesale natural gas prices have risen since 2000 and become more volatile, however, many utilities and commissions are reconsidering this emphasis on short-term market purchases.

While purchasing practices based on short-term supply contracts may offer consumers relatively low-cost natural gas, those consumers are also exposed to more volatile prices and natural gas bills that may rise and fall unpredictably. Public Utility Commissions should favorably consider gas distribution company proposals to manage volatility, such as through hedging, fixed-price contracts of various durations, energy-efficiency improvements in customers' buildings and equipment, and other measures designed to provide greater certainty about both supply

adequacy and price stability. Achieving these goals will sometimes require paying a premium over prevailing spot market prices. Like diversified investment portfolios that are designed to mitigate risk, prudent hedging plans should be encouraged as a way to help stabilize gas prices and ensure long-term access to affordable natural gas services.

This Joint Statement also has been reviewed and endorsed by:

ALLIANCE TO SAVE ENERGY

Creating an Energy Efficient World

Alliance to Save Energy

ACE3

American Council for an Energy-Efficient Economy

Resolution on Gas and Electric Energy Efficiency

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC), at its July 2003 Summer Meetings, adopted a *Resolution on State Commission Responses to the Natural Gas Supply Situation* that encouraged State and Federal regulatory commissions to review and reconsider the level of support and incentives for existing gas and electric utility programs designed to promote and aggressively implement cost-effective conservation, energy efficiency, weatherization, and demand response in both gas and electricity markets; *and*

WHEREAS, The National Petroleum Council (NPC), in its September 25, 2003 report on *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, found that greater energy efficiency and conservation are vital near-term and long-term mechanisms for moderating price levels and reducing volatility and recommended all sectors of the economy work toward improving demand flexibility and efficiency; *and*

WHEREAS, The NPC, in its report, identified key elements of the effort to maintain and continue improvements in the efficient use of electricity and natural gas, including (but not limited to):

(i) enhanced and expanded public education programs for energy conservation, efficiency, and weatherization,

(ii) DOE identification of best practices utilized by States for low-income weatherization programs and to encourage nation-wide adoption of these practices,

(iii) a review and upgrade of the energy efficiency standards for buildings and appliances (to reflect current technology and relevant life-cycle cost analyses) to ensure these standards remain valid under potentially higher energy prices

(iv) promote the use of high-efficiency consumer products including advanced building materials, Energy Star appliances, energy "smart" metering and information control devices

(v) on-peak electricity conservation to minimize the use of gas-fired electric generating plants,

(vi) the use of combined-cycle gas-fired electric generating units instead of less-efficient gas-fired boilers, and

(vii) clear natural gas and power price signals; and

(viii) remove regulatory and rate structure incentives to inefficient use of natural gas and electricity; and

WHEREAS, The NARUC, at its November 2003 annual convention, adopted a *Resolution Adopting Natural Gas Information "Toolkit"* which encouraged the NARUC Natural Gas Task Force, to review (among other things) the findings and recommendations in the NPC report that have regulatory implications for State commissions for improving and promoting energy efficiency and conservation initiatives, including consumer outreach and education, review of regulatory throughput incentives; *and*

WHEREAS, The American Council for an Energy-Efficient Economy ("ACEEE"), in its December 2003 report on *Responding to the Natural Gas Crisis: America's Best Natural Gas Energy Efficiency Programs*, (i) identified States and utilities with programs that many would consider best practice or model programs for all types of natural gas customers and all principal natural gas end-use technologies, and (ii) found that these programs are concentrated in relatively few States and regions and could be expanded in other parts of the country to great benefit; *and*

WHEREAS, the Natural Resources Defense Council (NRDC), the American Gas Association (AGA) and the ACEEE have recently adopted a Joint Statement noting that traditional rate structures often act as disincentives for natural gas utilities to aggressively encourage their customers to use less gas. Therefore, the NRDC, AGA, and the ACEEE have urged public utility commissions to align the interests of consumers, utility shareholders, and society as a whole by encouraging conservation. Among the mechanisms supported by these groups are the use of automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales; *now therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened in its 2004 Summer Meetings in Salt Lake City, Utah, encourages State commissions and other policy makers to support the expansion of natural gas energy efficiency programs and electric energy efficiency programs, including those designed to promote consumer education, weatherization, and the use of high-efficiency appliances, where economic, and to address regulatory incentives to address inefficient use of gas and electricity; *and be it further*

RESOLVED, That the Board of Directors of the NARUC, encourages State and Federal policy makers to: (i) review and upgrade the energy efficiency standards for buildings and appliances, where economic, to ensure these standards remain valid under potentially higher energy prices, and (ii) promote the use of high-efficiency consumer products, where economic, including advanced building materials, Energy Star appliances, and energy "smart" metering and information control devices; *and be it further*

RESOLVED, That Board of Directors of NARUC encourages State Commissions to review and consider the recommendations contained in the enclosed *Joint Statement of the American Gas Association, the Natural Resources Defense Council, and the American Council for an Energy-Efficient Economy; and be it further*

RESOLVED, That the Board of Directors of the NARUC recognizes that the best approach towards promoting gas energy efficiency programs and electric energy efficiency programs for any single utility, State or region may likely depend on local issues, preferences and conditions.

Sponsored by the NARUC Natural Gas Task Force, Committee on Gas, Committee on Consumer Affairs, Committee on Electricity, and Committee on Energy Resources and the Environment
Adopted by the NARUC Board of Directors July 14, 2004

Volume III

Testimony

10

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

PREPARED DIRECT TESTIMONY
OF
A. BROOKS CONGDON

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
Prepared Direct Testimony
Of
A. BROOKS CONGDON

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Appendix A - Summary of Qualifications of A. Brooks Congdon

Exhibit No.___(ABC-1)

Exhibit No.___(ABC-2)

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Exhibit No.___(ABC-5)

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
A. BROOKS CONGDON

I. 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 89150-0002.

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

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) as Manager/Pricing and Tariffs.

Q. 3 Please state your educational background and business experience.

A. 3 My background and experience are reflected in Appendix A to my direct testimony.

Q. 4 What is the purpose of your testimony?

A. 4 I am sponsoring the Company's rate design proposals.

II. RATE DESIGN INTRODUCTION

Q. 5 Please discuss the objective of Southwest's rate design and other tariff proposals in this case.

A. 5 Southwest continues to face significant instability in its cost recovery due to changes in customer consumption attributable to weather as well as erosion of revenues due to continued customer conservation. These effects are most pronounced in the residential class of customers but are also experienced to a lesser extent in

the weather-sensitive small, medium and large general service classes. Therefore, Southwest's rate design and tariff proposals in this case focus on achieving greater stability in revenues from these customer classes.

In Southwest's last general rate case, Docket No. G-01551A-04-0876, Decision No.68487, the Commission stated, "We encourage the parties to this proceeding to seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders". Accordingly, Southwest proposes the following tariff and rate design tools: (1) a new tariff mechanism, the Revenue Decoupling Adjustment Provision, to recover or return differences between customers' actual and authorized non-gas revenue; (2) a new tariff mechanism, the Weather Normalization Adjustment Provision, to remove weather-related volatility from the non-gas component of individual customer bills; (3) gradual increases to basic service charges (BSCs); and (4) elimination of Southwest's currently-effective declining block residential rate structure for billing purposes while stabilizing recovery of authorized non-gas revenue with offsetting blocks for the non-gas and gas cost components of the sales rate. The Company believes that these tools can resolve Southwest's cost recovery problems while benefiting customers and encouraging conservation efforts.

III. RESIDENTIAL RATE DESIGN

Q. 6 Please provide the background for the development of Southwest's residential rate design proposals in this case.

A. 6 In its last Arizona rate case, Southwest's residential rate design proposals were driven by the need to address cost recovery issues associated with a chronic decline in average use per residential customer. Using the rate design tools "traditionally" available, Southwest proposed shifting cost recovery away from usage-sensitive components of the rate structure into BSC and the less-usage-sensitive first block of the declining block commodity charge.

Southwest also requested the implementation of a regulatory mechanism, the Conservation Margin Tracker (CMT), to allow Southwest to record the difference between its actual monthly residential non-gas revenue and the amount that would have been realized at the Commission-authorized monthly non-gas revenue per customer for future recovery or refund. Although the Commission did not approve Southwest's residential rate design proposals, it acknowledged that Southwest "faces increased financial pressure due to declining usage on a per customer basis."

Q. 7 Why did the Commission reject Southwest's rate design and CMT proposals?

A. 7 The Commission indicated that Southwest's proposed increase to the BSC was too large and violated the principle of gradualism. Further, the Commission was concerned that Southwest's proposal to significantly reduce the marginal commodity charge of the rate design from its then-effective level would reduce customers' incentive to conserve. The Commission expressed similar conservation-related concerns regarding the CMT.

However, recognizing Southwest's cost recovery predicament, the Commission encouraged Southwest and other interested rate case participants to conduct discussions regarding this issue. In response, Southwest initiated a "rate design collaborative" which included Staff and Residential Utility Consumer Office (RUCO). The collaborative held four meetings from September 2006 thru April 2007.

In developing its proposals for this proceeding, Southwest considered the Commission's concerns and the opinions expressed at the rate design collaborative.

Q. 8. Please discuss Southwest's proposed new tariff mechanisms and rate design changes and how they conform to Decision No. 68487.

A. 8 The proposed tariff mechanism and rate design changes are discussed below.

A. Revenue Decoupling Adjustment Provision (RDAP)

Decision No. 68487 contained several references to the need to promote maximum energy efficiency. Clearly, the

Commission is committed to protecting energy supplies for future Arizona generations. Accordingly, Southwest's proposed RDAP is a tariff mechanism that positions the Company to aggressively promote customer conservation and energy efficiency, without adverse financial impact, by allowing the recovery or refund of any differences between actual and Commission-authorized non-gas revenue.

The RDAP is styled after a mechanism recently approved by the Public Service Commission of Utah for Questar Gas Company. The RDAP provides for recovery of non-weather related dollar differences between actual and authorized non-gas revenue by recording monthly differences in non-gas revenue in a deferred account and recovering the balance annually through a rate adjustment (surcharge). The process is identical in nature to the accounting for Southwest's Purchased Gas Cost Adjustment Provision. The mechanics of the RDAP are provided in Exhibit No.___(ABC-1). The following table illustrates that total customer savings, including the RDAP surcharge, can be increased thru a successful conservation program.

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	Effective Sales Rate	Change in Use/Customer	Annual Savings
Status Quo			
Per Customer Savings	$1.49065	-5.0 therms	-$7.45
Breakeven With RDAP			
Per Customer Savings	$1.49065	-6.1 therms	-$9.09
Plus RDAP Surcharge			1.65
Total Savings			-$7.44
Difference from Status Quo			$0.01

Breakeven RDAP Surcharge Calculation
6.1 therms * $.26956* = $1.65 / 325.9 = $0.00505

SWG Proposed DSM Programs With Decoupling			
Per Customer Savings	$1.49065	-6.7 therms	-$10.00
Plus RDAP Surcharge			1.81
Total Savings			-$8.19
Difference from Status Quo			$0.74

Breakeven RDAP Surcharge Calculation
6.7 therms * $.26956* = $1.81 / 325.3 = $0.00556

* $.26956 is weighted average winter non-base-load rate.

The "Status Quo" scenario shows that at Southwest's current average annual decline in use per residential customer of approximately 5 therms, per customer savings is $7.45.

The "Breakeven With RDAP" scenario demonstrates that if the Commission approves Southwest's proposed RDAP, conservation must be increased by slightly more than one therm, from 5 therms to 6.1 therms per customer in order for residential customers to be indifferent, in terms of the total amount paid, to the RDAP. Although customers may be indifferent financially, increasing conservation, will achieve reductions in the total amount of natural gas consumed.

If a more aggressive set of conservation measures,

such as those reflected in Southwest's 2006 Arizona Demand Side Management Program Plan filed in June of 2006, is successful in increasing conservation per customer from the base rate of 5 therms per year to 6.7 therms (as Southwest estimates would be accomplished with the implementation of its filed DSM programs), average customer savings, including the RDAP surcharge, can be increased by $0.74, or 10 percent, per customer per year on average. This equates to total additional residential customer savings of $0.7 million annually and an additional 1.6 million therm per year reduction in the amount of natural gas consumed vis-à-vis simply maintaining the status quo.

This information demonstrates that well-supported conservation and energy efficiency programs, in conjunction with the proposed RDAP, can "provide benefits to all affected stakeholders" as envisioned by the Commission in Decision No. 68487.

B. Weather Normalization Adjustment Provision (WNAP)

Southwest's proposed WNAP is a tariff mechanism that removes weather-related volatility from the non-gas component of customer bills for each winter season billing cycle. The WNAP functions similarly to two other utilities' weather adjustment mechanisms with which Southwest is familiar: Questar Gas in Utah and Northwest Natural Gas in Oregon. The mechanics of the WNAP are provided in Exhibit No.___(ABC-2).

Removing weather-related volatility from customer bills has the following benefits: (1) customers are shielded from over-paying for the fixed cost of distribution service when the weather is colder than normal; (2) the Company is protected from under-recovery of its cost of providing service when weather is warmer than normal; and (3) distribution revenues collected more closely mirror amounts authorized by the Commission in setting rates. Reducing weather-related volatility in customer bills improves the overall balance of risk for customers and the Company. As such, the WNAP is a proposal that benefits both customers and the Company.

Removing weather volatility on a real-time basis eliminates the Commission's concerns expressed in Decision No. 68487 that deferring dollar impacts of both weather- and non-weather-related changes in customer usage for amortization in a future period could result in potentially large swings in surcharge rates from year to year. In addition, it ensures that the dollar impacts related to each customer's usage is reflected on that customer's bill.

C. Basic Service Charge

In Decision No. 68487, the Commission authorized an increase of approximately twenty one (21) percent in Southwest's BSC from $8.00 to $9.70 per month. At $9.70 per month, approximately forty (40) percent of total

authorized residential non-gas revenue is recovered through the BSC. In authorizing a BSC of $9.70 per month, the Commission stated:

> "Based on consideration of competing interests and concerns, we agree that Staff's rate design recommendation appropriately makes significant movement towards cost based rates while providing a measure of protection for customers who will incur substantial rate increases as a result of this base rate case increase".

To continue building upon the movement toward cost-based rates authorized in Decision No. 68487, Southwest now proposes to increase the amount of its total residential non-gas revenue recovered through the BSC from forty (40) to forty-five (45) percent. This increase equates to a thirty-two (32) percent increase in Southwest's current single-family residential basic charge to $12.80 per month. Southwest proposes to retain its currently-effective multi-family basic service charge of $8.70 per month. Southwest's proposed basic service charges recover approximately forty-one (41) percent of the monthly fixed cost of service developed in Southwest's embedded customer class cost of service study and reflected on Sheet 1 of Exhibit No.___(ABC-4).

This more modest increase in Southwest's proposed single-family residential basic service charge responds to the Commission's concern in Decision No. 68487, that the movement of rates closer to cost-based rates "must

be balanced with consideration of the principles of gradualism, fairness, and encouragement of conservation."

D. Commodity Charge

In Decision No. 68487, the Commission encouraged the parties to seek rate design alternatives that would promote conservation efforts, while benefiting all affected stakeholders.

Southwest addressed these concerns through its proposal to flatten the sales rate (commodity charge) of its proposed residential rate design, while stabilizing its non-gas revenues through an innovative allocation of the non-gas and gas cost components of the sales rate as reflected below.

Illustrative "Average" and Proposed "Allocated" Single-Family Residential Rates

Description	Delivery (Non-Gas) Charge	Monthly Gas Cost & Rate Adj	Effective Sales Rate
Illustrative Average Rate Components			
Basic Service Charge	$12.80		$12.80
Commodity Charge per Therm			
All Usage	$.55376	$0.93689	$1.49065
Proposed Rate Components			
Basic Service Charge	$12.80		$12.80
Commodity Charge per Therm			
Summer			
First 15 Therms	$.88069	$0.60996	$1.49065
Over 15 Therms	.00000	1.49065	1.49065
Winter			
First 35 Therms	$.88069	$0.60996	$1.49065
Over 35 Therms	.00000	1.49065	1.49065

Southwest developed proposed rates for its single- and multi-family residential gas service as follows:

- Calculated basic service charges;
- Retained the currently effective summer and winter rate blocks for single- and multi-family residential service;
- Set the second block non-gas or delivery charge at $.00000 per therm;
- Calculated the first block non-gas rate required to recover the proposed residential non-gas revenue;
- Calculated the gas cost rates for each block so customers see a single charge per therm for all usage.

Unlike traditional declining block rates, Southwest's proposed rate design removes the declining block rate "price signal" from customers' bills. This rate design better aligns customer and Company interests, vis-à-vis traditional declining block rates, because 1) customers are provided greater incentive to "invest in conservation" thru elimination of the declining-block-rate price signal, and 2) cost recovery is enhanced by more accurately reflecting how non-gas and gas costs change, on average, with increases or decreases in customer usage. Exhibit No.___(ABC-3) provides a complete reconciliation of Southwest's proposed "Allocated" rate design versus a typical "Average" rate

design.

Laclede Gas Company, a natural gas distribution company in Saint Louis, Missouri, has had this type of residential rate design in place since November 2002. Southwest has a similar allocation of non-gas and gas cost between consumption blocks for service to residential natural gas customers in its South Lake Tahoe, California service area. Southwest has not experienced any customer or administrative difficulties related to this rate design. In both of these examples, the non-gas rate for second block consumption is zero.

Thus, Southwest's proposed rate design for residential gas service responds to the Commission's concerns that traditional declining block rate design can send the unintended message: "the more you use, the more you save."

IV. NON-RESIDENTIAL RATE DESIGN CHANGES

Q. 9 Please discuss the rate design changes Southwest proposes for its non-residential rate schedules.

A. 9 Southwest proposes to increase basic service charges for several of its non-residential rate schedules. Specifically, Southwest proposes to adjust basic service charges to the lesser of: 1) the monthly amount required to recover forty-one (41) percent of each schedules' allocated average fixed cost per month as reflected on Sheets 1 and 2 of Exhibit No.___(ABC-4) or 2) each schedules' currently effective basic charge increased by

thirty-two (32) percent. This approach gradually increases the basic service charges for non-residential schedules, with the exception of rate Schedule Nos. G-20, Master Meter Mobile Home Park; G-25(S), General Gas Service Small; and G-55(S), Gas Service for Compression Small. To avoid potentially large impacts on customers within these schedules, Southwest proposes to retain its currently effective basic service charges.

V. ALLOCATION OF SOUTHWEST'S PROPOSED NON-GAS REVENUE TO CUSTOMER CLASSES AND PROPOSED RATE DESIGN

Q. 10 Please describe Southwest's allocation of the proposed non-gas revenue requirement to customer classes.

A. 10 Southwest used the proportional cost responsibility method (PCRM) in apportioning its requested increase to customer classes. The PCRM is a cost of service based allocation methodology that narrows the difference between the system average rate of return on rate base and rate of return of the various classes of customers to establish non-gas revenue requirements by class that more accurately reflect the cost of providing service. Southwest used this method in prior rate cases and continues to believe that a cost of service based approach to determining each customer class' revenue requirement is superior to more subjective methods.

Q. 11 Have you summarized Southwest's proposed allocation of non-gas revenue and proposed rate design by customer classes?

A. 11 Yes. Southwest's allocation of non-gas revenue and resulting customer class rate design is developed in Exhibit No.___(ABC_4), Sheets 3-8. Sheets 3 and 4 reflect Southwest's PCRM allocation of non-gas revenue to customer classes. Southwest's proposed rates to recover proposed class non-gas revenue requirements are reflected on Sheets 5-8.

Q. 12. Can the PCRM and Southwest's proposed rate design methodology be utilized regardless of the level of non-gas revenue increase ultimately approved by the Commission?

A. 12. Yes.

VI. RATE DESIGN SUMMARY

Q. 13 Has Southwest prepared summary schedules quantifying the impact of its proposed changes in rates?

A. 13 Yes. Exhibit No.___(ABC-5) provides an in-depth look at Southwest's proposed rate designs and their impact on customers. Sheet 1 is a comparison of the differences between Southwest's currently-effective and proposed rates for single-residential service. Sheet 1 shows the dollar and percentage changes in rates by rate component as well as the per therm and percentage changes in the average rates for distribution sales service. Sheet 2 of Exhibit No.___(ABC_5) is a graphical representation

of the monthly bill impact that most single-family residential customers would experience. Sheets 3 and 4 of Exhibit No.___(ABC_5) are graphical representations of typical winter and summer season monthly bills at Southwest's currently-effective and proposed rates for service to single-family residential customers. Sheets 2-4 show that the effect of Southwest's proposed single-family residential rates is actually very smooth across the months and across various ranges of consumption. Sheets 5-8 of Exhibit No.___(ABC_5) reflect the above information for Southwest's currently-effective and proposed rates for multi-family residential service. Schedules H-1 through H-4 provide additional information for all customer classes on the impact of Southwest's proposed rate design changes. These schedules are discussed by Southwest witness Mr. Frank Maglietti in his prepared direct testimony.

Q. 14 Does this conclude your prepared direct testimony?

A. 14 Yes, it does.

SUMMARY OF QUALIFICATIONS
A. BROOKS CONGDON

I received a Bachelor of Science degree in Economics from Iowa State University in 1975.

From 1976 to 1980, I was employed as a Forecasting Analyst for General Telephone of the Midwest in the Company's Columbus, Nebraska office. My responsibilities there primarily involved projecting growth in demand for telephone service in eastern Nebraska and western Iowa.

From 1980 to 1984, I was employed as a Rate Analyst in the Rate Department of Pacific Power and Light Company in Portland, Oregon involved primarily in performing cost-of-service studies and designing rates for electric and water utilities.

In 1984, I accepted a position at Kansas Electric Power Cooperative in Topeka, Kansas where my primary responsibilities included coordination of intervention in wholesale power rate cases at the Federal Energy Regulatory Commission and preparation of the cooperatives' rate case activity before the Kansas Corporation Commission.

I began my employment with Southwest in 1987 in the Rate Department (now the Pricing and Tariffs Department) as a Rate Specialist. Since that time, I have held positions of increasing responsibility. My present position is Manager/Pricing and Tariffs. I report to the Director/Pricing and Tariffs. I am responsible for the

development of rate design and tariff proposals for Southwest in its three-state retail rate jurisdictions. I have submitted testimony and testified before the Public Utilities Commission of Nevada, the California Public Utilities Commission, the Arizona Corporation Commission and the Kansas Corporation Commission.

PARAMETERS FOR SOUTHWEST GAS' REVENUE DECOUPLING ADJUSTMENT PROVISION (RDAP)

Purpose of the RDAP:
The purpose of the RDAP is to maximize total customer savings thru aggressive promotion of conservation and energy efficiency without harming the Company financially by creating a new deferred account to record for future amortization differences between Southwest's Commission-authorized non-gas revenue calculated on a per customer basis, and weather-adjusted non-gas revenue actually billed. The RDAP applies to residential (G-5, G-6, G-10 and G-11) and general service (G-25S, G-25M and G-25L) customer classes.

Data Required:
Commission-authorized monthly non-gas revenue per customer, the number of customers billed in each month and monthly weather-adjusted non-gas revenue actually billed.

RDAP Process:
An entry will be made to the RDAP balancing account (RDAPBA) each month equal to the difference between authorized non-gas revenue on a per customer basis and actual weather-adjusted non-gas revenue billed. Separate subaccounts will be maintained for each customer class included in the RDAP. The RDAPBA will be amortized every twelve months by dividing the balance in each subaccount by the volume of gas expected to be delivered to the respective customer classes over the following twelve month period. Individual surcharges will be calculated for each customer class included in the RDAP. The RDAP process is set forth below.

- Calculate Commission-authorized monthly non-gas revenue per customer for each customer class included in the RDAP. Authorized monthly non-gas revenue per customer is set forth in Southwest's proposed RDAP tariff provision and the calculations are set forth in Sheets 2 and 3 of Exhibit No. ____(ABC-2).

- Calculate authorized monthly non-gas revenue for each class by multiplying the authorized non-gas revenue per customer by the number of customers actually billed.

- Using billing system records, determine the amount of monthly weather-adjusted non-gas revenue actually billed to customers.

- Record the difference between authorized and actual non-gas revenue in the RDAPBA for each customer class included in the RDAP. A credit RDAPBA entry will be made when actual non-gas revenue exceeds authorized non-gas revenue and a debit entry will be made when actual non-gas revenue is less than authorized non-gas revenue.

- After accumulating twelve months of entries, calculate RDAP surcharges/surcredits by dividing the balance for each customer class by the total volume of gas expected to be delivered to customers in the class over the following twelve month period.

- Include the resulting RDAP surcharges/surcredits in Southwest's Rate Adjustment.

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF MONTHLY MARGIN PER CUSTOMER
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	May-06	June-06	July-06	August-06	September-06	October-06	November-06	December-06	January-07	February-07	March-07	April-07	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Single-Family Residential														
	Monthly Billing Determinants														
1	Customers	853,757	851,528	850,729	849,993	849,419	852,433	857,966	863,798	866,438	870,117	871,261	860,591	10,298,030	1
2	First Block Volumes	10,253,294	8,236,001	7,270,996	6,928,414	7,368,261	7,991,675	14,290,707	24,402,411	26,537,666	26,133,576	24,457,474	18,134,523	182,004,998	2
3	Second Block Volumes	6,747,280	2,583,884	1,512,290	1,235,651	1,600,730	2,327,269	2,662,649	17,459,253	29,488,186	22,557,133	13,874,969	5,001,823	107,051,117	3
4	Total Volume	17,000,574	10,819,885	8,783,286	8,164,065	8,968,991	10,318,944	16,953,356	41,861,664	56,025,852	48,690,709	38,332,443	23,136,346	289,056,115	4
	Proposed Margin Rates														
5	Basic Service Charge	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80		5
6	First Block Margin Rate	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069		6
7	Second Block Margin Rate	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		7
	Proposed Margin														
8	First Block Margin Revenue	$ 9,029,973	$ 7,253,363	$ 6,403,493	$ 6,101,785	$ 6,489,154	$ 7,038,188	$ 12,585,683	$ 21,490,959	$ 23,371,457	$ 23,015,579	$ 21,539,453	$ 15,970,893	$ 160,289,981	8
9	Second Block Margin Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	9
10	Basic Service Charge Revenue	10,928,090	10,899,558	10,889,331	10,879,910	10,872,563	10,911,142	10,981,965	11,056,614	11,090,406	11,137,498	11,152,141	11,015,585	131,814,784	10
11	Total Margin Revenue	$ 19,958,063	$ 18,152,922	$ 17,292,825	$ 16,981,695	$ 17,361,717	$ 17,949,331	$ 23,567,648	$ 32,547,573	$ 34,461,864	$ 34,153,076	$ 32,691,594	$ 26,986,458	$ 292,104,765	11
12	Margin per Customer	$ 23.38	$ 21.32	$ 20.33	$ 19.98	$ 20.44	$ 21.06	$ 27.47	$ 37.68	$ 39.77	$ 39.25	$ 37.52	$ 31.36	$ 339.55	12
	Multi-Family Residential														
	Monthly Billing Determinants														
13	Customers	30,771	30,662	30,550	30,221	30,027	30,178	30,492	30,886	31,370	31,788	32,068	31,549	370,562	13
14	First Block Volumes	189,009	178,220	170,745	165,354	167,819	173,288	353,453	456,033	476,337	477,912	465,029	404,327	3,677,522	14
15	Second Block Volumes	278,619	163,312	128,508	113,302	124,189	142,074	88,792	378,605	534,182	441,523	300,073	137,356	2,830,537	15
16	Total Volume	467,628	341,532	299,253	278,656	292,008	315,360	442,245	834,638	1,010,519	919,435	765,102	541,683	6,508,059	16
	Proposed Margin Rates														
17	Basic Service Charge	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70		17
18	First Block Margin Rate	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069		18
19	Second Block Margin Rate	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		19
	Proposed Margin														
20	First Block Margin Revenue	$ 166,458	$ 156,956	$ 150,373	$ 145,626	$ 147,796	$ 152,611	$ 311,282	$ 401,623	$ 419,505	$ 420,893	$ 409,546	$ 356,087	$ 3,238,757	20
21	Second Block Margin Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	21
22	Basic Service Charge Revenue	267,708	266,759	265,785	262,923	261,236	262,549	265,280	268,708	272,919	276,556	278,992	274,476	3,223,889	22
23	Total Margin Revenue	$ 434,166	$ 423,716	$ 416,158	$ 408,548	$ 409,031	$ 415,160	$ 576,563	$ 670,332	$ 692,424	$ 697,448	$ 688,538	$ 630,563	$ 6,462,646	23
24	Margin per Customer	$ 14.11	$ 13.82	$ 13.62	$ 13.52	$ 13.62	$ 13.76	$ 18.91	$ 21.70	$ 22.07	$ 21.94	$ 21.47	$ 19.99	$ 208.53	24
	Special Residential														
	Monthly Billing Determinants														
25	Customers	108	108	108	108	108	108	108	108	108	108	108	108	1,296	25
26	First Block Volumes	1,383	1,295	1,309	1,245	1,331	1,336	2,537	3,437	3,581	3,569	3,393	2,792	27,208	26
27	Second Block Volumes	8,689	11,510	14,004	12,739	11,510	6,875	4,151	9,039	12,084	10,081	7,627	6,003	114,312	27
28	Total Volume	10,072	12,805	15,313	13,984	12,841	8,211	6,688	12,476	15,665	13,650	11,020	8,795	141,520	28
	Proposed Margin Rates														
29	Basic Service Charge	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80		29
30	First Block Margin Rate	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069		30
31	Second Block Margin Rate	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		31
	Proposed Margin														
32	First Block Margin Revenue	$ 1,218	$ 1,140	$ 1,153	$ 1,096	$ 1,172	$ 1,177	$ 2,234	$ 3,027	$ 3,154	$ 3,143	$ 2,988	$ 2,459	$ 23,962	32
33	Second Block Margin Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	33
34	Basic Service Charge Revenue	1,382	1,382	1,382	1,382	1,382	1,382	1,382	1,382	1,382	1,382	1,382	1,382	16,589	34
35	Total Margin Revenue	$ 2,600	$ 2,523	$ 2,535	$ 2,479	$ 2,555	$ 2,559	$ 3,617	$ 4,409	$ 4,536	$ 4,526	$ 4,371	$ 3,841	$ 40,551	35
36	Margin per Customer	$ 24.08	$ 23.36	$ 23.47	$ 22.95	$ 23.65	$ 23.69	$ 33.49	$ 40.83	$ 42.00	$ 41.90	$ 40.47	$ 35.57	$ 375.47	36

Exhibit No. ____(ABC-1)
Sheet 2 of 3

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF MONTHLY MARGIN PER CUSTOMER
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	May-06	June-06	July-06	August-06	September-06	October-06	November-06	December-06	January-07	February-07	March-07	April-07	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Small General Service														
	Monthly Billing Determinants														
1	Customers	16,641	16,463	16,346	16,429	16,398	16,481	16,742	17,075	17,437	17,416	17,433	16,944	201,805	1
2	Therms	243,327	154,277	134,964	136,522	141,052	157,208	247,474	718,732	1,112,774	970,917	659,709	343,798	5,020,754	2
	Proposed Margin Rates														
3	Basic Service Charge Revenue	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00		3
4	Margin Rate All Usage	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852		4
	Proposed Margin														
5	Commodity Margin Revenue	$ 184,568	$ 117,022	$ 102,373	$ 103,555	$ 106,991	$ 119,245	$ 187,714	$ 545,173	$ 844,061	$ 736,460	$ 500,402	$ 260,778	$ 3,808,342	5
6	Basic Service Charge Revenue	416,025	411,575	408,650	410,725	409,950	412,025	418,550	426,875	435,925	435,400	435,825	423,600	5,045,125	6
7	Total Margin Revenue	$ 600,593	$ 528,597	$ 511,023	$ 514,280	$ 516,941	$ 531,270	$ 606,264	$ 972,048	$ 1,279,986	$ 1,171,860	$ 936,227	$ 684,378	$ 8,853,467	7
8	Margin per Customer	$ 36.09	$ 32.11	$ 31.26	$ 31.30	$ 31.52	$ 32.24	$ 36.21	$ 56.93	$ 73.41	$ 67.29	$ 53.70	$ 40.39	$ 522.45	8
	Medium General Service														
	Monthly Billing Determinants														
9	Customers	16,117	16,079	16,023	16,002	15,958	16,048	16,059	16,242	16,368	16,293	16,333	16,268	193,790	9
10	Therms	3,020,571	2,505,961	2,234,466	2,142,536	2,335,242	2,566,274	3,596,629	5,691,658	6,455,032	5,939,096	5,222,869	3,829,935	45,530,269	10
	Proposed Margin Rates														
11	Basic Service Charge Revenue	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50		11
12	Margin Rate All Usage	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988		12
	Proposed Margin														
13	Commodity Margin Revenue	$ 1,238,072	$ 1,027,143	$ 915,863	$ 878,183	$ 957,169	$ 1,047,766	$ 1,474,186	$ 2,332,897	$ 2,645,789	$ 2,434,317	$ 2,140,750	$ 1,569,814	$ 18,661,947	13
14	Basic Service Charge Revenue	701,090	699,437	697,001	696,087	694,173	698,088	698,567	706,527	712,008	708,746	710,486	707,658	8,429,865	14
15	Total Margin Revenue	$ 1,939,161	$ 1,726,580	$ 1,612,863	$ 1,574,270	$ 1,651,342	$ 1,745,854	$ 2,172,753	$ 3,039,424	$ 3,357,797	$ 3,143,062	$ 2,851,235	$ 2,277,472	$ 27,091,812	15
16	Margin per Customer	$ 120.32	$ 107.38	$ 100.66	$ 98.38	$ 103.48	$ 108.79	$ 135.30	$ 187.13	$ 205.14	$ 192.91	$ 174.57	$ 140.00	$ 1,674.06	16
	Large General Service														
	Monthly Billing Determinants														
17	Customers	7,122	7,112	7,114	7,123	7,095	7,116	7,080	7,108	7,152	7,143	7,175	7,170	85,510	17
18	Therms	10,706,299	9,069,748	8,056,226	7,855,457	8,337,682	9,252,867	12,815,044	17,769,956	18,237,397	17,322,726	16,523,224	13,276,228	149,222,854	18
	Proposed Margin Rates														
19	Basic Service Charge Revenue	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00		19
20	Margin Rate All Usage	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843		20
	Proposed Margin														
21	Commodity Margin Revenue	$ 3,088,018	$ 2,615,987	$ 2,323,657	$ 2,265,749	$ 2,404,838	$ 2,668,804	$ 3,696,243	$ 5,125,388	$ 5,260,212	$ 4,996,394	$ 4,765,793	$ 3,829,262	$ 43,040,348	21
22	Basic Service Charge Revenue	1,139,520	1,137,920	1,138,240	1,139,680	1,135,200	1,138,560	1,132,800	1,137,280	1,144,320	1,142,880	1,148,000	1,147,200	13,681,600	22
23	Total Margin Revenue	$ 4,227,538	$ 3,753,907	$ 3,461,897	$ 3,405,429	$ 3,540,038	$ 3,807,364	$ 4,829,043	$ 6,262,668	$ 6,404,532	$ 6,139,274	$ 5,913,793	$ 4,976,462	$ 56,721,948	23
24	Margin per Customer	$ 593.59	$ 527.83	$ 486.63	$ 478.09	$ 498.95	$ 535.04	$ 682.07	$ 881.07	$ 895.49	$ 859.48	$ 824.22	$ 694.07	$ 7,956.53	24

Exhibit No. ____(ABC-1)
Sheet 3 of 3

PARAMETERS FOR SOUTHWEST GAS' WEATHER NORMALIZATION ADJUSTMENT PROVISION (WNAP)

Purpose of the WNAP:
The purpose of the WNAP is to eliminate weather-related risk by adjusting each customer's winter bill to reflect what the customer would have paid for delivery service assuming "normal" weather for each winter billing cycle. The WNAP applies to heat-sensitive residential (G-5, G-6, G-10 and G-11) and general service (G-25S, G-25M and G-25L) customer classes.

Data Required:
Actual average daily temperatures and 10-year average heating degree day (HDD) data.

WNAP Process:
A "WNAP Volume Adjustment" will be calculated for each customer for each winter billing cycle to reflect the difference between the customer's actual use and usage assuming normal weather. The WNAP Volume Adjustment will then be used to calculate a "WNAP Dollar Adjustment" to each customer's billed delivery charge. The WNAP process is set forth below.

- Obtain and store in Southwest's billing system actual average temperature and 10-year average HDDs for each day of the winter season. Actual average temperature for each day will be input into the billing system the following day, e.g.., Monday's temperature must be input Tuesday for Wednesday's billing.

- Calculate "Cycle HDD Variance" as follows:

Normal Cycle HDD =	10-year average HDDs for each day
Actual Cycle HDD =	The number of degrees that any day's average temperature is less than 65
Cycle HDD Variance =	Normal Cycle HDDs for each day in the billing cycle less Actual Cycle HDDs for each day in the billing cycle

- Calculate each customer's non-temperature sensitive "Base Load Volume per Day" by determining the customer's lowest average daily use for the June thru September billing periods. Average daily use is the customer's total monthly use divided by the number of days in the billing cycle. For new customers, Base Load Volume per Day will be estimated based upon the average Base Load Volume for other customers in each district. If necessary, Company personnel will adjust customers' Base Load Volume per Day to reflect a more representative amount.

- Calculate each customer's "Cycle Usage per HDD" by subtracting the customer's Base Load Volume (Base Load Volume = Base Load Volume per Day X Number of Days in Billing Cycle) from actual usage and dividing the difference by the Actual Cycle HDDs.

PARAMETERS FOR SOUTHWEST GAS' WEATHER NORMALIZATION ADJUSTMENT PROVISION (WNAP)

- Calculate each customer's WNAP Volume Adjustment by multiplying the customer's Cycle Usage per HDD by the Cycle HDD Variance.

- Calculate each customer's WNAP Dollar Adjustment by multiplying the WNAP Volume Adjustment by Southwest's delivery charge rates.

- Add the WNAP Dollar Adjustment to the customer's "regular" bill calculated using metered volumes and calculate taxes on the total including the WNAP Dollar Adjustment.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED ALLOCATION OF NON-GAS AND GAS COST RATE COMPONENTS FOR RESIDENTIAL GAS SERVICE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Delivery Charge Rates	Delivery Charges	Monthly Gas Cost [1]	Rate Adjustment	Monthly Gas Cost and Rate Adjustment Charges	Effective Sales Rate	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Average Non-Gas and Gas Rate Components [2]											
	Basic Service Charge per Month											
1	Single-Family Residential Gas Service	G-5	10,298,030		$ 12.80	$131,814,784				$ 12.80	$ 131,814,784	1
2	Multi-Family Residential Gas Service	G-6	370,562		8.70	3,223,889				8.70	3,223,889	2
3	Low-Income Residential Gas Service	G-10, G-11	338,294		7.50	2,537,205				7.50	2,537,205	3
4	Special Residential Gas Service	G-15	1,296		12.80	16,589				12.80	16,589	4
	Commodity Charge per Therm											
5	Single-Family Residential Gas Service			289,056,115	$ 0.55376	$160,067,714	$ 0.92426	$ 0.01263	$ 270,813,784	$ 1.49065	$ 430,881,498	5
6	Multi-Family Residential Gas Service			6,508,059	0.55376	3,603,903	0.92426	0.01263	6,097,335	1.49065	9,701,238	6
7	Low-Income Residential Gas Service			9,211,615	0.55376	5,101,024	0.81426	0.00322	7,530,311	1.37124	12,631,335	7
8	Special Residential Gas Service			141,520	0.55376	78,368	0.92426	0.00322	131,257	1.48124	209,625	8
9	Total Residential Gas Service		11,008,182	304,917,309		$306,443,476			$ 284,572,687		$ 591,016,163	9
	Allocated Non-Gas and Gas Rate Components [3]											
	Basic Service Charge per Month											
10	Single-Family Residential Gas Service	G-5	10,298,030		$ 12.80	$131,814,784				$ 12.80	$ 131,814,784	10
11	Multi-Family Residential Gas Service	G-6	370,562		8.70	3,223,889				8.70	3,223,889	11
12	Low-Income Residential Gas Service	G-10, G-11	338,294		7.50	2,537,205				7.50	2,537,205	12
13	Special Residential Gas Service	G-15	1,296		12.80	16,589				12.80	16,589	13
	Commodity Charge per Therm											
	Single-Family Residential Gas Service											
14	First Block Usage			182,004,998	$ 0.88069	$160,289,981	$ 0.59733	$ 0.01263	$ 111,015,768	$ 1.49065	$ 271,305,749	14
15	Second Block Usage			107,051,117	0.00000	0	1.47802	0.01263	159,575,748	1.49065	159,575,748	15
	Multi-Family Residential Gas Service											
16	First Block Usage			3,677,522	$ 0.88069	$ 3,238,757	$ 0.59733	$ 0.01263	$ 2,243,141	$ 1.49065	$ 5,481,898	16
17	Second Block Usage			2,830,537	0.00000	0	1.47802	0.01263	4,219,340	1.49065	4,219,340	17
	Low-Income Residential Gas Service											
18	First Block Usage			6,017,376	$ 0.88069	$ 5,299,443	$ 0.48733	$ 0.00322	$ 2,951,824	$ 1.37124	$ 8,251,267	18
19	Second Block Usage			3,194,239	0.00000	0	1.36802	0.00322	4,380,068	1.37124	4,380,068	19
	Special Residential Gas Service											
20	First Block Usage			27,208	$ 0.88069	$ 23,962	$ 0.59733	$ 0.00322	$ 16,340	$ 1.48124	$ 40,302	20
21	Second Block Usage			114,312	0.00000	0	1.47802	0.00322	169,324	1.48124	169,324	21
22	Total Residential Gas Service		11,008,182	304,917,309		$306,444,610			$ 284,571,553		$ 591,016,163	22
	Allocated Non-Gas and Gas Rate Components Change From Average Ratemaking											
23	First Block Usage				$ 0.32693		$ (0.32693)	$ 0.00000				23
24	Second Block Usage				(0.55376)		0.55376	0.00000				24

[1] Monthly Gas Cost and Rate Adjustment effective May 1, 2007. Schedules G-5, G-6 and G-15 include $.11000 per therm Gas Cost Balancing Account adjustment.
[2] Rates without Southwest's proposed allocation of non-gas and gas cost components of the sales rate.
[3] Southwest's proposed rates reflecting its proposed allocation of non-gas and gas cost rate components.

Exhibit No. ____(ABC-3)
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF MONTHLY FIXED COST OF SERVICE

Line No.	Description	Allocated Amount							Line No.
		Residential	Multi-Family Residential	MMMHP	Small General Service	Medium General Service	Large General Service	Transportation Eligible	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Total Fixed Cost Revenue Requirement at Proposed System ROR								
1	Customer-Related Costs	$ 268,059,972	$ 7,234,834	$ 158,967	$ 7,086,260	$ 17,178,690	$ 14,192,418	$ 1,814,331	1
2	Demand-Related Costs	$ 64,893,565	$ 1,196,003	$ 462,686	$ 1,264,556	$ 6,827,127	$ 19,293,885	$ 13,426,359	2
3	Total Fixed Costs	$ 332,953,537	$ 8,430,837	$ 621,653	$ 8,350,815	$ 24,005,817	$ 33,486,303	$ 15,240,690	3
4	Total Number of Monthly Bills	10,610,232	397,950	1,968	201,805	193,790	85,510	2,222	4
5	Average Fixed Cost per Month	$ 31.38	$ 21.19	$ 315.88	$ 41.38	$ 123.88	$ 391.61	$ 6,859.00	5
6	Total Commodity Revenue Requirement at Proposed System ROR	$ 1,325,033	$ 31,410	$ 9,894	$ 22,335	$ 202,544	$ 663,827	$ 442,749	6
7	Total Annual Throughput	297,856,607	7,060,702	2,223,993	5,020,754	45,530,269	149,222,854	99,526,400	7
8	Average Commodity Cost per Therm	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	8
9	Average Demand Cost per Therm	$ 0.21787	$ 0.16939	$ 0.20804	$ 0.25187	$ 0.14995	$ 0.12930	$ 0.13490	9
10	Average Annual Cost per Customer	$ 378.06	$ 255.18	$ 3,850.90	$ 497.90	$ 1,499.05	$ 4,792.44	$ 84,699.04	10
11	Per Month	$ 31.51	$ 21.26	$ 320.91	$ 41.49	$ 124.92	$ 399.37	$ 7,058.25	11

Exhibit No. ___(ABC-4)
Sheet 1 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF MONTHLY FIXED COST OF SERVICE

Line No.	Description	Air Conditioning	CNG - Small	CNG - Large	CNG - Residential	Electric Generation	Small Essential Agriculture	Gas Engine	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Total Fixed Cost Revenue Requirement at Proposed System ROR								
1	Customer-Related Costs	$ 10,698	$ 10,565	$ 94,707	$ 31,247	$ 103,343	$ 378,282	$ 1,305,476	1
2	Demand-Related Costs	$ 47,545	$ 12,146	$ 142,414	$ 5,650	$ 1,196,194	$ 1,245,080	$ 561,096	2
3	Total Fixed Costs	$ 58,243	$ 22,711	$ 237,121	$ 36,897	$ 1,299,537	$ 1,623,362	$ 1,866,572	3
4	Total Number of Monthly Bills	318	252	288	1,272	252	1,216	5,105	4
5	Average Fixed Cost per Month	$ 183.15	$ 90.12	$ 823.34	$ 29.01	$ 5,156.89	$ 1,335.00	$ 365.64	5
6	Total Commodity Revenue Requirement at Proposed System ROR	$ 4,975	$ 790	$ 9,165	$ 344	$ 95,742	$ 32,095	$ 58,147	6
7	Total Annual Throughput	1,118,252	177,495	2,060,152	77,361	21,521,946	7,214,684	13,070,981	7
8	Average Commodity Cost per Therm	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	8
9	Average Demand Cost per Therm	$ 0.04252	$ 0.06843	$ 0.06913	$ 0.07304	$ 0.05558	$ 0.17258	$ 0.04293	9
10	Average Annual Cost per Customer	$ 2,385.56	$ 1,119.06	$ 10,261.89	$ 351.33	$ 66,441.84	$ 16,336.74	$ 4,524.31	10
11	Per Month	$ 198.80	$ 93.26	$ 855.16	$ 29.28	$ 5,536.82	$ 1,361.40	$ 377.03	11

Exhibit No. ____(ABC-4)
Sheet 2 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
ALLOCATION OF PROPOSED MARGIN TO CUSTOMER CLASSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Total	Single Family Residential	Multi-Family Residential	MMMHP	General Gas Service				Air-Conditioning	Line No.
						Small	Medium	Large	Trans. Eligible		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	Margin at Requested System Rate of Return [1]	$ 449,454,506	$ 334,945,916	$ 8,589,901	$ 631,232	$ 8,497,194	$ 24,126,939	$ 33,785,216	$ 15,399,330	$ 63,059	1
2	Margin at Present Rates [2]	$ 399,234,678	$ 258,989,889	$ 7,115,596	$ 972,093	$ 7,867,642	$ 24,310,776	$ 53,003,981	$ 20,088,639	$ 123,697	2
3	Difference (Line 1 minus Line 2)	$ 50,219,828									3
4	System Average Percentage Increase (Line 3 / Line 2)	12.57902%									4
5	Ratio of Margin at System Return to Margin at Present Rates (Line 1 / Line 2)		1.29328	1.20719	0.64935	1.08002	0.99252	0.63741	0.76657	0.50979	5
6	Adjusted Percentage Increase (Line 4 X Line 5)		16.26818%	15.18532%	8.16823%	13.58557%	12.48494%	8.01798%	9.64269%	6.41260%	6
7	Adjusted Percentage Increase $ (Line 2 X Line 6)	$ 54,267,003	$ 42,132,929	$ 1,080,526	$ 79,403	$ 1,068,864	$ 3,035,185	$ 4,249,851	$ 1,937,085	$ 7,932	7
8	Adjusted Margin Requirement (Line 2 + Line 7)	$ 453,501,681	$ 301,122,818	$ 8,196,122	$ 1,051,496	$ 8,936,506	$ 27,345,961	$ 57,253,832	$ 22,025,724	$ 131,629	8
9	(Over) / Under Collection [3]	(4,047,175)	(2,798,669)	(76,176)	(9,773)	(83,057)	(254,156)	(532,123)	(204,710)	(1,223)	9
10	Proposed Class Margin Requirement (Line 8 plus Line 9)	$ 449,454,506	$ 298,324,149	$ 8,119,946	$ 1,041,723	$ 8,853,449	$ 27,091,805	$ 56,721,708	$ 21,821,015	$ 130,406	10
11	Proposed Dollar Increase in Margin	$ 50,219,828	$ 39,334,260	$ 1,004,350	$ 69,630	$ 985,807	$ 2,781,029	$ 3,717,727	$ 1,732,376	$ 6,709	11
12	Proposed Percentage Increase in Margin	12.58%	15.19%	14.11%	7.16%	12.53%	11.44%	7.01%	8.62%	5.42%	12
13	Rate of Return at Present Rates	6.68%	3.95%	5.69%	20.15%	7.80%	9.55%	21.08%	14.97%	28.63%	13
14	Present Rate of Return Indices	1.00	0.59	0.85	3.01	1.17	1.43	3.15	2.24	4.28	14
15	Rate of Return at Proposed Rates	9.45%	6.91%	5.09%	22.31%	11.01%	12.23%	23.35%	17.12%	30.72%	15
16	Proposed Rate of Return Indices	1.00	0.73	0.54	2.36	1.16	1.29	2.47	1.81	3.25	16

[1] Class margin required to earn proposed overall system rate of return on rate base.
[2] Schedule H-2, Sheets 1-4.
[3] Difference between total magin required and Line 8, Column (b) prorated to classes as a percentage of margin on Line 8.

Exhibit No. ____(ABC-4)
Sheet 3 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
ALLOCATION OF PROPOSED MARGIN TO CUSTOMER CLASSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Total	Street Lighting	Small CNG	Large CNG	Residential CNG	Electric Generation	Essential Agricultural	Gas Engines	Optional and Special Contract	Other Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	Margin at Requested System Rate of Return [1]	$ 449,454,506	$ 129,736	$ 23,454	$ 243,268	$ 37,732	$ 1,382,427	$ 1,640,387	$ 1,910,883	$ 5,784,028	$ 12,261,805	1
2	Margin at Present Rates [2]	$ 399,234,678	$ 55,850	$ 36,474	$ 404,946	$ 25,489	$ 2,529,330	$ 3,104,924	$ 2,559,519	$ 5,784,028	$ 12,261,805	2
3	Difference (Line 1 minus Line 2)	$ 50,219,828										3
4	System Average Percentage Increase (Line 3 / Line 2)	12.57902%										4
5	Ratio of Margin at System Return to Margin at Present Rates (Line 1 / Line 2)		2.32293	0.64305	0.60074	1.48034	0.54656	0.52832	0.74658	n/a	n/a	5
6	Adjusted Percentage Increase (Line 4 X Line 5)		29.22023%	8.08889%	7.55676%	18.62118%	6.87517%	6.64572%	9.39123%	n/a	n/a	6
7	Adjusted Percentage Increase $ (Line 2 X Line 6)	$ 54,267,003	$ 16,319	$ 2,950	$ 30,601	$ 4,746	$ 173,896	$ 206,345	$ 240,370	$ 0	$ 0	7
8	Adjusted Margin Requirement (Line 2 + Line 7)	$ 453,501,681	$ 72,169	$ 39,424	$ 435,547	$ 30,235	$ 2,703,226	$ 3,311,269	$ 2,799,889	$ 5,784,028	$ 12,261,805	8
9	(Over) / Under Collection [3]	(4,047,175)	(671)	(366)	(4,048)	(281)	(25,124)	(30,775)	(26,022)	0	0	9
10	Proposed Class Margin Requirement (Line 8 plus Line 9)	$ 449,454,506	$ 71,499	$ 39,058	$ 431,499	$ 29,954	$ 2,678,102	$ 3,280,493	$ 2,773,867	$ 5,784,028	$ 12,261,805	10
11	Proposed Dollar Increase in Margin	$ 50,219,828	$ 15,649	$ 2,584	$ 26,553	$ 4,465	$ 148,772	$ 175,569	$ 214,348	$ 0	$ 0	11
12	Proposed Percentage Increase in Margin	12.58%	28.02%	7.08%	6.56%	17.52%	5.88%	5.65%	8.37%	0.00%	0.00%	12
13	Rate of Return at Present Rates	6.68%	-0.71%	22.12%	23.21%	2.11%	25.45%	27.53%	17.22%	n/a	n/a	13
14	Present Rate of Return Indices	1.00	(0.11)	3.31	3.47	0.32	3.81	4.12	2.58	n/a	n/a	14
15	Rate of Return at Proposed Rates	9.45%	1.58%	23.00%	25.64%	4.83%	27.52%	29.68%	19.82%	n/a	n/a	15
16	Proposed Rate of Return Indices	1.00	0.17	2.43	2.71	0.51	2.91	3.14	2.10	n/a	n/a	16

[1] Class margin required to earn proposed overall system rate of return on rate base.
[2] Schedule H-2, Sheets 1-4.
[3] Difference between total magin required and Line 8, Column (b) prorated to classes as a percentage of margin on Line 8.

Exhibit No. ____(ABC-4)
Sheet 4 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF PROPOSED RATES AND REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants		Revenue at Proposed Rates					Line No.
			Number of Bills	Sales (Therms)	Basic Service Charge	Commodity Charge	Basic Service Charge	Commodity Charge	Total Margin	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Single-Family Residential Gas Service	G-5								
	Summer (May - October)									
1	Basic Service Charge per Month		5,107,859		$ 12.80		$ 65,380,595		$ 65,380,595	1
	Commodity Charge per Therm									
2	First 15 Therms			48,048,640		$ 0.88069		$ 42,315,957	42,315,957	2
3	Over 15 Therms			16,007,105		0.00000		0	0	3
	Winter (November - April)									
4	Basic Service Charge per Month		5,190,171		$ 12.80		$ 66,434,189		$ 66,434,189	4
	Commodity Charge per Therm									
5	First 35 Therms			133,956,357		0.88069		117,974,024	117,974,024	5
6	Over 35 Therms			91,044,013		0.00000		0	0	6
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 131,814,784	$ 160,289,981	$ 292,104,765	7
	Low Income Single-Family Residential Gas Service	G-10								
	Summer (May - October)									
8	Basic Service Charge		153,923		$ 7.50		$ 1,154,423		$ 1,154,423	8
	Commodity Charge per Therm									
	Summer (May - October)									
9	First 15 Therms			1,499,731		$ 0.88069		$ 1,320,798	1,320,798	9
10	Over 15 Therms			343,792		0.00000		0	0	10
	Winter (November - April)									
11	Basic Service Charge per Month		156,983		$ 7.50		$ 1,177,373		$ 1,177,373	11
	Commodity Charge per Therm									
12	First 35 Therms			4,229,842		0.88069		3,725,179	3,725,179	12
13	Next 115 Therms			2,532,839		0.00000		0	0	13
14	Over 150 Therms			52,769		0.00000		0	0	14
15	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,331,796	$ 5,045,977	$ 7,377,773	15
	Multi-Family Residential Gas Service	G-6								
	Summer (May - October)									
16	Basic Service Charge per Month		182,409		$ 8.70		$ 1,586,958		$ 1,586,958	16
	Commodity Charge per Therm									
17	First 7 Therms			1,044,432		$ 0.88069		$ 919,821	919,821	17
18	Over 7 Therms			950,005		0.00000		0	0	18
	Winter (November - April)									
19	Basic Service Charge per Month		188,153		$ 8.70		$ 1,636,931		$ 1,636,931	19
	Commodity Charge per Therm									
20	First 18 Therms			2,633,090		0.88069		2,318,936	2,318,936	20
21	Over 18 Therms			1,880,532		0.00000		0	0	21
22	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,223,889	$ 3,238,757	$ 6,462,646	22

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF PROPOSED RATES AND REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants		Revenue at Proposed Rates					Line No.
			Number of Bills	Sales (Therms)	Basic Service Charge	Commodity Charge	Basic Service Charge	Commodity Charge	Total Margin	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Low Income Multi-Family Residential Gas Service	G-11								
	Summer (May - October)									
1	Basic Service Charge per Month		13,560		$ 7.50		$ 101,700		$ 101,700	1
	Commodity Charge per Therm									
2	First 7 Therms			79,822		$ 0.88069		$ 70,298	70,298	2
3	Over 7 Therms			78,071		0.00000		0	0	3
	Winter (November - April)									
4	Basic Service Charge per Month		13,828		$ 7.50		$ 103,710		$ 103,710	4
	Commodity Charge per Therm									
5	First 18 Therms			207,982		0.88069		183,168	183,168	5
6	Next 132 Therms			186,423		0.00000		0	0	6
7	Over 150 Therms			345		0.00000		0	0	7
8	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 205,410	$ 253,466	$ 458,876	8
	Special Residential Gas Service for A/C	G-15								
	Summer (May - October)									
9	Basic Service Charge per Month		648		$ 12.80		$ 8,294		$ 8,294	9
	Commodity Charge per Therm									
10	First 15 Therms			7,899		$ 0.88069		$ 6,957	6,957	10
11	Over 15 Therms			65,327		$ 0.00000		0	0	11
	Winter (November - April)									
12	Basic Service Charge per Month		648		$ 12.80		$ 8,294		$ 8,294	12
	Commodity Charge per Therm									
13	First 35 Therms			19,309		$ 0.88069		17,005	17,005	13
14	Over 35 Therms			48,985		$ 0.00000		0	0	14
15	Total Special Residential Gas Service		1,296	141,520			$ 16,589	$ 23,962	$ 40,551	15
16	Total Residential Gas Service		11,008,182	304,917,309			$137,592,468	$168,852,143	$ 306,444,611	16
	Master Metered Mobile Home Park Gas Service	G-20								
17	Basic Service Charge per Month		1,968		$ 60.00		$ 118,080		$ 118,080	17
	Commodity Charge per Therm All Usage									
18	All Usage			2,223,993		$ 0.41531		$ 923,647	923,647	18
19	Total MMMHP Gas Service		1,968	2,223,993			$ 118,080	$ 923,647	$ 1,041,727	19
	General Gas Service - Small	G-25(S)								
20	Basic Service Charge		201,805		$ 25.00		$ 5,045,125		$ 5,045,125	20
	Commodity Charge per Therm All Usage									
21	Transportation Customers			10,138		$ 0.75852		$ 7,690	7,690	21
22	Sales Customers			5,010,616		0.75852		3,800,652	$ 3,800,652	22
23	Total Small General Gas Service		201,805	5,020,754			$ 5,045,125	$ 3,808,342	$ 8,853,467	23
	General Gas Service - Medium	G-25(M)								
24	Basic Service Charge		193,790		$ 43.50		$ 8,429,865		$ 8,429,865	24
	Commodity Charge per Therm All Usage									
25	Transportation Customers			172,365		$ 0.40988		$ 70,649	70,649	25
26	Sales Customers			45,357,904		0.40988		18,591,298	18,591,298	26
27	Total Medium General Gas Service		193,790	45,530,269			$ 8,429,865	$ 18,661,947	$ 27,091,812	27

Exhibit No. ____(ABC-4)
Sheet 6 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF PROPOSED RATES AND REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	General Gas Service - Large	G-25(L)								
1	Basic Service Charge		85,510		$ 160.00		$ 13,681,600		$ 13,681,600	1
	Commodity Charge per Therm All Usage									
2	Transportation Customers			3,556,829		0.28843		1,025,896	1,025,896	2
3	Sales Customers			145,666,025		0.28843		42,014,452	42,014,452	3
4	Total Large General Gas Service		85,510	149,222,854			13,681,600	43,040,348	56,721,948	4
	General Gas Service - Transportation Eligible	G-25(TE)								
5	Basic Service Charge		2,222		$ 950.00		$ 2,110,900		$ 2,110,900	5
6	Demand Charge per Month			12,803,712	0.064142			9,855,048	9,855,048	6
	Commodity Charge per Therm All Usage									
7	Transportation Customers			32,517,415		$ 0.09902		$ 3,219,874	3,219,874	7
8	Sales Customers			67,008,985		$ 0.09902		$ 6,635,230	6,635,230	8
9	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 2,110,900	$ 19,710,152	$ 21,821,052	9
10	Total General Gas Service		483,327	299,300,277			$ 29,267,490	$ 85,220,789	$ 114,488,279	10
	Air Conditioning Gas Service	G-40								
	Basic Service Charge									
11	W/ Other Service (No BSC)		60		$ 0.00		$ 0		$ 0	11
12	General Service - Small		198		25.00		4,950		4,950	12
13	General Service - Medium		0		43.50		0		0	13
14	General Service - Large		48		160.00		7,680		7,680	14
15	General Service -Transportation Eligible		12		950.00		11,400		11,400	15
16	Essential Agricultural		0		120.00		0		0	16
	Commodity Charge per Therm All Usage									
17	Transportation Customers			373,987		$ 0.09513		$ 35,577	35,577	17
18	Sales Customers			744,265		0.09513		70,802	70,802	18
19	Total Air Conditioning Gas Service		318	1,118,252			$ 24,030	$ 106,379	$ 130,409	19
	Street Lighting Gas Service	G-45								
	Commodity Charge per Therm of Rated Capacity									
20	All Usage		324	102,289		$ 0.69899		$ 71,499	71,499	20
21	Total Street Lighting Gas Service		324	102,289			$ 0	$ 71,499	$ 71,499	21
	Gas Service for Compression on Customer's Premises	G-55								
	Basic Service Charge									
22	Small		252		$ 25.00		$ 6,300		$ 6,300	22
23	Large		288		250.00		72,000		72,000	23
24	Residential		1,272		12.80		16,282		16,282	24
	Commodity Charge per Therm All Usage									
25	Transportation Customers			0		$ 0.17535		$ 0	0	25
	Sales Customers									
26	Small			177,495		0.17535		31,124	31,124	26
27	Large			2,060,152		0.17535		361,248	361,248	27
28	Residential			77,361		0.17535		13,565	13,565	28
29	Total CNG Gas Service		1,812	2,315,008			$ 94,582	$ 405,937	$ 500,519	29

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF PROPOSED RATES AND REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants		Revenue at Proposed Rates					Line No.
			Number of Bills	Sales (Therms)	Basic Service Charge	Commodity Charge	Basic Service Charge	Commodity Charge	Total Margin	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Electric Generation Gas Service	G-60								
	Basic Service Charge									
1	General Service - Small		36		$ 25.00		$ 900		$ 900	1
2	General Service - Medium		36		43.50		1,566		1,566	2
3	General Service - Large		84		160.00		13,440		13,440	3
4	General Service - Transportation Eligible		84		0.00		0		0	4
5	Essential Agricultural		12		120.00		1,440		1,440	5
	Commodity Charge per Therm All Usage									
6	Transportation Customers			0		$ 0.12363		$ 0	0	6
7	Sales Customers			21,521,946		0.12363		2,660,758	2,660,758	7
8	Total Electric Generation Gas Service		252	21,521,946			$ 17,346	$ 2,660,758	$ 2,678,104	8
	Small Essential Agriculture User Gas Service	G-75								
9	Basic Service Charge		1,216		$ 120.00		$ 145,920		$ 145,920	9
	Commodity Charge per Therm All Usage									
10	Transportation Customers			6,217,976		$ 0.23335		$ 1,450,965	1,450,965	10
11	Sales Customers			7,214,684		0.23335		1,683,547	1,683,547	11
12	Total Essential Agricultural Gas Service		1,216	13,432,660			$ 145,920	$ 3,134,512	$ 3,280,432	12
	Natural Gas Engine Gas Service	G-80								
	Basic Service Charge									
13	Off-Peak Season (Oct. - March)		2,516		$ 0.00		$ 0		$ 0	13
14	Peak Season (April - September)		2,589		125.00		323,625		323,625	14
	Commodity Charge per Therm All Usage									
15	Transportation Customers			0		$ 0.18746		$ 0	0	15
16	Sales Customers			13,070,981		0.18746		2,450,286	2,450,286	16
17	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 323,625	$ 2,450,286	$ 2,773,911	17
18	Total Tariff Sales		11,502,504	658,002,715			$167,583,541	$263,825,950	$ 431,409,491	18
19	Optional Gas Service	G-30	84	49,447,344			$ 120,540	$ 3,135,458	3,255,998	19
20	Special Contract Service	B-1	244	35,660,859			$ 449,274	$ 2,078,755	$ 2,528,029	20
21	Other Operating Revenues						$ 12,261,805		$ 12,261,805	21
22	Total Revenue		11,502,832	743,110,918			$ 180,415,160	$ 269,040,163	$ 449,455,324	22
23	Total Revenue Requirement								$ 449,454,506	23
24	Over/(Under)								$818	24

Exhibit No. ____(ABC-4)
Sheet 8 of 8

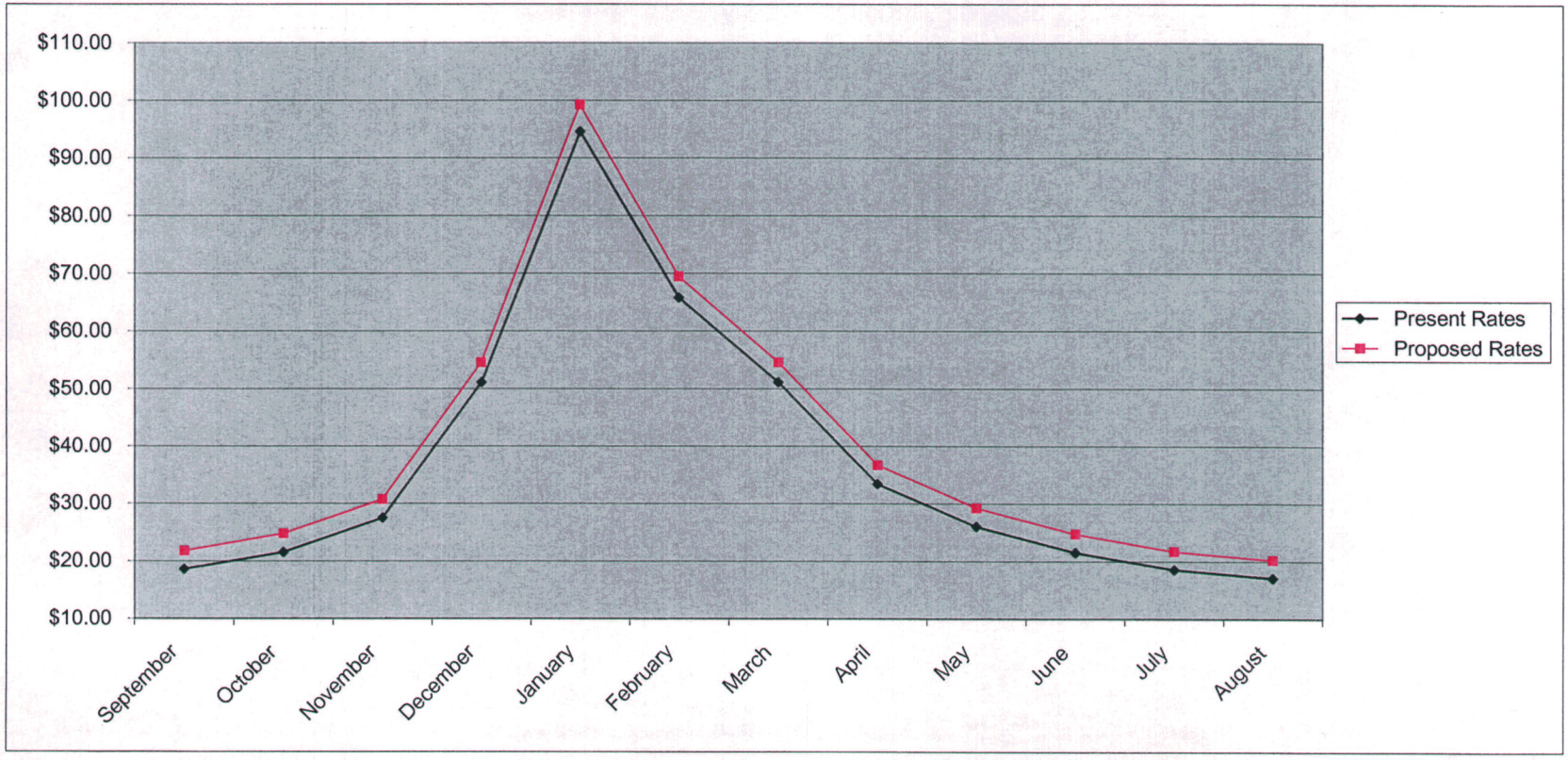
SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES BY RATE SCHEDULE
FOR RATE SCHEDULE NO. G-5 - SINGLE-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Billin Determinants Bills	Billin Determinants Volumes	Delivery Charge Rates	Distribution Service Revenue	Gas Cost Rate	Gas Cost Revenue	Effective Sales Rate	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Revenues at Present Rates									
	Summer (May-October)									
1	Basic Service Charge	5,107,859		$ 9.70	$ 49,546,232			$ 9.70	$ 49,546,232	1
	Commodity Charge									
2	First 15 Therms		48,048,640	$ 0.54200	$ 26,042,363	$ 0.93689	$ 45,016,291	$ 1.47889	$ 71,058,654	2
3	Over 15 Therms		16,007,105	0.50100	8,019,559	0.93689	14,996,896	1.43789	23,016,456	3
	Winter (November-April)									
4	Basic Service Charge	5,190,171		$ 9.70	$ 50,344,659			$ 9.70	$ 50,344,659	4
	Commodity Charge									
5	First 35 Therms		133,956,357	$ 0.54200	$ 72,604,346	$ 0.93689	$ 125,502,371	$ 1.47889	$ 198,106,717	5
6	Over 35 Therms		91,044,013	0.50100	45,613,050	0.93689	85,298,225	1.43789	130,911,276	6
7	Total at Present Rates	10,298,030	289,056,115		$ 252,170,210		$ 270,813,784		$ 522,983,993	7
	Revenues at Proposed Rates									
	Summer (May-October)									
8	Basic Service Charge	5,107,859		$ 12.80	$ 65,380,595			$ 12.80	$ 65,380,595	8
	Commodity Charge									
9	First 15 Therms		48,048,640	$ 0.88069	$ 42,315,957	$ 0.60996	$ 29,307,749	$ 1.49065	$ 71,623,706	9
10	Over 15 Therms		16,007,105	0.00000	0	1.49065	23,860,990	1.49065	23,860,990	10
	Winter (November-April)									
11	Basic Service Charge	5,190,171		$ 12.80	$ 66,434,189			$ 12.80	$ 66,434,189	11
	Commodity Charge									
12	First 35 Therms		133,956,357	$ 0.88069	$ 117,974,024	$ 0.60996	$ 81,708,020	$ 1.49065	$ 199,682,044	12
13	Over 35 Therms		91,044,013	0.00000	0	1.49065	135,714,758	1.49065	135,714,758	13
14	Total at Present Rates	10,298,030	289,056,115		$ 292,104,765		$ 270,591,517		$ 562,696,282	14

Increase/(Decrease) Information	Present Rates	Proposed Rates	Dollar	Percent
Basic Charge				
Revenue	$ 99,890,891	$131,814,784	$ 31,923,893	31.96%
Average Rate	$ 9.70	$ 12.80	$ 3.10	31.96%
Commodity Charge				
Revenue	$152,279,319	$160,289,981	$ 8,010,663	5.26%
Average Rate	$ 0.52682	$ 0.55453	$ 0.02771	5.26%
Total Distribution Service Revenue				
Revenue	$252,170,210	$292,104,765	$ 39,934,556	15.84%
Average Rate	$ 0.87239	$ 1.01055	$ 0.13816	15.84%
Total Revenue				
Revenue	$522,983,993	$562,696,282	$ 39,712,289	7.59%
Average Rate	$ 1.80928	$ 1.94667	$ 0.13739	7.59%

Exhibit No. ___(ABC-5)
Sheet 1 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
MONTHLY BILL COMPARISON AT MODE USAGE
RATE SCHEDULE NO. G-5 - SINGLE-FAMILY RESIDENTIAL GAS SERVICE

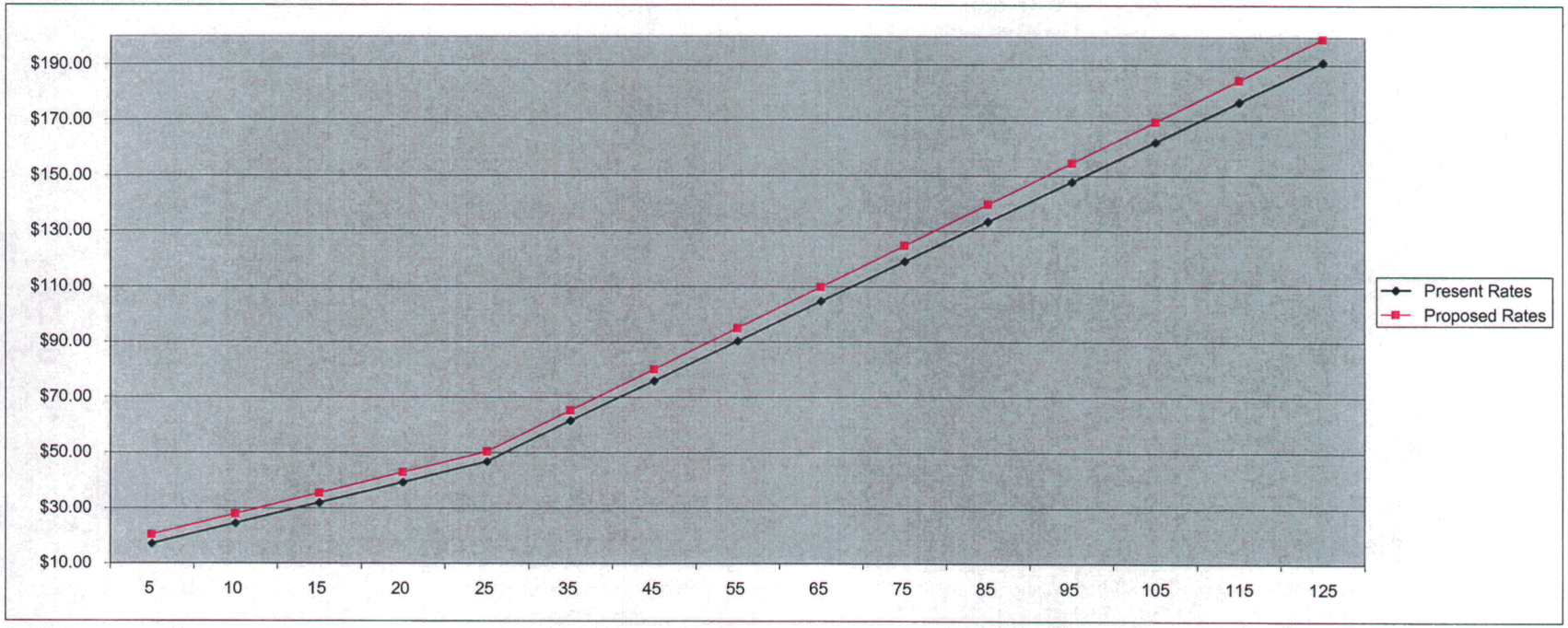


Description	September	October	November	December	January	February	March	April	May	June	July	August	Total
Mode Usage [1]	6	8	12	28	58	38	28	16	11	8	6	5	
Monthly Bill													
Present Rates	$ 18.57	$ 21.53	$ 27.45	$ 51.11	$ 94.53	$ 65.77	$ 51.11	$ 33.36	$ 25.97	$ 21.53	$ 18.57	$ 17.09	$ 446.61
Proposed Rates	$ 21.74	$ 24.73	$ 30.69	$ 54.54	$ 99.26	$ 69.44	$ 54.54	$ 36.65	$ 29.20	$ 24.73	$ 21.74	$ 20.25	$ 487.51
Dollar Change	$ 3.17	$ 3.19	$ 3.24	$ 3.43	$ 4.73	$ 3.67	$ 3.43	$ 3.29	$ 3.23	$ 3.19	$ 3.17	$ 3.16	$ 40.90
Percentage Change	17.1%	14.8%	11.8%	6.7%	5.0%	5.6%	6.7%	9.9%	12.4%	14.8%	17.1%	18.5%	9.2%

[1] Mode is the usage interval with the greatest number of monthly bills.

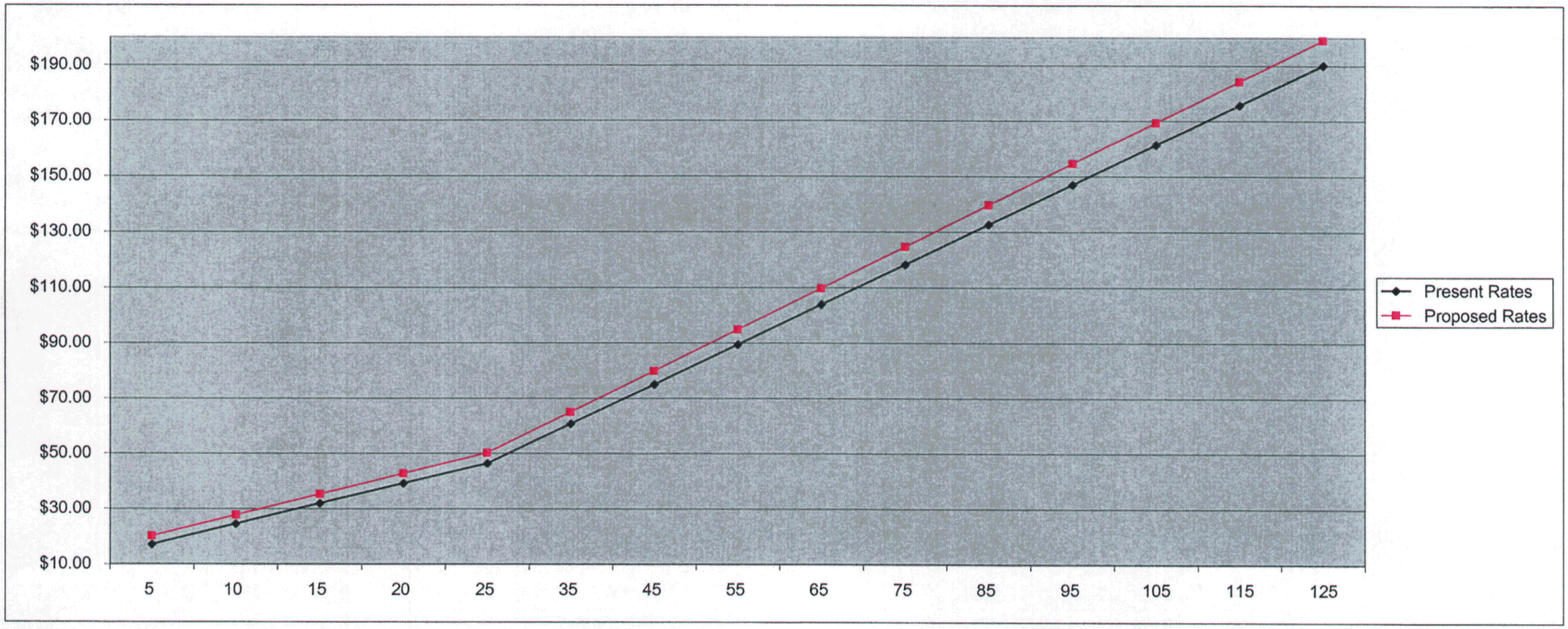
Exhibit No. ____(ABC-5)
Sheet 2 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
WINTER MONTHLY BILL COMPARISON
RATE SCHEDULE NO. G-5 - SINGLE-FAMILY RESIDENTIAL GAS SERVICE



Description	Monthly Usage														
Usage	5	10	15	20	25	35	45	55	65	75	85	95	105	115	125
Monthly Bill															
Present Rates	$ 17.09	$ 24.49	$ 31.88	$ 39.28	$ 46.67	$ 61.46	$ 75.84	$ 90.22	$ 104.60	$ 118.98	$ 133.36	$ 147.73	$ 162.11	$ 176.49	$ 190.87
Proposed Rates	$ 20.25	$ 27.71	$ 35.16	$ 42.61	$ 50.07	$ 64.97	$ 79.88	$ 94.79	$ 109.69	$ 124.60	$ 139.51	$ 154.41	$ 169.32	$ 184.22	$ 199.13
Dollar Change	$ 3.16	$ 3.22	$ 3.28	$ 3.34	$ 3.39	$ 3.51	$ 4.04	$ 4.57	$ 5.09	$ 5.62	$ 6.15	$ 6.68	$ 7.20	$ 7.73	$ 8.26
Percentage Change	18.5%	13.1%	10.3%	8.5%	7.3%	5.7%	5.3%	5.1%	4.9%	4.7%	4.6%	4.5%	4.4%	4.4%	4.3%

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMER MONTHLY BILL COMPARISON
RATE SCHEDULE NO. G-5 - SINGLE-FAMILY RESIDENTIAL GAS SERVICE



Description	Monthly Usage														
Usage	5	10	15	20	25	35	45	55	65	75	85	95	105	115	125
Monthly Bill															
Present Rates	$ 17.09	$ 24.49	$ 31.88	$ 39.07	$ 46.26	$ 60.64	$ 75.02	$ 89.40	$ 103.78	$ 118.16	$ 132.54	$ 146.91	$ 161.29	$ 175.67	$ 190.05
Proposed Rates	$ 20.25	$ 27.71	$ 35.16	$ 42.61	$ 50.07	$ 64.97	$ 79.88	$ 94.79	$ 109.69	$ 124.60	$ 139.51	$ 154.41	$ 169.32	$ 184.22	$ 199.13
Dollar Change	$ 3.16	$ 3.22	$ 3.28	$ 3.54	$ 3.80	$ 4.33	$ 4.86	$ 5.39	$ 5.91	$ 6.44	$ 6.97	$ 7.50	$ 8.02	$ 8.55	$ 9.08
Percentage Change	18.5%	13.1%	10.3%	9.1%	8.2%	7.1%	6.5%	6.0%	5.7%	5.5%	5.3%	5.1%	5.0%	4.9%	4.8%

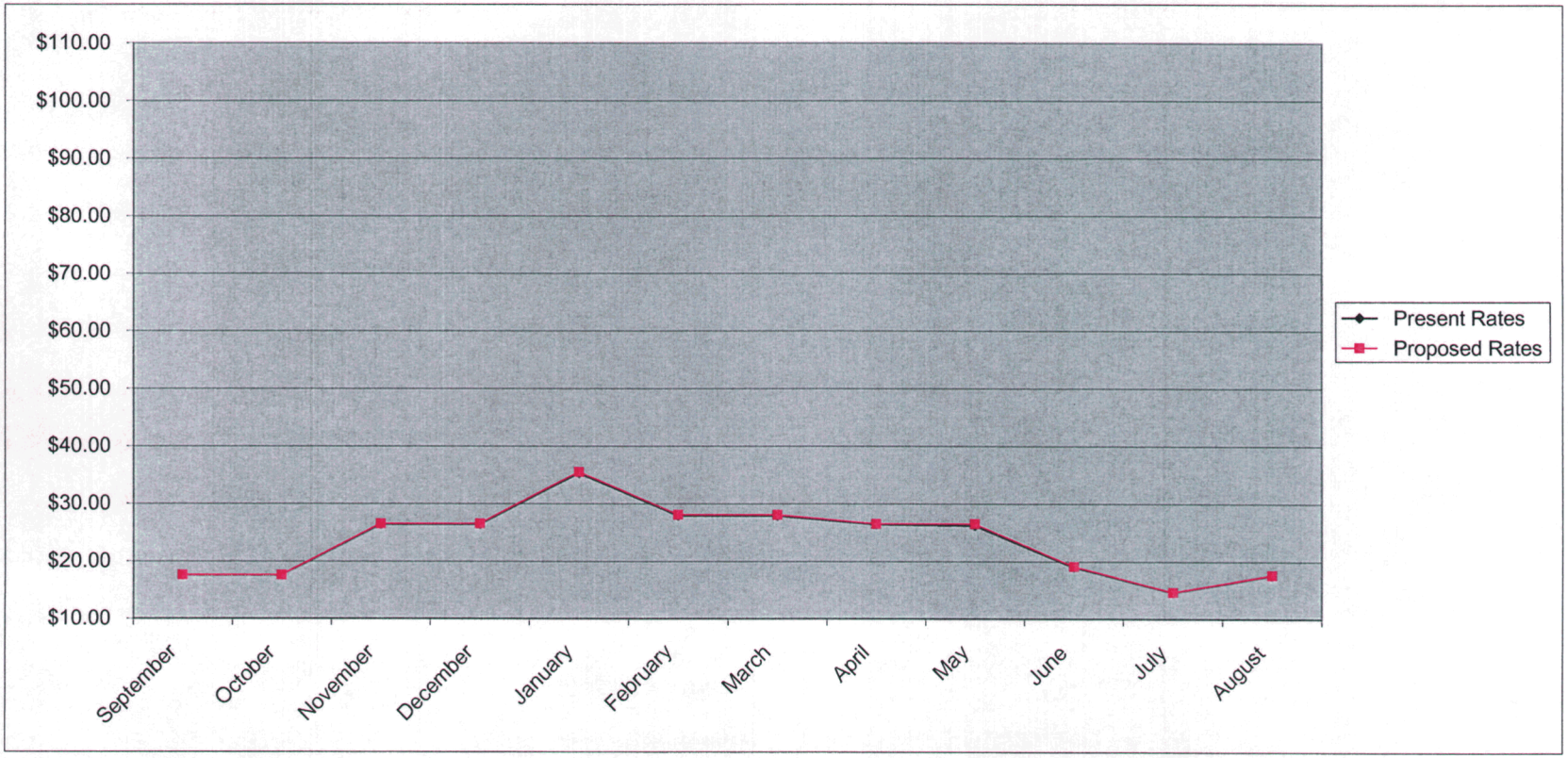
SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES BY RATE SCHEDULE
FOR RATE SCHEDULE NO. G-6 - MULTI-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Billin Determinants		Delivery Charge Rates	Distribution Service Revenue	Gas Cost Rate	Gas Cost Revenue	Effective Sales Rate	Total Revenue	Line No.
	(a)	Bills (b)	Volumes (c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Revenues at Present Rates									
	Summer (May-October)									
1	Basic Service Charge	182,409		$ 8.70	$ 1,586,958			$ 8.70	$ 1,586,958	1
	Commodity Charge									
2	First 7 Therms		1,044,432	$ 0.54200	$ 566,082	$ 0.93689	$ 978,518	$ 1.47889	$ 1,544,600	2
3	Over 7 Therms		950,005	0.50100	475,953	0.93689	890,050	1.43789	1,366,003	3
	Winter (November-April)									
4	Basic Service Charge	188,153		$ 8.70	$ 1,636,931			$ 8.70	$ 1,636,931	4
	Commodity Charge									
5	First 18 Therms		2,633,090	$ 0.54200	$ 1,427,135	$ 0.93689	$ 2,466,916	$ 1.47889	$ 3,894,051	5
6	Over 18 Therms		1,880,532	0.50100	942,146	0.93689	1,761,851	1.43789	2,703,998	6
7	Total at Present Rates	370,562	6,508,059		$ 6,635,205		$ 6,097,335		$ 12,732,541	7
	Revenues at Proposed Rates									
	Summer (May-October)									
8	Basic Service Charge	182,409		$ 8.70	$ 1,586,958			$ 8.70	$ 1,586,958	8
	Commodity Charge									
9	First 7 Therms		1,044,432	$ 0.88069	$ 919,821	$ 0.60996	$ 637,062	$ 1.49065	$ 1,556,882	9
10	Over 7 Therms		950,005	0.00000	0	1.49065	1,416,125	1.49065	1,416,125	10
	Winter (November-April)									
11	Basic Service Charge	188,153		$ 8.70	$ 1,636,931			$ 8.70	$ 1,636,931	11
	Commodity Charge									
12	First 18 Therms		2,633,090	$ 0.88069	$ 2,318,936	$ 0.60996	$ 1,606,080	$ 1.49065	$ 3,925,016	12
13	Over 18 Therms		1,880,532	0.00000	0	1.49065	2,803,214	1.49065	2,803,214	13
14	Total at Present Rates	370,562	6,508,059		$ 6,462,646		$ 6,462,481		$ 12,925,128	14

	Increase/(Decrease) Information			
	Present Rates	Proposed Rates	Dollar	Percent
Basic Charge				
Revenue	$ 3,223,889	$ 3,223,889	$ -	0.00%
Average Rate	$ 8.70	$ 8.70	$ -	0.00%
Commodity Charge				
Revenue	$ 3,411,316	$ 3,238,757	$ (172,559)	-5.06%
Average Rate	$ 0.52417	$ 0.49765	$ (0.02652)	-5.06%
Total Distribution Service Revenue				
Revenue	$ 6,635,205	$ 6,462,646	$ (172,559)	-2.60%
Average Rate	$ 1.01954	$ 0.99302	$ (0.02651)	-2.60%
Total Revenue				
Revenue	$ 12,732,541	$ 12,925,128	$ 192,587	1.51%
Average Rate	$ 1.95643	$ 1.98602	$ 0.02959	1.51%

Exhibit No. ____(ABC-5)
Sheet 5 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
MONTHLY BILL COMPARISON AT MODE USAGE
RATE SCHEDULE NO. G-6 - MULTI-FAMILY RESIDENTIAL GAS SERVICE

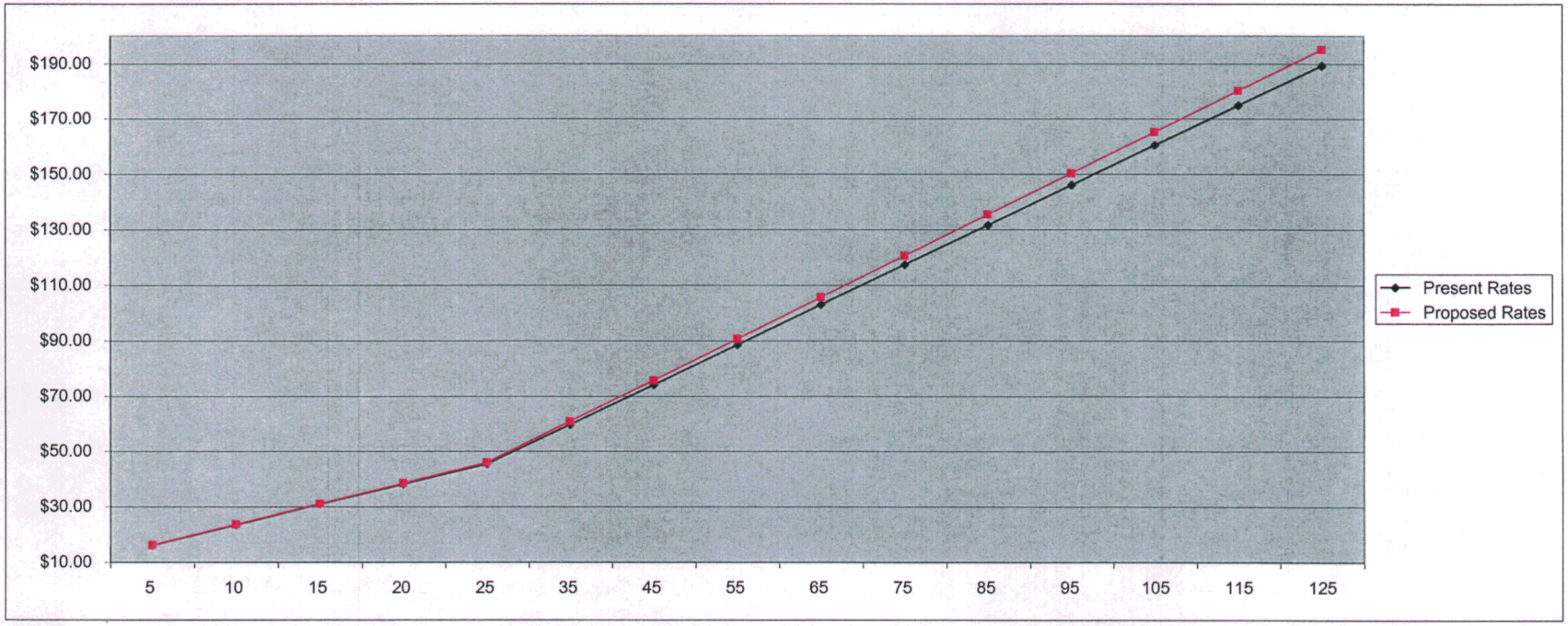


Description	September	October	November	December	January	February	March	April	May	June	July	August	Total
Mode Usage [1]	6	6	12	12	18	13	13	12	12	7	4	6	
Monthly Bill													
Present Rates	$ 17.57	$ 17.57	$ 26.45	$ 26.45	$ 35.32	$ 27.93	$ 27.93	$ 26.45	$ 26.24	$ 19.05	$ 14.62	$ 17.57	$ 283.14
Proposed Rates	$ 17.64	$ 17.64	$ 26.59	$ 26.59	$ 35.53	$ 28.08	$ 28.08	$ 26.59	$ 26.59	$ 19.13	$ 14.66	$ 17.64	$ 284.77
Dollar Change	$ 0.07	$ 0.07	$ 0.14	$ 0.14	$ 0.21	$ 0.15	$ 0.15	$ 0.14	$ 0.35	$ 0.08	$ 0.05	$ 0.07	$ 1.63
Percentage Change	0.4%	0.4%	0.5%	0.5%	0.6%	0.5%	0.5%	0.5%	1.3%	0.4%	0.3%	0.4%	0.6%

[1] Mode is the usage interval with the greatest number of monthly bills.

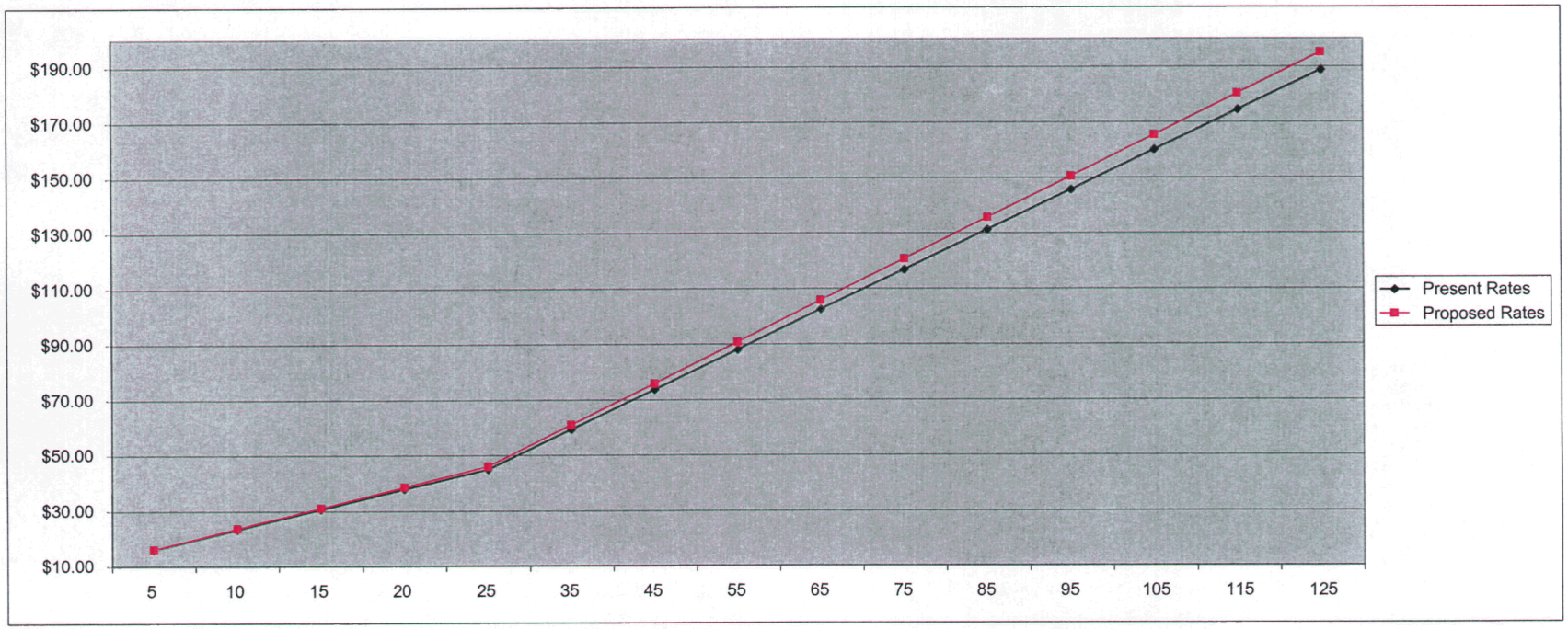
Exhibit No. ____(ABC-5)
Sheet 6 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
WINTER MONTHLY BILL COMPARISON
RATE SCHEDULE NO. G-6 - MULTI-FAMILY RESIDENTIAL GAS SERVICE



Description	Monthly Usage														
Usage	5	10	15	20	25	35	45	55	65	75	85	95	105	115	125
Monthly Bill															
Present Rates	$ 16.09	$ 23.49	$ 30.88	$ 38.20	$ 45.39	$ 59.76	$ 74.14	$ 88.52	$ 102.90	$ 117.28	$ 131.66	$ 146.04	$ 160.42	$ 174.80	$ 189.17
Proposed Rates	$ 16.15	$ 23.61	$ 31.06	$ 38.51	$ 45.97	$ 60.87	$ 75.78	$ 90.69	$ 105.59	$ 120.50	$ 135.41	$ 150.31	$ 165.22	$ 180.12	$ 195.03
Dollar Change	$ 0.06	$ 0.12	$ 0.18	$ 0.32	$ 0.58	$ 1.11	$ 1.64	$ 2.16	$ 2.69	$ 3.22	$ 3.75	$ 4.27	$ 4.80	$ 5.33	$ 5.86
Percentage Change	0.4%	0.5%	0.6%	0.8%	1.3%	1.9%	2.2%	2.4%	2.6%	2.7%	2.8%	2.9%	3.0%	3.0%	3.1%

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMER MONTHLY BILL COMPARISON
RATE SCHEDULE NO. G-6 - MULTI-FAMILY RESIDENTIAL GAS SERVICE



Description	Monthly Usage														
Usage	5	10	15	20	25	35	45	55	65	75	85	95	105	115	125
Monthly Bill															
Present Rates	$ 16.09	$ 23.37	$ 30.56	$ 37.74	$ 44.93	$ 59.31	$ 73.69	$ 88.07	$ 102.45	$ 116.83	$ 131.21	$ 145.59	$ 159.97	$ 174.34	$ 188.72
Proposed Rates	$ 16.15	$ 23.61	$ 31.06	$ 38.51	$ 45.97	$ 60.87	$ 75.78	$ 90.69	$ 105.59	$ 120.50	$ 135.41	$ 150.31	$ 165.22	$ 180.12	$ 195.03
Dollar Change	$ 0.06	$ 0.24	$ 0.50	$ 0.77	$ 1.03	$ 1.56	$ 2.09	$ 2.61	$ 3.14	$ 3.67	$ 4.20	$ 4.73	$ 5.25	$ 5.78	$ 6.31
Percentage Change	0.4%	1.0%	1.7%	2.0%	2.3%	2.6%	2.8%	3.0%	3.1%	3.1%	3.2%	3.2%	3.3%	3.3%	3.3%

Exhibit No. ___(ABC-5)
Sheet 8 of 8