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COMMISSIONERS
JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

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 THE STATE OF ARIZONA.	Docket No. G-01551A-04-0876 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

Staff of the Arizona Corporation Commission hereby files the Direct Testimony of James J. Dorf, Dennis R. Rogers, Stephen G. Hill, William Gehlen, William H. Musgrove, Steve P. Irvine, Prem K. Bahl, Robert G. Gray, and Robert E. Miller, in the above-referenced matter.

RESPECTFULLY SUMITTED this 26th day of July, 2005.

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DIRECT

TESTIMONY

OF

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STEPHEN G. HILL

WILLIAM GEHLEN

WILLIAM H. MUSGROVE

STEVE P. IRVINE

PREM K. BAHL

ROBERT G. GRAY

ROBERT E. MILLER

DOCKET NO. G-01551A-04-0876

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 THE STATE OF ARIZONA

JULY 26, 2005

DORF

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-01551A-04-0876

DIRECT

TESTIMONY

OF

JAMES J. DORF

CHIEF ACCOUNTANT

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 26, 2005

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
APPLICATION FOR A PERMANENT RATE INCREASE
Docket No. G-01551A-04-0876

The direct testimony of Staff witness James J. Dorf addresses the following issues:

Background – Southwest Gas Corporation ("SWG" or "Company") is a corporation organized and existing under the laws of the state of California. The Company is engaged in the business of purchasing, transporting, and distributing natural gas in service territories throughout the states of Arizona, California and Nevada. SWG has approximately 850,000 Arizona customers.

The Company filed an application for a permanent rate increase for its Arizona natural gas customers on December 9, 2004. The application requests a $70.8 million, or 21.9 percent, increase over test year revenues of $322.9 million. Staff found the filing sufficient on January 26, 2005. A Procedural Order issued on February 9, 2005, set this matter for hearing on October 3, 2005.

Wage Expense – Staff eliminated the Company's proposed $655,368 pro forma adjustment to increase operating expenses for in-grade wage increases as the effect is not known and measurable.

Transmission Integrity Management Program ("TRIMP") Expense – Staff made two adjustments to remove a portion of Company proposed pro forma TRIMP operating expenses. First, Staff removed the Company's $2,091,964 seven-year average projected on-going cost. Second, Staff removed a $1,183,333 amortization of 2004 and 2005 deferred TRIMP costs. Staff recommends an alternate treatment that allows deferral of TRIMP costs for potential recovery via a "DOT Pipeline Safety Surcharge" mechanism.

Sarbanes Oxley Expense – Staff made two adjustments to decrease operating expense for compliance with Sarbanes-Oxley. First, Staff removed $58,905 to provide for equal sharing of on-going costs between ratepayers and shareholders. Second, Staff removed $27,346 of non-recurring initial implementation costs.

Injuries and Damages Expense – Staff removed the Company's $3,043,711 pro forma adjustment to increase operating expenses primarily due to the Company's high claim experience which should not be the sole responsibility of ratepayers.

Management Incentive Program Expense -Staff decreased operating expenses by $969,258 to provide an equal sharing between ratepayers and shareholders of the Company's management incentive program.

INTRODUCTION

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

A. My name is James J. Dorf. I am the Chief Accountant employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as the Chief Accountant.

A. I am responsible for supervising the examination and verification of financial and statistical information included in utility rate applications, developing revenue requirements, designing rates, preparing written reports and/or testimonies and related schedules that present Staff's recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science, Accounting from Northern Michigan University and a Master of Science in Business Administration from Northern Illinois University. I am also a Certified Public Accountant. My qualifications and professional experience are summarized on Exhibit 1.

SUMMARY OF SOUTHWEST GAS CORPORATIONS FILING

Q. Please provide a summary of the Company's filling in this case.

A. Southwest Gas Corporation ("SWG" or "Company") is a corporation organized and existing under the laws of the state of California. The Company is engaged in the business of purchasing, transporting, and distributing natural gas in service territories throughout the states of Arizona, California and Nevada. SWG has approximately 850,000 Arizona customers.

The Company filed an application for a permanent rate increase for its Arizona natural gas customers on December 9, 2004. The application requests a $70.8 million, or 21.9 percent, increase over test year revenues of $322.9 million. Staff found the filing sufficient on January 26, 2005. A Procedural Order issued on February 9, 2005 set this matter for hearing on October 3, 2005.

The Company's filing addresses "the necessary pricing of the Company's services, the need for a reasonable regulatory capital structure/rate of return, initiatives undertaken by Southwest to control costs and become even more productive, and the impact of rapid growth in combination with regulatory lag".[1] In addition, it proposes a margin decoupling mechanism (SWG refers to this as a "Conservation Margin Tracker" or "CMT") to track residential per customer margins to remove what Southwest describes as an inherent disincentive to promote energy efficiency. The Company also proposes several conservation and efficiency programs. Table 1 summarizes the Company's proposed capital structure, cost of debt, cost of preferred securities, return on equity and overall rate of return.

Table 1

	Weight	Cost	Weighted Cost
Long-term Debt	53.0%	7.49%	3.97%
Preferred Securities	5.0%	8.20%	0.41%
Common Equity	42.0%	11.95%	5.02%
Cost of Capital (ROR)			**9.40%**

[1] Jeffrey Shaw, prepared direct testimony, page 3, lines 9-14.

SUMMARY OF STAFF'S REVIEW AND AUDIT

Q. What is the basis of Staff's recommendations?

A. Staff performed a regulatory audit of the Company's application and records. The regulatory audit consisted of examining and testing financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission adopted Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").

Staff conducted a review of each of the Company's proposed pro forma adjustments and the underlying supporting data. Staff also conducted interviews of Company witnesses and performed substantive audit procedures at the Company's administrative offices. Staff's procedures included reviewing numerous discovery responses to assess the efficacy of the Company's application.

Staff also utilized an outside consultant, Stephen G. Hill of Hill and Associates, to analyze and prepare a Staff recommendation for the capital structure, cost of debt, cost of preferred securities, return on equity and overall rate of return.

SUMMARY OF TESTIMONY

Q. Please describe the scope and order of your testimony in this case.

A. I present Staff's analysis and recommendations regarding Southwest Gas Corporation's application for a permanent rate increase in Docket No. G-01551A-04-0976. I address Staff's recommended adjustments to the Company's test year operating income in the following order: 1) pro forma adjustment for in-grade wage adjustments (Operating Income Adjustment No. 1); 2) pro forma adjustment for estimated on-going TRIMP operating costs (Operating Income Adjustment No. 2); 3) pro forma amortization of

deferred TRIMP costs (Operating Income Adjustment No. 3); 4) pro forma allowance for compliance with Sarbanes-Oxley costs (Operating Income Adjustment No. 4); 5) pro forma adjustment for injuries and damages expense (Operating Income Adjustment No. 5); 6) and finally, pro forma for management incentive program costs (Operating Income Adjustment No. 6).

Q. Are there other Staff witnesses presenting pre-filed direct testimony in this proceeding?

A. Yes. The Staff witnesses and the areas covered by their testimonies are as follows:

1. Dennis Rogers presents the revenue requirement rate base, and operating income components not presented in my testimony.
2. Stephen G. Hill (Hill & Associates), on behalf of Commission Staff, presents the capital structure, cost of debt, cost of preferred securities, return on equity and overall rate of return.
3. William Gehlen presents a review of the Company's procurement practices.
4. William Musgrove presents an evaluation of the Company's proposed Conservation Margin Tracker ("CMT").
5. Steven Irvine will review the Company's current and proposed demand side management ("DSM") programs.
6. Prem Bahl presents a cost of service analysis.
7. Robert Gray presents Staff's rate design and recommendation regarding the decoupling of gas costs from base rates.
8. Robert Miller discusses the status of the Company's compliance with applicable Pipeline Safety regulations and can respond to technical questions regarding the Company's operations and similar matters.

Q. Were there any changes to your testimony after Staff had finalized its rate design?

A. Yes, there were. I discovered errors in my computations for Staff Operating Income Adjustments Nos. 4 (Sarbanes-Oxley) and 6 (management incentive program). Although I was able to make my corrections in time, Robert Gray did not have sufficient time to make the required rate design corrections. A revised rate design will be filed as soon as the corrections can be made.

Q. What was the amount of the correction?

A. The adjustment to Sarbanes-Oxley was to increase the reduction to operating income by $11,209. There was a decrease to the adjustment for the management incentive program of $729,344. These revisions increased the revenue requirement by $718,135. Therefore, Robert Gray's rate design used a revenue requirement of $369,145,782 rather than the $369,865,063 determined herein.

OPERATING INCOME ADJUSTMENTS

Operating Income Adjustment No. 1 – In-Grade Wage Adjustment

Q. What is the Company proposing for Annualized Labor and In-Grade Wage adjustments?

A. The Company is proposing to adjust test year labor costs for two reasons. First, it adjusts labor costs for a Board of Directors' approved 2 percent increase to the wage structure for non-exempt employees.[2] The Company also makes an adjustment of 1 percent for estimated in-grade wage movement during the 12 months subsequent to the end of the test year.

[2] May, 2005, Board of Director meeting.

Q. Does Staff support recognition of the 2 percent wage increase for non-exempt employees?

A. Yes. Staff considers the wage increase that occurred after the test period a known and measurable change that is reasonable.

Q. Is the in-grade wage adjustment also known and measurable?

A. No. The Company does not have a factor for employee turnover. Employee turnover has the effect of offsetting the incremental cost of in-grade wage increases. The impact of in-grade wage increases cannot be determined in the absence of employee turnover information. Accordingly, the in-grade wage adjustment is not known and measurable and should not be recognized.

Q. What does Staff recommend?

A. Staff recommends that the Company's proposed labor annualization adjustment be reduced from $1,638,419 to $983,051 to exclude the effects of the Company's in-grade wage adjustment. See Schedule JJD-11.

Operating Income Adjustments No. 2 and No. 3 – TRIMP Costs[3]

Q. What are Transmission Integrity Management Program costs the Company is proposing to include in operating expenses?

A. The Company is proposing a pro forma adjustment to test year operating expenses to recover costs for complying with the United States Pipeline Safety Improvement Act of 2002. The new act was developed by the Office of Pipeline Safety ("OPS") and the Research and Special Programs Administration ("RSPA") divisions of the U.S.

[3] On September 7, 2004 the Company filed, with the Commission, an application requesting permission to defer TRIMP costs until its next general rate filing. On January 20, 2005 a Staff Report was filed stating that the TRIMP costs should be considered in the Company's pending rate filing. The related Docket was administratively closed on February 11, 2005.

Department of Transportation. The new regulations prescribe standards for transmission risk analysis and requires (sic) affected companies to adopt and implement a pipeline integrity management program.[4] The OPS and RSPA have subsequently promulgated regulations detailing the required elements for gas pipeline integrity management programs.[5]

The regulations require gas pipeline operators to identify transmission lines in all high consequence areas ("HCA") and to implement written integrity management programs for such areas. HCAs are defined by the OPS as "where the potential consequence of a gas pipeline accident may be significant or may do considerable harm to people and their property." The program must meet the following requirements:

1) Commence baseline assessments by June 17, 2004
2) Complete the identification of all HCAs by December 17, 2004.
3) Complete baseline assessments of at least 50 percent of the highest risk pipeline facilities by December 17, 2007.
4) Complete baseline assessments for the remaining segments by December 17, 2012.
5) For the life of the facilities, perform a reassessment of all pipeline segments every seven years.

The Company has identified approximately 335 miles of transmission facilities in Arizona located in HCAs.

Q. What costs will be incurred related to implementing TRIMP at the Company?

A. The Company will incur incremental operating and maintenance costs associated with complying with the new pipeline safety standards. The Company will conduct baseline direct assessments and reassessments which are performed by conducting pressure tests,

[4] 49 U.S.C.§ 60109
[5] OPS (December 15, 2003) Final Rule "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)" 68 Fed. Reg. 69778, amended in 69 Fed. Reg. 2307.

running internal inspection devices, or making direct examinations such as inspection of a pipeline section's condition by physical inspection. The Company will make any necessary maintenance or repairs as a result of its inspections. The Company also estimates that capitalizable replacements will be required. The Company believes these costs will be easy to identify as the TRIMP assessment and inspection activities will be performed by contract workers. The Company has indicated that the TRIMP costs will not be commingled with, or have an impact on, costs that may already be considered transmission operating and maintenance cost in nature and currently reflected in rates.

Q. Does Staff agree that all costs associated with TRIMP are incremental?

A. No, Staff does not agree that all repairs and maintenance identified during the TRIMP process would not have otherwise been a repair or maintenance charge or a capital replacement in the ordinary course of the Company's operations. Accordingly, as discussed below, Staff recommends a mechanism that provides an opportunity for review of such charges prior to them being passed on to ratepayers.

Q. Has the Company estimated the total TRIMP costs for the period 2004 through and including 2012?

A. Yes. The Company estimated the following:

Baseline Direct Assessments	$ 3,993,750
Direct Examinations	10,650,000
Maintenance & Repair	5,325,000
Total Operating Expense	$ 19,968,750
Capital Replacement	9,372,000
Total Costs	$ 29,340,750

A summary of the Company's annual cost estimates is contained on Schedule JJD-12, page 2.

Q. What TRIMP related costs did the Company incur during the test year?

A. The Company incurred $46,651 in TRIMP costs during the test year.[6] The Company claimed cumulative TRIMP costs of $717,864 as of May 2005.

Q. How did the Company calculate its pro forma adjustment to test year expenses for TRIMP costs?

A. The Company's pro forma adjustment for TRIMP costs is based on projected TRIMP costs using mileage based estimates of baseline direct assessments, direct examination, maintenance/repairs, and capital replacement for all years from 2004 through and including 2012. The Company's pro forma adjustment has two components. The first component represents TRIMP direct assessment and direct examination costs expected to be incurred through December 31, 2005, which total $3,550,000. The Company proposes to defer these costs to the Other Regulatory Asset Account 182.3 and then amortize this amount over three years to the Regulatory Debits Account 407.3 at $1,183,333 per year.

The second component represents on-going baseline direct assessment, direct examination and maintenance and repairs based on a seven-year average of these projected costs for the years 2006 through 2012. The projected average annual on-going TRIMP cost for these years is $2,091,964. Thus, the Company is proposing to include TRIMP costs of $3,275,297 ($1,183,333 + $2,091,964) in operating expenses for recovery in base rates. The Company's projections, by year, are shown on Schedule JJD-12, page 2.

[6] Response to Data Request JJD-14-1.

Q. Does the Company request to defer any TRIMP costs other than those discussed above pertaining to 2004 and 2005?

A. No. Since the Company's proposal includes a provision for recovering on-going costs beginning in 2006 and rates resulting from this proceeding are anticipated to be in effect in early 2006, the Company is not requesting deferral of costs after 2005.

Q. Is inclusion of projected cost consistent with normal ratemaking principles?

A. No. Normally, only known and measurable operating expenses are recognized for recovery in rates.

Q. How have other jurisdictions dealt with this issue?

A. Attached Schedule JJD-12 page 4 of 4 provides a summary of those jurisdictions that have ruled on TRIMP related costs. In general, state jurisdictions have implemented various methods to permit recovery of TRIMP costs. The FERC requires TRIMP costs to be recorded as maintenance expense unless other treatment has been authorized.

Q. Have other jurisdictions ruled on SWG's TRIMP costs?

A. Yes. In Nevada, the Public Utilities Commission issued an Order[7] granting the Company permission to defer certain TRIMP costs to Account No. 182.3 (Other Regulatory Assets) until December 31, 2007, or the effective date of the Company's rates set in its next general rate case, which ever is earlier. The deferred TRIMP cost will be evaluated in the Company's next Nevada rate case.

[7] Docket No. 04-9012, Order dated March 16, 2005.

Q. What other ruling did the Nevada Public Utilities Commission make regarding SWG's TRIMP costs in that order?

A. The Nevada Public Utilities Commission required a sharing of the TRIMP costs between ratepayers and shareholders. The Order noted that a "federal committee composed of representatives of the industry, government, and the public unanimously concluded that the expected benefits were substantial and justified the expected costs of the February 14, 2004 Regulations. Those benefits include improvements in the ability to site new pipelines and reduce damages from unexpected interruptions of gas service . . . . Therefore, the Commission concludes that both ratepayers and shareholders should share in these costs."[8]

Q. Does Staff agree with Nevada's Public Utility Commission on this issue?

A. Partially. Staff agrees that TRIMP costs should be shared equally between ratepayers and shareholders for the reasons cited in the Nevada Order. However, Staff recommends an alternate treatment rather than deferring TRIMP costs to a future rate case.

Q. What is Staff recommending?

A. Staff recommends establishing a surcharge to recover half of baseline direct assessment, direct examination, and maintenance and repairs TRIMP related costs, (no capital replacements) through a separate surcharge. Staff recommends a surcharge mechanism that provides for annual adjustments at the end of the 12th and 24th months and terminates in 36 months. The surcharge should be calculated using a numerator that includes actual and projected recoverable TRIMP costs for a period beginning in 2004 and ending 36 months after rates become effective from a decision in this proceeding less previously recovered surcharge amounts and a denominator that includes therms projected to be sold

[8] Ibid., paragraphs 36 and 37.

over the remaining portion of the 36 month post decision period to provide a per therm surcharge rate for the following 12 months. Staff should review the projections for reasonableness as no true-up is recommended upon termination of the surcharge. The Company should provide Staff with its surcharge and supporting data within 3 days of finalizing its calculation in the initial and 2 subsequent years. The Company should bill customers using its calculation without delay. However, in the event Staff subsequently challenges a surcharge calculation, adjustments shall be reflected on future billings. The need for a true-up is not seen as necessary because only 50 percent of the costs are eligible for recovery and the ending balance should be de minimis.

This method supports the Company's efforts to comply with appropriate pipeline safety regulations by allowing recovery of some TRIMP costs that cannot be recognized in base rates because they are not known and measurable while protecting ratepayers from paying more than the actual TRIMP costs. The surcharge period should provide sufficient TRIMP cost history to determine a normalized cost level going forward and an opportunity for the Company to file a rate application for recovery of those costs.

Q. What was the basis for this recommendation?

A. Staff rationale for recommending this treatment is as follows:

1. The Pipeline Safety Act of 2002 has significantly modified pipeline safety regulations.
2. The estimated costs of complying with the new regulations are significant.
3. Initial assessments must be performed in a compressed time period.
4. Current rates do not provide for recovery of these incremental costs.
5. The costs are estimated at this time and therefore inappropriate for inclusion in base rates.

6. Compliance with the new pipeline safety regulations should be encouraged.

Q. What information should the Company file to support its TRIMP surcharge calculation?

A. The Company's filing should include, at a minimum, the following information:

1. Contracts, invoices or similar documentation to support all costs.
2. Breakout of actual costs by category, by month and year.
3. Breakout of projected cost by category, by year, through 2012.
4. Number of therms sold each month the surcharge is in effect.
5. Dollar surcharge amounts billed for each month the surcharge is in effect.
6. Detailed calculation of the surcharge rate.

Q. Did Staff prepare an example of this surcharge calculation?

A. Yes. An example surcharge calculation is presented in Schedule JJD-12, page 3 of 4. The example presented is for the initial period presumed to be February 2006 through January 2007. If the surcharge begins in February 2006, the 36 month surcharge life terminates in January 2009. In the example, the total estimated recoverable TRIMP cost for the period beginning in 2004 and ending 36 months after rates become effective is $6,321,219. The estimated number of therms to be billed over the 36 month remaining surcharge life is 2,280,572,616. The initial surcharge rate is $0.00277 ($6,321,219/2,280,572,616 therms) per therm. Assume that 740,000,000 therms are sold in the first 12 months to provide surcharge revenue of $2,051,108, revised recoverable TRIMP cost estimates for the period beginning in 2004 and ending 36 months after rates become effective decreases to $6,000,000 and the projected therms sold for the 24 month remaining surcharge life is 1,520,234,177, the surcharge for the second year is $0.00260 [($6,000,000 – $2,051,108) / 1,520,234,177 therms]. Assume that 750,000,000 therms are sold in the second 12 months

to provide surcharge revenue of $1,948,166, revised recoverable TRIMP cost estimate for the period beginning in 2004 and ending 36 months after rates become effective increases to $6,500,000 and the projected therms sold for the 12 month remaining surcharge life is 770,000,000, the surcharge for the second year is $0.00325 [($6,500,000 - $2,051,108 - $1,948,166) / 770,000,000 therms].

Q. How should the Company disclose the surcharge on its monthly customer bills?

A. The Company should be required to reflect the surcharge as a separate line item labeled "**DOT Pipeline Safety Surcharge**". The Company should also provide an explanation of the surcharge on the reverse side of its bill, similar to the current explanations for "Billing Factor", "Therms", etc.

Q. Can Staff summarize its recommendation for TRIMP costs?

A. Yes. At this time, TRIMP costs are primarily estimates. Since TRIMP costs are not known and measurable, they should not be recognized in base rates. However, since TRIMP costs may be significant and the Company should be encouraged to comply with pipeline safety regulations, Staff recommends establishing a separate surcharge mechanism that would be in effect for 36 months to recover 50 percent of baseline direct assessment, direct assessment, and maintenance and repairs TRIMP related actual and estimated costs for a period beginning in 2004 and ending 36 months after rates become effective from a decision in this proceeding. The initial surcharge would become effective on the same date as base rates established in this proceeding and be revised each of the subsequent two years.

Q. What adjustments for TRIMP is Staff Recommending?

A. Staff recommends removal of the Company proposed operating expense adjustment of $2,091,964 (Schedule JJD-12, page 1) and a companion adjustment to eliminate the amortization of estimated 2004 and 2005 deferred TRIMP cost totaling $1,883,333 (Schedule JJD-13).

Operating Income Adjustment No. 4 – Sarbanes-Oxley Expense.

Q. What is Sarbanes-Oxley Expense?

A. Sarbanes-Oxley ("SOX") is legislation passed by the United States Congress. This legislation created the Public Company Accounting Oversight Board, and it requires that publicly traded entities' external auditors attest to and report on management's assessment of the effectiveness of their internal controls and procedures. Companies were required to be in compliance with SOX by December 31, 2004.

Q. What is the Company proposing to comply with Sarbanes-Oxley?

A. SWG incurred $82,990 in total of which $45,737 was allocable to Arizona in the test year. In addition to the test year amount, the Company's application includes two pro forma adjustments to operating expenses related to complying with Sarbanes-Oxley, Section 404. First, the Company's pro forma adjustment no. 8, Sarbanes Oxley 404, is proposing a $202,263 increase to operating expenses to reflect its estimate of the annual recurring costs for SOX compliance. Second, the Company's pro forma adjustment no. 17, Annualize Depreciation and Amortization, includes $27,346 for the amortization over three years of its estimated SOX initial implementation costs. In summary, the Company's application requests recovery of $248,000 ($45,737 + $202,263) for on-going annual expense and $27,346 for amortization of estimated implementation costs for a total of $275,346 in operating expenses for SOX.

Q. How did the Company derive its $202,263 pro forma adjustment?

A. In its application the Company's estimated the total on-going annual SOX costs of $450,000 of which $248,000 is allocable to Arizona. The since the Company had incurred SOX of $82,990 in total in the test year of which $45,737 was allocable to Arizona, it calculated the need for an additional $202,263 ($248,000 - $45,737) for annual Arizona SOX cost.

Q. Has the Company provided Staff with an updated SOX cost estimate?

A. Yes, it has. In response to Data Request JJD-8-2, the Company revised its total cost estimate to $915,000.

Q. Is this significant increase in the Company's estimate of its SOX costs reasonable?

A. Yes, it is. Many corporations subject to SOX have indicated that they significantly underestimated the cost to initially implement compliance. Additionally, during Staff's on-site audit, the Company presented additional documentation to support its updated cost estimates.

Q. What is Staff recommending?

A. Staff recommends reducing SOX expense by $86,251 from the Company's proposed $275,346 to $189,095. Staff's recommendation reflects a $189,095 pro forma allowance for on-going SOX expenses and $0 for the amortization of non-recurring implementation costs. In other words, Staff's $86,251 adjustment reduced the Company's proposed $202,263 pro forma adjustment to $189,095 and its $27,346 pro forma adjustment to $0. Staff's SOX allowance calculation is shown in Schedule JJD-14. Staff's calculation is base on the following:

1. Staff concludes that approximately 25 percent of the initial SOX implementation costs are non-recurring based upon numerous published articles that report on and evaluate company surveys of their first year experience in implementing SOX. Many companies complained of over zealous audit techniques, duplication of effort, and other implementation problems.
2. Staff recommends an equal sharing of SOX compliance cost between ratepayers and shareholders. The improved internal controls benefit both groups by protecting ratepayers with improved compliance and shareholder protection from management impropriety.
3. Non-recurring implementation costs should not be included in rates.

Operating Income Adjustment No. 5 – Injuries and Damages.

Q. What is the Company proposing for Injuries and Damages?

A. The Company is proposing a $3,043,711 pro forma adjustment to increase operating expenses over the test year amount. The adjustment annualizes test year insurance premiums and the Company's self- insurance component.

Q. Please describe the Company's self-insurance component for liability claims.

A. Prior to August, 2004, the Company was self-insured for the first $1 million of each general liability claim. The Company was unable to obtain this insurance coverage after August, 2004, because of its high claims experience.

Q. What has been the Company's general liability claims experience?

A. The Company reviewed its claims experience for the period 1990 through 2003. General liability claims totaled $36,347,300.[9] Those claims are for all of the Company's

[9] Company Workpaper Schedule C-2, Adjustment No. 10, sheet 2 of 2.

jurisdictions. The Company has traditionally used the "Modified Massachusetts Formula" to allocate insurance expense to each of its jurisdictions.

Q. Please describe the Company's current general liability self-insurance coverage?

A. The Company is self-insured for up to $10 million for each occurrence. If a claim exceeds $10 million, the Company's insurance carrier is responsible.

Q. How did the Company calculate its proposed adjustment for general liability self-insurance coverage?

A. The Company used the 14-year history noted above which was developed for negotiating with its insurance carriers. The Company's pro forma adjustment is calculated as the excess of the 14-year average over the test year expense.

Q. What were the self-insured general liability costs in the test year?

A. The self-insured general liability insurance cost in the test year was $562,552.[10] The Company's self-insurance adjustment was $1,598,744.

Q. Why is the Company's $3,043,711 total adjustment for injuries and damages $1,444,967 more than its $1,598,744 adjustment for self-insured liability costs?

A. Injuries and damages expense includes other insurance costs in addition to self-insured general liability insurance. The Company annualized the premiums for 14 different insurance policies which resulted in an increase of $2,621,915 over test year expense of $5,450,501, an increase of 48.1 percent. Of the increased premiums, approximately $2,553,562[11] represented increases in excess liability, excess director and officer, and

[10] Company Workpaper Schedule C-2, Adjustment No. 10, sheet 1 of 2.
[11] Company Workpaper Schedule C-2, ADJ. 10, sheet 3.

other excess coverages. The allocable amount of the increase for Arizona of these other insurance costs amounted to $1,444,967.

Q. What is Staff recommending for injuries and damages?

A. Staff is recommending disallowance of the Company's proposed pro forma adjustment. Staff is concerned that the Company's general liability claims experience is such that the Company cannot even obtain insurance for the first $10 million of each occurrence. The Company's ratepayers should not bear the cost of the Company's poor claims experience. Self-insurance can be appropriate under certain circumstances; however, the incremental cost of the forced self-insurance option in this instance should be responsibility of the Company's shareholders.

Staff also recommends that the Company evaluate its claims experience to determine the primary causes for such claims and include those factors as a part of its evaluation of high consequence areas under its TRIMP program. Further emphasis on pipeline safety may also have a beneficial effect on reducing liability claims.

Q. Has the Company made any steps to reduce its exposure to liability claims?

A. The Company utilizes both internal and external risk management advisors to evaluate insurance policies and self-insurance reserves. In addition to monthly reporting, the Company also reviews injuries and damages with its outside auditor each quarter.

The Company has targeted improvements in training, public education via print and radio, and other loss control measures. The Company is also training contractors on proper excavation procedures.

Q. Will Staff entertain revisions to its recommended adjustment?

A. Yes, it will. If the Company can provide compelling evidence that ratepayers clearly benefit from the Company's required self-insurance situation, Staff will reconsider its position.

Operating Income Adjustment No. 6 – Management Incentive Program.

Q. Is Staff recommending an adjustment to the Company's test year management incentive program costs?

A. Yes. Staff suggests that while some elements of the Company's Management Incentive Program ("MIP") reward improvements in operating efficiency, others reward achievement of earnings targets. Therefore, the costs of such programs should be shared equally between ratepayers and shareholders. For this reason, Staff is recommending a 50 percent reduction in the MIP award as allocated to Arizona.

Q. How did Staff calculate it adjustment?

A. Staff's adjustment used a pro-ration of the years 2003 (4/12 of $4.1million) and 2004 (8/12 of $3 million) which totaled $3,366,667 in MIP expense and, after applying the appropriate allocation percentage, reduced the prorated amount by 50 percent. This results in a reduction of $969,259. See Schedule JJD-16.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit 1

WITNESS QUALIFICATIONS FOR JAMES J. DORF
1200 West Washington Street, Phoenix, AZ 85007

EDUCATION:

Master of Science in Business Administration, specialization in Accounting, Northern Illinois University

Bachelor of Science, Accounting, Northern Michigan University

Certified Public Accountant

EXPERIENCE:

Chief Accountant, Financial & Regulatory Analysis Section, Utilities Division, Arizona Corporation Commission, 2004 to present.

Adjunct Professor of Accounting, Western International University, 2002 to 2004. Introductory & Cost Accounting. On-line Cost Accounting.

Chief Financial Officer/Vice President, Great Lakes Gas Transmission Company, 1978 to 2001. Complete financial, regulatory, and tax compliance responsibilities for a $2 billion interstate natural gas pipeline system. Issued over $750 million in privately placed Senior Notes. Responsible for preparing numerous general rate and purchased gas adjustment filings before the Federal Regulatory Energy Commission.

Audit Supervisor, KPMG Peat Marwick, CPA's, 1973 to 1978. Supervisory responsibility for audits of manufacturing, insurance, contracting, governmental and other entities. Computer audit specialist. Income tax return preparation and compliance.

Appeared as expert witness or submitted written testimony in rate proceedings before the Federal Energy Regulatory Commission, on tax policy and regulatory accounting issues before legislative bodies and tax litigation in Minnesota and Michigan.

Member, American Institute of Certified Public Accountants.
Member, National Association of Regulatory Utility Commissioners, Staff Subcommittee on Accounting and Finance.
Past member of the American Gas Association Accounting Committee.
Past member of the Interstate Natural Gas Association of America Accounting and Tax Committees.

SOUTHWEST GAS CORPORATION July 26, 2005
Docket No. G-01551A-04-0876
DIRECT TESTIMONY OF JAMES J. DORF AND DENNIS R. ROGERS

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DRR-19	Operating Income Adjustment No.9 - Income Tax Expense

Schedules DRR sponsored by Dennis R. Rogers
Schedules JJD sponsored by James J. Dorf

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule DRR-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RECONSTRUCTION COST	(C) COMPANY FAIR VALUE	(D) STAFF ORIGINAL COST	(E) STAFF RECONSTRUCTION COST	(F) STAFF FAIR VALUE
1	Adjusted Rate Base	$ 925,212,452	$ 1,418,490,765	$ 1,171,851,609	$ 924,927,566	$ 1,418,205,879	$ 1,171,566,722
2	Adjusted Operating Income (Loss)	$ 44,233,351	$ 44,233,351	$ 44,233,351	$ 49,397,250	$ 49,397,250	$ 49,397,250
3	Current Rate of Return (L2 / L1)	4.78%	3.12%	3.77%	5.34%	3.48%	4.22%
4	Required Rate of Return	9.40%	6.13%	7.42%	8.40%	5.48%	6.63%
5	Required Operating Income (L4 * L1)	$ 86,957,925	$ 86,957,925	$ 86,957,925	$ 77,693,916	$ 77,693,916	$ 77,693,916
6	Operating Income Deficiency (L5 - L2)	$ 42,724,574	$ 42,724,574	$ 42,724,574	$ 28,296,665	$ 28,296,665	$ 28,296,665
7	Gross Revenue Conversion Factor	1.6573	1.6573	1.6573	1.6609	1.6609	1.6609
8	Required Revenue Increase (L7 * L6)	$ 70,809,100	$ 70,809,100	$ 70,809,100	$ 46,999,085	$ 46,999,085	$ 46,999,085
9	Adjusted Test Year Revenue	$ 322,865,978	$ 322,865,978	$ 322,865,978	$ 322,865,978	$ 322,865,978	$ 322,865,978
10	Proposed Annual Revenue (L8 + L9)	$ 393,675,078	$ 393,675,078	$ 393,675,078	$ 369,865,063	$ 369,865,063	$ 369,865,063
11	Required Increase in Revenue (%)	21.93%	21.93%	21.93%	14.56%	14.56%	14.56%
12	Rate of Return on Common Equity (%)	11.95%	11.95%	11.95%	9.50%	9.50%	9.50000%

References:
Column (A): *Company Schedule B-1*
Column (B): Company Schedule B-1
Column (C): Company Schedules A-1, A-2, & D-1
Column (D): Staff Schedules DRR-3, DRR-9 AND SH-1
Column (E): Staff Schedules DRR-6, DRR-9 AND SH-1
Column (F): Staff Schedules DRR-3, DRR-6, DRR-9 AND SH-1

(SH-1; Steven Hill)

SOUTHWEST GAS CORPORATION
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Schedule DRR-2

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	Calculation of Gross Revenue Conversion Factor:				
1	Revenue	100.0000%			
2	Uncollecible Factor (Line 11)	0.1328%			
3	Revenues (L1 - L2)	99.8672%			
4	Combined Federal and State Tax Rate (Line 17)	39.6604%			
5	Subtotal (L3 - L4)	60.2068%			
6	**Revenue Conversion Factor (L1 / L5)**	1.660941			
	Calculation of Uncollectible Factor:				
7	Unity	100.0000%			
8	Combined Federal and State Tax Rate (Line 17)	39.6604%			
9	One Minus Combined Income Tax Rate (L7 - L8)	60.3396%			
10	Uncollectible Rate	0.2201%			
11	Uncollectible Factor (L9 * L10)	0.1328%			
	Calculation of Effective Tax Rate:				
12	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
13	Arizona State Income Tax Rate	6.9680%			
14	Federal Taxable Income (L12 - L13)	93.0320%			
15	Applicable Federal Income Tax Rate (Line 47)	35.1410%			
16	Effective Federal Income Tax Rate (L14 x L15)	32.6924%			
17	Combined Federal and State Income Tax Rate (L13 +L16)	39.6604%			
18	Required Operating Income (Schedule JJD-1, Line 5)	$ 77,693,916			
19	Adjusted Test Year Operating Income (Loss) (Schedule JJD-9, Line 51)	$ 49,397,250			
20	Required Increase in Operating Income (L18 - L19)		$ 28,296,665		
21	Income Taxes on Recommended Revenue (Col. (D), L43)	$ 25,495,159			
22	Income Taxes on Test Year Revenue (Col. (B), L43)	$ 6,855,157			
23	Required Increase in Revenue to Provide for Income Taxes (L21 - L22)		$ 18,640,002		
24	Recommended Revenue Requirement (Schedule JJD-1, Line 10)	$ 369,865,063			
25	Uncollectible Rate (Line 10)	0.1328%			
26	Uncollectible Expense on Recommended Revenue (L24 * L25)	$ 491,209			
27	Adjusted Test Year Uncollectible Expense	$ 428,790			
28	Required Increase in Revenue to Provide for Uncollectible Exp. (L26 - L27)		$ 62,418		
29	Total Required Increase in Revenue (L20 + L23 + L28)		$ 46,999,085		
	Calculation of Income Tax:	Test Year		STAFF Recommended	
30	Revenue (Schedule JJD-9, Col (C), Line 5 & Sch JJD-1, Col. (B), Line 10)	$ 322,865,978	$ 46,999,085	$ 369,865,063	
31	Operating Expenses Excluding Income Taxes	$ 266,613,570		$ 266,613,570	
32	Synchronized Interest (L47)	$ 38,754,465		$ 38,754,465	
33	Arizona Taxable Income (L30 - L31 - L32)	$ 17,497,943		$ 64,497,028	
34	Arizona State Income Tax Rate	6.9680%		6.9680%	
35	Arizona Income Tax (L33 x L34)		$ 1,219,257		$ 4,494,153
36	Federal Taxable Income (L33 - L35)	$ 16,278,686		$ 60,002,875	
37	Federal Tax on First Income Bracket ($1 - $50,000) @ 15%	$ 7,500		$ 7,500	
38	Federal Tax on Second Income Bracket ($50,001 - $75,000) @ 25%	$ 6,250		$ 6,250	
39	Federal Tax on Third Income Bracket ($75,001 - $100,000) @ 34%	$ 8,500		$ 8,500	
40	Federal Tax on Fourth Income Bracket ($100,001 - $335,000) @ 39%	$ 91,650		$ 91,650	
41	Federal Tax on Fifth Income Bracket ($335,001 -$10,000,000) @ 34%	$ 3,286,100		$ 3,286,100	
42	Federal Tax on Sixth Income Bracket ($10,000,001 -$15,000,000) @ 35%	$ 1,750,000		$ 1,750,000	
43	Federal Tax on Seventh Income Bracket ($15,000,001 -$18,333,333) @ 38%	$ 485,901		$ 1,266,667	
44	Federal Tax on Eighth Income Bracket (Over $18,333,333) @ 35%	$ -		$ 14,584,340	
45	Total Federal Income Tax		$ 5,635,901		$ 21,001,006
46	Combined Federal and State Income Tax (L35 + L42)		$ 6,855,157		$ 25,495,159
47	Applicable Federal Income Tax Rate [Col. (D), L42 - Col. (B), L42] / [Col. (C), L36 - Col. (A), L36]				35.1410%
	Calculation of Interest Synchronization:				
48	Rate Base (Schedule DRR-3, Col. (C), Line 17)	$ 924,927,566			
49	Weighted Average Cost of Debt (Schedule SH-1)	4.19%			
50	Synchronized Interest (L45 X L46)	$ 38,754,465			

SOUTHWEST GAS CORPORATION
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Test Year Ended August 31, 2004

Schedule DRR-3

RATE BASE - ORIGINAL COST

LINE NO.		(A) COMPANY AS FILED	(B) STAFF ADJUSTMENTS	(C) STAFF AS ADJUSTED
1	Plant in Service	$ 1,685,504,157	$ (284,886)	$ 1,685,219,271
2	Less: Accumulated Depreciation	593,542,012	-	593,542,012
3	Net Plant in Service	$ 1,091,962,145	$ (284,886)	$ 1,091,677,259
	LESS:			
4	Customer Advances for Construction	$ 7,027,372	$ -	$ 7,027,372
5	Less: Accumulated Amortization	-	-	-
6	Net CIAC	7,027,372	-	7,027,372
7	Customer Deposits	23,912,141	-	23,912,141
8	Deferred Income Tax Credits	136,691,328	-	136,691,328
9	Total Deductions	167,630,841	-	167,630,841
	ADD:			
10	Working Capital	881,148	-	881,148
11	**Original Cost Rate Base**	$ 925,212,452	$ (284,886)	$ 924,927,566

References:
Column (A), Company Schedule B-1
Column (B): Schedule DRR-4
Column (C): Column (A) + Column (B)

SOUTHWEST GAS CORPORATION
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Test Year Ended August 31, 2004

Schedule DRR-4

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	ACCT. NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ No.1 Company Adj. No. 20 CCNC	[C] STAFF ADJUSTED
		DIRECT GAS PLANT IN SERVICE:			
1		Intangible Plant	$ 3,702,685	$ -	$ 3,702,685
2		Distribution Plant	1,502,889,184	-	1,502,889,184
3		General Plant	90,766,242	-	90,766,242
4	101	Total Gas Plant In Service	$ 1,597,358,111	-	$ 1,597,358,111
		ACCUM. PROVISION FOR DEPR. AND AMORT.			
5		Intangible Plant	$ 2,196,699	-	$ 2,196,699
6		Distribution Plant	527,648,429	-	$ 527,648,429
7		General Plant	16,140,237	-	16,140,237
8	108 & 111	Total Accumulated Depr. & Amort.	545,985,365	-	$ 545,985,365
9		Total Net Gas Plant In Service	$ 1,051,372,746	-	$ 1,051,372,746
		SYSTEM ALLOCABLE GAS PLANT IN SERVICE			
10		Intangible Plant	$ 106,236,031	$ (494,768)	$ 105,741,263
11		General Plant	46,849,120	-	46,849,120
12	101	Total System Allocable Gas Plant	$ 153,085,151	$ (494,768)	$ 152,590,383
		ACCUM. PROVISION FOR DEPR. AND AMORT.			
13		Intangible Plant	$ 60,385,073	-	$ 60,385,073
14		General Plant	22,207,588	-	22,207,588
15		Total System Allocable Accum. Depr. & Amort.	$ 82,592,661	-	$ 82,592,661
16		System Allocable Net Gas Plant In Service	$ 70,492,490	$ (494,768)	$ 69,997,722
17		4-Factor Allocation Rate (Sch. C-1, Sh 18)	57.58%	57.58%	57.58%
18		Allocated System Allocable Gas Plant	$ 88,146,046	$ (284,886)	$ 87,861,160
19		Allocated System Allocable Accum. Depr. & Amort.	47,556,647	-	47,556,647
20		Total System Allocable Net Gas Plant In Service	$ 40,589,399	$ (284,886)	$ 40,304,513
21		Total Plant in Service	$ 1,685,504,157	$ (284,886)	$ 1,685,219,271
22		Less: Accumulated Depreciation	593,542,012	-	593,542,012
23		Net Plant in Service (L59 - L 60)	$ 1,091,962,145	$ (284,886)	$ 1,091,677,259
		LESS:			
24		Contributions in Aid of Construction (CIAC)	$ 7,027,372	$ -	$ 7,027,372
25		Less: Accumulated Amortization	-	-	-
26		Net CIAC (L25 - L26)	$ 7,027,372	-	$ 7,027,372
27		Customer Meter Deposits	23,912,141	-	23,912,141
28		Deferred Income Tax Credits	136,691,328	-	$ 136,691,328
		ADD:			
29		Working Capital	881,148	-	$ 881,148
30		**Original Cost Rate Base**	$ 925,212,452	$ (284,886)	$ 924,927,566

ADJ No.	
1	Completed Construction Not Classified

SOUTHWEST GAS CORPORATION
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Test Year Ended August 31, 2004

Schedule DRR-5

ORIGINAL COST RATE BASE ADJUSTMENT No.1 - REMOVAL OF POST-TEST YEAR PLANT (CCNC)

Line No.	Removal of Post Test Year Plant (Completed Construction Not Classified)	
1	Company Projected Intangible System Allocable Plant	$ 1,473,459
2	Actual Plant in Service 12/31/2004	$ 978,691
3	Increase/(Decrease) to Plant-In-Service	$ (494,768)
4	4-Factor Allocation Rate (Sch. C-1, Sh 18)	57.58%
5	Removal of System Allocable Net Gas Plant In Service	$ (284,886)

References:
Line 1: Company Adjustment No. 20.
Line 2: Company Response to RUCO Data Request 4-3.
Line 3: Line 2 minus Line 3.

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule DRR-6

RATE BASE - RECONSTRUCTION COST

LINE NO.		(A) COMPANY AS FILED	(B) STAFF ADJUSTMENTS	(C) STAFF AS ADJUSTED
1	Plant in Service	$ 2,442,053,861	$ (284,886)	$ 2,441,768,975
2	Less: Accumulated Depreciation	856,813,403	-	856,813,403
3	Net Plant in Service	$ 1,585,240,458	$ (284,886)	$ 1,584,955,572
	LESS:			
4	Advances in Aid of Construction (AIAC)	$ 7,027,372	$ -	$ 7,027,372
5	Less: Accumulated Amortization	-	-	-
6	Net CIAC	7,027,372	-	7,027,372
8	Customer Deposits	23,912,141	-	23,912,141
9	Deferred Income Tax Credits	136,691,328	-	136,691,328
	ADD:			
12	Working Capital	881,148	-	881,148
17	**Reconstruction Cost New Rate Base**	$ 1,418,490,765	$ (284,886)	$ 1,418,205,879

References:
Column [A], Company Schedule B-3
Column [B]: Schedule DRR-7
Column [C]: Column [A] + Column [B]

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule DRR-7

SUMMARY OF RECONSTRUCTION COST RATE BASE ADJUSTMENTS

LINE NO.	ACCT. NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ No.1 Completed Construction Not Classified	[C] STAFF ADJUSTED
		DIRECT GAS PLANT IN SERVICE:			
1		Intangible Plant	$ 3,271,604	$ -	$ 3,271,604
2		Distribution Plant	2,236,345,320	-	2,236,345,320
3		General Plant	109,432,123	-	109,432,123
4	101	Total Gas Plant In Service	2,349,049,047	-	2,349,049,047
		ACCUM. PROVISION FOR DEPR. AND AMORT.			
5		Intangible Plant	2,196,699	-	2,196,699
6		Distribution Plant	785,179,009	-	785,179,009
7		General Plant	19,509,899	-	19,509,899
8	108 & 111	Total Accumulated Depr. & Amort.	806,885,607	-	806,885,607
9		Total Net Gas Plant In Service	1,542,163,440	-	1,542,163,440
		SYSTEM ALLOCABLE GAS PLANT IN SERVICE			
10		Intangible Plant	106,236,031	(494,768)	105,741,263
11		General Plant	55,286,744	-	55,286,744
12	101	Total System Allocable Gas Plant	161,522,775	(494,768)	161,028,007
		ACCUM. PROVISION FOR DEPR. AND AMORT.			
13		Intangible Plant	60,385,073	-	60,385,073
14		General Plant	26,325,236	-	26,325,236
15		Total System Allocable Accum. Depr. & Amort.	86,710,309	-	86,710,309
16		System Allocable Net Gas Plant In Service	74,812,466	(494,768)	74,317,698
17		4-Factor Allocation Rate (Sch. C-1, Sh 18)	57.58%	57.58%	57.58%
18		Allocated System Allocable Gas Plant	93,004,814	(284,886)	92,719,928
19		Allocated System Allocable Accum. Depr. & Amort.	49,927,796	-	49,927,796
20		Total System Allocable Net Gas Plant In Service	43,077,018	(284,886)	42,792,132
21		Total Plant in Service	$ 2,442,053,861	$ (284,886)	2,441,768,975
22		Less: Accumulated Depreciation	856,813,403	-	856,813,403
23		Net Plant in Service (L59 - L 60)	$ 1,585,240,458	$ (284,886)	1,584,955,572
		LESS:			
24		Contributions in Aid of Construction (CIAC)	$ 7,027,372	$ -	$ 7,027,372
25		Less: Accumulated Amortization	-	-	-
26		Net CIAC (L25 - L26)	7,027,372	-	7,027,372
27		Customer Meter Deposits	23,912,141	-	23,912,141
28		Deferred Income Tax Credits	136,691,328	-	136,691,328
		ADD:			
29		Working Capital	881,148	-	881,148
30		**Original Cost Rate Base**	$ 1,418,490,765	$ (284,886)	1,418,205,879

ADJ No.	
1	Completed Construction Not Classified - DRR-8

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule DRR-8

RECONSTRUCTION COST RATE BASE ADJUSTMENT No.1 - REMOVAL OF POST-TEST YEAR PLANT (CCNC)

Line	Description	[A] Estimated PIS	[B] Actual PIS	[C] Rate Base Adjustment	[D] Company Amortization
1	Purchase Software for EMRS	$ 212,459	$ 212,459	$ -	$ 70,820
2	Riser Verification - CSS/EMRS	500,000	-	(500,000)	166,667
3	Purchase DB Microwave Software	277,000	267,153	(9,847)	92,333
4	Software Licenses - Mobile Facility Data Mgmt.	434,000	454,500	20,500	144,667
5	Purchase Com Software for Output to Microfiche	50,000	44,579	(5,421)	16,667
6	Total Adjustment to Intangible Plant	$ 1,473,459	$ 978,691	$ (494,768)	$ 491,153
7	Arizona 4-Factor	57.58%	57.58%	57.58%	57.58%
8	Arizona Adjustment Amounts	$ 848,414	$ 563,528	$ (284,886)	$ 282,805

References:
Column [A]: Company Adjustment Nos. 17 and 20, Workpapers Schedule C-2, ADJ. 17, Sheet 9
Column [B]: Company's Response to RUCO Data Request 4-3.
Column [C]: Column [B] minus Column [A]
Column [D]: Company Workpapers Schedule C-2, Adj. 17, Sheet 9

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule DRR-9

OPERATING INCOME STATEMENT - ADJUSTED TEST YEAR AND STAFF RECOMMENDED

LINE NO.	DESCRIPTION	[A] COMPANY ADJUSTED TEST YEAR AS FILED	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF PROPOSED CHANGES	[E] STAFF RECOMMENDED
1	*REVENUES:*					
2	Revenues	$ 322,865,978	$ -	$ 322,865,978	$ 46,999,085	$ 369,865,063
3	Gas Cost	-	-	-	-	-
4						
5	**Total Operating Revenues**	$ 322,865,978	$ -	$ 322,865,978	$ 46,999,085	**$ 369,865,063**
6	*OPERATING EXPENSES:*					
7	Other Gas Supply	$ 740,391	$ (7,834)	$ 732,557	$ -	$ 732,557
10	Distribution	78,580,466	(2,426,289)	76,154,177	-	76,154,177
11	Customer Accounts	34,003,279	(173,145)	33,830,134	62,418	33,892,552
13	Customer Information	548,496	(1,760)	546,736	-	546,736
14	Sales	-	-	-	-	-
15	Administrative & General	-	-	-	-	-
16	Direct	6,993,300	(138,304)	6,854,996	-	6,854,996
17	System Allocable	45,487,895	(4,071,875)	41,416,020	-	41,416,020
18	Depreciation & Amortization	-	-	-	-	-
19	Direct	67,338,861	-	67,338,861	-	67,338,861
20	System Allocable	7,062,583	(94,962)	6,967,621	-	6,967,621
21	Regualtory Amortizations	1,548,204	(1,210,679)	337,525	-	337,525
22	Other Taxes	33,455,124	(1,737,545)	31,717,579	-	31,717,579
23	Interest On Customer Deposits	717,364	-	717,364	-	717,364
24	Income Taxes	2,156,664	4,698,493	6,855,157	18,640,002	25,495,159
40						
41	**Total Operating Expenses**	$ 278,632,627	$ (5,163,899)	$ 273,468,728	$ 18,702,420	$ 292,171,148
42	**Operating Income (Loss)**	$ 44,233,351	$ 5,163,899	$ 49,397,250	$ 28,296,665	**$ 77,693,916**

References:
Column [A]: Company Schedule C-1
Column [B]: Schedule DRR-10
Column [C]: Column [A] + Column [B]
Column [D]: Schedules DRR-1 and DRR-2
Column [E]: Column [C] + Column [D]

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule DRR-10

SUMMARY OF OPERATING INCOME STATEMENT ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[D] ADJ No.1 Eliminate In Grade Adj.	[H] ADJ No.2 TRIMP Opr. Expense	[I] ADJ No.3 TRIMP Amortization	[B] ADJ No.4 Sarbanes-Oxley	[C] ADJ No.5 Injuries and Damages	[E] ADJ No.6 Management Incent. Program	[F] ADJ No.7 Estimated Sys Alloc. PIS	[G] ADJ No.8 Property Taxes	[J] ADJ No.9 Income Taxes	[I] STAFF ADJUSTED
	REVENUES:											
1	Revenues	$ 322,865,978	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 322,865,978
2	Gas Cost	-	-	-	-	-	-	-	-	-	-	$ -
5	**Total Margin**	$ 322,865,978	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 322,865,978
6	OPERATING EXPENSES:											
7	Other Gas Supply	$ 740,391	$ (7,834)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 732,557
8	Distribution	78,580,466	(334,325)	(2,091,964)	-	-	-	-	-	-	-	76,154,177
9	Customer Accounts	34,003,279	(173,145)	-	-	-	-	-	-	-	-	33,830,134
10	Customer Information	548,496	(1,760)	-	-	-	-	-	-	-	-	546,736
11	Sales	-	-	-	-	-	-	-	-	-	-	-
12	Administrative & General											
13	Direct	6,993,300	(138,304)	-	-	-	-	-	-	-	-	6,854,996
14	System Allocable	45,487,895	-	-	-	(58,905)	(3,043,711)	(969,259)	-	-	-	41,416,020
15	Depreciation & Amortization											
16	Direct	67,338,861	-	-	-	-	-	-	-	-	-	67,338,861
17	System Allocable	7,062,583	-	-	-	-	-	-	(94,962)	-	-	6,967,621
18	Regualtory Amortizations	1,548,204	-	-	(1,183,333)	(27,346)	-	-	-	-	-	337,525
19	Other Taxes	33,455,124	-	-	-	-	-	-	-	(1,737,545)	-	31,717,579
20	Interest On Customer Deposits	717,364	-	-	-	-	-	-	-	-	-	717,364
21	Income Taxes	2,156,664	-	-	-	-	-	-	-	-	4,698,493	6,855,157
22	**Total Operating Expenses**	$ 278,632,627	$ (655,368)	$ (2,091,964)	$ (1,183,333)	$ (86,251)	$ (3,043,711)	$ (969,259)	$ (94,962)	$ (1,737,545)	$ 4,698,493	$ 273,468,728
23	**Operating Income (Loss)**	$ 44,233,351	$ 655,368	$ 2,091,964	$ 1,183,333	$ 86,251	$ 3,043,711	$ 969,259	$ 94,962	$ 1,737,545	$ (4,698,493)	$ 49,397,250

ADJ No.		References:
1	In-Grade Adjustments	Schedule JJD-11
2	TRIMP Operating Expenses	Schedule JJD-12
3	TRIMP Amortization	Schedule JJD-13
4	Sarbanes Oxley	Schedule JJD-14
5	Injuries and Damages	Schedule JJD-15
6	Management Incentive Program	Schedule JJD-16
7	Estimated System Allocable PIS	Schedule DRR-17
8	Property Taxes	Schedule DRR-18
9	Income Taxes	Schedule DRR-19

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule JJD-11

OPERATING INCOME ADJUSTMENT No.1 - TO ELIMINATE IN-GRADE ADJUSTMENTS

LINE NO.	Functionalization	[A] Company Proposed	[B] Staff Recommended	[C] Staff Adjustment
1	Other Gas Supply	$ 19,584	$ 11,750	$ (7,834)
2	Distribution	835,813	501,488	$ (334,325)
3	Customer Accounts	432,863	259,718	$ (173,145)
4	Customer Service & Information	4,399	2,639	$ (1,760)
5	Administrative & General	345,760	207,456	$ (138,304)
6	Totals	$ 1,638,419	$ 983,051	$ (655,368)

References:
Column [A]: Company Ajustment No. 3, Schedule C-2, Sheet 1
Column [B]: Testimony JJD
Column [C]: Column [B] minus Column [A]

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

OPERATING INCOME ADJUSTMENT No.2 - REMOVAL OF ESTIMATED OPERATING TRIMP COSTS

LINE NO.	Removal of Estimated TRIMP Operating Costs		
1	Company Proposed	$	2,091,964
2	Staff Recommended		-
3	Adjustment	$	(2,091,964)

SUMMARY OF TRIMP COSTS

Estimated Cost Incurrance	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Baseline & Confirmatory Assessments	355,000	532,500	532,500	532,500	319,500	319,500	319,500	497,000	585,750	3,993,750
Direct Examination Cost	1,065,000	1,597,500	1,597,500	1,597,500	958,500	958,500	958,500	958,500	958,500	10,650,000
Maintenance & Repairs	532,500	798,750	798,750	798,750	479,250	479,250	479,250	479,250	479,250	5,325,000
Total Expense	1,952,500	2,928,750	2,928,750	2,928,750	1,757,250	1,757,250	1,757,250	1,934,750	2,023,500	19,968,750

Company Proposed Regulatory Recovery*										
Amortization of 2004/2005 (Acct 407.3)			1,183,333	1,183,333	1,183,333					
Direct Assessment (Acct 874)**			380,357	380,357	380,357					
Direct Examination (Acct 874)**			1,141,071	1,141,071	1,141,071					
Maintenance & Repair (Acct 887)**			570,536	570,536	570,536					
Operating Expense			2,091,964	2,091,964	2,091,964					
Total Annual Recovery			3,275,297	3,275,297	3,275,297					
Cummulative Company Expense	1,952,500	4,881,250	7,810,000	10,738,750	12,496,000	14,253,250	16,010,500	17,945,250	19,968,750	
Cummulative Recovery			3,275,297	6,550,594	9,825,891	13,101,188	16,376,485	19,651,782	22,927,079	

***Does not include Capital Replacements totaling $9,372,000**
which will be capitalized and included in rate base in the Company's subsequent rate applications.

**Based on seven year average of years 2006 through 2012

TRIMP SURCHARGE CALCULATION & EXAMPLE

YEAR 1

Line No.	Year	[A] Initial Cost Estimates	[B] Ratepayer Share (50%)	[C] Cumulative Recoverable	[D] Projected[1] Therm Sales	
1	2004	1,952,500	976,250	976,250		
2	2005	2,928,750	1,464,375	2,440,625		
3	2006	2,928,750	1,464,375	3,905,000	737,834,487	
4	2007	2,928,750	1,464,375	5,369,375	759,969,522	
5	2008	1,757,250	878,625	6,248,000	782,768,607	
6	2009	1,757,250	878,625	7,126,625		
7	2010	1,757,250	878,625	8,005,250		
8	2011	1,934,750	967,375	8,972,625		
9	2012	2,023,500	1,011,750	9,984,375		
10	Totals	19,968,750	9,984,375		2,280,572,616	
11						
12	Est. TRIMP cost 2004 thru Jan '09: 1/12*878,625 + 6,248,000:					$ 6,321,219
13	Projected 36-month (Feb '06 - Jan '09) therm sales:					2,280,572,616
14	TRIMP Surcharge Rate for first 12 months					**$ 0.00277**
15	Assume actual therm sales for Feb '06 - Jan '07 period:					740,000,000
16	Surcharge revenue in first 12 months:					$ 2,051,108
17						
18				**YEAR 2**		
19						
20	2004	1,952,500	976,250	976,250		
21	2005	2,928,750	1,464,375	2,440,625		
22	2006	2,286,312	1,143,156	3,583,781		
23	2007	2,928,750	1,464,375	5,048,156	752,591,177	
24	2008	1,757,250	878,625	5,926,781	767,643,000	
25	2009	1,757,250	878,625	6,805,406		
26	2010	1,757,250	878,625	7,684,031		
27	2011	1,934,750	967,375	8,651,406		
28	2012	2,023,500	1,011,750	9,663,156		
29	Totals	19,326,312	9,663,156		1,520,234,177	
30						
31	Revised est. TRIMP cost 2004 thru Jan '09: 1/12*878,625 + 5,926,781:					$ 6,000,000
32	Less: Surcharge from first twelve months (L16)					$ 2,051,108
33	Est. recoverable TRIMP surcharge in remaining 24 months =					$ 3,948,891
34	Projected 24-month (Feb '07 - Jan '09) therm sales:					1,520,234,177
35	TRIMP Surcharge Rate for second 12 months					$ 0.00260
36	Assume actual therm sales for Feb '07 - Jan '08 period:					750,000,000
37	Surcharge revenue in second 12 months:					$ 1,948,166
38						
39				**YEAR 3**		
40						
41	2004	1,952,500	976,250	976,250		
42	2005	2,928,750	1,464,375	2,440,625		
43	2006	2,286,312	1,143,156	3,583,781		
44	2007	3,428,750	1,714,375	5,298,156		
45	2008	2,257,250	1,128,625	6,426,781	770,000,000	
46	2009	1,757,250	878,625	7,305,406		
47	2010	1,757,250	878,625	8,184,031		
48	2011	1,934,750	967,375	9,151,406		
49	2012	2,023,500	1,011,750	10,163,156		
50	Totals	20,326,312	10,163,156		770,000,000	
51						
52	Revised est. TRIMP cost 2004 thru Jan '09: 1/12*878,625 + 6,426,781:					$ 6,500,000
53	Less: Surcharge from first twenty-four months (L16 + L39)					$ 3,999,274
54	Est. recoverable TRIMP surcharge in remaining 12 months =					$ 2,500,725
55	Projected 12-month (Feb '08 - Jan '09) therm sales:					770,000,000
56	TRIMP Surcharge Rate for second 12 months					$ 0.00325
57	Assume actual therm sales for Feb '07 - Jan '08 period:					771,000,000
58	Surcharge revenue in second 12 months:					$ 2,503,973

[1] Based on Company Schedule H-8, page 3, line, column (d) for first 12 months and 3 percent annual growth.

SUMMARY OF TRIMP COST TREATMENT

STATE JURISDICTIONS

Transmission Integrity Management Program cost have received different treatment in the various jurisdictions that have already ruled on TRIMP costs. Presented below is a summary of jurisdictions that have issued rulings as of April, 2005.

Deferred Accounting Orders -	North Carolina Utah Nevada*
Capitalized Cost -	Oregon
Base Rate Case -	Kentucky New Mexico Michigan Alabama Washington Oklahoma
Trackers -	Indiana Ohio

* The costs for TRIMP will be shared equally by ratepayers and shareholders. Allowed to defer until 12/31/2007 or earlier rate case, subject to prudency review. No return or cost of money allowed on the deferral balance.

FEDERAL ENERGY REGULATORY COMMISSION ("FERC") -

The FERC issued an "Order on Accounting For Pipeline Assessment Costs" on June 30, 2005 providing guidance on accounting for pipeline assessment activities. In general, it requires an entity to recognize costs incurred in performing assessments as part of a pipeline integrity management program as maintenance expense.

Source: American Gas Association

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule JJD-13

OPERATING INCOME ADJUSTMENT No.3 - REMOVAL OF TRIMP AMORTIZATION

LINE NO.	Removal of TRIMP Amortization		
1	Company Proposed	$	1,183,333
2	Staff Recommended		-
3	Adjustment	$	(1,183,333)

SOUTHWEST GAS CORPORATION
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Test Year Ended August 31, 2004

Schedule JJD-14

OPERATING INCOME ADJUSTMENT No.4 - SARBANES OXLEY

LINE NO.	Sarbanes Oxley					
1	Estimated Annual Compliance Costs	$ 915,000				
2	Non-recurring Start-up Costs	(228,750)				
3	Subtotal		$ 686,250			
4	Less:					
5	Stockholders Share (50%)	$ (343,125)				
6	Paiute Allocation (4.29%)	(14,720)	(357,845)			
7	Subtotal		$ 328,405			
8	Arizona 4-Factor Percentage		57.58%			
9	Allocable to Arizona				$	189,095
10	Less:					
11	Allocated Test Year Amount					(45,737)
12	Staff Recommended				$	143,358
13	Company as Filed					202,263
14	Increase (decrease) Sarbanes Oxley				$	(58,905)
	Amortization of Deferred Sarbanes Oxley Costs					
15	Disallowance of Amortization (Reference Workpapers Schedule C-2, Adj. 17)					(27,346)
16	Total Adjustments				$	(86,251)

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule JJD-15

OPERATING INCOME ADJUSTMENT No.5 - INJURIES AND DAMAGES

LINE NO.	Injuries and Damages		
1	Company Test Year Proposed	$	3,043,711
2	Staff Recommended		-
3	Increase (decrease)	$	(3,043,711)

References:
Line 1: Company Schedule
Line 2: Testimony JJD
Line 3: Line 2 minus Line 1

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule JJD-16

OPERATING INCOME ADJUSTMENT No.6 - MANAGEMENT INCENTIVE PROGRAM

LINE NO.	Management Incentive Program		
1	Company Expensed	$	3,366,667
2	System Allocable Percentage		57.58%
3	Amount Available	$	1,938,518
4	Staff Recommends a 50/50 split, between ratepayers and shareholders		50.00%
5	Staff Recommended Adjustment	$	(969,259)

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule DRR-17

OPERATING INCOME ADJUSTMENT No.7 - SYSTEM ALLOCABLE AMORTIZATION EXPENSE

Line	Description	[A] Estimated PIS	[B] Actual PIS	[C] Rate Base Adjustment	[D] Company Amortization	[E] Staff Amortization	[F] Amortization Adjustment
1	Purchase Software for EMRS	$ 212,459	$ 212,459	$ -	$ 70,820	$ 70,820	$ -
2	Riser Verification - CSS/EMRS	500,000	-	(500,000)	166,667	-	(166,667)
3	Purchase DB Microwave Software	277,000	267,153	(9,847)	92,333	89,051	(3,282)
4	Software Licenses - Mobile Facility Data Mgmt.	434,000	454,500	20,500	144,667	151,500	6,833
5	Purchase Com Software for Output to Microfiche	50,000	44,579	(5,421)	16,667	14,860	(1,807)
6	Total Adjustment to Intangible Plant	$ 1,473,459	$ 978,691	$ (494,768)	$ 491,153	$ 326,230	$ (164,923)
7	Arizona 4-Factor	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%
8	*Arizona Adjustment Amounts*	$ 848,414	$ 563,528	$ (284,886)	$ 282,805	$ 187,843	**$ (94,962)**

References:
Column [A]: Company Adjustment Nos. 17 and 20, Workpapers Schedule C-2, ADJ. 17, Sheet 9
Column [B]: Company's Response to RUCO Data Request 4-3.
Column [C]: Column [B] minus Column [A]
Column [D]: Company Workpapers Schedule C-2, Adj. 17, Sheet 9
Column [E]: Three year amortization rate times Column [C]
Column [F]: Column [E] minus Column [D]

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule DRR-18

OPERATING INCOME ADJUSTMENT No.8 - PROPERTY TAXES

Line No.	Description	
1	Net Plant in Service	$ 1,051,372,747
	Add:	
2	Customer Contributions in Aid of Construction	-
3	Materials and Supplies	9,222,489
	Less:	
4	Transportation Equipment	(25,153,605)
5	Land Rights	(797,670)
6	Estimated Full Cash Value	$ 1,034,643,961
7	Assessment Rate	24.00%
8	Assessed Value	$ 248,314,551
9	Property Tax Rate With Bond Issues	12.77%
10	Staff Annualized Property Tax Expense	$ 31,709,768
11	Company as Filed	$ 33,447,313
12	Staff Recommended Adjustment	$ (1,737,545)

References:
Line 1: Company Schedule B-2, Sheet 1.
Line 2: Testimony DRR
Line 3: Company Schedule C-2, Adj. No. 18, Sheet 1 of 1.
Line 4: Company Workpapers Schedule B-2
Line 5: Company Workpapers Schedule B-2
Line 6: Line 1 to Line 5.
Line 7: Testimony DRR
Line 8: Line 6 times Line 7.
Line 9: Company Schedule C-2, Adj. No. 18, Sheet 1 of 1.
Line 10: Line 8 times Line 9.
Line 11: Company Schedule C-2, Adj. No. 18, Sheet 1 of 1.
Line 12: Line 10 minus Line 11.

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

Schedule DRR-19

OPERATING INCOME ADJUSTMENT No.9 - INCOME TAX EXPENSE

Line No.	Income Tax Expense		
1	Staff Calculated Income Tax	$	6,855,157
2	Company Income Tax		2,156,664
3	Increase/(Decrease) to Income Tax Expense	$	4,698,493

References:
Line 1: Staff Schedule DRR-2; Line 46.
Line 2: Per Company Schedule C-1.
Line 3: Line 1 minus Line 2.

ROGERS

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES	))))	DOCKET NO. G-01551A-04-0876

DIRECT

TESTIMONY

OF

DENNIS R. ROGERS

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 26, 2005

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION, INC.
RATES AND CHARGES APPLICATION
DOCKET NO. G-01551A-04-0876

The direct testimony of Staff witness Dennis R. Rogers addresses the following issues:

Revenue Requirement – Staff recommends a $46,999,085, or 14.56 percent, revenue increase over adjusted test year revenue of $322,865,978 resulting in a revenue requirement of $369,865,063. Staff's recommended revenue would produce an operating income of $77,693,916 for an 8.40 percent rate of return on an original cost rate base of $924,927,566 and a 6.63 percent rate of return on a fair value rate base of $1,171,566,722.

Completed Construction Not Classified – Staff decreased Allocated System Allocable Plant by $284,886 from $88,146,046 to $87,861,160 to reflect items not completed and the difference between actual and estimated costs.

Depreciation and Amortization – Staff decreased amortization expenses by $94,962, from $7,062,583 to $6,967,621, to reflect its adjustment to remove Completed Construction Not Classified from plant in service.

Property Tax Expense – Staff decreased this expense by $1,737,545 from $33,447,313 to $31,709,768 to reflect changes in the statutory assessment rate and the definition of "Plant" for property tax expense calculations.

Income Tax Expense – Staff increased test year expenses by $4,698,493 from $2,156,664 to $6,855,157 to reflect federal and state statutory rates on Staff adjusted taxable income.

INTRODUCTION

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

A. My name is Dennis R. Rogers. I am a Public Utilities Analyst IV employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

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

A. I am responsible for the examination and verification of financial and statistical information included in utility rate applications, developing revenue requirements, designing rates, preparing written reports and/or testimonies and related schedules that present Staff's recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Business Administration with an emphasis in Accounting from Arizona State University.

I have participated in multiple rate case, financing and other regulatory proceedings. I attended the National Association of Regulatory Utility Commissioners Utilities Rate School, and have attended seminars and courses in utility regulation and utility accounting and finance.

I began employment with the Commission as a utilities regulatory analyst in May 2001. Prior to joining the Commission, I worked at the Department of Revenue in the Taxpayer Assistance Section.

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

A. I am presenting Staff's Revenue Requirement for the Southwest Gas Corporation's ("SWG" or "Company") application for a permanent rate increase filed on December 9, 2004. I am also presenting Staff's analysis and recommendations regarding the rate base component Completed Construction Not Classified; and operating expense components, 1) Amortization of Completed Construction Not Classified: 2) Property Tax expense and 3) Income Tax expense. Mr. James Dorf is presenting Staff's recommendations pertaining to the operating expenses components: 1) In-Grade Adjustments, 2) TRIMP Operating Costs, 3) TRIMP Amortization, 4) Sarbanes Oxley, 5) Injuries and Damages, and 6) Management Incentive Program (Schedules JJD-11 through JJD-16).

Q. What is the basis of Staff's recommendations?

A. Staff performed a regulatory audit of the Company's application and records. The regulatory audit consisted of examining and testing financial information, accounting records, data responses, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission adopted Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").

REVENUE REQUIREMENT

Q. What is Staff's recommended Revenue Requirement?

A. Staff recommends a $46,999,085, or 14.56 percent, revenue increase over adjusted test year revenue of $322,865,978 resulting in a revenue requirement of $369,865,063. Staff's recommended revenue would produce an operating income of $77,693,916 for an 8.40 percent rate of return on an original cost rate base of $924,927,566 and a 6.63 percent rate of return on a fair value rate base of $1,171,566,722 as shown on Schedule DRR-1.

RATE BASE ADJUSTMENT – COMPLETED CONSTRUCTION NOT CLASSIFIED

Q. What is Completed Construction Not Classified ("CCNC")?

A. CCNC is a clearing account for temporarily recording completed plant that is providing service. CCNC is later transferred into other plant accounts as the proper classification is determined.

Q. Is the Company proposing to include any CCNC in rate base?

A. Yes. The Company proposes to include in rate base $1,819,949 for Direct Gas Plant and $969,345 for System Allocable Gas Plant in Service for a total of $2,789,294 CCNC items. These items are reflected in the Company's application as pro forma adjustment No. 20.

Q. What are the primary reasons stated by the Company for requesting to include CCNC in rate base?

A. The Company's application states that the tangible Plant was placed in service by the end of the test year, but was not entered into the proper accounts because of "delays in the field in entering the required information into the Company's computer systems."[1] The intangible computer software costs were supposed to be completed by the end of the test year and "therefore, it is equitable to propose removing from amortization expense those software projects that will be fully amortized by December 31, 2004."[2]

[1] Direct Testimony Randi L. Aldridge, page 11, lines 16 thru 22.
[2] Id. Page 13, lines 5 thru 8.

Q. Did Staff examine whether the proposed CCNC tangible plant was actually placed in service by the end of the test year, August 31, 2003?

A. Yes. Staff's examination verified that the tangible plant was used and useful by the end of the test year, August 31, 2003, and had been moved from CWIP to the proper plant in service accounts by the Company's normal year end closing at December 31, 2004.

Q. Did Staff make any adjustments to CCNC – System Allocable Intangible Plant?

A. Yes. Staff found that certain items were not completed or the final costs were different than what the Company proposed as a part of its pro forma adjustment No. 20. The various elements and the reconciliation of estimated and actual figures are depicted on Schedule DRR – 8.

Q. What is the total for the adjustments Staff made for the CCNC - System Allocable Intangible Plant?

A. Staff made adjustments to the various elements of the CCNC – System Allocable Intangible Plant totaling $284,886.

OPERATING EXPENSE ADJUSTMENTS

Operating Expense Adjustment No. 7 – Amortization of CCNC

Q. Did the Company propose a pro forma adjustment to increase its CCNC System Allocable Amortization Expense?

A. Yes. The Company proposed a $282,805 increase in System Allocable Amortization Expense to synchronize the amortization expense with its proposed increase in test year plant in service.

Q. Did Staff adjust the Company's proposed System Allocable Amortization Expense?

A. Yes.

Q. What was Staff's adjustment to System Allocable Amortization Expense?

A. Staff decreased the Company's proposed System Allocable Amortization Expense by $94,962 from $282,805 to $187,843 as shown on Schedule DRR-17. This adjustment is the companion entry to Staff's CCNC rate base adjustment.

Operating Expense Adjustment No. 8– Property Tax Expense

Q. What is the Company proposing for Property Tax Expense?

A. The Company is proposing $33,447,313 which represents the result of an annualization calculation presented as pro forma adjustment No. 18 of the application.

Q. Is the Company's proposed Property Tax Expense representative of its future costs?

A. No. The Company filed its application on December 9, 2004. The Company used an assessment rate of 25 percent and added back Contributions in Aid of Construction ("CIAC") totaling $12,779,095 as shown on Company Schedule C-2, Adjustment No. 18 Sheet 1 to calculate its Property Tax Expense. Subsequent to the Company's filing, the Arizona State Legislature passed House Bill No. 2779 which set a new schedule for property tax assessments and House Bill No. 2056 which defined "Plant" to not include CIAC. The new assessment rate schedule provides for decreasing the current 25 percent rate in 0.5 percent steps each year until a 20 percent rate is attained in 2015. Consequently, the Company's calculation overstates its expenses.

Q. What assessment rate did Staff utilize in determining the recommended Annualized Property Tax Expense?

A. Staff used a property tax assessment rate of 24 percent as representative of the Company's assessment rate.

Q. How did Staff determine its recommended assessment rate?

A. The current assessment rate is 25 percent. Staff concluded that since the Commission approved rates won't become effective until 2006, and the Company historically files rate cases every three to four years, the property tax assessment rate that will be in effect during the year 2007 is appropriate.

Q. Did Staff calculate Property Tax Expense excluding the Company's recorded Contributions in Aid of Construction?

A. Yes. In accordance with House Bill 2056, Staff removed Contributions in Aid of Construction totaling $12,779,095 from its Property Tax Expense calculation as shown on Schedule DRR-18.

Q. What is Staff's recommended Property Tax Expense?

A. Staff recommends decreasing Property Tax Expense by $1,737,545, from $33,447,313 to $31,709,768, to reflect the effects of House Bills 2056 and 2779, respectively, as shown on Schedule DRR-18.

Operating Expense Adjustment No. 9 – Income Tax Expense

Q. What did the Company propose as its adjusted Test Year Income Tax Expense?

A. The Company proposed an adjusted test year Income Tax Expense of $2,156,664.

Q. Did Staff adjust Income Tax Expense?

A. Yes. Staff increased Income Tax Expense by $4,698,493 from $2,156,664 to $6,855,157 as shown on Schedules DRR-2 and DRR-10 to reflect application of the statutory federal and state rates to Staff's taxable income.

Q. Does this conclude your testimony?

A. Yes, it does.

HILL

BEFORE THE ARIZONA CORPORATION COMMISSION

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	)	Docket No. G-01551A-04-0876
FAIR VALUE OF THE PROPERTIES OF	)	
SOUTHWEST GAS CORPORATION DEVOTED	)	
TO ITS OPERATIONS THROUGHOUT THE	)	
STATE OF ARIZONA	)	

DIRECT TESTIMONY OF

STEPHEN G. HILL

ON BEHALF OF THE

ARIZONA CORPORATION COMMISISON STAFF

JULY 26, 2005

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DIRECT TESTIMONY

STEPHEN G. HILL

Docket No. G-01551A-04-0876

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INTRODUCTION / SUMMARY

Q. Please state you name, occupation and address.

A. My name is Stephen G. Hill. I am self-employed as a financial consultant, and principal of Hill Associates, a consulting firm specializing in financial and economic issues in regulated industries. My business address is P. O. Box 587, Hurricane, West Virginia, 25526 (e-mail: sghill@compuserve.com).

Q. Briefly, what is you educational background?

A. After graduating with a Bachelor of Science degree in Chemical Engineering from Auburn University in Auburn, Alabama, I was awarded a scholarship to attend Tulane Graduate School of Business Administration at Tulane University in New Orleans, Louisiana. There I received a Master's Degree in Business Administration. More recently, I have been awarded the professional designation, "Certified Rate of Return Analyst" by the Society of Utility and Regulatory Financial Analysts. This designation is based upon education, experience and the successful completion of a comprehensive examination. I have also been elected to the Board of Directors of that national organization. A more detailed account of my educational background and occupational experience appears in Appendix A.

Q. Have you testified before this or other regulatory commissions?

A. Yes, I have previously presented testimony in this jurisdiction and have testified on cost of capital, corporate finance and capital market issues in over 220 regulatory proceedings before the following regulatory bodies: the West Virginia Public Service Commission, the Texas Public Utilities Commission, the Oklahoma Corporation Commission, the Public Utilities Commission of the State of California, the Public Service Commission of New Hampshire, the Georgia Public Service Commission, the Public Utilities Commission of the State of Minnesota, the Ohio Public Utilities Commission, the Insurance Commissioner of the State of Texas, the North Carolina Insurance Commissioner, the Rhode Island Public Utilities Commission, the City Council of Austin, Texas, the State of Maine Public Service

Commission, the South Carolina Public Service Commission, the Public Utilities Commission of the State of Hawaii, the New Mexico Corporation Commission, the Wisconsin Public Service Commission, the State of Texas Railroad Commission, the Public Service Commission of Utah, the Illinois Commerce Commission, the Kansas Corporation Commission, the Indiana Utility Regulatory Commission, the Virginia Corporation Commission, the Public Service Commission of Maryland, the Pennsylvania Public Utilities Commission, the Montana Public Service Commission, the Washington Utilities and Transportation Commission, the Vermont Public Service Board, the Federal Communications Commission and the Federal Energy Regulatory Commission. I have also testified before the West Virginia Air Pollution Control Commission regarding appropriate pollution control technology and its financial impact on the company under review.

Q. On behalf of whom are you testifying?

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

Q. What is the purpose of your testimony?

A. I have been requested to present a cost of capital analysis for the gas distribution operations of Southwest Gas Company ("SWG" or the "Company"), a subsidiary of Southwest Gas Corporation, Inc. ("SWX" or the "Parent"). As part of my analysis, I recommend and testify to the appropriate ratemaking capital structure, embedded cost of debt and the overall rate of return I believe should be utilized in determining regulated rates for the Company in this proceeding. I also review and critique the cost of capital testimony presented by Mr. Frank Hanley on behalf of SWG in this proceeding.

Q. Have you prepared exhibits in support of your testimony?

A. Yes. Exhibit_(SGH-1), attached to this testimony, consists of 11 Schedules and provides the analytical support for the conclusions reached regarding the forward-looking overall cost of capital for Southwest Gas Company's gas distribution operations presented in the body of

this testimony. This Exhibit was prepared by me and is correct to the best of my knowledge and belief. Also, I have provided four Appendices ("A" through "D"), which contain additional detail regarding certain aspects of my narrative testimony in this proceeding.

Q. Please summarize your testimony and findings concerning the rate of return that should be utilized in setting rates for Southwest Gas Company's gas distribution operations in this proceeding.

A. My testimony is organized into four sections. First, I discuss the cost of capital standard as a measure of the return to be allowed for regulated industries, and review the current economic environment in which the equity return estimate is made. Second, I review the Company's actual capital structure in comparison to capital structures employed by its Parent company, the natural gas utility industry, generally, and prior ratemaking capital structures employed by this Commission. Following that review, I recommend an appropriate ratemaking capital structure.

Third, I evaluate the cost of equity capital for similar-risk operations using Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Modified Earnings-Price Ratio (MEPR), and Market-to-Book Ratio (MTB) analyses. Fourth, I discuss the cost of capital testimony of Company witness, Mr. Frank Hanley, underscoring the shortcomings contained therein.

I have estimated the equity capital cost of the utility operations similar in risk to Southwest Gas Company to be in the range of 9.00% to 9.50%. The Company has a lower bond rating, and the ratemaking capital structure I recommend contains a percentage of common equity that is slightly below the average of the sample group of gas distributors used to estimate the cost of equity. Therefore, within that range of current capital costs for gas distributors, a reasonable point estimate of the current cost of equity capital for SWG would be at the upper end of that range, or 9.50%. Utilizing a 9.50% equity cost rate, with the Company's most recently available embedded cost of debt and preferred stock, and a reasonable rate-setting capital structure, produces an overall cost of capital for Southwest Gas Company's operations of 8.40%. (see Exhibit_(SGH-1), Schedule 11). Also, that

overall return affords the Company an opportunity to achieve a pre-tax interest coverage of 2.38 times which, according to Standard & Poor's (S&P) published bond rating benchmarks would allow the Company to maintain its current investment-grade bond rating.[1] The Company's total debt as a percent of total capital is well within S&P's parameters for a "BBB" bond rating for a company in the risk-class of SWG.[2] Moreover, the actual pre-tax interest coverage ratio for Southwest's parent company over the past three years has averaged 1.83 times. The equity return I recommend affords the Company an opportunity to achieve a higher interest coverage and, thus, improve its financial risk position. Therefore, the equity return I recommend fulfills the regulatory requirements that the regulated firm be allowed a return that will afford the Company an opportunity to maintain its credit and attract capital.

Q. Have other regulatory bodies awarded single-digit equity returns over the last year?

A. Yes, while *Public Utilities Fortnightly* reports that the majority of the equity return awards over the last year (October 2003-October 2004) have been in the 10% to 10.5% range,[3] capital costs have been low and there have been many single-digit equity return awards over the past couple of years. The regulatory jurisdictions of New York, New Jersey, Arkansas, Tennessee, Colorado, Connecticut, New Hampshire and Wyoming awarded equity returns below 10% during 2003 and 2004.[4] In addition, the West Virginia Public Service

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[1] Standard & Poor's Utility Perspectives, Utility Financial Targets are Revised, June 1999.; Business Position 3 (out of 10), pre-tax interest coverage required for a BBB bond rating: 1.8-2.8 times.

[2] Standard & Poor's Ratings Direct, "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised," June 2, 2004.

[3] *Public Utilities Fortnightly*, November 2004, pp. 49-51; 30 out of 50 equity return awards over the October 2003 through November 2004 period were 10.5% or below.

[4] New York: Rochester Gas & Electric, 9.96%, NY PUC Lexis 140; St. Lawrence Gas Co., 9.5%, NY PUC Lexis 427; Crown Point Telephone Corp., 8.93%, NY PUC Lexis 474; Chazy & Westport Telephone Corp., 8.01%, NY PUC Lexis 475; Fishers Island Electric, 9.0%, NY PUC Lexis 497. New Jersey: Jersey Central Power & Light, 9.5%, NJ PUC Lexis 248; Rockland Electric Co., 9.75%, NJ PUC Lexis 259. Arkansas: Arkansas Western Gas Co., 9.9%, Ark. PUC Lexis 397. Tennessee: Tennessee-American Water Co., 9.9%, Case No. 03-00118. Wyoming: Lower Valley Energy, Inc., 9.21%, Wyo. PUC Lexis, 128, Colorado: Phillips County Telephone, 9.5%, Col. PUC Lexis 1428, Connecticut: Connecticut Light & Power, 9.85%, Docket No. 03-07-02, New Hampshire: Kearsarge Telephone Company, 8.89%, Docket No. DT 01-221, Verizon New Hampshire, 8.82%, Docket No. DT 02-110.

Commission awarded a water utility company an equity return of 7.0% in early 2004.[5] More recently, the New Hampshire Public Service Commission determined the cost of equity capital of electric transmission and distribution operations (similar in operating risk to gas distribution operations) to be 9.4%. [6]

Q. Why should the cost of capital serve as a basis for the proper allowed rate of return for a regulated firm?

A. Investors in regulated firms are to be given an opportunity to earn returns that are sufficient to attract capital and are comparable to returns investors would expect in the unregulated sector for assuming the same degree of risk. However, regulation does not guarantee profitability and, while investor interests (profitability) are certainly pertinent to setting adequate rates, those interests do not exhaust the relevant considerations. The public interest should be afforded appropriate protection.

As a starting point in the rate-setting process, then, the cost of capital of a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. Since financial theory holds that investors will not provide capital for a particular investment unless that investment is expected to yield their opportunity cost of capital, the correspondence of the cost of capital with the guidelines for appropriate earnings is clear.

I. ECONOMIC ENVIRONMENT

Q. Why is it important to review the economic environment in which an equity cost estimate is made?

A. The cost of equity capital is an expectational, or *ex ante*, concept. In seeking to estimate the cost of equity capital of a firm, it is necessary to gauge investor expectations with regard to the relative risk and return of that firm, as well as that for the particular risk-class of

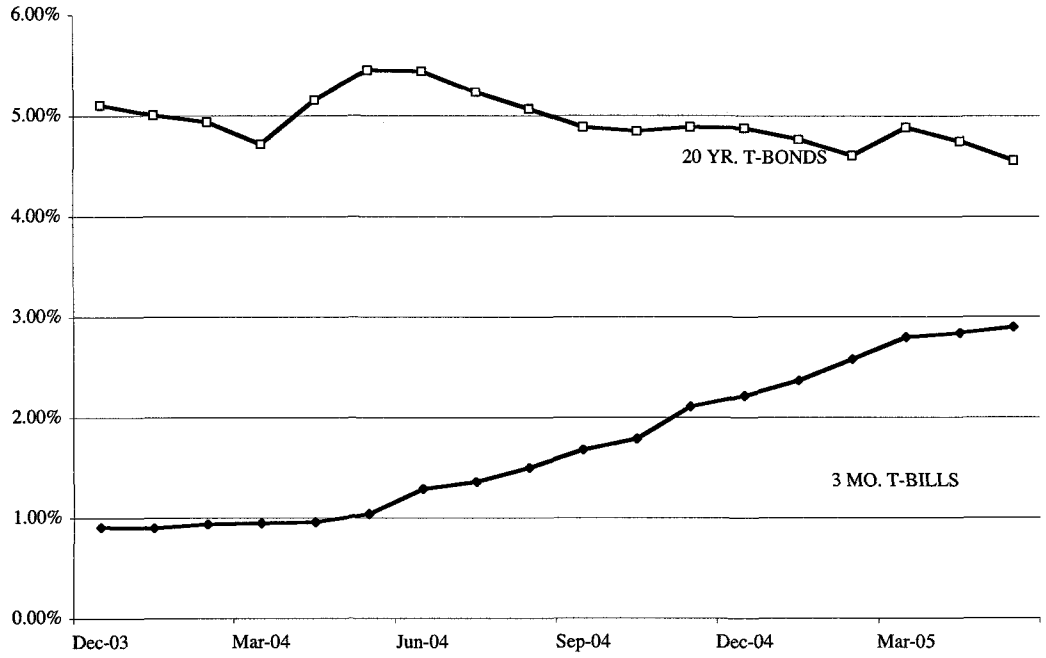
[5] W.V.P.S.C. Case No. 03-0353-W-42T, West Virginia-American Water Works, January 2, 2004.
[6] Docket No. DE 04-177, Public Service Company of New Hampshire, New Hampshire Pubic Utilities Commission Order No. 24,473, June 8, 2005.

investments in which that firm resides. Because this exercise is, necessarily, based on understanding and accurately assessing investor expectations, a review of the larger economic environment within which the investor makes his or her decision provides a relevant context. Investor expectations regarding the strength of the U.S. economy and the level of inflation (factors that are determinative of capital costs) are key building blocks in the investment decision. They should be reviewed by the analyst and the regulatory body in order to assess accurately investors' required return—the cost of equity capital.

Q. Why do you believe an equity return in the range of 9.00% to 9.50% is reasonable for gas distribution utility companies in today's economic environment?

A. The overall level of fixed-income capital costs has been relatively low for several years, and continues to be quite low at the current time. Although, as shown in the following chart, while there has been some upward movement in *short-term* interest rate levels over the past year as the economy has improved, long-term interest rates have remained relatively consistent. Moreover, as the economy began to improve at mid-year 2004 and as short-term rates started to climb in response to Federal Reserve (Fed) credit-tightening, long-term rates actually declined. This indicates that even though the Fed has raised short-term interest rates, investors are not convinced that the overall level of economic growth will be sufficient to create the inflation necessary to warrant an increase in long-term interest rates.

RECENT INTEREST RATE CHANGES



Also, there are examples in the marketplace for utility equities that indicate that investor return requirements remain relatively low by historical standards.

A recent A.G. Edwards report on the gas utility industry shows that market return expectations for gas utility stocks are well below historical earned returns.[7] The report states that, for a sample of 20 large and small gas distributors, the median total return expectation (dividend yield plus expected growth—a DCF-type calculation) is 8.2%. None of the total return estimates for the gas distribution companies published by AG Edwards is above 9%.

In addition, in a letter recently published by Public Utilities Fortnightly an electric industry analyst confirms that investors currently expect single-digit returns from their utility investments:

> "Finally, let's get real about investor expectations, now that investors have begun to get real. Articles on the topic fill the financial journals. They feature variants on this theme: Over time the average equity investment produces an

[7] A.G. Edwards, "Gas Utilities Quarterly Review," January 5, 2005.

> annual total return (dividends plus stock price appreciation) of 6.5 per cent per year in real terms, the bulk of which comes from the dividend component. Add inflation expectations to that number, and you get an 8.5 to 9.5 percent return in nominal terms. The average back-to-basics utility yields about 5 to 6 percent and might grow 3 to 4 percent per year, which adds up to produce a total return expectation of 8 to 10 percent per year, not far from the return the journals posit for the market." (Hyman, Leonard, Senior Consultant, R.J. Rudden Associates, "Letters to the Editor, *Public Utilities Fortnightly*, August 2004, p. 10)

The "articles in the financial journals," to which the author of the preceding quote refers, relate to recent econometric research involving the market risk premium. The market risk premium is the additional return above the risk-free rate of interest that investors expect to earn by investing in stocks rather than risk-free U.S. Treasury securities. The traditional view (largely supported by the earned return data over the past 70 years published by Ibbotson associates) assumes that investors require a risk premium of about 6 1/2% above the risk-free rate to invest in stocks. With a current long-term T-Bond yield of 5%, that traditional assumption indicates an investor expectation of an 11.5% return for the stock market in general [5% + 6.5% = 11.5%]. Of course, expected utility returns would be lower, because those firms have less investment risk than the stock market generally.

However, the new research referenced in the cite above indicates that the historical Ibbotson data is skewed upward and the actual market risk premium is substantially lower—in the range of 3% to 4.5%[8]. In other words, the recent academic research indicates that investor return requirements are considerably lower than traditionally assumed.

Even Roger Ibbotson, whose firm (Ibbotson Associates) is probably the largest purveyor of historical market return data, recently published a paper confirming that risk premium expectations for the future are below what they were in the past. While Ibbotson projected a risk premium of 4% to 6% for investors, which is lower than historical return averages indicate, his estimates are at the upper end of the spectrum produced by the current

[8] Fama, E., French, K., "The Equity Premium," *The Journal of Finance*, Vol. LVII, No. 2, April 2003, pp. 637-659.

research.[9] With a current T-Bond yield of about 5%, the new information regarding expected equity risk premiums confirms that investor's stock market return expectations range from approximately 8% to 10%—i.e., single digit equity returns.

Finally, the Company in its recently published 2004 Annual Report, confirms that single-digit equity returns are reasonable expectations for utility stocks. At pages 63 and 64 of Southwest Gas Corporation's 2004 Annual Report, the parent company reports to the investment community the composition of its pension fund portfolio and the expected long-term return for each asset class. The assumed rate of return for Southwest's retirement portfolio is 8.75%. According to SWX, its employee's retirement and pension benefit investments are comprised of about 70% stock and 30% bonds. Using the Parent's assumption that high-quality fixed income securities will provide a 6% yield, the projected investment returns imply an expected stock return of about 10%. That return is for stocks, generally, not only utility stocks. By this measure, the equity return I recommend for SWG's gas distribution utility assets, 9.5%, is quite reasonable, given what the Company itself believes is reasonable for all common stocks, generally.

The information available to investors in the capital markets confirms that my 9.00%-9.50% equity return range for the gas distribution operations under consideration here is reasonable, if not overly conservative (i.e., too high). In addition, those data represent information to which investors are exposed in the equity marketplace for rate-regulated companies and underscore the fact that, currently, investor return requirements for that type of equity investment are low by historical standards.

Q. Are there other indications that capital costs are currently relatively low?

A. Yes. Another indication of the reason investors are willing to buy and hold stocks that offer what seem to be "low" returns is shown in Exhibit__(SGH-1), Schedule 1, page 1. It depicts Moody's Baa-rated bond yields from 1984 through May 2005. Page 1 of Schedule 1 shows that interest rates and capital costs remain very low relative to the interest rate levels

[9] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

that existed in the mid-1980s, and have continued a general downward trend begun in 2000.

Also, page 2 of Schedule 1 (Exhibit__(SGH-1)), which presents the year-average Moody's Baa-rated bond yields for each year over the past 37 years (1968-2005), shows that Baa-rated bond yields in 2005 (thus far) are below the bond yield levels in 2004 and are also below the yields on similar bonds the U.S. in the late 1960s. Also, the most recent average Baa-rated utility bond yield, 5.72%[10], falls well below the lower range of interest rates that have existed over the past 40 years. (See Schedule 1, page 2) Simply put, a fundamental reason that the current cost of common equity capital for gas distribution utility operations of 9.0% to 9.50% is reasonable is that capital cost rates are lower than they have been in more than thirty years.

The above data indicate that capital costs, even with the recent credit tightening by the Federal Reserve Bank (the Fed), remain at low levels and generally support the efficacy of my range of equity capital costs. However, it is important to note here that equity capital cost rates and bond yields do not move in lock-step fashion over time. In fact, the variability of that return differential is a fundamental reason why risk premium type analyses—which attempt to quantify the additional return over bond yields required by equity investors—are not reliable as primary indicators of equity capital cost. Therefore, it is necessary to perform an independent cost of equity capital analysis, rather than to simply "index" the cost of capital to current interest rates.

Q. Please describe the interest rate changes that have occurred in the U. S. economy over the past few years and how they impact capital cost rate expectations for the future.

A. The substantial interest rate decline that occurred following the historically high interest rates in the early 1980s spurred increased economic activity in the U.S. The rate of growth in the U.S. Gross Domestic Product (GDP) began to increase at a rapid rate by the end of 1987 and showed signs of continuing to gain strength. That increased economic activity, in

[10] Value Line *Selection & Opinion*, most recent six weekly editions (4/22/05-5/27/05, inclusive), 20/30-year Baa-rated utility bond yield averages.

turn, led to increased inflation expectations (a rapid rate of economic growth creates shortages in labor and materials, driving up the price of those factors of production, which ultimately results in higher prices in all sectors of the economy). The expectation of increased inflation, in turn, caused the Fed to act aggressively to slow down what was widely believed to be an overheating economy. The very sharp interest rate rise that followed in late 1987 and 1988, shown on Exhibit__(SGH-1), page 1 of Schedule 1, succeeded in damping down the economy, reducing inflationary pressures, and allowing interest rates to fall again.

Since that time, the interaction between the Federal Reserve's moves to expand or restrain the money supply and burgeoning inflation has been a primary influence in the U.S. macro-economy and the level of interest rates. Overall, as inflation has remained calm and economic activity has been moderate, interest rates have trended downward, but that general downward direction has been interrupted when investors (and/or the Fed) believed that falling interest rates would spur too-rapid economic growth. Rapid economic growth can create unwanted inflation. Anticipating that higher inflation and interest rates might be the result of rapid economic expansion, investors have reacted to positive economic news (e.g., increasing GDP growth rates, lower unemployment) or negative inflation news (e.g., increasing commodity prices, factory capacity or labor shortages) by bidding down debt prices and driving up interest rates.

As shown on page 2 of Schedule 1, Baa-rated debt yielded 7.87%, on average, in 1999, while, in 2000, equivalently rated debt was priced to yield 8.36%, on average. That cost rate increase was due to investors' concerns regarding the continued strength of the U.S. economic expansion and the potential for increased inflation caused by what was perceived to be a rapid level of growth. However, that rapid rate of economic growth did not come to pass, and the interest rate increases engineered by the Federal Reserve in 2000 to slow down a rapidly growing economy worked a little too well, resulting in declining economic growth.

Then, in response to an economy that was slowing down, the Fed elected to increase the supply of money by dramatically lowering the Federal Funds rate. The Federal Funds rate is the rate at which money center banks can lend funds on an overnight basis—a

fundamental building block of capital costs in the U.S. In order to revive what became a slowing economy, the Fed lowered short-term interest rates eleven times in 2001 (and again in early November 2002 as well as at mid-year 2003). By 2003, Baa-rated debt was trading at prices that produced yields averaging 6.76% and in 2004 that average fell further to 6.39%.

More recently, in response to a recovering economy, the Fed has reversed course and has begun raising short-term interest rates. Over the past year, the Federal Funds rate has moved upward from about 1% to about 3.25% currently. As shown previously, however, long-term rates have actually declined slightly over the last six months.

As Value Line notes in its most recent Quarterly Review regarding economic growth, inflation and the interest rate environment, the current expectation is that as the economy continues to expand during 2005 and 2006, inflation and interest rates will increase to some degree. Importantly, with regard to the estimation of capital costs, the interest rates projected by Value Line through 2008, even with anticipated increases, will remain below the levels that existed in 1999 and 2000. The following excerpts from Value Line explain how a relatively low interest rate environment will be preserved:

> **Economic Growth**: As noted above, the economy didn't get out of the gate quickly this year, although it didn't stumble either. The trend was more mixed than not, with the deceleration in GDP growth largely the result of a slow down in personal spending and nonresidential construction activivity [chart omitted]....We see no reason, at this point, to expect a noticeable shift in the demand pattern over the balance of this quarter or the second half. In all, we expect growth to average just over 3% in the final three quarters of this year. We expect GDP growth to stabilize in the area of 3.0%-3.3% in 2006.
>
> **Inflation**: Here, as well, we think that moderation and stability will be the rule over the next several years. That should not imply that there will not be selective pricing disruptions from time to time. The sharp runup in oil prices over the past two years should leave no doubt that inflation flare-ups can take place within the general confines of aggregate pricing stability. On the whole, though, we sense that a quick response policy by an ever-vigilant Federal Reserve Board should limit the inflation risk.

> ...
> **Interest Rates**: The Federal Reserve has now raised short-term interest rates (specifically the Federal Funds rate) eight times since last June and we believe that this rate cycle has yet to run its course. That's because the lead bank seems intent on balancing the risks between stabilizing inflation and sustaining the maturing business up cycle. All told, the Federal Funds rate has risen from 1.00% to 3.00% in the interim. Interestingly, the Fed's tightening has calmed inflation fears sufficiently to push certain long-term rates—including the 10-year Treasury note rate—down modestly in recent weeks. The drop in certain long-term interest rates (notably mortgages) will help to prop up an already vigorous housing market as well as the U.S. economy in general. At this point, we think the Fed is more than halfway through its tightening cycle and that the Federal Funds rate will peak at about 4% late this year [chart omitted].

(The Value Line Investment Survey, *Selection & Opinion*, May 27, 2005, pp. 1707, 1708).

In that most recent Quarterly Economic Review, Value Line projects long-term Treasury bond rates will average 5.3% through 2006 and 5.9% through 2007. The recent six-week average 30-year T-bond yield is 4.6% (data from Value Line, *Selection & Opinion*, six weekly editions, April 22, through May 27, 2005, inclusive).

Also, while Value Line projects that short-term Treasury Bill rates will rise from 1.4% in 2004 to 4.2% in 2009, that investor service publication projects a much smaller increase in corporate bond yields: 5.6% in 2004 to 6.8% in 2009. Finally, those projected interest rate levels (4.2% for T-Bills and 6.8% for AAA-rated Corporate Bonds) are well below the average levels for those securities in 2000 [5.8% for T-Bills and 7.6% for Corporate Bonds]. Therefore, although it is difficult to predict interest rates with any accuracy, the indicated expectation is that interest rates are likely to move somewhat higher in coming years (as long as the economic recovery stays on track), but will remain at relatively low levels for some time to come.

Q. Is it reasonable to conclude that utility investors are aware of the expectations for somewhat higher interest rates in the future, and have reacted to that news?

A. Yes. A widely accepted tenet of modern finance is that U.S. capital markets are efficient in quickly assimilating into stock prices news that impacts stock valuation. Higher interest rates have been forecast for some time, and, it is reasonable to believe, utility investors have incorporated the expectation of higher interest rates into the stock prices they are currently willing to provide for utility stocks.

Q. Are there other reasons to believe that common equity capital costs for utilities are generally lower today than they have been in the past?

A. Yes. The recently enacted change in the Federal tax law lowered the tax rate on dividends. Under the old law, dividends were taxed at rates that typically were approximately 30%;[11] now dividends are taxed at no more than 15%. The result of this tax cut is that a greater percentage of dividend income is kept by investors, and dividend-paying stocks such as utilities have become more valuable than they were before the change in the tax law. In other words, because investors can now keep more of their dividends from their utility investment, they are willing to pay more for those same stocks, resulting in a lower cost of equity capital.

The impact of the tax change on the stock prices of gas distribution utilities has been recognized by investor advisory services:

> **Tax reform has resulted in a fundamental shift in the group's trading range.** We estimate that the reduction in dividend and capital gains taxes should result in a 10% increase in the average gas utility stock price. Prior to tax reform, the median gas utility P/E [price/earnings ratio] traded in a range of 11.5X to 14.5X. With the tax reduction, we believe the new trading range is now 12.5X to 16.0X. (A. G. Edwards, Gas Utilities Quarterly Review, October 3, 2003, p. 5)

[11] Prior to the tax law change, federal income tax rates were 10%, 15%, 27%, 30%, 35%, or 38.6%, depending upon the relevant income bracket. Under the newly passed law, the 27% drops to 25%, the 30% to 28%, the 35% to 33% and the 38.6% to 35%. Since the old 27% tax bracket applied to married couples with a combined income of no more than $47,450, it is reasonable to say that the dollar weighted dividends paid to most individual investors were in brackets of between 27% and 38.6%.

A simple example will facilitate understanding how the tax law change has lowered the cost of equity. Assume a utility with a dividend of $0.50, a stock price of $10, and a long-term investor-expected growth rate of 5.5%. A simple DCF estimate of the cost of equity for that utility would be 10.5%, comprised of a dividend yield of 5.0% ($0.50/$10) and a growth rate of 5.5%. When the taxes on dividends are lowered, investors increase the price they are willing to provide for that stock by 10%, to $11 per share [$10/share x 1.10 = $11/share]. Due to the re-valuation of the stock to $11/share, the dividend yield now becomes 4.5% [$0.50/$11 = 4.545%, rounded to 4.5%]. Because the tax law does not affect the company or its utility operations, its anticipated long-term growth does not change; it remains at 5.5%. The new cost of equity, however is 10% (4.5% dividend yield + 5.5% growth rate), roughly 50 basis points below the pre-tax change cost of equity capital. In sum, another factor contributing to the relatively low cost of common equity capital for utilities in the current capital markets is the recent dividend tax law change.

Q. Does the current level of market-to-book ratios existing in the gas industry, along with investors' expectations regarding the return on equity that gas utilities are expected to earn also support your equity cost estimate in this proceeding?

A. Yes. It is a long-held and widely understood tenet of regulatory finance that when investors are providing market prices above book value of utility stocks the return investors expect (the cost of capital) is below the return the utility will earn on its book value. In other words, when market prices are above book value, investors expect utilities to earn equity returns that are greater than the market-based cost of equity capital for those companies.

In the current market environment, the market prices of gas utility stocks are approximately 65% higher than their book value (i.e., M/B = 1.65).[12] Moreover, Value Line reports that gas distribution utilities are expected to earn returns on the book value of their equity capital over the next three to five years of approximately 10.5% to 11%.[13] Those data indicate both that it is unreasonable to believe the cost of equity capital for gas utilities

[12] See Exhibit__(SGH-1), Schedule 4, page 1.

[13] The Value Line Investment Survey, *Ratings & Reports*, March 18, 2005, p. 459.

is even near, much less above 11% (e.g., 11.95%, as Mr. Hanley testifies), and that the lower cost of equity that I recommend, is more representative of investor expectation.

Q. What is the difference between the expected return and the cost of capital?

A. The expected return is the return on book equity (ROE) that the utility is expected to earn. That return is an accounting return. It is based, in part, on the return allowed by the regulator, the company's operating efficiency and on other income available to the firm (if the firm has unregulated operations). The cost of equity capital is the return investors require to commit equity capital to a particular enterprise. That is the cost of equity capital to the firm—the minimum return investors require in order to invest in a particular type of company. That return is a market-based return, because whatever return the investor receives (yield + dividend growth) will be measured against the market price the investor provided to purchase the stock.

Regulators seek to set the allowed return equal to the cost of equity capital for the same reason they set the return allowed on utility debt equal to the cost of that type of capital. Although there are often other considerations, the cost of service must be factored into utility rates. That includes the cost of money—equity and debt. Investors understand that utility returns are allowed and earned on the book value (original cost less depreciation) of the utility's plant investment. That long-standing regulatory paradigm has been in existence for many, many years and, through informationally efficient markets, utility investors are aware of that fact.

Q. Please explain in more detail why a utility's market-to-book ratio is indicative of the relationship between the expected return and the cost of equity capital.

A. A simple example will illustrate this important point. Assume that a utility has a book value of equity capital equal to $10 per share. Let's also assume, for simplicity, that this utility pays out all its earnings in dividends. If regulators allow the utility a 12% return on that equity, investors will expect the company to earn (and pay out) $1.20 per share (12% allowed return x $10 book value/share = $1.20 earnings/share, all paid out as dividends). If

investors require a 12% return on this investment, they will be willing to provide a market price of $10 per share for this stock ($1.20 dividends/$10 market price = 12% required return). In that case, the allowed/expected return (12%) is equal to the cost of capital (investors' required return, 12%), and the market price is equal to the book value (M=B, or M/B=1.0).

To conform our example to the market situation that presently exists with gas utilities, let's assume that investors' required return (the utility's cost of equity capital) falls to 10%, but the utility continues to be allowed a 12% return on the equity portion of its rate base investment. Investors would be drawn to a utility stock in a risk class for which they require a 10% return but which was expected to pay out a 12% return. This increased demand by investors would result in an increase in the market price of the stock until the point at which the total share yield (earnings divided by the stock price) equaled the investors' required return. In our example, that point would be $12 per share ($1.20 dividends/$12 market price = 10% required return). Now, in this new circumstance, the allowed/expected return (12%) is greater than the required return (10% - the cost of equity capital) *and* the market price ($12/share) exceeds the book value ($10/share). This produces a market-to-book ratio greater than one ($12/$10 = 1.20).

Therefore, the market-to-book / expected return relationship that actually exists today in the market for gas utility stocks indicates that investors expect those companies will earn a return on the book value of their equity (ROE) which exceeds the cost of equity capital.

Q. How can gas utilities have projected book equity returns of 11% and a cost of equity of 9.00% to 9.50%?

A. If investors were providing stock prices (market prices) that approximated the book value of gas utilities (if M/B ≈ 1.0), then it would be reasonable to believe that the cost of capital (investors' market-required return) would approximate 11%—the expected return on the book value of common equity. However, investors are willing to provide a stock price that is considerably *more* than book value for a group of stocks that is expected to earn an 11%

return on book value. Therefore, investors' expected return based on the stock price they are willing to pay (the cost of equity capital to the firm) must be less than the expected return on book value—i.e., less than 11%. Currently, investors are paying about 165% of book value for their gas utility investments. Therefore, they require a return substantially below the 11% expected to be earned on book value. In that regard, the cost of equity estimates in this proceeding between 9% and 9.5% are most reasonable.

Finally, the market data cited above provides dramatic evidence that Mr. Hanley's equity return recommendation of 11.95% cannot represent investor's expectations. Would an investor that requires an 11.95% return on a stock and expects it to earn only 11% on book value, pay more than book value for that stock? Clearly, the answer is no. Therefore, Mr. Hanley's 11.95% cost of equity estimate cannot be an accurate measure of investor market return requirements.

Q. Does this relationship between market price, book value, the earned return and the cost of capital hold for unregulated firms?

A. No. Unlike regulated firms, there is no nexus between the book value of an unregulated firm and its earnings. Therefore, a market price above book value is not indicative of whether not an unregulated firm is earning its cost of capital. For a utility firm however, a market price well above book value indicates that investors expect that firm to earn a return above the cost of equity capital.

Q. Is the relationship between a utility's market-to-book ratio, the expected book return and the cost of equity capital you have outlined well documented in the financial literature?

A. Yes. The DCF model is often referred to as the "Gordon model" because of the definitive work Professor Myron Gordon has done regarding the DCF model and the cost of equity capital of utilities. Professor Gordon has explained that the market-to-book value ratio is greater than (equal to, less than) one when the ratio of the allowed (or expected) rate of return to the cost of capital is greater than (equal to, less than) one. Gordon, M.J., The Cost

of Capital to a Public Utility, 63-64 (1974). There is additional support in the financial literature for the value of market-to-book ratios in regulation.[14]

Company witness Hanley cites Dr. Roger Morin for authority in his testimony in this proceeding. Dr. Morin also recognizes the theoretical relationship between utility market price, book value, ROE and the cost of equity capital. With "P" representing the stock price, "B" the per share book value, "r" the expected return on equity (the ROE), and "K" the cost of equity capital, Dr. Morin states:

> "From Equation 10-6, it is clear that the market-to-book, or P_0/B, will be unity [1.0] if $r = K$, greater than unity if $r > K$, and less than unity if $r < K$:
>
> $$P/B \begin{matrix} > \\ = \\ < \end{matrix} 1.0 \text{ as } r \begin{matrix} > \\ = \\ < \end{matrix} K."$$
>
> (Morin, R. Regulatory Finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington VA, 1994, p. 248)

Finally, it is important to understand that the relationship between market price and book value for a utility operation is not a linear or one-for-one relationship. That is, just because the stock price of a particular utility might be 50% above its book value does not indicate that its cost of equity is 50% below the utility's expected book return. Also, there are differences between book value and rate base, which means that, even if a utility is allowed and expected to earn its cost of equity capital, the market price may not exactly equal book value. For utility operations, it will approximate book value, however, as supported in the financial literature noted above. Therefore, market-to-book ratios, when reviewed in conjunction with expected returns on book equity, provide a reliable indication of the proper range of equity capital costs for utilities.

Q. Mr. Hill, are you suggesting that utility market prices should equal book value, or should be "driven" to book value by regulation?

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[14] Kolbe, Read, Hall, The Cost of Capital, Estimating the Rate of Return for Public Utilities, 25-33 (1986); Lawrence Booth, ("The Importance of Market-to-Book Ratios in Regulation," NRRI Quarterly Bulletin, Vol. 18, No. 4, at 415-16 (Winter 1997)

A. No, that is not my testimony. Regulation is not designed to be a stock price setting mechanism, and regulators should not target any particular stock price in the ratesetting process. That is, regulators should not attempt to achieve a market price to book value ratio of 1.0, nor should they attempt to maintain current price-book ratios (which is also "targeting" market prices) through the ratesetting process. Investors set the market price, depending on the risk/return matrix presented to them in the current market environment. However, the relationship among utility market price, book value, expected ROE and the cost of capital is well known and offers valuable information regarding the reasonableness of a cost of equity estimate. Without making any determination of what electric utility stock prices ought to be, we can observe these facts: utility market prices are about 65% higher than book value. Gas distribution utilities are projected to earn a return on book value of about 11%. Because utility investors are paying 65% <u>more</u> than book value their required market return (the cost of equity capital to the utility) must be well below the expected 11% return on book value. Those data are informational and indicate that 9.5% can be a reasonable estimate of the current cost of equity capital for gas distribution operations, while 11.95% cannot.

II. CAPITAL STRUCTURE

Q. With what capital structure does SWG request rates be set in this proceeding?

A. As shown in the Company's filing, Schedule D-1, Southwest Gas Company requests that its rates be set with a hypothetical capital structure based on assumed capital levels and embedded cost rates at August 31, 2004. The Company's requested ratemaking capitalization consists of 42.00% common equity, 5.00% preferred trust securities, and 53.00% total debt.

Q. Does Southwest Gas Company have a separate, stand-alone capital structure, apart from that of its parent company, Southwest Gas Corporation, Inc.?

A. No. Southwest Gas Company is a division of Southwest Gas Corporation, not a separate subsidiary with its own books of account and separate capital structure. Southwest Gas Company does not have its own separate capital structure. Therefore, the capital structure with which the Parent manages all of its operations in its multiple regulatory jurisdictions as well as its unregulated operations is the capital structure of the Parent, Southwest Gas Corporation.

Q. What has been the parent company's capital structure over the past year?

A. In response to Staff-SH-12-1, the Company provided the capital structure for Southwest Gas Corporation's consolidated operations over the most recent five quarters. That capital structure data is shown on page 1 of Schedule 2. Over the most recent five quarters, (March '04-March '05, inclusive) SWX's consolidated operations have been capitalized, on average, with 34.42% common equity, 4.99% preferred securities, 58.32% long-term debt and 2.27% short-term debt.

At page 9 of his Direct Testimony in this proceeding, Company witness Theodore Wood confirms that the Parent company capital structure consisted of 34.5% common equity and 65.5% total debt (debt and preferred securities) during the test year.

Therefore, the Company is requesting that its rates be set with more common equity and less debt than that with which it has been actually been capitalized. While Southwest Gas Corporation has capitalized its operations with about 35% common equity, the Company requests that this Commission set rates for its Arizona gas distribution operations with a 42% common equity ratio.

What the Company is requesting is that this Commission require Arizona ratepayers to provide an equity return on approximately 7% (42%-35%) of the Company's capital base that is actually funded by debt. Because common equity (on a ratemaking basis) is more than twice as costly as debt capital, the Company's request would require ratepayers to provide substantially more in capital costs than it actually incurs.

For example, assuming a combined tax rate of 40%, the Company's Filing, Schedule D-1, indicates that its requested pre-tax overall return would be 12.74%. Using

Southwest Gas Corporation's actual capital structure and the Company's requested cost rate (i.e., changing nothing else), the pre-tax overall cost of capital falls to 11.87%. That 87 basis point difference in overall capital cost, multiplied by the Company's requested original cost rate base in this proceeding ($0.925 Billion) indicates that, with a hypothetical capital structure of 42% common equity rolled into rates, Arizona ratepayers would be providing the Company with $8 Million annually in capital costs it does not actually incur. (*see* page 2 of Schedule 2).

Q. Is the parent company's relatively low common equity an aberration, or has it been consistently low over a long period of time?

A. The common equity ratio of Southwest Gas Corporation has been consistently low—well below 40% of total capital—for many years. Company witness Hanley's Exhibit__(FJH-3), Sheet 1, shows that over the past five years Southwest Gas Corporation has capitalized its operations with an average common equity ratio between 32% and 34% of total capital. Page 3 of Schedule 2 attached to my testimony shows the parent company's debt-to-equity ratio and corresponding common equity percentage over the past ten years, as reported in the financial research section of MSN.com. Those data show that the average common equity ratio for Southwest Gas Corporation was 36% of total capital over the past ten years.

Therefore, despite Company witness Hanley's claim, at page 5 of his Direct Testimony in this proceeding, that Southwest Gas Corporation has made "herculean efforts to boost its common equity ratio," the parent company's average common equity ratio over the most recent five months, 34%, is very similar to the manner in which it has been capitalized for as long as ten years.

Moreover, during the time when the parent company was capitalized with less equity and more debt, the Company sought rate relief in all of its regulatory jurisdictions, just as it does in this proceeding, with hypothetical common equity ratios that were much higher than actually employed by the parent company (ranging from 42% to 45% of total capital). As I noted above, setting rates using a hypothetical capital structure that contains considerably

more common equity than actually used by the Company results in ratepayers providing an equity return on a portion of rate base financed with debt capital.

Q. Has this Commission previously recognized and addressed this problem?

A. Yes. In prior rate orders regarding Southwest Gas, this Commission has recognized that the Company was requesting that its rates be set using a capital structure that was more expensive than that with which it was actually capitalized. The Commission also recognized that setting rates with the parent company's debt-heavy capital structure could put undue financial strain on the Company's Arizona utility operations. Therefore, in order to balance the interests of ratepayers and investors in prior decisions this Commission has set rates for Southwest Gas using a capital structure containing 40% common equity and 60% fixed-income capital (debt and preferred). The ratemaking capital structure previously employed by this Commission in setting rates for SWG affords ratepayers more savings from lower-cost debt capital than offered by the Company's requested 42% common equity ratio, while providing investors an additional equity cushion above the actual common equity ratio utilized by the Parent, Southwest Gas Corporation.

Q. Do you recommend that the Commission continue its prior policy with Southwest and set rates using a 40% common equity ratio?

A. Yes. I believe that a capital structure consisting of 40% common equity and 60% fixed-income capital continues to provide an appropriate balance of financial safety and economy, and is appropriate for ratemaking purposes in this proceeding.

Q. How does a 40% common equity ratio compare with the capitalization of other gas utilities today?

A. A ratemaking capital structure containing 40% common equity is similar to but slightly below average for the gas utility industry. Page 4 of Schedule 2 shows that the recent average common equity ratio of the gas industry (distribution and integrated companies) is 41.7%. For companies with investment grade bond ratings (i.e., bond ratings at triple-B

(BBB), or higher), the average common equity ratio is 43.9% of total capital. Finally, the sample group of eleven gas distributors selected as similar in risk to SWG (my cost of equity sample group) shows a current average common equity ratio of 42.7%.

As noted above, a ratemaking common equity ratio of 40% is slightly lower than that of the industry generally. However, the standard deviation of the gas utility common equity ratios shown on page 4 of Schedule 2 is approximately 10% and the average is 41.7%. A ratemaking common equity ratio of 40% is only 17% of one standard deviation unit below the average for the industry. For that reason, the 40% common equity ratio ratemaking capital structure recommended is reasonable for ratemaking purposes.

Q. What is your recommendation with regard to the capital structure and embedded cost rates that should be used in determining the overall cost of capital to be used in setting rates in this proceeding?

A. Page 5 of Schedule 2 attached to my testimony shows my recommended ratemaking capital structure and embedded cost rates. Like the Company, I assume that Southwest is capitalized with 5% preferred securities. However, I have reduced the common equity ratio to 40% of total capital and increased the total debt capital by 2% to 55% of total capital.

For the embedded cost rates, I have followed the Company's methodology as set out in Schedule D-2 of its filing and have used the most recent data available (March 31, 2005, provided by the Company in response to Staff-SH-12-2). The cost rate of preferred securities at March 31, 2005 is 8.20%, which is the same rate as requested by the Company. The cost rate of debt (fixed and variable rate term facility) at March 31, 2005 is 7.61%. Due to the increase in short-term debt cost since the Company's filing, that debt cost rate is higher than the debt cost rate requested by the Company (7.49%). The embedded debt costs are calculated on page 6 of Schedule 2.

Q. Do you have any other comments or recommendations regarding the ratemaking capital structure in this proceeding, Mr. Hill?

A. Yes. I believe it is reasonable, in this instance, to set rates for Southwest's Arizona ratepayers with a ratemaking capital structure that contains more common equity and less debt than actually employed by Southwest Gas Corporation. However, that relationship effectively requires a ratepayer subsidy of the Company's financial strength. For that reason, I do not believe it is fair to ratepayers for that ratemaking relationship (i.e., ratepayers providing an equity return on debt capital) to be continued for long periods of time. Unfortunately, that has been the case with Southwest Gas in Arizona. I have testified on cost of capital issues in Southwest Gas rate proceedings before this Commission dating back to the late 1980s (Docket No. U-1551-89-102), and, to my knowledge, the Company's rates have, since that time, been set with a common equity ratio that exceeds that of its parent, Southwest Gas Corporation.

The *quid pro quo* in a ratemaking arrangement in which ratepayers are asked to provide a return on common equity that the company does not have is that the extra equity return will provide the company an additional return above its actual capital cost in order that it can improve its financial position. With an improved financial position (i.e., a consolidated Southwest Gas Corporation capital structure with 40% common equity), the utility would enjoy reduced financial risk, be able to obtain lower debt costs and the ratepayer subsidy would no longer be necessary. However, as I discussed above, even though ratepayers in Arizona (and other jurisdictions) have provided a return on common equity Southwest does not have, the parent company has not improved its capital structure and continues to be capitalized with approximately the 35% equity/65% debt ratios it has employed for more than a decade. As a result, this Commission is again faced in this proceeding with a decision as to whether it should require Arizona ratepayers to provide a return on common equity Southwest does not have.

Q. What do you recommend for the Commission's consideration?

A. While I noted above that I believe the use of a hypothetical 40% common equity ratio is reasonable in this proceeding, I recommend that the Commission consider making other additional findings in this proceeding that will serve to eliminate any continuing ratepayer

subsidy in the future. The Commission could, for example, require the Company to meet certain common equity ratio targets or face equity return penalties. This procedure was undertaken recently by the Washington Utilities and Transportation Commission in a Puget Energy rate proceeding (Docket Nos. UE-040640/UG-040641), and was successful in encouraging the parent company to increase its common equity ratio.

In this instance, however, Staff recommends that the Commission require the Company to submit a plan to re-capitalize its operations with at least 40% common equity. That recapitalization plan should be designed to reach the 40% equity goal prior to the Southwest's next rate proceeding in Arizona.

If, following a clear request by this Commission that the Company increase its common equity ratio to at least 40% of total capital, Southwest management elects not to do so, then Staff reserves the right to recommend that the actual common equity ratio and capital structure be used to set rates, thereby ending the ratepayer subsidy. In that instance (i.e., if Southwest management elects to continue to capitalize its operations as it has in the past), Staff also reserves the right to re-configure Southwest's embedded debt costs, which would be lower if the Company were actually capitalized with more common equity and less debt. That is, if Southwest Gas had actually been capitalized with the 40% common equity layer included in rates for many years, its debt costs would have been lower because of the reduced financial risk. Further, because ratepayers in Arizona have been providing an equity return on equity capital the Company did not have, they should not also be required to pay the inflated embedded debt costs occasioned by the high risk capital structure utilized by Company management.

If, by the time of the next Arizona rate proceeding, Southwest management lowers its financial risk and improves its common equity ratio to 40%, then the Company would be financially stronger, no ratepayer equity subsidy would be necessary and the embedded debt costs, while overstated due to prior issuances, would decline over time also due to the reduction in financial risk. Therefore, no additional adjustment to the Company's debt costs would be necessary.

The salient point here is that Southwest Gas Corporation has, for many years, maintained a debt-heavy capital structure, while requesting that its ratepayers provide a return on a hypothetical capital structure that contains more equity and less debt that actually used by the Company. At the same time, the Company requests higher common equity returns because of the financial risk created by its actual capital structure. Ratepayers have done their part for many years by providing rates based on common equity the Company did not have. It is time, in my view, for the Company to lower its financial risk by increasing its common equity ratio and eliminate the need for any hypothetical capital structure or ratepayer subsidy. Therefore, I recommend that this Commission consider providing appropriate signals to the Company in order to eliminate the need for additional ratepayers subsidies in the future.

Q. Does this conclude you discussion of capital structure issues?

A. Yes, it does.

III. METHODS OF EQUITY COST EVALUATION

A. DISCOUNTED CASH FLOW MODEL

Q. Please describe the Discounted Cash Flow (DCF) model you used to arrive at an estimate of the cost rate of common equity for the Company in this proceeding.

A. The DCF model relies on the equivalence of the market price of the stock (P) with the present value of the cash flows investors expect from the stock, providing the discount rate equals the cost of capital. The total return to the investor, which equals the required return according to this theory, is the sum of the dividend yield and the expected growth rate in the dividend.

The theory is represented by the equation,

$$k = D/P + g, \qquad (1)$$

where "k" is the equity capitalization rate (cost of equity, required return), "D/P" is the dividend yield (dividend divided by the stock price) and "g" is the expected sustainable growth rate.

Q. What growth rate (g) did you adopt in developing your DCF cost rate of common equity?

A. The growth rate variable in the traditional DCF model is quantified theoretically as the dividend growth rate investors expect to continue into the indefinite future. The DCF model is actually derived by 1) considering the dividend a growing perpetuity, that is, a payment to the stockholder which grows at a constant rate indefinitely, and 2) calculating the present value (the current stock price) of that perpetuity. The model also assumes a steady state environment, i.e., the payout ratio and the expected return are constant and the earnings, dividends, book value and stock price all grow at the same rate, forever. As with all mathematical models of real-world phenomena, the DCF theory does not exactly "track" reality. Payout ratios and expected equity returns do change over time. Therefore, in order to properly apply the DCF model to any real-world situation and, in this case, to find the long-term sustainable growth rate called for in the DCF theory, it is essential to understand the determinants of long-run expected dividend growth.

Q. Can you provide an example to illustrate the determinants of long-run expected dividend growth?

A. Yes, in Appendix B, I provide an example of the determinants of a sustainable growth rate on which to base a reliable DCF estimate. In addition, in Appendix B, I show how reliance on earnings or dividend growth rates alone, absent an examination of the underlying determinants of long-run dividend growth, can produce inaccurate DCF results.

Q. Did you use a sustainable growth rate approach to develop an estimate of the expected growth rate for the DCF model?

A. Yes. As a starting point in my DCF growth rate analysis, I have calculated both the historical and projected sustainable growth rate for a sample of gas distribution utility firms with similar-risk operations. However, as noted above, I use that analysis as a means to evaluate the determinants of long-term dividend growth, but in so doing, I have not relied exclusively on a simple "b times r" analysis. In addition to the sustainable growth rate analysis, I have also analyzed published data regarding both historical and projected growth rates in earnings, dividends, and book value for each company in a sample group of electric utility companies. Through an examination of all of those data, which are available to and used by investors, I estimate investors' long-term (i.e., sustainable) growth rate expectations for each company under review. To that long-term growth rate estimate, I add any additional growth that is attributable to investors' expectations regarding the on-going sale of stock for each of the companies under review.

Q. Why have you used the technique of analyzing the market data of several companies?

A. I have used the "similar sample group" approach to cost of capital analysis because it yields a more accurate determination of the cost of equity capital than does the analysis of the data of one individual company. Any form of analysis, in which the result is an estimate, such as growth in the DCF model, is subject to measurement error, i.e., error induced by the measurement of a particular parameter or by variations in the estimate of the technique chosen. When the technique is applied to only one observation (e.g., estimating the DCF growth rate for a single company) the estimate is referred to, statistically, as having "zero degrees of freedom." This means, simply, that there is no way of knowing if any observed change in the growth rate estimate is due to measurement error or to an actual change in the cost of capital. The degrees of freedom can be increased and exposure to measurement error reduced by applying any given estimation technique to a sample of companies rather than one single company. Therefore, by analyzing a group of firms with similar characteristics, the estimated value (the growth rate and the resultant cost of capital) is more likely to equal the "true" value for that type of operation.

Q. How were the sample companies selected?

A. In selecting a sample of gas distribution firms to analyze, I screened all the gas distribution firms followed by Value Line. I selected companies from that group that had a continuous financial history and had at least 90% of net operating revenues generated by gas distribution operations. In addition, I eliminated companies that were in the process of merging or being acquired and had realized an upward stock price shift due to that activity or companies that had omitted dividends[15]. The data for the sample group regarding the percent of revenues generated by gas distribution operations were obtained from Edward Jones Natural Gas Industry Summary, March 31, 2005 edition, and the Value Line Investment Survey, *Ratings and Reports*, March 18, 2005.

The companies included in the similar-risk sample group in this proceeding, in addition to the Parent company Southwest Gas Corporation (SWX), are AGL Resources (ATG), Atmos Energy Corporation (ATO), Cascade Natural Gas Corporation (CGC), Laclede Group (LG), New Jersey Resources (NJR), Northwest Natural Gas (NWN), Peoples Energy Corp. (PGL), Piedmont Natural Gas Company (PNY), South Jersey Industries (SJI), and WGL Holdings (WGL).[16]

Q. How have you calculated the DCF growth rates for the sample of comparable companies?

A. Schedule 3, pages 1 through 4, shows the retention ratios, equity returns, sustainable growth rates, book values per share and number of shares outstanding for the comparable companies for the past five years for each of the utilities under study. Also included in the information presented in Schedule 3, are Value Line's projected 2005, 2006 and 2008-2010 values for equity return, retention ratio, book value growth rates and number of shares outstanding.

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[15] For example, Atmos Energy Corp. recently acquired the Texas gas distribution operations of TXU, but in so doing, did not experience any upward shift in stock price.

[16] In the Schedules attached to my testimony, the gas distributors are referred to by their stock ticker symbols, which are shown in parentheses.

In evaluating these data, I first calculate the five-year average sustainable growth rate, which is the product of the earned return on equity (r) and the ratio of earnings retained within the firm (b). For example, Schedule 3, page 2, shows that the five-year average internal sustainable growth rate for Northwest Natural Gas (NWN) is 2.72%. The simple five-year average sustainable growth value is used as a benchmark against which I measure the company's most recent growth rate trends. Recent growth rate trends are more investor-influencing than are simple historical averages. Continuing to focus on NWN, we see that sustainable growth in 2001 was about 3.4%— above the average growth for the five-year period. Also, Value Line reports that sustainable growth in the most recent years, 2003 and 2004 was below historical average growth. Thus, the historical data would indicate a downward trend in long-term growth. However, by the 2008-2010 period, Value Line projects NWN's sustainable growth will reach a level above the recent five-year average—4%. The projected data would indicate that investors expect NWN to grow at a rate in the future above the growth rate that has existed, on average, over the past five years.

At this point it is important to note that, while the five-year projections are given due consideration in estimating a proper growth rate because they are available to and are used by investors, they are not given sole consideration. Without reviewing all the data available to investors, both projected and historic, sole reliance on projected information can be misleading. Value Line readily acknowledges to its subscribers the subjectivity necessarily present in estimates of the future:

> We have greater confidence in our year-ahead ranking system, which is based on proven price and earnings momentum, than in 3- to 5-year projections. (Value Line Investment Survey, Selection and Opinion, June 7, 1991, p.854).

Another factor to consider is that NWN's book value growth is expected to maintain a relatively steady rate of increase, increasing at a 4% level over the next five years, after increasing at a 3.5% rate historically. Also, as shown on Schedule 4, page 2, NWN's dividend growth rate, which was 1% historically, is expected to increase to 2.5% in the

future—less than the sustainable growth rate projections, but an increase over historical rates of growth. That information would tend to support investor expectations regarding higher growth in the future.

Earnings growth rate data available from Value Line indicate that investors can expect a higher growth rate in the future (5%) than has existed over the past five years (2%). However, First Call (an investor advisory service that polls institutional analysts for growth earnings rate projections) projects a higher earnings growth rate for NWN—5.8%—over the next five years. Zack's (another investor service that polls sell-side analysts for 5-year earnings growth projections) predicts 5.1% earnings growth for NWN.

NWN's projected sustainable growth, as well as available projected earnings growth estimates, indicate that investors can expect higher growth than has occurred, on average, in the past. Those projections are moderated by an expectation of dividend growth below the level of earnings growth projections. A long-term sustainable growth rate of 4.25% is a reasonable expectation for NWN.

Q. Is the internal (b x r) growth rate the final growth rate you use in your DCF analysis?

A. No. An investor's sustainable growth rate analysis does not end upon the determination of an internal growth rate from earnings retention. Investor expectations regarding growth from external sources (sales of stock) must also be considered and examined. For NWN, page 2 of Schedule 3 shows that the number of outstanding shares increased at about a 2.2% rate over the most recent five-year period, due to an equity issuance in 2004. Prior to that time the growth rate was less that 1%. Value Line expects the number of shares outstanding to increase at a slower rate through the 2007-2009 period, bringing the share growth rate to about a 0.7% rate by that time. An expectation of share growth of 1.25% is reasonable for this company.

The current market price of Northwest Natural is approximately 60% above its book value. As I noted previously a utility market price significantly above book value indicates that the utility is earning a return in excess of its cost of capital. If the external ("sv")

portion of the sustainable growth rate is estimated using a market-to-book ratio that is indicative of over-earnings, then the growth rate will be effectively based on an expectation of perpetual over-earnings and, thus, overstated. If that expected DCF growth rate, predicated on the expectation of over-earning the cost of capital, is then used to set the allowed return the process becomes cyclical, leading to higher and higher allowed returns.

Also, a goal of regulation is to duplicate the strictures of the competitive marketplace and, in so doing, to allow a utility to recover no more than its cost of capital. Therefore, it is reasonable to assume that the market price/book value ratio would have a tendency toward unity in order to mitigate the impact of over-earning on the projected external growth rate.

Finally, although I have selected gas distribution firms for analysis which derive the majority of their revenues from utility operations, those firms are not "pure play" utilities—they do have some other operations. Those other operations, therefore, are likely to have an upward impact on the market price and the market-to-book ratio of those companies.

Therefore, a reasonable estimate of investors' expectations for utility price/book ratios is that it will range between current levels and 1.0. I have used the average as an estimate of investors' expectations for the future. At the time of this analysis, NWN's market price is 160% of its year-end book value (M/B = 1.60). The result of combining expected internal (b x r = 4.25%) and external growth rates (1.25%) yields an investor-expected long-term growth rate of 4.62% (see Exhibit__(SGH-1), Schedule 4, page 1 of 2).

I have included the details of my growth rate analyses for Northwest Natural Gas as an example of the methodology I use in determining the DCF growth rate for each company in the utility sample groups. A description of the growth rate analyses of each of the companies included in my sample groups is set out in Appendix C. Schedule 4, page 1, of Exhibit_(SGH-1) attached to this testimony shows the internal, external and resultant overall growth rates for the gas distribution utility companies analyzed.

Q. Have you checked the reasonableness of your growth rate estimates against other, publicly available, growth rate data?

A. Yes. Page 2 of Schedule 4 shows the results of my DCF sustainable growth rate analysis and compares those estimates to the following: 5-year historic and projected earnings, dividends and book value growth rates from Value Line, earnings growth rate projections from First Call (Thomson Financial), the average of Value Line and First Call growth rates and the 5-year historical compound growth rates for earnings, dividends and book value for each company under study. Projected earnings growth rates from Zack's are also shown.

For the gas distribution sample group, Schedule 4, page 2, shows that my DCF growth rate estimate for those companies is 5.12%. That long-term growth rate estimate is higher than Value Line's projected average earnings, dividend and book value growth rate, 5.06% and almost 200 basis points higher than the historical average of those same parameters published by Value Line, 3.21%. Also, my 5.12% growth rate estimate for the DCF is above the simple compound historical growth rate average for those companies, 4.4%. Finally, my DCF growth rate estimate for the gas distributors is also higher than the First Call projected earnings growth rate estimates of 4.98% and virtually equal to the average earnings growth rate projection from Zack's (5.11%).

In sum, when compared to other published growth rates available to investors, discussed below, my growth rates are currently at the top of a reasonable range. My average DCF growth rate estimate is higher than both the projected and historical growth rates available to investors, and, for that reason, should be considered conservative.

Q. Does this conclude the growth rate portion of your DCF analysis?

A. Yes, it does.

Q. How have you calculated the dividend yields?

A. I have estimated the next quarterly dividend payment of each firm analyzed and annualized them for use in determining the dividend yield. If the quarterly dividend of any company were expected to be raised in the next quarter (the 3rd quarter of 2005), I increased the current quarterly dividend by (1+g). Most of the companies under review had recently increased their dividend rate or were not expected to increase dividends in 2005, however,

dividend adjustments were necessary for Laclede Gas, Northwest Natural Gas, and WGL Resources.

The next quarter annualized dividends were divided by a recent daily closing average stock price to obtain the DCF dividend yields. I use the most recent six-week period to determine an average stock price in a DCF cost of equity determination because I believe that period of time is long enough to avoid daily fluctuations and recent enough so that the stock price captured during the study period is representative of current investor expectations.

Schedule 5 contains the market prices, annualized dividends and dividend yields of the companies under study. Schedule 5 indicates that the average dividend yield of the gas utilities companies under study is 4.08%. The average year-ahead dividend projected by Value Line for those same companies is similar to but below my average dividend yield—4.02%.[17] Because the dividend yield is added to the growth rate in the DCF model, the published Value Line dividend yield indicates that my DCF result may slightly overstate investor expectations (4.08% - 4.02% = 0.06%; 6 basis points). By this measure, my DCF result would be conservative.

Q. What is your cost of equity capital estimate for the gas distribution utility companies, utilizing the DCF model?

A. Schedule 6 shows that the average DCF cost of equity capital for the gas distribution companies is 9.20%.

Q. Does this conclude your DCF analysis of the cost of equity capital for SWG?

A. Yes, it does.

B. CORROBORATIVE EQUITY COST ESTIMATION METHODS

Q. In addition to the DCF, what other methods have you used to estimate the cost of

[17] Value Line, *Summary & Index*, May 27, 2005.

equity capital for Southwest Gas Company in this proceeding?

A. To support and temper the results of my DCF analysis, I have used three additional econometric methods to estimate the cost of equity capital for the group of firms similar in investment risk to Southwest Gas Company. The three additional equity cost estimation methodologies are: 1) the Capital Asset Pricing Model (CAPM), 2) the Modified Earnings-Price Ratio (MEPR) analysis, and 3) the Market-to-Book Ratio (MTB) analysis. The similar risk sample group of firms analyzed with these three methods is the same as that selected for the DCF analysis, discussed previously. The theoretical details of each of those analyses are contained in Appendix D, attached to this testimony. The actual calculations and data supporting the results of each of these models are shown in the attached Schedules.

Schedule 7 attached to this testimony shows the detail regarding the CAPM analysis, which indicates a cost of capital for gas distributors ranging from 7.71% to 9.38%. Schedule 8 provides support for the assumptions contained in the Modified Earnings Price Ratio (MEPR) analysis, and Schedule 9 shows the data and calculations regarding the that analysis, which indicates a current cost of equity capital ranging from 8.68% to 8.78%. Schedule 10 attached to this testimony contains the supporting detail for the Market-to-Book Ratio (MTB) analysis, which indicates a current cost of equity capital ranging from 8.84% to 9.46%.

C. SUMMARY

Q. Please summarize the results of your equity capital cost analyses for the sample group of similar-risk gas distribution companies.

A. My analysis of the cost of common equity capital for the sample group of gas distribution companies is summarized in the table on the following page.

METHOD	COST OF EQUITY
DCF	9.20%
CAPM	7.71%/9.38%
MEPR	8.68%/8.78%
MTB	8.84%/9.46%

The DCF result noted above, which is my primary indication of the cost of equity capital, is 9.20%. Averaging the lowest and the highest results of the corroborative analyses (CAPM, MEPR, and MTB) produces an equity cost rate range of 8.41% to 9.21%—a range that is almost entirely below the DCF result. Therefore, in total, the other corroborative analyses indicate that my DCF results represent a conservative (i.e., high) estimate of the actual cost of common equity of gas distributors, and the DCF result should be considered to be in the upper portion of a reasonable range of equity capital cost for the Company. However, due to the expectation of higher short-term interest rates over the near term, I believe it is reasonable to set a range so that the DCF result is near the middle of a reasonable range. Weighing all the evidence presented herein, my best estimate of the cost of equity capital for a company facing similar risks as that group of gas distribution utility companies ranges from 9.00% to 9.50%.

Q. Does your equity cost estimate include an increment for flotation costs?

A. No, it does not.

Q. Please explain why an explicit adjustment to the cost of equity capital for flotation costs is unnecessary.

A. An explicit adjustment to "account for" flotation costs is unnecessary for several reasons. First, it is often noted in support of a flotation cost adjustment that flotation costs associated with common stock issues are exactly like flotation costs associated with bonds. As a preliminary matter, that is not a correct statement because bonds have a fixed cost and

common stock does not. Moreover, even if it were true, the current relationship between gas utility stock price and book value would indicate a reduction to the market-based cost of equity, not an increase.

When a bond is issued at a price that exceeds its face (book) value, and that difference between market price and the book value is greater than the flotation costs incurred during the issuance, the embedded cost of that debt (the cost to the company) is *lower* than the coupon rate of that debt. In the current market environment for gas utility common stock, those stocks are selling at market prices well above book value.[18] The difference between the market price of gas distribution stock and their book value dwarfs any out-of-pocket issuance expense those companies might incur. Therefore, if common equity flotation costs are, indeed, "exactly like flotation costs with bonds," then, the adjustment to the cost of common equity should be downward, not upward.

Second, because gas distribution utility stock prices are well above its book value, every time a new share of stock is sold, all shareholders realize an *increase* in the per share book value of their investment. The difference between the market price and the book value of the new shares adds to the book value of all the other existing shares. In other words, the stockholders' investment value is increased when new stock is issued. As a result, there is no need to "compensate" stockholders by increasing the profit allowed.

Third, assuming *arguendo* the need for an issuance expense adjustment to the cost of equity, the vast majority of the issuance expenses incurred in any public offering are "underwriter's fees" or "discounts." Underwriter's discounts are not out-of-pocket expenses for the issuing company. On a per share basis, they represent only the difference between the price the underwriter receives from the public and the price the utility receives from the underwriter for its stock. As a result, underwriter's fees are not an expense incurred by the issuing utility and recovery of such "costs" should not be included in rates. Moreover, the amount of the underwriter's fees are prominently displayed on the front page of every stock offering prospectus and, as a result, the investors who participate in those offerings (e.g., large brokerage firms, banks) are quite aware that a portion of the price they

[18] See Exhibit__(SGH-1), Schedule 4, p. 1.

pay does not go to the company but goes, instead, to the underwriters. By electing to buy the stock with that knowledge, those investors have effectively accounted for those issuance costs in their risk-return framework by paying the offering price. Therefore, they do not need any additional adjustments to the allowed return of the regulated firm to "account" for those costs.

Fourth, my DCF growth rate analysis includes an upward adjustment to equity capital costs that accounts for investor expectations regarding stock sales at market prices in excess of book value. Any further explicit adjustment for issuance expenses is unnecessary.

Fifth, research has shown that a specific adjustment for issuance expenses is unnecessary.[19] There are other transaction costs which, when properly considered, eliminate the need for an explicit issuance expense adjustment to equity capital costs. The transaction cost that is improperly ignored by the advocates of issuance expense adjustments is brokerage fees. Issuance expenses occur with an initial issue of stock in a primary market offering. Brokerage fees occur in the much larger secondary market where pre-existing shares are traded daily. Brokerage fees tend to increase the price of the stock to the investor to levels above that reported in the *Wall Street Journal*, i.e., the market price analysts use in a DCF analysis. Therefore, if brokerage fees were included in a DCF cost of capital estimate, they would raise the effective market price, lower the dividend yield and lower the investors' required return. If one considers transaction costs that, supposedly, raise the required return (issuance expenses), then a symmetrical treatment would require that costs, which lower the required return (brokerage fees), should also be considered. As shown by the research noted above, those transaction costs essentially offset each other and no specific equity capital cost adjustment is warranted.

Q. Are there factors that should be considered in determining a point-estimate for Southwest Gas's equity return, within the range of 9.0% to 9.5%?

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[19] "A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," Habr, D., National Regulatory Research Institute Quarterly Bulletin, January 1988, pp. 95-103.

A. Yes. As I noted in Section II of this testimony, while my recommended ratemaking capital structure contains more common equity and less debt that actually employed by Southwest, that capital structure contains less common equity than average for the gas companies I used to estimate the cost of equity capital. Therefore, taking additional risk factors into account, I recommend the Commission allow an equity return for Southwest at the high end of a reasonable range—in this case 9.50%.

Q. What is the overall cost of capital for SWG's utility operations in Arizona, based on an allowed equity return of 9.50%, and a reasonable ratemaking capital structure?

A. Schedule 11 attached to my testimony shows that, with an allowed return on equity capital of 9.50%, using a reasonable ratemaking capital structure, Southwest Gas Company's overall cost of capital would be 8.40%. As also shown on Schedule 11, the equity return I recommend affords the Company the opportunity to achieve a pre-tax interest coverage of 2.38 times. That level of interest coverage, according to Standard & Poor's published benchmarks is sufficient to maintain the Company's current bond rating, and is much higher than the actual level of pre-tax interest earned by the Parent company over the past three years. The return on equity capital I recommend affords the Company an opportunity to maintain its credit and its ability to attract capital and is appropriate for use in setting rates in this proceeding.

Q. Does this conclude your analysis of the Company's overall cost of capital?

A. Yes, it does.

IV. COMMENTS ON COMPANY COST OF CAPITAL TESTIMONY

Q. What methods has Company witness Hanley used to estimate the cost of equity capital in this proceeding?

A. Company witness Hanley has based his equity return recommendation for SWG on a DCF analysis, a beta-adjusted Risk Premium analysis and a Capital Asset Pricing Model analysis of the market data of a sample of gas distribution utilities and a sample of integrated gas companies. As a check on his results, the Company witness performs a comparable earnings test on a sample of unregulated firms.

Witness Hanley also discusses his concerns regarding the reliability of DCF results in estimating the cost of equity capital. I will discuss Mr. Hanley's concerns regarding the DCF initially and, in so doing, point out that the witness' position on that issue is without theoretical foundation. Contrary to the testimony of Mr. Hanley in this proceeding, the DCF methodology provides accurate estimates of the cost of equity capital no matter what the relationship between market price and book value.

Subsequent to discussing the flawed logic on which the Company witness relies in order to attempt to diminish the usefulness of a DCF analysis, I address the practical shortcomings of each of witness Hanley's other equity cost estimation techniques. A central flaw in all of the analyses performed by Company witness Hanley—including his comparable earnings check—is that they all depend, in a fundamental way, on beta. The Company's Risk Premium, CAPM and Comparable Earnings analyses all use beta as a measure of relative risk and return.

As I have discussed at some length in Appendix D, the financial literature indicates that beta is not a good indicator of relative risk. Moreover, that evidence comes from a source that Company witness Hanley cites for authority—Professor Eugene Fama. Therefore, the results derived from Mr. Hanley's non-DCF equity cost estimation procedures are of questionable reliability. In other words, the Company places more weight on the results of the analyses that are less reliable (i.e., beta-adjusted Risk Premium, CAPM and Comparable Earnings) than on his more reliable DCF analysis.

Q. Has the "reliability" of DCF equity cost estimates been questioned by utility-sponsored rate of return witnesses in other regulatory proceedings in which you have participated?

A. Yes. As capital costs have fallen over the past few years and the DCF has (appropriately) produced lower equity cost estimates, it has become rare, in my experience, when utility-sponsored rate of return witnesses do not attempt to convince regulators that DCF results are biased downward for one reason or another. Such claims are uniformly without merit. The Company's testimony on that issue in this case is no exception.

Q. Have utility witnesses that argue against reliance on DCF results been successful in their endeavor to persuade regulators to reduce their use of DCF in ratesetting?

A. In my experience, attempts by utilities to dissuade regulators from relying on DCF equity cost estimates (which have become prevalent in recent years) have not been successful. That experience is confirmed by an article appearing in Public Utility Reports, entitled "Cost of Equity Determinations—State Regulators Turn Back Challenges to the DCF Model." The fact that utility-sponsored rate of return witnesses are downplaying the reliability of DCF equity cost estimates has been with us for many years and is evidenced by the date of the article—1994—more than ten years ago.

> "The discounted cash flow (DCF) model, the methodology most frequently relied upon to establish authorized ROE, has often engendered spirited debate over the technical aspects of its application. Of late, however, some utilities have shifted the focus of the debate, urging that the DCF model no longer produces reasonable results....
>
> Despite utility claims in numerous rate proceedings that the DCF model is producing unreasonably low estimates of investor-expected return on investment in utility equity, state regulators have not reduced their reliance on the model as the primary tool in setting rate of return. In fact the opposite may be true." (148 P.U.R. 4th, Advance Sheets, p. i, iii (March 4, 1994)).

The article concludes by listing states in which regulators have recently stated their intent to continue to rely on the DCF: Arizona, California, Colorado, Connecticut, District of Columbia, Florida, Illinois, Maryland, Massachusetts, Minnesota, Rhode Island and Utah. From my personal experience in over 220 rate proceedings, I have yet to appear before a regulatory commission that does not rely on a DCF analysis of the cost of equity capital.

Q. What rationale does Mr. Hanley offer for his caution regarding the DCF method?

A. Mr. Hanley testifies at page 25 of his Direct Testimony in this proceeding that the DCF has a tendency to "mis-specify investors' required return" when utility market prices are substantially different from book value. According to Mr. Hanley, the "problems" inherent in the DCF are related to the fact that the model utilizes stock prices and is applied to a book value rate base. He offers a numerical example that purports to support his position in Exhibit__(FJH-6). In attempting to show that the DCF estimates the cost of equity incorrectly when market prices are different from book value, Mr. Hanley has created a hypothetical example that cannot exist in reality and is contrary to one of the most fundamental precepts in finance. I will discuss that flawed numerical example in detail subsequently.

In addition, Mr. Hanley, in his attempt to characterize the DCF as somehow more suspect than the other equity cost estimation methods he utilized, cites Phillips at page 22 of his Direct[20]. However, Phillips also finds fault with the other equity cost estimation methods on which Mr. Hanley elects to rely more heavily, the Risk Premium and the CAPM:

> "[Capital Asset Pricing Model]
> Despite its appeal, the CAPM also has both theoretical and practical problems. The theoretical issues include the model's basic assumptions [footnote: 'These assumptions are: (1) Investors are risk averse...(2) All investors compose their portfolios (with regard to anticipated risk and return) using a common single investment period...(3) Investors make decisions to maximize their expected utility of wealth...(4) Capital markets are perfect...(5) All investors form, on the basis of this common information, identical subjective expectations of future returns, the variance of these returns for specific securities and the covariance among securities...(6) There is a riskless rate of return investment opportunity with no variance or covariance commonly available to all with the same rate of return prospect for each investor.'] and the static nature of the model [footnote omitted]. The practical problems surround the beta coefficient..."

[20] Phillips, C. F., The Regulation of Public Utilities, Theory and Practice, Public Utilities Reports, Inc. Arlington VA, 1993, pp. 396.

> [Risk Premium Analysis]
> "...the risk premium method, ... is based upon the premise that common equity carries a higher risk than debt....Like other methods, however, there are a number of specific problems. Over what period of time should the spread be established? Does the spread between the return on debt and the return on equity remain constant over time and at all interest levels? [footnote omitted] Should the spread be expressed on a before- or after-tax basis to the investor? What debt instruments would be used (e.g., government securities versus corporate or utility bonds)? What equity securities should be used? How should the resulting return requirement be adjusted for risk that corresponds to a given utility? In light of these problems many use the risk premium approach as a subsidiary method to test the results of other approaches." (Phillips, C. F., The Regulation of Public Utilities, Theory and Practice, Public Utilities Reports, Inc. Arlington VA, 1993, pp. 394-9)

Even though the authority on which Mr. Hanley relies finds fault with his other equity cost estimation methodologies, Mr. Hanley elects to cite only Dr. Phillips' views on the DCF.

Mr. Hanley also elects to cite Morin and some of his published concerns regarding the DCF[21]. Again however, Mr. Hanley does not inform the Commission that there are five chapters in the Morin text devoted to DCF theory and the proper application of the DCF while only one chapter of the Morin text is devoted to the risk premium and the CAPM models.

Finally, as I note in Appendix B attached to this testimony, the constant growth DCF model is often called the "Gordon model." The DCF has that pseudonym due to the pioneering work done by Professor Myron Gordon regarding the DCF. I am familiar with Professor Gordon's work in the development of the DCF and there is no assumption contained in that work which indicates that the market price of a stock must equal its book value in order for the model to provide reliable results. Previously in this testimony, I pointed out that Professor Gordon's published work indicates that when utility market prices exceed book value, the expected return on book value exceeds the investors' required return (the cost of equity capital); however, there is no mention by Professor Gordon of any

[21] Morin, R. A., Regulatory Finance - Utilities' Cost of Capital, 1994, Public Utilities Reports, Inc., Arlington, VA.

"miss-specification" of the DCF or the model's ability to accurately estimate the cost of equity capital when market prices are different from book value.

Q. You have addressed the theoretical shortcomings of Mr. Hanley's position regarding the efficacy of the DCF when market prices are above book value. Would you please now address the numerical example regarding the same issue presented in Exhibit__(FJH-6)?

A. Yes. In attempting to show that the DCF estimates the cost of equity incorrectly when market prices are different from book value, Mr. Hanley has created a hypothetical example that cannot exist in reality and is contrary to one of the most fundamental precepts in finance.

In Exhibit__(FJH-6), Mr. Hanley posits a firm that has an allowed return of 10% (which is supposedly determined by the DCF), a book value of $13.33 and for which investors are paying a stock price equal to 180% of book value ($24.00). (This is shown on Mr. Hanley's Exhibit__(FJH-6) in column 2). That company will earn $1.33 on its rate base investment (10% allowed return x $13.33 rate base/book value), and that $1.33 return represents only a 5.55% return to the investors that paid $24 for the stock.

Mr. Hanley, through this example, ostensibly "proves" that the DCF does not provide the investors' required 10% return (the DCF-determined return) when it is applied to a rate base (book value) that is smaller than the market price. His example is wrong for two reasons.

First, if the investor's required return is actually 10% (which appears to be Mr. Hanley's assumption) and the utility is expected by investors to earn a 10% return on its book value, then no investor would pay 1.8 times book value for the stock, and Mr. Hanley's numerical example is a non-sequitur at the outset. Imagine a broker trying to sell a stock to an investor who requires a 10% return. "I've got a stock for you that's going to pay a 10% return on a $13.33 per share book value—in other words one share will get you $1.33, but each share will cost you $24. What do you say?" Any rational investor who required a 10% return would turn down that offer. No investor would knowingly pay $24

for a stock that will earn $1.33 when they require a 10% return for that type of stock. Mr. Hanley's "example" defies fundamental financial precepts in that regard and is without theoretical foundation.

Second, the only reason for an investor to pay $24 for a stock that will provide a $1.33 income stream is if that investor requires a 5.55% return for that type of stock. In Mr. Hanley's example if we take the 10% number to be the allowed return and the investor's required return (the cost of equity capital) to be 5.55% (a DCF result derived from a 4% dividend yield and 1.55% growth), then Mr. Hanley's "Column 2" numerical example makes economic sense. If the investor's required return is 5.55% and the stock in question is expected to pay a 10% return on a $13.33 book value, then, *and only then*, is the $24 stock price rational.

Therefore, the only situation under which the "Column 2" conditions set out in Exhibit__(FJH-6) attached to Mr. Hanley's testimony can exist is one that conforms with the widely accepted relationship between market price, book value, ROE and the cost of capital discussed previously in my testimony. Namely, when the expected/allowed return (r = 10% in Hanley's "Column 2") exceeds the investors' required return (K = 5.55% in Hanley's "Column 2") the market price (P = $24) will exceed the book value (B = $13.33).

In summary, Mr. Hanley's numerical example in Exhibit__(FHJ-6) that purports to show the DCF understates the cost of equity when market prices are greater than book value, does not do so. As posed by Mr. Hanley, his Exhibit__(FHJ-6) numerical example is a construct that cannot exist in reality and the conclusions that proceed from his construct have no economic credibility. Instead, under the *only* circumstance that makes economic sense, his example shows that when utility market prices are significantly above book value, the investors' required return (the cost of equity capital) is below the ROE expected to be earned by those companies.

Q. Do you have any other comments regarding Mr. Hanley's "DCF miss-specification" position?

A. Yes. Two other points deserve mention. First, Mr. Hanley devotes quite a bit of testimony to the efficient market hypothesis, which holds that all publicly-available information is incorporated into market prices. It is certainly public knowledge that utilities are almost exclusively regulated based on the book value of their plant investment, and any return that is allowed, will be earned on and measured against book value. That is public knowledge and is incorporated into stock prices. Therefore, when an investor provides a per share stock price which is more than the per share book value of a utility, the return required by that investor must be below the expected return on book value. The expected return on book value for gas utilities is currently 11% according to Value Line. Therefore, one of the fundamental principles of modern financial theory, cited by Mr. Hanley in his example—the efficient market hypothesis—indicates that his 11.95% cost of equity capital cannot be an accurate estimate of the current cost of common equity capital for that type of firm.

Second, it is important to note that, according to Mr. Hanley, the "miss-specifications" of the DCF-derived cost of equity are symmetrical; that is, when market prices are above book value (as they are currently) the DCF will "understate" the cost of equity and when market prices are below book value, the DCF will "overstate" the cost of equity. However, I have testified on the subject of utility cost of capital during periods when market prices were below book value for utilities and am unaware of any utility-sponsored cost of capital witness ever stating that the DCF *overstated* the cost of equity because market price/book value inequalities.

In Staff-SH-12-24, when asked to provide any testimony in which he has taken the position that the DCF *overstated* the cost of equity because the market price was below book value, Mr. Hanley supplied no such testimony. Mr. Hanley indicated that he has discarded all of his testimony from the time when market prices of utilities were below book value. In addition, although Mr. Hanley is able to recall that his DCF results were the "highest" in those testimonies he discarded, he does acknowledge that he "...did not state that the DCF cost rate overstated the cost of common equity..." during the early 1980s when market prices of utilities were below book value.

In sum, the Company's position that the DCF model miss-specifies the cost of equity capital when market prices are different from book value is without theoretical merit, is logically unsound and should not deter this Commission from its long-standing reliance on the Discounted Cash Flow equity cost estimation methodology.

Q. Mr. Hill is it your position that the DCF is infallible and produces precise estimates of the cost of equity capital?

A. No. The DCF is a tool with which an experienced analyst can estimate the cost of equity capital. The theory is sound; it is not adversely affected by differences between the market price and book value of utility equities and, when properly applied, the DCF produces reliable estimates of the cost of equity capital. However, it is important to note that I have always used the DCF in conjunction with other methodologies to estimate the cost of equity capital, not because I believe the DCF results are unreliable, but because I believe it is better to rely on more information rather than less in attempting to estimate the cost of equity capital. My testimony regarding the DCF here is not intended to support the notion that the DCF is infallible. Rather, it is intended to underscore the flaws in the position espoused by the Company regarding the reliability of equity cost estimates currently provided by the DCF model.

Q. What comments do you have regarding the mechanics of Mr. Hanley's DCF analysis?

A. Mr. Hanley uses a "generic" approach to calculating his DCF dividend yield in which the current annualized dividend is assumed to be increased half-way during the coming year. This is accomplished by multiplying the current annualized dividend by one plus one-half the growth rate he determines to be appropriate for his DCF analysis. However, his methodology gives no consideration to investor's actual dividend expectations for the coming year.

For example, Value Line reports in its March 18, 2005 edition of *Ratings and Reports* that Cascade Natural Gas, Laclede Group and Southwest Gas (three firms included

in Mr. Hanley's gas distributor sample group) are not expected to increase their current dividend between 2005 and 2006. Mr. Hanley's dividend yield methodology, then, will overstate the expected dividend yield for those companies. In fact, Value Line's most recent year-ahead dividend yield projection for the gas distributors in Mr. Hanley's eleven-company sample group is 3.95%[22]. Mr. Hanley's DCF dividend yield for those same companies is 4.28%, 33 basis points higher than Value Line's current year-ahead dividend yield projections.

Q. What are your comments regarding Mr. Hanley's DCF growth rate analysis?

A. First, Mr. Hanley's growth rate analysis is mechanistic in that it simply plugs selected projected data into a formula to produce a growth rate with no underlying analysis of either the historical or projected growth rate fundamentals. Regarding that fact, it is interesting to note that Morin (on whose authority Mr. Hanley relies) at page 244 of Regulatory Finance - Utilities' Cost of Capital, discusses the drawbacks of "mechanical" DCF techniques of the type employed by Mr. Hanley.

> "The DCF method cannot be applied in a robotic, mechanistic manner. Mechanical approaches designed to simply insert numbers into an algebraic equation without regard to the reasonableness of such inputs in a regulatory setting must be avoided." (Morin, R. A., Regulatory Finance - Utilities' Cost of Capital, 1994, Public Utilities Reports, Inc., Arlington, VA., p. 244)

Second, Mr. Hanley's growth rate analysis relies exclusively on earnings growth rate projections. As I discuss in more detail in Appendix B attached to this testimony, heavy reliance on earnings growth can lead to inaccurate equity cost estimates. Therefore, while I have no problem with the consideration of earnings growth rate projections in determining DCF growth, they should not be afforded the exclusive consideration afforded by Mr. Hanley.

[22] Value Line, *Summary & Index*, May 27, 2005.

Q. Are there additional reasons why Mr. Hanley's DCF analysis produces unreliable results?

A. Yes. Mr. Hanley doesn't report the actual results of his DCF analysis. For example, in Exhibit__(FJH-1), Sheet 2, Mr. Hanley indicates that the average DCF result for his eleven-company gas distribution sample group is 10.36%. However, the actual DCF results shown on his Exhibit__(FJH-7) indicate an average DCF for those eleven gas distributors of 9.20%. That result is identical to my own DCF result.

In reporting his DCF results, Mr. Hanley simply elected to ignore the low results and report only the high results. There is no symmetrical elimination of too-high and too-low results, which would present a reliable statistical treatment of those data. Instead, Mr. Hanley has simply elected to eliminate all the low numbers and provides a result designed to be biased on the high side. Mr. Hanley's treatment of his DCF results is illogical and statistically unreliable. This Commission should not rely on Mr. Hanley's reported DCF results.

Q. Does that conclude your comments regarding Mr. Hanley's DCF analyses?

A. Yes, it does.

Q. What are your comments on the mechanics of Mr. Hanley's Risk Premium analysis?

A. A fundamental precept on which the risk premium methodology is based holds that the higher risk of stocks over bonds requires an incrementally higher return for those stocks in order for investors to be compensated for assuming the higher risk (e.g., see Hanley Direct, p. 33). Although that is generally true, it is most important to realize that, given a current bond yield of 6% for utilities, an equity return of 8%, 10% or even 50% would fulfill the requirement of providing "a premium" over debt costs. The real issue with a risk premium analysis is determining the premium with any precision. It is not a directly observable phenomenon and must be estimated.

There are two other fundamental tenets on which risk premium-type analyses are grounded which, when examined, indicate that this equity cost estimation methodology should not be given primary consideration in setting allowed rates of return. First, since risk premium analyses look backward in time, they assume "past is prologue." In other words, the investors' expectations for the future are assumed to mirror the average results they have experienced in the past. Second, implicit in the use of an average historical return premium of equities over debt is the assumption that the risk premium is constant over time. Neither of these assumptions on which the risk premium analysis rests is true.

Witness Hanley uses two methodologies of measuring return differences between stocks and bonds. One looks backward over many years and relies on the Ibbotson Associates return data. This sort of analysis necessarily assumes that long-term historical averages will equal future expectations and risk premiums are, therefore, constant. However, over time, risk premiums (the differences in historical returns between stocks and bonds) vary greatly from period to period. The practical impact of the volatility of historical risk premium data is that with the selection of any particular period over which to average the historical data, virtually any risk premium result can be produced. In addition, the use of historical earned return data (such as that published by Ibbotson Associates, a data source on which Company witness Hanley relies in his Risk Premium analysis) to estimate current equity capital costs has been questioned in the financial literature:

> "There are both conceptual and measurement problems with using I&S [Ibbotson and Sinquefield] data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet they can result in significant differences in the final outcome." ("The Risk Premium Approach to Measuring a Utility's Cost of Equity," Brigham, Shome and Vinson, Financial Management, Spring 1985, p. 34)

Also, there is additional evidence that analyzes market risk premiums over a very long-term period (dating back to the early 1800s). That study shows that the risk premiums obtained from the time period studied by Mr. Hanley (starting in the late 1920s or early 1930s) are exaggerated and are unrepresentative of long-term investor expectations. Moreover, those studies show that a more normal risk premium between stocks and bonds ranges from 2% to 3% (Siegel, J., Stocks for the Long Run, 1994, Irwin, Chicago IL, p. 20). Subsequent to the publication of the Siegel text, the market risk premium has become the focus of much research in the academic community.

As noted above, Mr. Hanley has relied, in part on Ibbotson's published historical data to determine the market risk premium (i.e., the expected return difference between stocks and bonds). However, in a recent paper published by Ibbotson in the Financial Analysts Journal, he indicates that the expected market risk premium (the return equity investors expect over bond yields) is 4% to 6%, not the 7.3% used by Mr. Hanley in his testimony (Exhibit__FHJ-13, Sheet 2).[23] In that recently published paper, Dr. Ibboston also discusses the current theoretical debate over the market risk premium. That debate centers on the fact that recent studies have shown that long-term historical risk premiums (such as the Ibbotson data Mr. Hanley relies on) overstate current investor expectations. As Ibbotson, himself, notes the current research indicates that the market risk premium going forward ranges from 0% to a maximum of about 5% (op cit., pp. 88, 89). Ibbotson disagrees with that current research and provides his analysis of the issue, which shows a prospective market risk premium to range from 4% to 6%.

In that regard, a risk premium in the middle of Ibbotson's projected range, 5%, which would be appropriate for stocks generally and too high for less-risky utilities, added to Mr. Hanley's projected 5.5% Treasury bond yield (Hanley Exhibit__(FHJ-13), Sheet 4) would produce a cost of equity estimate of 10.5%. Therefore, recent market risk premium data available from the source on which Mr. Hanley relies (Ibbotson), indicates that the cost of equity for the market, generally is 10.5%. That information indicates the cost of equity

[23] Ibbotson, R., Peng, C., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts' Jounal*, January/February 2003, pp. 88-98.

estimate for a lower-risk gas distribution utility of 9.5% provided in my testimony is reasonable, while Mr. Hanley's 11.95% estimate substantially overstates Southwest's cost of equity capital.

Q. Are there other concerns regarding Mr. Hanley's Risk Premium analysis?

A. Yes, a more serious theoretical problem with Mr. Hanley's Risk Premium analysis is his use of beta. The witness multiplies the market risk premium he derives from his historical and forward-looking analyses by a beta coefficient and then adds the resulting company-specific risk premium to utility bond rates. In his Direct Testimony, Mr. Hanley states:

> "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, i.e., unsystematic or company-specific risks are reflected in the RPM [Risk Premium Method] 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." (Hanley Direct, p. 33, ll. 10-16)

First, as I have pointed out in my discussion of the CAPM in Appendix D, recent evidence presented by prominent economists, cited as authority by Mr. Hanley (Eugene Fama), shows that over the past thirty years beta *has not been* a good indicator of relative risk. Therefore, witness Hanley's beta-adjusted Risk Premium methodology that gives beta substantial weight, fails as a primary equity cost estimation methodology on this point alone.

Second, in attempting to distinguish his beta-adjusted Risk Premium analysis from his CAPM analysis (the only difference is the use of utility bond rates in the former rather than US Government bond rates in the latter), witness Hanley underscores the fundamental flaw in his Risk Premium analysis. He opines that beta is supposed to capture the market risk of each stock (which he admits is a relatively small percentage of total investment risk) and that his use of beta along with utility bond yields (which measures total risk, including company-specific, non-market risk) is, somehow, better because it pays heed to both kinds

of risk. However, that analysis is a theoretical mixed metaphor, and has no economic meaning.

The very essence of the concept of beta is that investors are well diversified and it is only market risk captured by beta that is priced (i.e., included in the market price of the stock). All other company-specific risk is diversified away. Mr. Hanley's use of beta in a model which supposedly recognizes both systematic (market) and non-systematic (company-specific) risk, at the very least double-counts systematic risk and, in the final analysis, is an untenable mix of two different equity cost estimation paradigms.

In other words, Mr. Hanley has used betas (which assume no company-specific risk) that are theoretically designed to be applied to a risk-free rate of interest (Treasury securities), and has placed them in a model which knowingly includes company-specific risks. If the betas were designed to be applied to corporate bond yields, they would be lower that those on which Mr. Hanley relied. Therefore, Mr. Hanley's ad-hoc use of beta in his Risk Premium method overstates the cost of equity, at a minimum, by the difference between utility bond yields and Treasury bond yields.

Mr. Hanley's "borrowing" betas from a CAPM analysis and applying it to a risk premium analysis is similar in nature to adding a DCF growth rate to a utility bond yield, and calling that an equity cost estimate. Such a methodology, i.e., taking one parameter from one econometric model and inserting it in another is both theoretically and logically inconsistent and does not provide a reliable basis from which this Commission could determine equity capital costs rates. Mr. Hanley's beta-adjusted Risk Premium results should be afforded little, if any, weight by this Commission in reaching its decision regarding the cost of equity capital for Southwest Gas in this proceeding.

Q. What are your comments on Mr. Hanley's CAPM analysis?

A. I have previously discussed the issues relevant to the CAPM in Appendix D of this testimony, and will not repeat the entirety of that logic here. However, it is important to note that Mr. Hanley has elected to utilize only long-term US Government securities as the risk-

free rate and has used only the arithmetic mean of historical market risk premium data, both of which can result in overstated CAPM equity cost estimates.

Mr. Hanley also performed what is termed and "empirical" CAPM (ECAPM). As Mr. Hanley notes at page 46 of his Direct, the "empirical" CAPM is designed to account for the fact that the security market line is believed to have a lower slope than postulated theoretically. A lower slope for the capital market line implies that the CAPM understates equity costs for low beta stocks like utilities and over-estimates the equity cost rate for high beta stocks like "dot-com" companies. The flaw in Mr. Hanley's "empirical" CAPM analysis and the reason (in addition to the other reasons outlined above for the standard CAPM) that his equity cost estimate substantially overstates SWG's actual cost of capital is that he uses "adjusted" betas in his ECAPM analysis.

First, the econometric research that supports the premise of the ECAPM (i.e., that the CAPM produces low results for low-beta stocks) is based on "raw" or "un-adjusted" betas. Value Line, the source of Mr. Hanley's betas, publishes "adjusted" betas. A "raw" beta is the actual numerical result from the historical regression analyses that compare the return volatility of one stock with that of the market. Value Line adjusts those betas to account for a tendency of betas to approach 1.0, the beta value of the overall market. Value Line increases the betas of low beta companies like utilities and decreases the betas of high beta companies like "dot-com" companies. In other words, the use of adjusted betas makes the same kind of adjustment as does Mr. Hanley's "empirical" CAPM, i.e., it increases the equity cost estimate produced by the CAPM for low-beta stocks like utilities. Therefore, a shortcoming of the standard CAPM, which Mr. Hanley's ECAPM is supposed to remedy, is already accounted for through the use of adjusted Value Line betas in his standard CAPM. Mr. Hanley's ECAM double-counts that upward adjustment and overstates the cost of equity capital.

Sheet 3 of Mr. Hanley's Exhibit_(FJH-14) shows the magnitude of Value Line's beta adjustment. For a sample of gas distributors, Value Line's adjusted beta is 0.74, while the "raw" beta for those firms is 0.58—a difference of 0.16. A difference between Value Line's "raw" and adjusted betas of that magnitude, multiplied by Mr. Hanley's selected

market risk premium (7.3%—Hanley Exhibit_(FJH-13), Sheet 2) indicates an equity cost impact of 1.2%. If Mr. Hanley had utilized "raw" betas for his six-company sample group in his ECAPM analysis, his result would have been 10.5% rather than the 11.4% he reports on his Exhibit__(FHJ-13), Sheet 1)[24]. In sum, in addition to the shortcomings of the CAPM generally, the inclusion of adjusted betas in his ECAPM analysis is theoretically incorrect, double-counts the "low-beta/high-beta stock" effect and results in an inflated equity cost estimate.

Q. Have other regulatory bodies recently rejected the use of the ECAPM?

A. Yes. Mr. Hanley references Dr. Roger Morin as his source for the ECAPM. Dr. Morin recently presented that analysis in a gas utility rate proceeding in Tennessee. The Tennessee Regulatory Authority had the following comments regarding the ECPM:

> By placing a 75% weight on the adjusted beta for CGC [Chatanooga Gas Company] and a 25% weight on the market beta of one, the E-CAPM arrives at an inflated beta for CGC of 0.8275. In other words, a mean adjusted beta of 0.77 has become 0.8275 in the E-CAPM, thus inflating beta by 7.5%. Thus, the panel concluded that the E-CAPM was merely another method to further inflate an already adjusted beta estimate for CGC and, therefore, rejected Dr. Morin's empirical CAPM analysis. (Tennessee Regulatory Authority Order, Docket No. 04-00034, Chatanooga Gas Company, October 20, 2004, pp. 54, 55)

Q. What are your comments regarding Mr. Hanley's Comparable Earnings analysis?

A. The Comparable Earnings (CE) analysis presented by Company witness Hanley is based on the accounting returns of a group of unregulated, competitive companies that had betas similar to that of his sample group of gas distributors. Although proponents of Comparable Earnings analyses often claim that such an analysis is a type of market-based analysis because the returns being measured are determined in competitive markets, that type of analysis is based on accounting returns, not on returns expected by investors in the capital

[24] From footnote 5 on Hanley Exhibit__(FJH-13), Sheet 4: R(s) = R(f) + 0.25(R(m)-R(f)) + 0.75β(R(m)-R(f)). Also, R(f) = 5.5%; (R(m)-R9f)) = 7.3%. Therefore, if the beta is 0.58 (Value Line's adjusted beta of 0.74 less 0.16), the ECAPM result is 11.7% [5.5% + 0.25(7.3%) + 0.75(0.58)(7.3%)].

marketplace. Moreover, it is the latter—investors' required market return—we seek in setting profit levels for regulated firms. Only through setting regulated rates with market-based cost of equity capital can the goals of maximizing economic efficiency and balancing the interests of investors and ratepayers be met. Comparable Earnings is simply not a market-based equity cost estimation methodology.

While, as I have noted previously in my testimony, historical and projected accounting rates of return for utility operations, in conjunction with current market prices and book values, can provide useful information which can be used to indicate an appropriate range for the cost of equity, accounting data alone is not necessarily indicative of investors' required return. It is that fact, along with the development of market-based equity cost estimation techniques in the 1960s and 1970s (e.g., DCF and CAPM), that led regulators to use market-based equity cost models to supplant the Comparable Earnings methodology. It has been my experience over the past twenty years that Comparable Earnings is rarely used in regulatory proceedings as a procedure on which to base the allowed cost of equity capital.

Moreover, a comparable earnings standard of ratesetting actively *ignores* the actions of capital markets and the information that may be gleaned from those markets in estimating the cost of capital. For example, if interest rates rise or fall by substantial amounts, the opportunity cost of capital and the allowed profitability of utilities should also change, generally, in the same direction. However, if the focus of cost of capital becomes accounting returns, no particular change would be warranted by a shift in interest rate levels.

Moreover, if interest rates jumped up by, say, 2%, capital costs for the utility would rise and, with higher costs the utility's profitability would be impaired, that is, the return on book value would fall. If, in that situation, regulators set equity returns by considering future accounting returns, they would recommend that the utility's profit levels be lowered as a result of an increase in interest rates. Clearly, cost of capital regulation dependent on accounting returns would be economically inefficient, would send the wrong signals to both management and stockholders and fail to ensure financial integrity for the utility over the

long term. Setting allowed rates of return by relying on either actual or projected accounting returns (returns on book value) is not a reasonable ratemaking strategy.

Finally, the *only* screening criteria Mr. Hanley used in selecting his sample group is that they all have similar betas. Investment risk is a multi-dimensional parameter and cannot be accurately assessed through the use of only one type of risk measure, especially beta (the shortcomings of which are discussed in more detail in Appendix D attached to this testimony).

For example, even though Mr. Hanley's sample selection process purports to consider companies of similar risk, one key risk element omitted from his Comparable Earnings sample selection process is the level of competition to which the firms are exposed. For example, it is simply difficult to believe that investors consider regulated gas distribution utility operations to be similar in risk to a candy company (Tootsie Roll Industries, see Hanley Exhibit__(FJH-14), Sheet 3). It is reasonable to believe, therefore, that the sample group on which Mr. Hanley's CE results are based has a risk profile that is greater than that of SWG's gas utility operations, and the results of that analysis substantially overstate the Company's actual cost of equity.

In sum, Mr. Hanley's Comparable Earnings analysis does not identify the market-based cost of equity capital, is based on a sample group of firms which are selected on the basis of only one unreliable risk parameter (beta) and which are unlikely to be similar in overall investment risk to SWG.

Q. **Does this conclude your direct testimony, Mr. Hill?**

A. Yes, it does.

APPENDIX A

EDUCATION AND EMPLOYMENT HISTORY
OF
STEPHEN G. HILL

EDUCATION

Auburn University - Auburn, Alabama - Bachelor of Science in Chemical Engineering (1971); Honors - member Tau Beta Pi national engineering honorary society, Dean's list, candidate for outstanding engineering graduate; Organizations - Engineering Council, American Institute of Chemical Engineers

Tulane University - New Orleans, Louisiana - Masters in Business Administration (1973); concentration: Finance; awarded scholarship; Organizations - member MBA curriculum committee, Vice-President of student body, academic affairs

Continuing Education - NARUC Regulatory Studies Program at Michigan State University

EMPLOYMENT

West Virginia Air Pollution Control Commission (1975)
Position: Engineer ; Responsibility: Overseeing the compliance of all chemical companies in the State with the pollution guidelines set forth in the Clean Air Act.

West Virginia Public Service Commission-Consumer Advocate (1982)
Position: Rate of Return Analyst ; Responsibility: All rate of return research and testimony promulgated by the Consumer Advocate; also, testimony on engineering issues, when necessary.

Hill Associates (1989)
Position: Principal; Responsibility: Expert testimony regarding financial and economic issue in regulated industries.

PUBLICATIONS

"The Market Risk Premium and the Proper Interpretation of Historical Data," Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, Volume I, pp. 245-255.
"Use of the Discounted Cash Flow Has Not Been Invalidated," Public Utilities Fortnightly, March 31, 1988, pp. 35-38.

MEMBERSHIPS

American Institute of Chemical Engineers; Society of Utility and Regulatory Financial Analysts (Certified Rate of Return Analyst, Member of the Board of Directors)

APPENDIX B

LONG-TERM GROWTH

Q. PLEASE PROVIDE AN EXAMPLE WHICH DESCRIBES THE DETERMINANTS OF LONG-TERM SUSTAINABLE GROWTH.

A. Assume that a hypothetical regulated firm had a first period common equity or book value per share of $10, the investor-expected return on that equity was 10% and the stated company policy was to pay out 60% of earnings in dividends. The first period earnings per share are expected to be $1.00 ($10/share book equity x 10% equity return) and the expected dividend is $0.60. The amount of earnings not paid out to shareholders ($0.40), the retained earnings, raises the book value of the equity to $10.40 in the second period. The table below continues the hypothetical for a five year period and illustrates the underlying determinants of growth.

TABLE A.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
EQUITY RETURN	10%	10%	10%	10%	10%	-
EARNINGS/SH.	$1.00	$1.040	$1.082	$1.125	$1.170	4.00%
PAYOUT RATIO	0.60	0.60	0.60	0.60	0.60	-
DIVIDENDS/SH.	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

We see that under steady-state conditions, the earnings, dividends and book value all grow at the same rate. Moreover, the key to this growth is the amount of earnings retained or reinvested in the firm and the return on that new portion of equity. If we let "b" equal the retention ratio of the firm (1 – the payout ratio) and let "r" equal the firm's expected return on equity, the DCF growth rate "g" (also referred to as the internal or sustainable growth rate) is equal to their product, or

$$g = br. \qquad \text{(i)}$$

Professor Myron Gordon, who developed the Discounted Cash Flow technique and first introduced it into the regulatory arena[1], has determined that Equation (i) embodies the underlying fundamentals of growth and, therefore, is a primary measure of growth to be used in the DCF model. Professor Gordon's research also indicates that analysts' growth rate projections are useful in estimating investors' expected sustainable growth.

I should note here that the above hypothetical does not allow for the existence of external sources of equity financing, i.e., sales of common stock. Stock financing will cause investors to expect additional growth if the company is expected to issue new shares at a market price that exceeds book value. The excess of market over book would inure to current shareholders, increasing their per share equity value. Therefore, if the company is expected to continue to issue stock at a price that exceeds book value, the shareholders would continue to expect their book value to increase and would add that growth expectation to that stemming from earnings retention or internal growth. Conversely, if a company were expected to issue new equity at a price below book value, that would have a negative effect on shareholder's current growth rate expectations. In such a situation, shareholders would perceive an overall growth rate less than that produced by internal sources (retained earnings). Finally, with little or no expected equity financing or a market-to-book ratio near unity, investors would expect the sustainable growth rate for the company to equal that derived from Equation (i), "g = br." Dr. Gordon[2] identifies the growth rate which includes both expected internal and external financing as:

$$g = br + vs, \qquad \text{(ii)}$$

where,

g = DCF expected growth rate,
r = return on equity,
b = retention ratio,
v = fraction of new common stock

[1] In fact, the DCF is often called the "Gordon Model."

[2] Gordon, M.J., The Cost of Capital to a Public Utility, MSU Public Utilities Studies, East Lansing, Michigan, 1974, pp., 30–33.

sold that accrues to the current shareholder,
s = funds raised from the sale of stock as a fraction of existing equity.

Additionally,

$$v = 1 - BV/MP, \qquad \text{(iii)}$$

where,

MP = market price,
BV = book value.

I have used Equation (ii) as the basis for my examination of the investor expected long-term growth rate (g) in this proceeding.

Q. IN YOUR PREVIOUS EXAMPLE, EARNINGS AND DIVIDENDS GREW AT THE SAME RATE (br) AS DID BOOK VALUE. WOULD THE GROWTH RATE IN EARNINGS OR DIVIDENDS, THEREFORE, BE SUITABLE FOR DETERMINING THE DCF GROWTH RATE ?

A. No, not necessarily. Rates of growth derived from earnings or dividends alone can be unreliable due to extraneous influences on those parameters such as changes in the expected rate of return on common equity or changes in the payout ratio. That is why it is necessary to examine the underlying determinants of growth through the use of a sustainable growth rate analysis.

If we take the hypothetical example previously stated and assume that, in year three, the expected return on equity rises to 15%, the resultant growth rate for earnings and dividends far exceeds that which the company could sustain indefinitely. The potential error in using those growth rates to estimate "g" is illustrated in the following table.

TABLE B.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.47	$12.157	5.00%
EQUITY RETURN	10%	10%	15%	15%	15%	10.67%
EARNINGS/SH.	$1.00	$1.040	$1.623	$1.720	$1.824	16.20%
PAYOUT RATIO	0.60	0.60	0.60	0.60	0.60	-
DIVIDENDS/SH.	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

What has happened is a shift in steady-state growth paths. For years one and two, the sustainable rate of growth (g=br) is 4.00%, just as in the previous hypothetical. Then, in the last three years, the sustainable growth rate increases to 6.00% (g=br = 0.4x15%). If the regulated firm were expected to continue to earn a 15% return on equity and retain 40% of its earnings, then a growth rate of 6.0% would be a reasonable estimate of the long-term sustainable growth rate. However, the compound annual growth rate for dividends and earnings exceeds 16% which is the result only of an increased equity return rather than the intrinsic ability of the firm to grow continuously at a 16% annual rate. Clearly, this type of estimate of future growth cannot be used with any reliability at all. In the case of the hypothetical, to utilize a 16% growth rate in a DCF model would be to expect the company's return on common equity to increase by 50% every five years into the indefinite future. This would be a ridiculous forecast for any regulated firm and underscores the importance of utilizing the underlying fundamentals of growth in the DCF model.

It can also be demonstrated that a change in our hypothetical regulated firm's payout ratio makes the past rate of growth in dividends an unreliable basis for predicting "g". If we assume our regulated firm consistently earns its expected equity return (10%) but in the third year, changes its payout ratio from 60% to 80% of earnings, the results are shown in the table below.

TABLE C.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.036	$11.26	3.01%
EQUITY RETURN	10%	10%	10%	10%	10%	-
EARNINGS/SH.	$1.00	$1.040	$1.082	$1.104	$1.126	3.01%
PAYOUT RATIO	0.60	0.60	0.80	0.80	0.80	7.46%
DIVIDENDS/SH.	$0.60	$0.624	$0.866	$0.833	$0.900	10.67%

What we see here is that, although the company has registered a high dividend growth rate (10.67%), it is, again, not at all representative of the growth that could be sustained indefinitely, as called for in the DCF model. In actuality, the sustainable growth rate has declined from 4.0% the first two years to only 2.0% (g=br = 0.2x10%) during the last three years due to the increased payout ratio. To utilize a 10% growth rate in a DCF analysis of this hypothetical regulated firm would 1) assume the payout ratio of the firm would continue to increase 33% every five years into the indefinite future, 2) lead to the highly implausible result that the firm intends to consistently pay out more in dividends than it earns and 3) grossly overstate the cost of equity capital.

APPENDIX C
SAMPLE COMPANY GROWTH RATE ANALYSES

GAS DISTRIBUTORS

ATG - AGL Resources - ATG's sustainable growth rate has averaged 4.64% over the most recent five year period (2000-2004). VL expects ATG's sustainable growth to rise above that historical growth rate level in 2005 and 2006 and, then, to reach 6% by the 2008-2010 period. ATG's book value growth rate is expected to be 8% over the next five years, a significant increase from the 3.5% rate of growth experienced over the past five years. Also, ATG's earnings per share are projected to increase at a 5% (VL), TO 4% (First Call), to 4.7% (Zack's) rate— all below the indicated sustainable growth rate. However, ATG's dividends are expected to show only 2.5% annual growth over the next five years, moderating long-term sustainable growth expectations. Over the past five years, ATG's earnings showed 11% growth (due to the inclusion of a 1999—a poor earnings year), while its dividends increased at only a 0.5% rate. Investors can reasonably expect a sustainable growth rate in the future of **5.25%** for ATG.

Regarding share growth, ATG's shares outstanding increased at a 9% rate over the past five years due to an equity issuance in 2004, used to fund the acquisition of another gas distributor (NUI Corp.). Prior to that equity issuance, in 1998 shares outstanding were higher than in 2002. The number of shares is projected by VL to increase at only a 0.34% rate between 2004 and the 2008-10 period. An expectation of share growth of **1%** for this company is reasonable.

ATO – Atmos Energy Corp - ATO's sustainable growth rate averaged about 1.5% for the five-year historical period. However, sustainable growth in 2000 fell into negative territory. Absent the negative results, ATO's historical sustainable growth averaged 2.1%. Value Line projects positive growth in 2005 and 2006, and then a rise by the 2008-10 period to a level near 3.75%. Also, ATO's book value growth during the most recent five years (6.5%) is expected to increase to an 8.5% rate in the future due to that company's on-going acquisition of gas distribution properties. ATO's earnings per share are projected to increase at a 6.5% (VL and First Call) to 5% (Zack's) rate, but its dividends are expected to grow at only a 2.0% rate, moderating long-term growth expectations. Historically ATO's earnings have shown 3.5% growth, while its dividends increased at a 2.5% rate. Investors can reasonably expect a sustainable growth rate higher than that established historically, but not as high as the earnings growth projected by Value Line; **4.25%** is a reasonable long-term expectation for this company.

Regarding share growth, ATO's shares outstanding grew at approximately a 18% rate over the past five years, due to acquisition-related equity issuances. Because of the company's acquisition of TXU's gas utility operations and its assumption of that company's heavy debt, ATO will have to issue substantial amounts of additional equity in 2005. Between 2004 and 2005, ATO's net plant is expected to double due to the TXU acquisition. Therefore, the increase in the number of shares outstanding associated with that acquisition cannot be considered to be sustainable. Following the completion of the acquisition of TXU, Value Line

expects the number of shares outstanding for ATO to grow at a 4% rate. An expectation of share growth of **5%** for this company is reasonable.

CGC - Cascade Natural Gas Company - CGC's sustainable growth rate averaged 2.30% over the five-year historical period with the company paying out more in dividends that it had in earnings in 2003. VL projects that CGC's retention ratio and ROE will rise through 2008-10, bringing sustainable growth near 4.5%. CGC's book value, which did not increase during the most recent five years, is expected to increase at a 6% rate in the future, above the sustainable growth projection. CGC's earnings per share are projected to increase at a 7% (VL) to 4.5% (FirstCall) to 6% (Zack's) rate, but its dividends are expected to grow at only a 0.5% annual rate. Historically CGC's earnings grew at a 1% rate, according to Value Line's methodology (the compound growth rate over the past five years is actually negative), and its dividends showed 0% growth historically. The projected sustainable growth, earnings and book value growth rate data indicate that investors can expect the growth from CGC to be higher in the future than has existed in the past. Investors can reasonably expect a sustainable growth rate of **4.75%** for CGC.

Regarding share growth, CGC's shares outstanding showed a 0.49% increase over the past five years. Further, after showing 0% growth from 1999 to 2002, CGC's growth rate in shares outstanding is expected to rise at about a 1.25% rate of increase through 2008-10. Those projections indicate that future share growth will be above past averages. An expectation of share growth of **0.75%** for this company is reasonable.

LG – Laclede Group - LG's sustainable growth rate has averaged only 1.3% over the most recent five year period. LG's sustainable growth rose well above that historical growth rate level in 2003 and 2004 and is projected to reach 3% by the 2008-2010 period. LG's book value growth rate is expected to be 11% over the next five years, up significantly from the 1.5% rate of growth experienced over the past five years. Also, LG's earnings per share are projected to increase at a 5% (FirstCall and Zack's) to 6% (VL) rate—also above the indicated sustainable growth rate. However, its dividends are expected to grow at 1%. Over the past five years, LG's earnings growth was -0.5%, according to Value Line, while its dividends increased at a 0.5% rate. Investors can reasonably expect a sustainable growth rate in the future of **4.25%** for LG.

Regarding share growth, LG's shares outstanding increased at approximately a 2.5% rate over the past five years. The number of shares outstanding in 2008-2010 is expected to increase at a rate of about 0.5% from 2004. An expectation of share growth of **1%** for this company is reasonable.

NJR - New Jersey Resources - NJR's sustainable growth rate averaged 6.57% over the most recent five-year period. NJR's average historical sustainable growth has shown steady improvement, reaching 7.5% in 2004. However, VL projects, by the 2008-10 period, sustainable growth will decline to levels approximating 5.6%. Therefore, Value Line's sustainable growth measure shows a declining growth rate for this company. NJR's projected book value indicates the opposite trend -- book value grew at a 6% rate during the most recent five years but is expected to rise at an 11% rate in the future, according to Value Line. Value Line projects a rate of earnings increase for NJR of 8%, while FirstCall projects 5.5% and Zack's projects 6.5%. Dividends are expected to grow at a 3% rate, moderating long-term growth expectations. Historically NJR's earnings grew at an 8% rate while its dividends increased at a 2.5% rate. Therefore, like many other gas distributors, NJR's

earnings cannot be expected support dividend increases at the same rate. Investors can reasonably expect a long-term sustainable growth rate of **6.25%.**

Regarding share growth, NJR's shares outstanding grew at a 1.26% rate over the past five years. The five-year average level of share growth is expected to decrease at approximately 2% annually through 2008-10. An expectation of share growth of **–0.5%** for this company is reasonable.

NWN - Northwest Natural Gas - NWN's sustainable growth rate averaged 2.72% for the five-year period, with the results in the most recent year, 2.71%, approximating the average. VL expects sustainable growth to rise to a 4% level by the 2008-10 period. NWN's book value growth is expected to increase at a 4% rate, just above the historical level of 3.5%. NWN's earnings per share growth is projected to range from 5% (VL) to 5.8% (FirstCall) to 5.1% (Zack's) rate, and its dividends are expected to grow at a 2.5% rate. Historically NWN's earnings and dividends increased at 2% and 1% rates, respectively, according to Value Line. The compound historical growth rates are slightly higher. Investors can reasonably expect sustainable growth from NWN to exceed past averages, a sustainable internal growth rate of **4.25%** is reasonable for this company.

Regarding share growth, NWN's shares outstanding grew at a 2.2% rate over the past five years, due to an equity issuance in 2004. Prior to that time the shares outstanding showed very little growth. The growth in the number of shares is expected by VL to be 0.68% through 2008-10. An expectation of share growth of **1.25%** for this company is reasonable.

PGL – Peoples Energy - PGL's sustainable growth rate has averaged 2.95% over the most recent five year period, with the most recent results being well below that level. VL expects PGL's sustainable growth fall below that historical growth rate level, reaching 2.5% by the 2008-2010 period. However, PGL's book value growth rate is expected to be 4.5% over the next five years, above the 2.5% rate of growth experienced over the past five years. Also, PGL's earnings per share are projected to increase at a 1% (VL) to 4% (FirstCall) to 4.5% (Zack's) rate—the latter earnings growth projections are above the indicated sustainable growth rate. However, its dividends are expected to grow at only 1.5% per year. Over the past five years, PGL's earnings and dividends grew at a 2% rate. Investors can reasonably expect a sustainable growth rate in the future of **4.0%** for PGL.

Regarding share growth, PGL's shares outstanding increased at approximately a 0.97% rate over the past five years. The number of shares outstanding in 2008-2010 is expected to decline at a 1% rate. An expectation of share growth of **0%** for this company is reasonable.

PNY - Piedmont Natural Gas - PNY's sustainable internal growth rate averaged 2.94% over the five-year historical period, with recent results being higher (indicating an increasing trend). VL projects PNY's sustainable growth to rise to a level of approximately 3.75% through 2008-10. Also, PNY's book value growth rate is expected to continue in the future at 7.5%, above the historical level of 5.5%, pointing to increasing growth for this company. PNY's earnings per share are projected to increase at 7.5% (VL) to 5% (FirstCall) to 4.9% (Zack's), while its dividends are expected to grow at a 4% rate, down from 5%, historically. Sustainable growth has been relatively consistent for this company and is expected to trend upward somewhat in the future to near the 4% level. Dividend growth has been 5% but is expected to fall to the 4% level in the future. Earnings growth is projected to

be slightly higher, therefore, investors can reasonably expect a sustainable growth rate of **4.25%**, from PNY.

Regarding share growth, PNY's shares outstanding grew at about a 4.7% rate over the past five years, due to an equity issuance in 2004. Prior to that equity issuance, shares increased at about 1.5% annually. The level of share growth is expected by VL to decline at about a 1% rate through 2008-10, compared to 2003. An expectation of share growth of **1.5%** for this company is reasonable.

SJI – South Jersey Industries - SJI's internal sustainable growth rate has averaged 4.63% over the most recent five year period (2000-2004), with results in 2003 and 2004 above the historical growth rate level, indicating an increasing trend. That higher level of sustainable growth is expected to increase to approximately 6% by the 2008-2010 period. SJI's book value growth rate is expected to be 5% over the next five years—a decline from the 7% rate of growth experienced over the past five years. SJI's earnings per share are projected to increase at a 5.5% (VL & FirstCall, respectively) to 6% (Zack's) rate, while its dividends are expected to grow at 4.5%. Over the past five years, SJI's earnings grew at a 9.5% rate while its dividends showed only a 1% increase. Investors can reasonably expect a sustainable growth rate in the future to be higher than past averages, **5.25%** is reasonable for SJI.

Regarding share growth, SJI's shares outstanding grew at a 4.7% rate over the past five years. The number of shares outstanding is projected by VL to rise at a 1.7% rate through 2008-10. An expectation of share growth of **2%** for this company is reasonable.

WGL – WGL Holdings - WGL's sustainable growth rate has averaged 3.34% over the most recent five year period. VL expects WGL's sustainable growth to rise above that historical growth rate level to 5.5% by the 2008-2010 period. WGL's book value growth rate is expected to be 4.5% over the next five years, above the 3% rate of growth experienced over the past five years. WGL's earnings per share are projected to increase at a 6.5% (VL) to 4% (FirstCall) to 3.9% (Zack's) rate. However, like the other gas distributors, its dividends are expected to grow at a slower rate than earnings, in this instance, only 1.5% per year. Over the past five years, WGL's earnings growth was 2% while its dividends increased at a 1.5% rate. Investors can reasonably expect a sustainable growth rate in the future of **4.5%** for WGL.

Regarding share growth, WGL's shares outstanding increased at approximately a 1.1% rate over the past five years. That rate of increase is expected to slow in the future with number of shares outstanding in 2008-2010 is expected to remain essentially constant. An expectation of share growth of **0%** for this company is reasonable.

SWX – Southwest Gas Corp - SWX's sustainable growth rate averaged 2.03% for the five-year historical period. Value Line projects increased growth in 2005 and 2006, and then a rise by the 2008-10 period to a level near 6.5%. However, SWX's book value growth during the most recent five years (4%) is expected to remain stable at 4% in the future. SWX's earnings per share are projected to increase at a 10.5% (VL), 5% (First Call), and 4.6% (Zack's) rate. The difference in Value Line's earnings growth projections is probably due to that investor service's expectation that SWX's ROE will increase from an average of 6.4% to 10%—an increase of 56%. Therefore, only if one believes that SWX's ROE will continue to increase 56% every five years into the indefinite future would a sustainable growth

rate of 10.5% be a reasonable expectation. However, that is not a reasonable expectation, evidenced by other investor services that indicate substantially lower earnings growth for SWX in the future. In addition, SWX's dividends are expected to grow at only a 1.5% rate, moderating long-term growth expectations. Historically SWX's earnings have shown 5% growth, while its dividends did not increase at all. Investors can reasonably expect a sustainable growth rate higher than that established historically, but not as high as the earnings growth projected by Value Line; **5.75%** is a reasonable long-term growth rate expectation for this company.

Regarding share growth, SWX's shares outstanding grew at approximately a 3.3% rate over the past five years. Further, Value Line expects the number of shares outstanding for SWX to grow at a 2% rate through the 2008-2010 period. An expectation of share growth of **2.5%** for this company is reasonable.

APPENDIX D

CORROBORATIVE EQUITY CAPITAL COST ESTIMATION METHODS

CAPITAL ASSET PRICING MODEL

Q. PLEASE DESCRIBE THE CAPITAL ASSET PRICING MODEL (CAPM) YOU USED TO ARRIVE AT AN ESTIMATE FOR THE COST RATE OF THE COMPANY'S EQUITY CAPITAL.

A. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (systematic) risk of a security. Systematic risk refers to the risk associated with movements in the macro-economy (the economic "system") and, thus, cannot be eliminated through diversification by holding a portfolio of securities. The beta coefficient (β) is a statistical measure which is an attempt to quantify the non-diversifiable risk of the return on a particular security against the returns inherent in general stock market fluctuations. The formula is expressed as follows:

$$k = r_f + \beta(r_m - r_f), \qquad \text{(i)}$$

where "k" is the cost of equity capital of an individual security, "r_f" is the risk-free rate of return, "β" is the beta coefficient, "r_m" is the average market return and "$r_m - r_f$" is the market risk premium. The CAPM is used in my analysis, not as a primary cost of equity analysis, but as a check of the DCF cost of equity estimate. Although I believe the CAPM can be useful in testing the reasonableness of a cost of capital estimate, certain theoretical shortcomings of this model (when applied in cost of capital analysis) reduce its usefulness.

Q. CAN YOU EXPLAIN WHY YOU APPLY THE CAPM ANALYSIS WITH CAUTION?

A. There are many reasons why the Capital Asset Pricing Model (CAPM) should be used

with caution in estimating the cost of equity capital. The CAPM was originally designed as a point-in-time tool for selecting stock portfolios that matched a particular investor's risk/return preference. Its use in rate of return analysis to estimate multi-period return expectations for one stock or one type of stock, rather than a diversified portfolio of stocks, takes the model out of the context for which it was intended. Also, questions regarding the fundamental applicability of the CAPM theory and the veracity of beta have arisen recently in the financial literature.

Over the past few years there has been much comment in the financial literature over the strength of the assumptions that underlie the CAPM and the inability to substantiate those assumptions through empirical analysis. Also, there are three concerns with the key CAPM risk measure (beta) that place in question the reliability of CAPM analysis. The first two have been widely known for some time, and the third has emerged only in the past few years.

First, cost of capital analysis is a decidedly forward-looking, or *ex-ante*, concept. Beta is not. The measurement of beta is derived completely with historical, or *ex-post*, information. Therefore, the beta of a particular company, because it is usually derived with five years of historical data, is slow to change to current (i.e., forward-looking) conditions, and some price abnormality that may have happened four years ago could substantially affect beta while, currently, being of little actual concern to investors. Moreover, this same shortcoming which assumes that past results mirror investor expectations for the future plagues the market risk premium in an ex-post, or historically-oriented CAPM.

Second, the beta coefficients for any individual stock have very low "r^2" values and, statistically, must be considered relatively poor indicators of company-specific risk. The statistical reliability of beta is thought to increase when it is used to identify the risk/return profile of a diversified group of stocks. However, that is not the manner in which beta is used in regulation, and the low statistical reliability of beta is problematic in cost of capital analysis. As a result of the low statistical reliability of beta, different investor services offer different (and sometimes widely divergent) estimates of beta.

Third, a relatively recent study performed for the Center for Research in Security

Prices at the University of Chicago Graduate School of Business shows that the assumed relationship between beta, risk and return (i.e., beta varies directly with risk and return) simply does not exist in the marketplace.

Therefore, I use the CAPM for informational purposes and do not rely on that methodology as a primary equity capital cost estimation technique.

Q. WHAT VALUE HAVE YOU CHOSEN FOR A RISK-FREE RATE OF RETURN IN YOUR CAPM ANALYSIS?

A. As the CAPM is designed, the risk-free rate is that short-term rate of return investors can realize with certainty. The nearest analog in the investment spectrum is the 13-week U. S. Treasury Bill. Although longer-term Treasury bonds have equivalent default risk to T-Bills, those longer-term government securities carry maturity risk that the T-Bills do not have. When investors tie up their money for longer periods of time, as they do when purchasing a long-term Treasury, they must be compensated for future investment opportunities forgone as well as the potential for future changes in inflation. Investors are compensated for this increased investment risk by receiving a higher yield on T-Bonds.

As I noted in my previous discussion of the macro-economy, the Fed has acted over the past year to raise short-term interest rates. Over the most recent six-week period, T-Bills have produced an average yield of 2.84% (data from Value Line *Selection & Opinion*, six most recent weekly editions[1]). Over that same time period US Treasury long-term bonds have provided a yield of 4.58%.

Q. DO YOU BELIEVE THE USE OF A LONG-TERM TREASURY BOND RATE IS APPROPRIATE IN THE CAPM?

A. No. Although the selection of a long- or short-term Treasury security as the risk free rate of return to be used in the CAPM is often one of the areas of contention in applying the model in cost of capital analysis, the use of a normalized short-term T-Bill rate is the more theoretically correct parameter. However, the T-Bill yield can be influenced by

[1] Current T-Bill yield, six-week average yield from Value Line Selection & Opinion (4/22/05-5/27/05).

Federal Reserve policy, as noted above. Also, the current yield differential between T-Bills and T-Bonds is similar to the differential that has existed, on average. Over the past 75 years. Therefore, for purposes of analysis in this proceeding I will present both the T-Bill and long-term Treasury bond yields for the risk-free rate in the CAPM, and will rely on the results of the CAPM based on both long- and short-term Treasury yields. Also, along with those measures of the risk-free rate I use the corresponding measures of market risk premiums.

Q. WHAT HAVE YOU CHOSEN AS THE MARKET RISK PREMIUM FOR THE CAPM ANALYSIS?

A. In their 2004 edition of Stocks, Bonds, Bills and Inflation, R.G. Ibbotson Associates indicates that the average market risk premium between stocks and T-Bills over the 1926–2003 time period is 8.6% (based on an arithmetic average), and 6.7% (based on a geometric average). For long-term Treasuries, the market risk premiums are 6.6% (based on an arithmetic average) and 5.0% (based on a geometric average). I have used these values to estimate the market risk premium in the CAPM analysis. The geometric mean is based on compound returns over time and the arithmetic mean is based on the average of single-period returns.

Q. WHAT VALUES HAVE YOU CHOSEN FOR THE BETA COEFFICIENTS IN THE CAPM ANALYSIS?

A. Value Line reports beta coefficients for all the stocks it follows. Value Line's beta is derived from a regression analysis between weekly percentage changes in the market price of a stock and weekly percentage changes in the New York Stock Exchange Composite Index over a period of five years. The average beta coefficient of the sample group of gas distributors is 0.73.

Q. WHAT IS YOUR RECOMMENDED COST OF EQUITY CAPITAL FOR THE SAMPLE GROUPS USING THE CAPITAL ASSET PRICING MODEL ANALYSIS?

A. Schedule 7 shows that the average Value Line beta coefficient for the group of gas

distribution companies under study is 0.73. The overall arithmetic average market risk premium between stocks and long-term Treasuries of 6.6% would, upon the adoption of a 0.73 beta, become a sample group premium of 4.80% (0.73 x 6.6%). That non-specific risk premium added to the current T-Bond yield of 4.58%, previously derived, produces a common equity cost rate estimate of 9.38%. Schedule 7 also shows that using an average T-Bill yield (2.84%) and a larger historical market risk premium between stocks and T-Bills of 8.6%, the CAPM produces equity cost estimate of 9.09%.

Because the current yield differential between long- and short-term U.S. Treasury securities is similar to long-term average yield differences, the results of the CAPM using T-Bonds and T-Bills are similar. The CAPM results which employ the long-term Treasury yields produces a range of equity cost estimates from 8.22% to 9.38%, while the result using T-Bills ranges from 7.71% to 9.09%. The CAPM results for the gas utility companies are generally lower than DCF results derived previously, indicating that my DCF equity cost estimate for those companies may be overstated.

MODIFIED EARNINGS-PRICE RATIO ANALYSIS

Q. PLEASE DESCRIBE THE MODIFIED EARNINGS-PRICE RATIO (MEPR) ANALYSIS OF THE COST OF COMMON EQUITY CAPITAL.

A. The earnings-price ratio is calculated simply as the expected earnings per share divided by the current market price. In cost of capital analysis, the earnings-price ratio (which is one portion of this analysis) can be useful in a corroborative sense, since it can be a good indicator of the proper range of equity costs when the market price of a stock is near its book value. When the market price of a stock is *above* its book value, the earnings-price ratio *understates* the cost of equity capital. Schedule 8 contains mathematical support for this concept. The opposite is also true, i.e.; the earnings-price ratio *overstates* the cost of equity capital when the market price of a stock is *below* book value.

Under current market conditions, the utility firms under study have an average market-to-book ratios well above 1.0 (1.65 for the gas distributors) and, therefore, the average earnings-price ratio alone would understate the cost of equity for the sample

group. However, it is important to emphasize that I do not use the earnings-price ratio alone as an indicator of equity capital cost rates. Because of the relationship among the earnings-price ratio, the market-to-book ratio and the investor-expected return on equity, I have modified the standard earnings-price ratio analysis by including expected returns on equity for the companies under study. It is that modified analysis, the MEPR analysis, I will use to assist in estimating an appropriate range of equity capital costs in this proceeding.

Q. PLEASE EXPLAIN THE RELATIONSHIP AMONG THE EARNINGS-PRICE RATIO, THE EXPECTED RETURN ON EQUITY AND THE MARKET-TO-BOOK RATIO.

A. When the investor-expected return on equity for a company exceeds the investor-required return (the cost of equity capital), the market price of the firm will tend to exceed its book value. As explained above, when the market price exceeds book value, the earnings-price ratio understates the cost of equity capital. Therefore, when the expected equity return (ROE) exceeds the cost of equity capital, the earnings-price ratio will understate that cost rate.

Also, in situations where the expected equity return is below what investors require for that type of investment, market prices fall below book value. Further, when market-to-book ratios are below 1.0, the earnings-price ratio overstates the cost of equity capital. Thus, the expected rate of return on equity and the earnings-price ratio tend to move in a countervailing fashion about the cost of equity capital. When market-to-book ratios are above one, the expected equity return exceeds and the earnings-price ratio understates the cost of equity capital. When market-to-book ratios are below one, the expected equity return understates and the earnings-price ratio exceeds the cost of equity capital. Further, as market-to-book ratios approach unity, the expected return and the earnings price ratio approach the cost of equity capital. Therefore, the average of the expected book return and the earnings price ratio provides a reasonable estimate of the cost of equity capital.

These relationships represent general rather than precisely quantifiable tendencies

but are useful in corroborating other cost of capital methodologies. The Federal Energy Regulatory Commission, in its generic rate of return hearings, found this technique useful and indicated that under the circumstances of market-to-book ratios exceeding unity, the cost of equity is bounded above by the expected equity return and below by the earnings-price ratio (e.g., 50 Fed Reg, 1985, p. 21822; 51 Fed Reg, 1986, pp. 361, 362; 37 FERC ¶ 61,287). The mid-point of these two parameters, therefore, produces an estimate of the cost of equity capital which, when market-to-book ratios are different from unity, is far more accurate than the earnings-price ratio alone.

Q. WHAT ARE THE RESULTS OF YOUR EARNINGS-PRICE RATIO ANALYSIS OF THE COST OF EQUITY FOR THE SAMPLE GROUP?

A. Schedule 9 shows the First Call projected 2006 per share earnings for each of the firms in the sample groups. Recent average market prices (the same market prices used in my DCF analysis), Value Line's projected 2005 and 2008-2010 equity returns for each of the companies are also shown.

The average earnings-price ratio for the gas sample group, 6.51%, is below the cost of equity for those companies due to the fact that their average market-to-book ratio is currently well above 1.0. The sample gas companies' 2005 expected book equity return averages 11.05%. That return rate is above the companies' cost of equity capital, again due to the fact that the market prices for those firms are above their book values. For the entire sample group, then, the mid-point of the earnings-price ratio and the current equity return is 8.78%.

Schedule 9 also shows that the average expected book equity return over the next three- to five-year period for the gas group is 10.85%, lower than the current-year return. The midpoint of these two boundaries of equity capital cost for the whole group, i.e., the long-term projected return on book equity (10.85%) and the current earnings-price ratio (6.51%) is 8.68%, and provides another forward-looking estimate of the equity capital cost rate of an gas utility firm. The results of this MEPR analysis for the gas companies also indicate that the DCF equity cost estimate previously derived may be overstated (i.e., too high).

MARKET-TO-BOOK RATIO ANALYSIS

Q. PLEASE DESCRIBE YOUR MARKET-TO-BOOK (MTB) ANALYSIS OF THE COST OF COMMON EQUITY CAPITAL FOR THE SAMPLE GROUP.

A. This technique of analysis is a derivative of the DCF model that attempts to adjust the capital cost derived with regard to inequalities that might exist in the market-to-book ratio. This method is derived algebraically from the DCF model and, therefore, cannot be considered an independent check of that method. However, the MTB analysis is useful in a corroborative sense. The MTB seeks to determine the cost of equity using market-determined parameters in a format different from that employed in the DCF analysis. In the DCF analysis, the available data is "smoothed" to identify investors' long-term sustainable expectations. The MTB analysis, while based on the DCF theory, relies instead on point-in-time data projected one year and five years into the future and, thus, offers a practical corroborative check on the traditional DCF. The MTB formula is derived as follows:

Solving for "P" from Equation (1), the standard DCF model, we have

$$P = D/(k-g). \qquad \text{(ii)}$$

But the dividend (D) is equal to the earnings (E) times the earnings payout ratio, or one minus the retention ratio (b), or

$$D = E(1-b). \qquad \text{(iii)}$$

Substituting Equation (iii) into Equation (ii), we have

$$P = \frac{E(1-b)}{k-g} \ . \qquad \text{(iv)}$$

The earnings (E) are equal to the return on equity (r) times the book value of that equity (B). Making that substitution into Equation (iv), we have

$$P = \frac{rB(1-b)}{k-g} \quad . \qquad \text{(v)}$$

Dividing both sides of Equation (v) by the book value (B) and noting from Equation (iii) in Appendix B that g = br+sv,

$$\frac{P}{B} = \frac{r(1-b)}{k-br-sv} \quad . \qquad \text{(vi)}$$

Finally, solving Equation (vi) for the cost of equity capital (k) yields the MTB formula:

$$k = \frac{r(1-b)}{P/B} + br + sv. \qquad \text{(vii)}$$

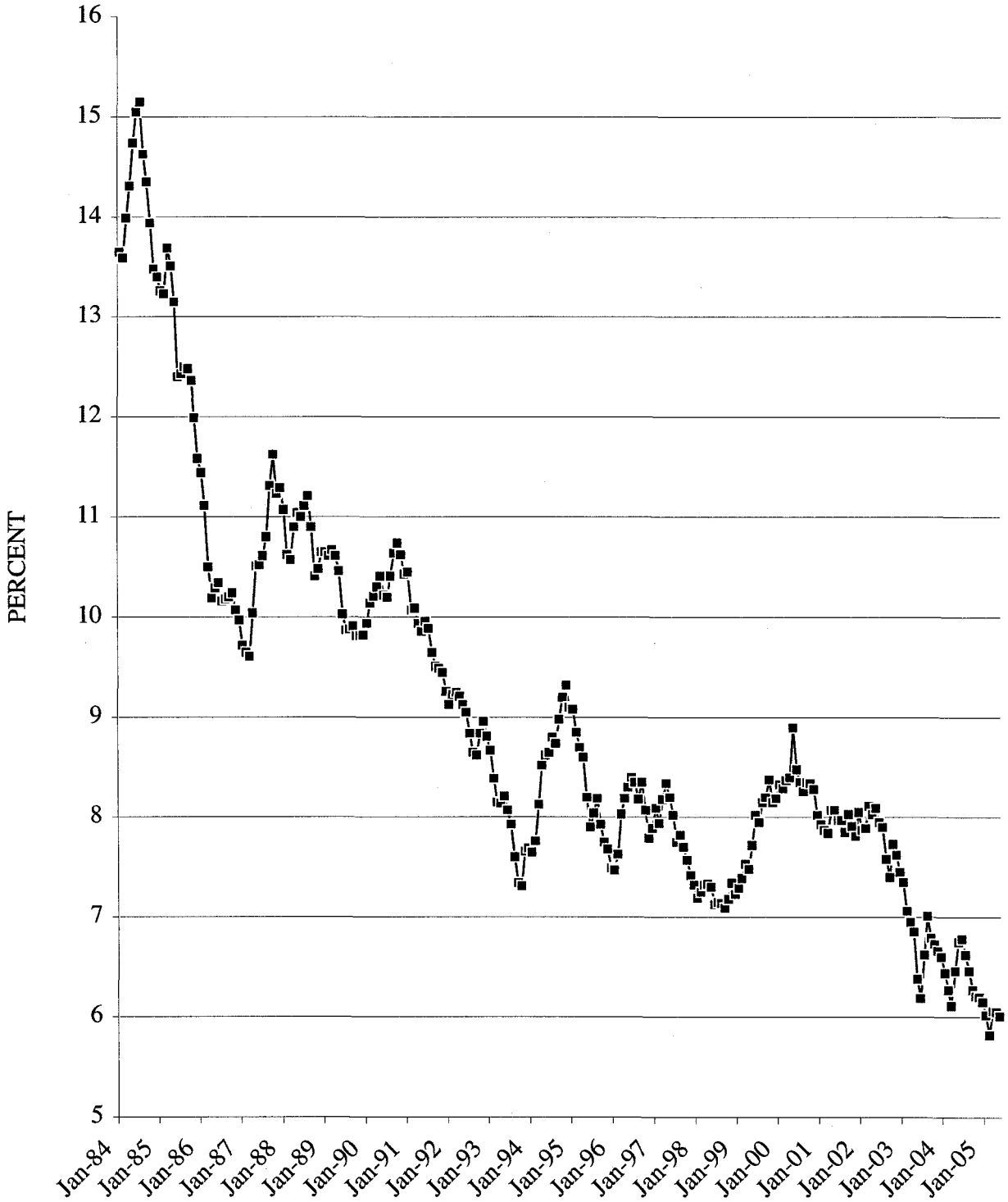
Equation (vii) indicates that the cost of equity capital equals the expected return on equity multiplied by the payout ratio, divided by the market-to-book ratio plus growth. Schedule 10 shows the results of applying Equation (vii) to the defined parameters for the utility firms in the comparable sample. Page 1 of Schedule 10 utilizes current year (2005) data for the MTB analysis of the gas companies while page 2 of Schedule 10 utilizes Value Line's 2008-2010 projections.

The MTB cost of equity for the entire sample of gas utility firms, adjusted for a current average market-to-book ratio of 1.65 is 9.46% using the current year data and 8.84% using projected three- to five-year data. These results, which are both above and below my DCF result for the gas companies indicates that my DCF estimate for the gas utilities is reasonable.

SOUTHWEST GAS COMPANY

MOODY'S BAA BOND YIELDS

1984-2005

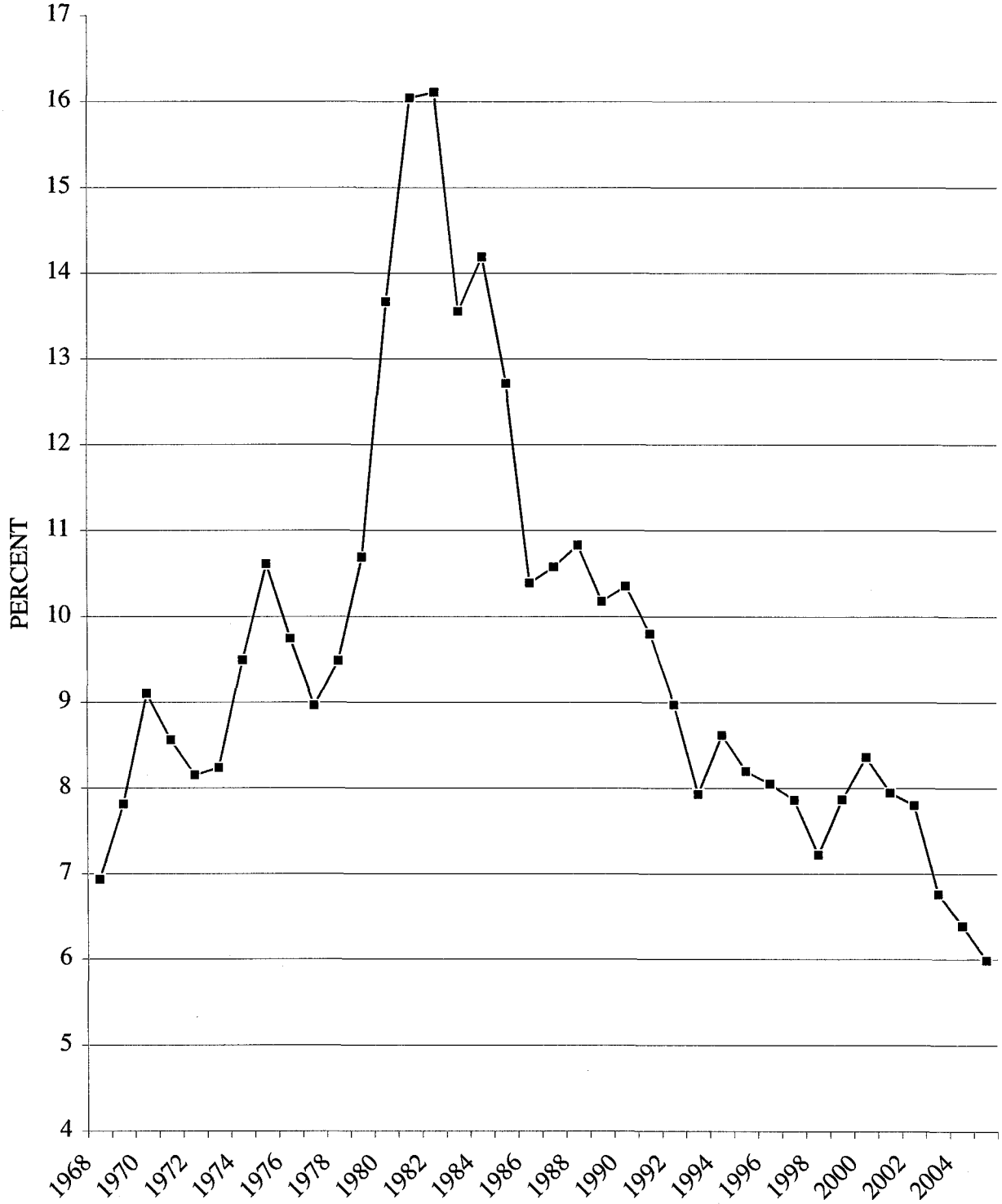


Data from Federal Reserve Release H.15.

SOUTHWEST GAS COMPANY

MOODY'S BAA BOND YIELDS

1968-2005



Data from Federal Reserve Release H.15.

SOUTHWEST GAS COMPANY
SOUTHWEST GAS CORPORATION
RECENT HISTORICAL CAPITAL STRUCTURE

AMOUNT

Type of Capital	Mar-04	Jun-04	Sep-04	Dec-04	Mar-05	Average
Common Equity	$669,840	$667,131	$661,662	$705,676	$742,235	$689,309
Preferred Securities	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
Long-term Debt	$1,126,176	$1,132,744	$1,195,555	$1,192,757	$1,191,378	$1,167,722
Short-term Debt	$24,000	$54,000	$38,000	$100,000	$11,000	$45,400
TOTAL	$1,920,016	$1,953,875	$1,995,217	$2,098,433	$2,044,613	$2,002,431

PERCENTAGE

Type of Capital	Mar-04	Jun-04	Sep-04	Dec-04	Mar-05	Average
Common Equity	34.89%	34.14%	33.16%	33.63%	36.30%	34.42%
Preferred Securities	5.21%	5.12%	5.01%	4.77%	4.89%	4.99%
Long-term Debt	58.65%	57.97%	59.92%	56.84%	58.27%	58.32%
Short-term Debt	1.25%	2.76%	1.90%	4.77%	0.54%	2.27%
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Data from Company response to Staff-SH-12-1.

SOUTHWEST GAS COMPANY
RATE IMPACT OF HYPOTHETICAL CAPITAL STRUCTURE

Company-requested Capitalization

Type of Capital	Percent	Cost Rate	Wt. Average Cost Rate	Pre-tax Cost Rate (t=40%)
Common Equity	42.00%	11.95%	5.02%	8.37%
Preferred Securities	5.00%	8.20%	0.41%	0.41%
Debt	53.00%	7.49%	3.97%	3.97%
Total	100.00%			**12.74%**

Actual Southwest Gas Corporation Capital Structure

Type of Capital	Percent	Cost Rate	Wt. Average Cost Rate	Pre-tax Cost Rate (t=40%)
Common Equity	35.00%	11.95%	4.18%	6.97%
Preferred Securities	5.00%	8.20%	0.41%	0.41%
Debt	60.00%	7.49%	4.49%	4.49%
Total	100.00%			**11.87%**

Overall Cost of Capital Differential = **0.87%**

Original Cost Rate Base = **$0.925 Bill.**

Annual Rate Impact of Hypothetical Capital Structure = **$8,048,115**

SOUTHWEST GAS COMPANY
SOUTHWEST GAS CORPORATION
LONG-TERM HISTORICAL CAPITAL STRUCTURE

YEAR	DEBT/EQUITY RATIO	PERCENT EQUITY
1995	1.71	36.90%
1996	1.75	36.36%
1997	2.02	33.11%
1998	1.71	36.90%
1999	1.70	37.04%
2000	1.68	37.31%
2001	1.42	41.32%
2002	1.83	35.34%
2003	1.94	34.01%
2004	1.79	35.84%
AVERAGE	1.76	36.41%

Data from MSN.com (http://moneycentral.msn.com/investor/research/printrep.asp?Symbol=swx).

SOUTHWEST GAS COMPANY
GAS INDUSTRY COMMON EQUITY RATIOS

	COMPANY	COMMON EQUITY RATIO (Including STD)
1	AGL Resources†	41%
2	Atmos Energy†	41%
3	Cascade Natural Gas†	40%
4	Chesapeake Utilities	51%
5	Delta Natural Gas	40%
6	El Paso Corporation	16%
7	Energen Corporation	51%
8	Energy West Incorporated	26%
9	EnergySourth, Inc.	50%
10	Equitable Resources	49%
11	KeySpan Corp.	42%
12	Kinder Morgan, Inc.	41%
13	Laclede Group, Inc.†	40%
14	National Fuel Gas	50%
15	New Jersey Resources†	45%
16	NICOR, Inc.	43%
17	Northwest Natural Gas†	49%
18	ONEOK, Inc.	39%
19	Peoples Energy Corporation†	45%
20	Piedmont Natural Gas†	52%
21	Questar Corporation	59%
22	RGC Resources, Inc.	46%
23	SEMCO Energy, Inc.	22%
24	South Jersey Industries†	31%
25	Southern Union Company	34%
26	Southwest Gas Corporation†	34%
27	Southwestern Energy	57%
28	UGI Corporation	31%
29	WGL Holdings†	52%
30	Williams Companies	35%
	INDUSTRY AVERAGE	**41.7%**
	INVESTMENT GRADE AVG.**	**43.9%**
	SAMPLE GROUP AVG.	**42.7%**

C.A Turner's Utility Reports, May 2005, pp. 15, 16.
†Companies included in Hill sample group.
**Companies with bonds rated "BBB-" or above.

SOUTHWEST GAS COMPANY
GAS INDUSTRY COMMON EQUITY RATIOS

	COMPANY	COMMON EQUITY RATIO (Including STD)
1	AGL Resources†	41%
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20	Piedmont Natural Gas†	52%
21	Questar Corporation	59%
22	RGC Resources, Inc.	46%
23	SEMCO Energy, Inc.	22%
24	South Jersey Industries†	31%
25	Southern Union Company	34%
26	Southwest Gas Corporation†	34%
27	Southwestern Energy	57%
28	UGI Corporation	31%
29	WGL Holdings†	52%
30	Williams Companies	35%
	INDUSTRY AVERAGE	**41.7%**
	INVESTMENT GRADE AVG.**	**43.9%**
	SAMPLE GROUP AVG.	**42.7%**

C.A Turner's Utility Reports, May 2005, pp. 15, 16.
†Companies included in Hill sample group.
**Companies with bonds rated "BBB-" or above.

SOUTHWEST GAS COMPANY
RATEMAKNG CAPITAL STRUCTURE

Type of Capital	PERCENT	COST RATE*	WT. AVG. COST RATE
Common Equity	40.00%	-	-
Preferred Securities	5.00%	8.20%	0.97%
Total Debt	55.00%	7.61%	4.19%
TOTALS	100.00%		

* See page 6 for determination of debt cost rate.

SOUTHWEST GAS COMPANY
DEBT COST RATE AT MARCH 31, 2005

Description	Net Principal Outstanding	Percent of Total Debt	Interest Rate*	Wt. Average Cost Rate
Fixed Rate Debt	$679,050,093	87.23%	8.20%	7.15%
Term Facility	$99,371,603	12.77%	3.54%	0.45%
Total Debt	$778,421,696			7.61%

*Data from Company response to STAFF-SH-12-2

SOUTHWEST GAS COMPANY
DCF GROWTH RATE PARAMETERS
GAS DISTRIBUTORS

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
ATG	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	0.1628	11.5%	1.87%	11.50	54.00	
2001	0.2800	12.3%	3.44%	12.19	55.10	
2002	0.4066	14.5%	5.90%	12.52	56.70	
2003	0.4663	14.0%	6.53%	14.66	64.50	
2004	0.4956	11.0%	5.45%	18.06	76.70	
AVERAGE GROWTH			4.64%	3.50%		9.17%
2005	0.4609	12.0%	5.53%		76.80	0.13%
2006	0.4750	12.0%	5.70%		77.00	0.20%
2008-2010	0.5273	11.5%	6.06%	8.00%	78.00	0.34%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
ATO	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	-0.1068	08.2%	-0.88%	12.28	31.95	
2001	0.2109	09.6%	2.02%	14.31	40.79	
2002	0.1862	10.4%	1.94%	13.75	41.68	
2003	0.2982	09.3%	2.77%	16.66	51.48	
2004	0.2278	07.6%	1.73%	18.05	62.80	
AVERAGE GROWTH			1.52%	6.50%		18.41%
2005	0.2914	09.0%	2.62%		82.00	30.57%
2006	0.3189	09.0%	2.87%		86.00	17.02%
2008-2010	0.4130	09.0%	3.72%	8.50%	97.00	9.08%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
CGC	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	0.3094	12.9%	3.99%	10.79	11.05	
2001	0.3469	13.3%	4.61%	11.01	11.05	
2002	0.1504	10.9%	1.64%	10.34	11.05	
2003	-0.1034	08.6%	-0.89%	10.11	11.13	
2004	0.1933	11.2%	2.16%	10.52	11.27	
AVERAGE GROWTH			2.30%	0.00%		0.49%
2005	0.1652	10.5%	1.73%		11.30	0.27%
2006	0.2320	10.5%	2.44%		11.30	0.13%
2008-2010	0.3875	11.5%	4.46%	6.00%	12.00	1.26%

SOUTHWEST GAS COMPANY
DCF GROWTH RATE PARAMETERS
GAS DISTRIBUTORS

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
LG	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	0.0219	09.1%	0.20%	14.99	18.88	
2001	0.1677	10.5%	1.76%	15.26	18.88	
2002	-0.1356	07.8%	-1.06%	15.07	18.96	
2003	0.2637	11.6%	3.06%	15.65	19.11	
2004	0.2527	10.1%	2.55%	16.96	20.98	
AVERAGE GROWTH			1.30%	1.50%		2.67%
2005	0.2541	09.5%	2.41%		21.50	2.48%
2006	0.2923	09.0%	2.63%		21.50	1.23%
2008-2010	0.3689	08.0%	2.95%	11.00%	21.50	0.49%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
NJR	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	0.3575	14.6%	5.22%	12.43	26.39	
2001	0.4000	14.9%	5.96%	13.2	26.66	
2002	0.4258	15.7%	6.69%	13.06	27.67	
2003	0.4790	15.6%	7.47%	15.38	27.23	
2004	0.4902	15.3%	7.50%	16.87	27.74	
AVERAGE GROWTH			6.57%	6.00%		1.26%
2005	0.4963	14.5%	7.20%		27.50	-0.87%
2006	0.5000	14.0%	7.00%		27.00	-1.34%
2008-2010	0.5097	11.0%	5.61%	11.00%	25.00	-2.06%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
NWN	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	0.3073	10.0%	3.07%	17.93	25.23	
2001	0.3351	10.2%	3.42%	18.56	25.23	
2002	0.2222	08.5%	1.89%	18.88	25.59	
2003	0.2784	09.0%	2.51%	19.52	25.94	
2004	0.3011	09.0%	2.71%	20.65	27.55	
AVERAGE GROWTH			2.72%	3.50%		2.22%
2005	0.3667	10.0%	3.67%		27.75	0.73%
2006	0.3911	10.0%	3.91%		28.00	0.81%
2008-2010	0.4000	10.0%	4.00%	4.00%	28.50	0.68%

SOUTHWEST GAS COMPANY
DCF GROWTH RATE PARAMETERS
GAS DISTRIBUTORS

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
PGL	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	0.2620	12.4%	3.25%	22.02	35.30	
2001	0.3576	13.9%	4.97%	22.76	35.40	
2002	0.2607	12.3%	3.21%	22.74	35.46	
2003	0.2613	12.3%	3.21%	23.11	36.69	
2004	0.0092	09.4%	0.09%	23.06	36.69	
AVERAGE GROWTH			2.95%	2.50%		0.97%
2005	0.1774	11.0%	1.95%		38.00	3.57%
2006	0.2000	11.5%	2.30%		37.00	0.42%
2008-2010	0.2400	10.5%	2.52%	4.50%	35.00	-0.94%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
PNY	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	0.2871	12.1%	3.47%	8.26	63.83	
2001	0.2475	11.7%	2.90%	8.63	64.93	
2002	0.1579	10.6%	1.67%	8.91	66.18	
2003	0.2613	11.8%	3.08%	9.36	67.13	
2004	0.3228	11.1%	3.58%	11.15	76.67	
AVERAGE GROWTH			2.94%	5.50%		4.69%
2005	0.2640	11.0%	2.90%		77.00	0.43%
2006	0.2462	11.0%	2.71%		76.00	-0.44%
2008-2010	0.3125	12.0%	3.75%	7.50%	73.00	-0.98%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
SJI	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	0.3241	12.2%	3.95%	14.5	11.50	
2001	0.3537	10.8%	3.82%	15.62	11.86	
2002	0.3786	12.5%	4.73%	19.34	12.21	
2003	0.4286	11.6%	4.97%	22.52	13.23	
2004	0.4727	12.0%	5.67%	25.75	13.80	
AVERAGE GROWTH			4.63%	7.00%		4.66%
2005	0.4769	12.5%	5.96%		14.20	2.90%
2006	0.4706	12.5%	5.88%		14.30	1.80%
2008-2010	0.4750	13.0%	6.18%	5.00%	15.00	1.68%

SOUTHWEST GAS COMPANY
DCF GROWTH RATE PARAMETERS

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
WGL	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	0.3073	11.7%	3.59%	15.31	46.47	
2001	0.3298	11.2%	3.69%	16.24	48.54	
2002	-0.1140	07.2%	-0.82%	15.78	48.56	
2003	0.4435	14.0%	6.21%	16.25	48.63	
2004	0.3434	11.7%	4.02%	16.95	48.67	
AVERAGE GROWTH			3.34%	3.00%		1.16%
2005	0.3000	10.5%	3.15%		48.70	0.06%
2006	0.3463	11.0%	3.81%		48.70	0.03%
2008-2010	0.4615	12.0%	5.54%	4.50%	48.70	0.01%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
SWX	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
2000	0.3223	07.2%	2.32%	16.82	31.71	
2001	0.2870	06.6%	1.89%	17.27	32.49	
2002	0.2931	06.5%	1.91%	17.91	33.29	
2003	0.2743	06.1%	1.67%	18.42	34.23	
2004	0.4710	05.0%	2.35%	18.85	36.10	
AVERAGE GROWTH			2.03%	4.00%		3.29%
2005	0.5176	08.0%	4.14%		36.50	1.11%
2006	0.5684	09.0%	5.12%		37.00	1.24%
2008-2010	0.6511	10.0%	6.51%	4.00%	40.00	2.07%

Data from Value Line Ratings & Reports, March 18, 2005.

SOUTHWEST GAS COMPANY

DCF GROWTH RATES
GAS DISTRIBUTORS

COMPANY	br	+	sv=g*((M/B+1)/2-1)			=	g
ATG	5.25%	+	1.00%	((1.71	+ 1)/2-1)	=	5.60%
ATO	4.25%	+	5.00%	((1.31	+ 1)/2-1)	=	5.01%
CGC	4.75%	+	0.75%	((1.63	+ 1)/2-1)	=	4.99%
LG	4.25%	+	1.00%	((1.24	+ 1)/2-1)	=	4.37%
NJR	6.25%	+	-0.50%	((2.11	+ 1)/2-1)	=	5.97%
NWN	4.25%	+	1.25%	((1.60	+ 1)/2-1)	=	4.62%
PGL	4.00%	+	0.00%	((1.67	+ 1)/2-1)	=	4.00%
PNY	4.25%	+	1.50%	((1.97	+ 1)/2-1)	=	4.98%
SJI	5.25%	+	2.00%	((2.04	+ 1)/2-1)	=	6.29%
WGL	4.50%	+	0.00%	((1.71	+ 1)/2-1)	=	4.50%
SWX	5.75%	+	2.50%	((1.19	+ 1)/2-1)	=	5.99%

Average Market-to-Book Ratio = 1.65

ATG	=	AGL Resources
ATO	=	Atmos Energy Corporation
CGC	=	Cascade Natural Gas Corporation
LG	=	Laclede Group
NJR	=	New Jersey Resources Corp.
NWN	=	Northwest Natural Gas Co.
PGL	=	Peoples Energy Corp.
PNY	=	Piedmont Natual Gas Company
SJI	=	South Jersey Industries, Inc.
WGL	=	WGL Holdlings
SWX	=	Southwest Gas

g*= expected growth in number of shares outstanding

SOUTHWEST GAS COMPANY

GROWTH RATE COMPARISON
GAS DISTRIBUTORS

		Value Line Projected			FirstCall	Value Line Historic			FirstCall & VL	5-yr Compound Hist.		
COMPANY	br + sv	EPS	DPS	BVPS	EPS	EPS	DPS	BVPS	AVGS.	EPS	DPS	BVPS
ATG	5.60%	5.00%	2.50%	8.00%	4.00%	11.00%	0.50%	3.50%	4.93%	12.26%	2.80%	10.74%
ATO	5.01%	6.50%	2.00%	8.50%	6.50%	3.50%	2.50%	6.50%	5.14%	11.18%	1.70%	9.69%
CGC	4.99%	7.00%	0.50%	6.00%	4.50%	1.00%	0.00%	0.00%	2.71%	-3.72%	0.00%	0.48%
LG	4.37%	6.00%	1.00%	11.00%	5.00%	-0.50%	0.50%	1.50%	3.50%	6.19%	0.59%	5.51%
NJR	5.97%	8.00%	3.00%	11.00%	5.50%	8.00%	2.50%	6.00%	6.29%	8.57%	3.41%	8.57%
NWN	4.62%	5.00%	2.50%	4.00%	5.80%	2.00%	1.00%	3.50%	3.40%	3.25%	1.41%	3.65%
PGL	4.00%	1.00%	1.50%	4.50%	4.00%	2.00%	2.00%	2.50%	2.50%	-0.45%	1.74%	1.22%
PNY	4.98%	7.50%	4.00%	7.50%	5.00%	3.00%	5.00%	5.50%	5.36%	4.36%	5.02%	6.75%
SJI	6.29%	5.50%	4.50%	5.00%	5.50%	9.50%	1.00%	7.00%	5.43%	8.51%	3.09%	12.82%
WGL	4.50%	6.50%	1.50%	4.50%	4.00%	2.00%	1.50%	3.00%	3.29%	1.20%	1.41%	2.71%
SWX	5.99%	10.50%	1.50%	4.00%	5.00%	5.00%	0.00%	4.00%	4.29%	7.04%	0.00%	3.58%
		6.23%	2.23%	6.73%		4.23%	1.50%	3.91%		5.31%	1.92%	5.97%
AVERAGES	5.12%		5.06%		4.98%		3.21%		4.26%		4.40%	

Zack's Growth Rates: ATG-4.7%; ATO-5.0%; CGC-6.0%; LG-5.0%; NJR-6.5%; NWN-5.1%; PGL-4.5%; PNY-4.9%; SJI-6%; WGL-3.9%; SWX-4.6%. Average Zack's Growth = 5.11%

SOUTHWEST GAS COMPANY

STOCK PRICE, DIVIDENDS, YIELDS
GAS DISTRIBUTORS

COMPANY	AVG. STOCK PRICE 4/18/05-5/27/05 (PER SHARE)		ANNUALIZED DIVIDEND (PER SHARE)	DIVIDEND YIELD
ATG	$34.45		$1.24	3.60%
ATO	$27.09		$1.24	4.58%
CGC	$19.06		$0.96	5.04%
LG	$28.94	*	$1.42	4.90%
NJR	$44.45		$1.36	3.06%
NWN	$35.95	*	$1.36	3.78%
PGL	$40.72		$2.18	5.35%
PNY	$23.45		$0.92	3.92%
SJI	$56.07		$1.70	3.03%
WGL	$31.20	*	$1.36	4.35%
SWX	$24.87		$0.82	3.30%
			AVERAGE	**4.08%**

* Dividend increased by (1+g), derived on Schedule 4.

SOUTHWEST GAS COMPANY

DCF COST OF EQUITY CAPITAL
GAS DISTRIBUTORS

COMPANY	DIVIDEND YIELD Schedule 5	GROWTH RATE Schedule 4	DCF COST OF EQUITY CAPITAL
ATG	3.60%	5.60%	9.20%
ATO	4.58%	5.01%	9.59%
CGC	5.04%	4.99%	10.02%
LG	4.90%	4.37%	9.27%
NJR	3.06%	5.97%	9.03%
NWN	3.78%	4.62%	8.41%
PGL	5.35%	4.00%	9.35%
PNY	3.92%	4.98%	8.90%
SJI	3.03%	6.29%	9.32%
WGL	4.35%	4.50%	8.85%
SWX	3.30%	5.99%	9.29%
		AVERAGE	**9.20%**
		STANDARD DEVIATION	**0.44%**

SOUTHWEST GAS COMPANY

CAPM COST OF EQUITY CAPITAL
GAS DISTRIBUTORS

k = rf + B (rm - rf)

T-BILLS

[rf]* = 2.84%
[rm - rf]† = 6.70% (geometric mean)
[rm - rf]† = 8.60% (arithmetic mean)
average beta = 0.73

k = 2.84% + 0.7 (6.70%/8.60%)
k = 2.84% + 4.87%/6.25%
k = 7.71% / 9.09%

T-BONDS

[rf]* = 4.58%
[rm - rf]† = 5.00% (geometric mean)
[rm - rf]† = 6.60% (arithmetic mean)
average beta = 0.73

k = 4.58% + 0.73 (5.00%/6.60%)
k = 4.58% + 3.63%/4.80%
k = 8.22% / 9.38%

*Current T-Bill & T-Bond yields, six-week average yield from Value Line Selection & Opinion (4/22/05-5/27/05)
†Geometric and arithmetic market risk premiums from Ibbotson Associates 2004 SBBI Yearbook, p. 117.

SOUTHWEST GAS COMPANY
PROOF

If market price exceeds book value,
the market-to-book ratio is greater than 1.0,
and the earnings-price ratio understates the cost of capital.

MP = market price
BV = book value
i = cost of equity capital
r = earned return
E = earnings

1. At $MP = BV$, $i = r = \frac{E}{MP}$.
2. $E = rBV$.
3. Then, $\frac{E}{MP} = \frac{rBV}{MP}$.
4. When $BV < MP$, i.e., $\frac{BV}{MP} < 1$, then,
   a. $\frac{E}{MP} < r$, since $\frac{E}{MP} = \frac{rBV}{MP} < r$, because $\frac{BV}{MP} < 1$;
   b. $i < r$, since at $\frac{BV}{MP} = 1$, $i = \frac{E}{MP} = \frac{rBV}{MP}$, but if $\frac{BV}{MP} < 1$, then $i < r$; and
   c. $\frac{E}{MP} < i$, since at $\frac{BV}{MP} = 1$, $i = \frac{E}{MP} = \frac{rBV}{MP}$, but if $\frac{BV}{MP} < 1$, then $\frac{E}{MP} < i$, because,
      1) $\frac{BV}{MP} < 1$, through MP increasing, and, if so, $\frac{E}{MP}$ decreases, therefore, $\frac{E}{MP} < i$, or
      2) $\frac{BV}{MP} < 1$, through BV decreasing, and, if so, given $E = rBV$, $\frac{E}{MP}$ decreases, therefore, $\frac{E}{MP} < i$.
5. Ergo, $\frac{E}{MP} < i < r$, the cost of capital is lower than the earned return.

Exhibit_(SGH-1)
Schedule 9

SOUTHWEST GAS COMPANY

MODIFIED EARNINGS-PRICE RATIO ANALYSIS
GAS DISTRIBUTORS

COMPANY	FirstCall 2006 EARNINGS (Per Share)	MARKET PRICE (Per share)	EARNINGS-PRICE RATIO		CURRENT R.O.E. 2005	PROJECTED R.O.E. 2008-2010
ATG	$2.44	$34.45	7.08%		12.00%	11.50%
ATO	$1.86	$27.09	6.87%		9.00%	9.00%
CGC	$1.26	$19.06	6.61%		10.50%	11.50%
LG	$2.00	$28.94	6.91%		9.50%	8.00%
NJR	$2.76	$44.45	6.21%		14.50%	11.00%
NWN	$2.29	$35.95	6.37%		10.00%	10.00%
PGL	$2.81	$40.72	6.90%		11.00%	10.50%
PNY	$1.34	$23.45	5.71%		11.00%	12.00%
SJI	$3.43	$56.07	6.12%		12.50%	13.00%
WGL	$1.98	$31.20	6.35%		10.50%	12.00%
SWX	$1.79	$24.87	7.20%		8.00%	10.00%
		AVERAGE	6.51%		11.05%	
		CURRENT M.E.P.R.		**8.78%**		
		AVERAGE	6.51%			10.85%
		PROJECTED M.E.P.R.			**8.68%**	

SOUTHWEST GAS COMPANY

MARKET-TO-BOOK RATIO ANALYSIS
GAS DISTRIBUTORS

k = R.O.E.(1-b)/(M/B) + g
[2005]

COMPANY									MARKET-TO-BOOK COST OF EQUITY
ATG	k= 12.0%	(1-	0.4609)/	1.71	+	5.60%	=		9.40%
ATO	k= 09.0%	(1-	0.2914)/	1.31	+	5.01%	=		9.90%
CGC	k= 10.5%	(1-	0.1652)/	1.63	+	4.99%	=		10.37%
LG	k= 09.5%	(1-	0.2541)/	1.24	+	4.37%	=		10.09%
NJR	k= 14.5%	(1-	0.4963)/	2.11	+	5.97%	=		9.44%
NWN	k= 10.0%	(1-	0.3667)/	1.60	+	4.62%	=		8.59%
PGL	k= 11.0%	(1-	0.1774)/	1.67	+	4.00%	=		9.43%
PNY	k= 11.0%	(1-	0.2640)/	1.97	+	4.98%	=		9.09%
SJI	k= 12.5%	(1-	0.4769)/	2.04	+	6.29%	=		9.50%
WGL	k= 10.5%	(1-	0.3000)/	1.71	+	4.50%	=		8.80%
SWX	k= 08.0%	(1-	0.5176)/	1.19	+	5.99%	=		9.23%
								AVERAGE	**9.46%**
								STANDARD DEVIATION	**0.55%**

Note: Equity returns and retention ratios based on Value Line current year projections.

SOUTHWEST GAS COMPANY

MARKET-TO-BOOK RATIO ANALYSIS
GAS DISTRIBUTORS

k = R.O.E.(1-b)/(M/B) + g
[2008-2010]

COMPANY								MARKET-TO-BOOK COST OF EQUITY
ATG	k= 11.5%	(1- 0.5273)/	1.71	+	5.60%	=		8.79%
ATO	k= 09.0%	(1- 0.4130)/	1.31	+	5.01%	=		9.06%
CGC	k= 11.5%	(1- 0.3875)/	1.63	+	4.99%	=		9.31%
LG	k= 08.0%	(1- 0.3689)/	1.24	+	4.37%	=		8.44%
NJR	k= 11.0%	(1- 0.5097)/	2.11	+	5.97%	=		8.53%
NWN	k= 10.0%	(1- 0.4000)/	1.60	+	4.62%	=		8.38%
PGL	k= 10.5%	(1- 0.2400)/	1.67	+	4.00%	=		8.79%
PNY	k= 12.0%	(1- 0.3125)/	1.97	+	4.98%	=		9.16%
SJI	k= 13.0%	(1- 0.4750)/	2.04	+	6.29%	=		9.64%
WGL	k= 12.0%	(1- 0.4615)/	1.71	+	4.50%	=		8.28%
SWX	k= 10.0%	(1- 0.6511)/	1.19	+	5.99%	=		8.92%
							AVERAGE	**8.84%**
							STANDARD DEVIATION	**0.45%**

Note: Equity returns and retention ratios based on Value Line three- to five-year projections.

SOUTHWEST GAS COMPANY
OVERALL COST OF CAPITAL

Type of Capital	Percent of Total	Cost Rate	Wt. Average Cost of Capital
Common Equity	40.00%	9.50%	3.80%
Preferred Securities	5.00%	8.20%	0.41%
Total Debt	55.00%	7.61%	4.19%
TOTALS	100.00%		8.40%

PRE-TAX INTEREST COVERAGE* = 2.38x

*Assuming the Company experiences, prospectively, a combined income tax rate of 40%, the pre-tax overall return would be 10.93% [8.40%-(0.41%+4.19%)=3.80% /(1-40%) = 6.33%+(0.41%+4.19%)]. That pre-tax overall return (10.93%), divided by the weighted cost of debt (0.41%+4.19%), indicates a pre-tax interest coverage level of 2.38 times.

GEHLEN

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-01551A-04-0876

DIRECT

TESTIMONY

OF

WILLIAM GEHLEN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 26, 2005

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-04-0876

Southwest Gas Corporation ("Southwest" or "Company") is engaged in the business of constructing infrastructure and purchasing, transporting, and distributing natural gas in Arizona service territories in Cochise, Gila, Graham, Greenlee, La Paz, Maricopa, Mohave, Pima, Pinal and Yuma counties. Southwest serves approximately 900,000 customers across its customer classifications in Arizona.

The rates paid by Arizona customers are directly influenced by the costs of construction and natural gas. Construction costs are rate based, while the gas costs are a direct pass through. The total cost to the customer is influenced by how professionally the company builds its infrastructure as well as the price it pays for gas. The Company's purchasing department and fuel procurement functions were analyzed for efficiency of operation, appropriate procedures, presence of checks and balances, and conflicts of interest.

The results of Staff's analysis indicate that the Southwest purchasing function properly documents its procurement decisions, has no apparent conflicts of interest, has a highly trained staff, and has been able to limit or control costs on pipe and meters during a period of price escalation. The gas procurement function is effective but can be improved by upgrading portfolio optimization software, utilizing a best practices study, evaluating risk management techniques and addressing the apparent lack of checks and balances in its gas procurement process.

INTRODUCTION

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

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

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

A. In my capacity as a Public Utilities Analyst V, I provide recommendations to the Commission on energy related issues.

Q. Please describe your educational background and professional experience.

A. I earned a BS degree in Business Administration from Aquinas College, and a MBA from Western Michigan University. My background includes 26 years of utility industry experience with 16 years in investor-owned utilities. In the fuels area, I have been responsible for the planning, procurement and transportation of multiple fuel categories (natural gas, gasoline, coal, oil and nuclear). In addition, I have had responsibility for the procurement of land, equipment, services, consulting and construction contracts, and purchased power (short, medium and long term). Management positions also included responsibility for Integrated Resource Planning (supply side and demand side), long range forecasting, transmission planning, environmental affairs and strategic planning. My most recent 10 years experience includes 1 year with the Office of Consumer Advocate for the State of Nevada as a regulatory analyst, and 9 years in the development and marketing of energy trading platforms, origination of purchase power agreements, and support of merchant generators in gathering market intelligence on fuel and product issues to aid in understanding inter and intra regional market design issues and solutions.

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

A. I will address Southwest Gas' ("Southwest" or "Company") natural gas procurement, and purchasing departments' policies and procedures for effectiveness and compare the policies and procedures to actual purchase of natural gas, and goods and services including pipe, meter, meter subassemblies, automobiles and computers. As part of the analysis a review of the natural gas marketplace and safeguards to prevent conflict of interests by the use of appropriate checks and balances was performed.

NATURAL GAS PROCUREMENT

National and Arizona natural gas markets

Q. Are domestic natural gas supplies and demand in balance?

A. There is a balance in the natural gas marketplace but this is a result of a decline in usage by the industrial sector that resulted from the 2001 to 2003 price spikes. Prior to these price spikes gas consumption had increased in correlation with increases in Gross Domestic Product ("GDP"). Most natural gas production is domestic and was supplemented by Canadian gas. Recent reductions in domestic and Canadian supplies have required an increased reliance on Liquefied Natural Gas ("LNG") to maintain adequate supply levels to a market that has had a decrease in consumption in three of the last four years[1].

Q. Describe the natural gas marketplace for Arizona.

A. The natural gas marketplace for Arizona is comprised of a set number of suppliers that offer natural gas at either fixed, indexed, or basis differential pricing. All deliveries for the Southwest Gas market areas must be taken off the El Paso pipeline system. There are numerous suppliers but the existence of only one delivery source, El Paso Natural Gas

[1] According to Simmons & Company International, Energy Industry Research - Outlook for Natural Gas: 2005 and Beyond, January 18, 2005

("EPNG") Pipeline, limits the leverage of gas buyers in Arizona. The pricing in the marketplace is homogenous with little to no price differentials among sellers. Historically, gas prices tend to follow the price of oil even though there is little opportunity for fuel switching in Arizona. What we are seeing is that natural gas prices in Arizona are influenced by the world economy, and competing domestic markets, and are not directly tied to costs of production.

Natural Gas Procurement Overview

Q. Describe the fuel procurement activities performed by Southwest for its Arizona customers.

A. Southwest utilizes a portfolio approach to obtaining gas supplies for its Arizona customers. The portfolio will contain a mix of procurement options including index and fixed price contracts for varying durations. Typical procurement durations include spot purchases of one month or less ("Next Day" and "Next Month"), and durations of one year or less ("Term" and Arizona Price Stability Purchases ("APSP")). Typical pricing is index for spot and "Term" purchases, and fixed price for "APSP".

Q. Is there any one best approach for setting the portfolio makeup?

A. No. The mix of contract types and durations will vary depending on supply and pipeline options, scarcity or abundance of gas, and market volatility. Each of these factors together or individually will have an impact on designing the makeup of the fuel portfolio. The mix has to address procuring enough gas without paying too high a premium for guaranteed delivery. The more physical price hedges, such as storage and alternate pipelines that are available, the greater the portfolio options for consideration.

Q. Does Southwest have any physical price hedges?

A. No. Southwest is presently limited to taking gas deliveries from a single pipeline company, EPNG pipeline, with no transportation price differential between the northern and southern systems. In addition, there is no storage available in Arizona where Southwest could store gas when prices are low and release gas when prices are higher. Storage could assist in managing costs as well adding operational flexibility. Southwest does not own any reserves or production facilities and this, combined with lack of storage capability, makes Southwest totally reliant on the market and market pricing for its Arizona customers.

Q. Are there new short term market or delivery developments that would offer Southwest Gas pricing leverage?

A. No. Price transparency is increasing through the usage of electronic trading platforms. There are numerous publications, both industry and government which project and post pricing. However, both buyers and sellers benefit equally from these platforms and publications. In addition, the institutional trading parameters force trading to occur in short, set time frames where business must be transacted and sellers typically hold prices for a very short duration.

Q. Does Southwest Gas utilize hedging to moderate price volatility?

A. Yes. Southwest Gas operates a very conservative passive procurement business plan. Hedging activities for their Arizona customers consist of buying on average 50% of gas requirements at a fixed price utilizing APSP. Southwest does not trade (buy and sell) in the gas markets or utilize financial hedging, are a price taker, and generally seek to run a risk free operation and take gas at plus or minus index, or basis differential. This approach tends to provide some price stability to the customer but it can not be expected

to put significant downward pressure on Southwest's fuel costs. The utilization of financial hedging is an additional option that should be considered. The success of Southwest Airlines fuel hedging strategy is an example of how fuel costs can be successfully controlled.

Natural Gas Procurement Review

Q. Describe the review of Southwest's natural gas procurement process undertaken by Staff.

A. Staff's review included an analysis of Southwest's internal audit reports, fuel procurement policies and procedures, signature authority levels, checks and balances in the procurement process, potential for conflict of interest, personnel qualifications and training of procurement personnel. Staff requested and reviewed the "Term" and fixed price procurements (APSP) conducted with TXU for the year period September 2003 through August 2004 for compliance with policies and procedures. In addition, Staff reviewed all individual gas purchases with all suppliers for the months of January 2004 and July 2004. The review was performed to assess whether the purchases were reasonable given prices and market conditions. The January and July purchase review is addressed in Staff Witness Robert Gray's testimony in this case. The initial review was conducted in Phoenix mainly through data requests. Staff continued the review with an on site visit to the Southwest Gas offices in Las Vegas, Nevada. During the on site visit the "Next Month", and "Next Day", bidding processes were witnessed and a review of Southwest Gas' portfolio analysis and software were provided. Southwest Gas also provided the "Term" and fixed price procurements (APSP) conducted with BP Energy for the period September 2003 through August 2004. Subsequent to the on site visit follow up interviews were conducted on Southwest's APSP and were utilized to identify any unique procurement issues related to the bidding process.

Q. What summary conclusions were reached as a result of the review?

A. Based on its review, Staff believes the gas procurement function is fundamentally sound, was adequate for a price taker in a static market, but needs to be enhanced to better cope in a marketplace with volatile pricing, diminishing domestic and Canadian supplies, and an increasing reliance on LNG. Market dynamics have changed and a broader market view with additional checks and balances needs to be incorporated into procurement and planning processes and decisions.

Q. Was any improper procurement activity found?

A. No. Staff did not find any instances where Southwest violated its internal policies and procedures for the time period and purchases reviewed.

Q. Discuss the review of the TXU and BP Energy procurements.

A. The TXU and BP Energy procurements were selected for review because they were large dollar contracts with multiple releases over a year period. The procurement reviews showed that Southwest Gas awarded these contracts as a result of competitive bid processes. The types of contracts awarded to TXU and BP Energy included base load fixed price purchases (APSP), "Term" (indexed based), and interruptible (indexed based). The combined amount spent on these contracts for the period September 2003 through August 2004 was approximately $78,000,000. Total spending on gas from all suppliers during this period was approximately $251,000,000. Staff reviewed documents related to these procurements and interviewed Company personnel involved in these procurements. Bidding, award and contract administration procedures were followed and to a large degree the process was documented.

Q. Based on the BP Energy and TXU procurement reviews are there recommended changes to the procurement or contract administration procedures?

A. Yes. The primary issue that needs addressing in the gas supply function is the lack of an independent entity in the procurement, administration and invoice approval process. In many instances the same person evaluating the bids approves the contract award and approves invoices for payment. A single person has the ability to influence all aspects of the business process. This could allow an employee to steer business to specific suppliers or engage in other inappropriate activity. As currently organized, the fuel supply Contract Audit section, which functions as a contract administration function, (not an audit function), is responsible for settlement statements, payment authorizations, and reporting monthly gas purchases. The payment authorizations are in turn approved by the gas supply function senior management. One standard approach to solving this problem is to have the accounting department verify receipt information and authorize payment. Where discrepancies occur they would be returned to the gas procurement group for resolution.

Q. Describe the "Next Month", and "APSP" procurement processes.

A. The "Next Month" bids are typically held the last week of each month while the "APSP" bids are held annually. Both procurements are similar in that bidders are notified of the bid date and time. Bids are received via fax during the open bid time frame. "Next Month" bids are submitted at index, plus or minus, while the "APSP" bids are submitted at a basis differential which is based on the price difference between two production basins. Bid receipt is confirmed with the bidders by Southwest. Subsequent to bid confirmation, negotiations are then commenced with the lowest bidders to determine if any further price reductions can be negotiated. The negotiations and bid confirmations are conducted via phone and/or cell phone. Upon completion of negotiations the successful bidders are notified. The "APSP" contracts are awarded on a fixed price basis with the fixed price

determined during the negotiation process. The "Next Month" contracts can be awarded on a fixed price basis or at index. The entire bid process inclusive of bid receipt, evaluation, negotiation and contract award for the "Next Month" and "APSP" contracts takes less than 2 hours. The "Next Month" bid and evaluation is typically conducted in the fuel procurement area, while the "APSP" bid and evaluation is held in the executive offices and attended and participated in by the senior management of the Fuel Procurement function.

Q. Are there recommendations for the "Next Month" and "APSP" procurement process?

A. Yes. The use of cell phones to conduct negotiations should be eliminated, and all negotiation discussions between the parties should be recorded. This is standard industry practice and is important as a record in the event of pricing or quantity disputes. It is also recommended that a neutral person from a group outside of the fuel procurement area monitor both bid processes. Many companies require their procurement personnel to open large dollar value bids in a neutral department location, and have each page of the bid initialed by someone in the procurement function as well as a neutral function (typically accounting or auditing). The "Next Month" and "APSP" bidding processes both begin with a faxed quote but quickly turn to oral communication during negotiation and confirmation phases. These are high dollar procurements and the overview of neutral personnel is a positive way to ensure that an adequate and accurate analysis of bids is performed. In addition, neutral personnel can attest to the fairness of the process in the event of tie bids and the negotiations conducted to determine the eventual winning bidder.

Q. How does the "Term" procurement process differ from the "APSP" and "Next Month" procurements?

A. The "Term" procurement and evaluation process is different than the "APSP" and "Next Month" processes in that the bids are received electronically over a period of 2 weeks with pricing held for an extended period of time, rather than by fax with pricing held for a 1 to 2 hour period. The term bids are for a gas year that typically runs from November through October of the next year and requests bids for periods of 1, 3, 6, and 12 months. In summary, the "Term" contract bids are based on index, received electronically and evaluated over an extended period of time. Over a period of months various scenarios are run utilizing the "Term" bids, pipeline information, changes in capacity rights, forward price curves, and changing market factors to develop an optimized supply plan. When the computer analysis is complete a final review is conducted and "Term" contracts are awarded for the upcoming gas year. The final review takes into account any last minute market changes.

Q. Provide a summary of the portfolio analysis program utilized by Southwest Gas.

A. The Company utilizes software to aid in developing an optimal supply portfolio. The intent is to match the weather adjusted load forecast to the most cost effective mix of base load (fixed price), term (indexed) and peaking supplies. As part of this analysis the software is utilized in the annual term (indexed) bid process

Q. **Can the portfolio analysis process be improved?**

A. Yes. The software used by the Company was originally designed to be utilized by electric utilities and was modified for gas use. The software requires a labor intensive, iterative process and may take months to complete an analysis. In addition, the software has not been upgraded in the last 3 to 4 years. Market volatility has increased dramatically in that

time and the Company should aggressively look for a program that would enable more iterative runs to be made in a shorter time frame. A survey conducted by Staff indicates that there is software designed specifically for gas companies that is presently available and additional software is scheduled for release in the near future.

Q Did Staff evaluate the gas procurement function personnel?

A Yes. Summary resumes were provided on the gas procurement function personnel including executive management. The personnel makeup of the group provides a diverse pool of talent with both utility and gas market experience. Cross training is an on going process so that personnel become proficient in their Arizona, Nevada, and California markets. However, the Company was vague on outside training and did not supply a list of specific training that would enhance the understanding of options available for hedging and the impact that world markets exert on its ability to buy natural gas.

Other Areas of concern

Q. Were any other areas of concern identified as a result of Staff's natural gas procurement process review?

A. Yes. There are two additional areas that Staff is concerned about: Code of Conduct and lack of benchmarking. As part of its review, Staff analyzed Southwest's code of conduct. "THE SOUTHWEST GAS CORPORATION CODE OF BUSINESS CONDUCT & ETHICS" in the "CONFLICTS OF INTEREST" section states the following as an example of a situation that would be in conflict with Company policy: "Holding any ***substantial*** stock or other financial interest in any competitor, supplier or vendor or other organization with which an employee is engaged in a business relationship". When queried as to how the company determined if the stock owned by any employee was "substantial", Southwest responded that at present no procurement personnel own any

stock in any company with whom they conduct business. Based on the Southwest response, Staff must assume that criteria are not in place that would determine what constitutes a substantial interest. The clearest way to eliminate conflicts is to preclude stock ownership (substantial or otherwise), or other financial interest with any supplier, or within a class of suppliers, with whom an employee may conduct business.

Staff requested that Southwest provide any inside and outside audits, and benchmarking studies performed on the gas procurement process since its last rate case. Southwest provided internal audits and has not contracted with any outside auditing firms or consulting companies to evaluate its natural gas procurement practices. Since that time there has been a significant change in the price and volatility of gas. The rapid price increase has had major impacts on gas companies, electric utilities and manufacturers such as Dow Chemical. Impacts have been made on the way gas is purchased, hedged, traded and utilized. To a degree these changes have been driven by events tangential to gas markets. A prime mover has been the increase in the price of oil, which to a large degree is being driven by global economies rather than solely by domestic consumption. Through this change Southwest has remained introspective in its fuel procurement activities. In the absence of competition, in order to ensure that the Company is doing all it can do to control gas prices to its customers, Staff recommends that the Company utilize the services of an impartial industry consultant to benchmark its operations against industry best practices.

Q. Why is Staff recommending a best practices study?

A Through Staff data requests, Southwest was asked to supply any studies that had been completed that ranked or evaluated its procurement practices since its last rate case. None were performed. Southwest was asked if it was aware of the practices utilized by equivalent companies. Southwest was not aware of how its peers procured gas.

Southwest was asked what actions it was taking to address increased use of LNG. Southwest was not evaluating LNG. In addition, there are numerous other factors which lead Staff to recommend a best practices study: increased price volatility, reduced domestic and Canadian production and an increased reliance on LNG. In other words, rapidly changing market dynamics is prompting Staff's recommendation for a best practices study.

Q. Was the review Staff conducted consistent with similar reviews conducted in other jurisdictions?

A. Yes. Staff conducted a survey of various state jurisdictions. There was a broad range of regulatory approaches from after the fact prudency reviews in Colorado and Florida to regularly scheduled mandated management reviews by outside consultants in Pennsylvania. Nevada is taking a more active role by evaluating gas planning and procurement, and hedging in conjunction with its yearly prudency review.

Recommendations

Q. Summarize your recommendations for the Company's natural gas procurement activities.

A. Based on the analysis of Southwest Gas' natural gas procurement process Staff recommends the following:

1. Southwest Gas should be required to conduct a best practices review of the fuel procurement and planning functions by an impartial outside organization.
2. Southwest Gas should preclude employee stock ownership, or other financial interest, with any supplier or class of suppliers with whom they conduct business.
3. Southwest Gas should provide a check and balance in the fuel procurement process that would separate contract award authority from invoice approval authority.

4. Southwest Gas should eliminate the use of cell phones during fuel bidding and negotiating activities, and ensure all discussions are recorded. During the "Next Month" and "APSP" procurements neutral personnel should monitor the bidding and negotiation activities.
5. Southwest Gas should upgrade its portfolio evaluation software.

Q. Are there recommended deadlines for completing the Staff recommendations?

A. Yes. Recommendations 2 through 4 should be implemented immediately. Within 60 days of an order in this case Southwest Gas should docket evidence that it has complied with recommendations 2 through 4. Recommendations 1 and 5 should be completed by June 30, 2006. The software evaluation and upgrade could be identified in conjunction with the best practices evaluation. Copies of the completed best practices and software reviews should be filed in Docket Control in conjunction with a schedule for implementation on or before June 30, 2006. If the Company has concerns related to any of the recommendations, Staff is willing to reconsider and/or modify its recommendations based upon the rational provided in Southwest Gas' rebuttal testimony.

PURCHASING

Q Describe the purchasing department activities performed by Southwest for its Arizona customers.

A The purchasing department's primary purpose is the purchase of goods and services to support construction, maintenance and general office activities and do not include the purchase of natural gas. The purchases involved include one time procurements, annual bidding procurements, sole source procurements and blanket purchase orders. The purchases could be project specific, inventory replenishment or for emergency purposes. For calendar year 2004 the purchasing department issued 11,700 purchase orders with a

value of $89,447,373. Included in this amount are the dollars required for purchases to maintain the min/max inventory levels for the 17,709 catalog items (inventory replenishment).

Q. Describe the differences between the fuel procurement and the purchasing functions at Southwest Gas.

A. The gas procurement function buys a single commodity. It is designed to forecast the need for, arrange transportation and purchase that commodity. The purchasing function is responsible for the procurement and delivery of 17,709 catalog items in addition to emergency orders and service related products. The purchasing department buyers handle multiple product lines and negotiate contracts for a diverse portfolio of products. Due to the sheer size of the items required to be supplied by the purchasing department purchasing authority is delegated from time to time where strict quality or central control isn't required. Fuel procurement responsibility is not delegated.

Q Was a review of the purchasing department conducted?

A Yes. A review of the purchasing department organization, policies and procedures, employee qualifications, system checks and balances and procurement techniques was conducted. The procurements of pipe (steel and plastic), meters, meter subassemblies, risers, computers and vehicles were evaluated for calendar year 2004. These six categories account for approximately 50 percent of the annual purchasing department awards at Southwest Gas.

Q What conclusions were developed from the procurement review?

A The purchasing department staff is well qualified and experienced. Purchasing policies and procedures are up to date and concise. Adequate checks and balances are in place and

there is a clear separation of responsibility for the requisitioning, procurement, receiving and payment functions. All purchase order files reviewed showed that policies and procedures were followed, and all changes were documented.

Q. Describe how the procurement review was conducted.

A. The procurement review of the 2004 purchasing activity was conducted in two phases. The first phase was completed in Phoenix with information provided in response to Staff's data requests. This phase included a review of department policies and procedures, organization charts, personnel qualification and training, and internal audit reports. The second phase was conducted on site in Las Vegas, Nevada. This phase included a review of the actual procurement files for pipe (steel and plastic), meters, meter subassemblies, risers, computers and vehicles for 2004. A room was made available containing the contract folders that were to be reviewed. Southwest Gas personnel were available to answer any questions. All procurement files reviewed were complete including bidding, evaluation, negotiation, award documentation and sole source justifications if utilized.

Recommendations

Q. Are there any recommendations for the purchasing department?

A Yes. The purchasing department does not actively project the future prices of items it is responsible for buying. Purchasing personell are aggressive in contract negotiations and have successfully held down the price of these items through quantity discounts. But it has become apparent that Southwest is competing on a global level for many items including steel. Six categories make up 50 percent of the spending by the purchasing department. A broader planning view is needed going forward and the utilization of hedging opportunities in these categories should be studied. Staff recommends that

Southwest Gas investigate how other peer utilities address commodity price hedging, with an emphasis on steel, and file a report in Docket Control by June 30, 2006.

Q. Does Staff recommend adoption of the gas procurement recommendations for the purchasing department?

A. Staff believes that the same procurement conflict of interest issues apply to both procurement functions. As such Recommendation 2, "Company should preclude employee stock ownership, or other financial interest, with any supplier or class of suppliers with whom they conduct business", should apply equally to both procurement departments. Staff's recommendations 1, 3, 4 and 5 for fuel procurement are not needed in the purchasing department.

Q. Does this conclude your testimony?

A. Yes it does.

MUSGROVE

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISMENT 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

DIRECT TESTIMONY

OF

WILLIAM H. MUSGROVE

ON BEHALF OF STAFF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 26, 2005

Q. Please state your name and business address.

A. My name is William H. Musgrove. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. What is the nature of your work relationship with the Arizona Corporation Commission?

A. I am an Independent Contractor providing utilities consulting services to the Arizona Corporation Commission Staff.

Q. Please state your educational background and business experience.

A. I received a Master of Business Administration Degree with a tested concentration in Finance and an elected concentration in Economics from Loyola College located in Baltimore, Maryland. I also received a Bachelor of Science Degree with a concentration in Business Administration from Johns Hopkins University located in Baltimore, Maryland, and later augmented the Undergraduate Degree with twenty-four credits of college-level mathematics, which credits were also received from Johns Hopkins University. I am a tested Certified Energy Manager as certified by the Association of Energy Engineers; and, in 2004 received a tested certification as a Tax Counselor from the Internal Revenue Service. My business experiences entail 40-plus years in various positions with the Baltimore Gas and Electric Company ("BGE"). The positions relevant to the testimony I am sponsoring in this Proceeding involve more than 10 years experience in the Economic Research Department at BGE. During that period, I became fully proficient in understanding gas and electric utility financial records and the rate making process. I am thoroughly familiar with all phases and components of a gas or electric rate case, including rate design and Cost of Service protocols.

Q. Have you previously testified before any regulatory commission?

A. Yes. I have testified before the Public Service Commission of Maryland regarding rate design and applications matters.

Q. What is the scope of your testimony in this Case?

A. I will address a proposal by Southwest Gas Corporation ("Southwest") to decouple Southwest's recovery of Arizona Corporation Commission ("Commission") authorized residential margin from sales as sponsored in the Prepared Direct Testimony of Edward B. Gieseking (EBG).[1] The proposed decoupling mechanism is presented by Southwest as a Special Supplementary Tariff provision entitled the Conservation Margin Tracker ("CMT").

Q. For clarification, will you please define the word "Margin" as you are using it in the context of this Case?

A. Yes. Unlike Mr. Gieseking, I am explicitly referring to the Commission-authorized Base Tariff Rate Margin for Gas Service schedules filed, in part, as Current Tariff Sheet A.C.C. Sheet No. 11, in the "Current Tariff Sheets" Section of the Application filed by Southwest in this Rate Case. I have only included a copy of Current Tariff Sheet No. 11 as Attachment 1 to my Direct Testimony, because the proposed CMT would only apply to proposed residential Rate Schedule Nos. G-5, G-6, and G-20. For example, the G-5 Commission-authorized Margin currently consists of a Basic Service Charge in the amount of $8.00 per month per customer, and first/second block Commodity Charge rates in the amounts of $.48762/$.40344 per Therm, respectively.

[1] EBG, p. 3, ll. 7-10

Q. For further clarification, will you please identify the expense components traditionally included in and therefore recovered through the Base Tariff Rate Margin Basic Service Charge and Commodity Charge as discussed in your preceding answer?

A. Yes. Before identifying expenses recovered through the Basic Service Charge, it is important to keep in mind that Southwest has no production, storage or transmission plant in Arizona, therefore expense recovery is limited to customer-related and distribution-related investments and expenses.[2] The investment, operating and maintenance expenses recovered through the Basic Service Charge are traditionally classified as Customer-related or Customer Accounting expenses. These expenses include, for example, acquiring and processing meter readings; establishing and maintaining billing records; bill rendering and collections; customer call center activities; customer-related labor; depreciation expense associated with office furniture and equipment; depreciation expense associated with services, meters and certain customer classified mains; taxes; and, a rate-of-return on all customer classified and depreciated plant in service as authorized by the Commission.

Q. Will you please continue by addressing expenses traditionally recovered through the Commodity Charge?

A. Yes. Commodity Charge rates traditionally recover investment and operating distribution-related expenses; but the word "commodity" must first be qualified due to semantics. Distribution-related investment and operating expenses traditionally underlie the commodity portion of Base Tariff Rate Margin rates. However, expenses that traditionally support commodity margin rates contained in the Tariff are classified as being "demand"-related expenses in the Cost of Service Study filed in this Rate Case. To

[2] C. M. Berger Direct Testimony, p.4, ll. 11-13

further complicate the matter, there is also a "commodity"-related classification of expenses in the Cost of Service Study; but, these commodity-related expenses are associated with the cost of gas.[3] Therefore, it is important to clarify the word "commodity" and clearly identify if it is being used in the context of Tariff rates or Cost of Service expenses. My testimony, in part, addresses the former. In other words, I am identifying distribution-related investment and operating expenses that are traditionally included in Base Tariff Rate Commodity Charges. These expenses include such items as the cost to install, maintain, repair or replace main; labor, material and supplies associated with mains; depreciation associated primarily with mains; taxes; and, a rate-of-return on all Cost of Service demand classified and depreciated plant in service as authorized by the Commission.

Q. Is Southwest proposing margin tariff rates that are supported by traditional investments and expenses as discussed by you in your preceding responses?

A. No. In his Prepared Direct Testimony, Mr. A. Brooks Congdon (ABC) discusses rate design parameters proposed for single and multi-family residential customers. These parameters are clearly not traditional. For example, his sponsorship of a methodology that would place a "significant portion" of customer-related costs in the proposed second Commodity rate block[4] illustrates a point on which I will expand. The CMT proposed by Southwest in this Rate Case would further distort traditional rate design practices. For example, Mr. Congdon's Testimony helps to convince Staff that it would be a mistake to introduce a sales decoupling mechanism that has the potential to swing a second block residential Margin Commodity rate by 10-cents per therm.[5] Rate design proposals of this magnitude should not, in Staff's opinion, be considered outside the boundaries of full

[3] C. M. Berger Direct Testimony, p.4, ll. 17-27 and p.5, ll. 1-10
[4] ABC, p. 16, ll. 7-10
[5] ABC, p. 16, ll. 16-21

discovery and the evidentiary processes that are integral parts of formal rate case proceedings.

Q. Will you be elaborating on the rate design proposals being presented by Southwest in this Rate Case?

A. No. Mr. Robert G. Gray is sponsoring Prepared Direct Testimony for Staff in which he addresses the pertinent aspects of rate design proposals being sponsored by Southwest in this Rate Case. To the extent that it is practicable, my Testimony focuses on the Conservation Margin Tracker as it has been proposed by Southwest and sponsored by Mr. Gieseking in this Rate Case.

Q. Is Mr. Gieseking sponsoring a mechanism that would allow Southwest to adjust the Commission-authorized Margins you referenced as shown on Attachment 1?

A. No. Mr. Gieseking is sponsoring a mechanism referred to by Southwest as the CMT[6]. The proposed CMT would re-state revenues collected under Commission-authorized Tariff "margins" by developing Average per Customer per Month revenue margins as shown in Attachment 2. The derivation of these data may be found in Schedule H-6, Sheet 9 filed by Southwest. Differences between actual billed revenue "margins" per Customer per Month (as calculated by Southwest) and comparable CMT-related average margin per customer per-month revenues would be debit or credit entries to an account created for the purpose of identifying balances to be trued-up at later dates.

Q. What concerns do you have regarding the CMT as proposed in this Case?

A. There are four critical aspects to be aware of in weighing the merits of the proposed CMT: 1) the Commission did not authorize residential Average Margin per Customer per Month

[6] EBG, p. 5, ll. 3-8

Rates in its Final Order in Southwest's last general rate case in Arizona; 2) an inequitable new residential rate making process and element would be created through CMT-driven rates, which include additional carrying charge adders, derived from Balancing Account Balances to be trued-up annually[7]; 3) Southwest's annual residential sales (therms) have not been decreasing as stated by Mr. Gieseking in his Direct Testimony in this Case,[8] rather, there has been a clear trend of Increasing Sales to Residential Customers since 1987; and, 4) a mechanism similar to the proposed CMT was sponsored by Mr. Gieseking in a recent rate case before the Public Utilities Commission of Nevada, wherein the Nevada Commission rejected the proposal and characterized a CMT-Like Mechanism as being too drastic of a change to be implemented at this time.[9]

Q. Will you please elaborate on the four critical aspects of the proposed CMT just outlined in your Direct Testimony?

A. Yes.

1) Average Margin per Customer per Month Rates

The rates proposed by Southwest and shown on A.C.C. Sheet No. 13 (Attachment 2) are clearly not the margin rates authorized by the Commission in Decision 64172 dated October 30, 2001[10]. Commission-authorized margin rates are the rates shown, for example, in Attachment 1. It is totally inappropriate, as is being proposed by Southwest in its filing (see Attachment 3, Item 1), to define authorized margin as "... the product of the monthly margin-per-customer authorized in the Utility's last general rate case, ..., and the actual number of customers during the month."[11] The only Commission-authorized margins are the margins shown, for example, in Attachment 1. The Average Margin per

[7] First Revised Proposed Tariff Sheet A.C.C. Sheet No. 98, Item 3 (see Attachment 3)
[8] EBG, p. 4, ll. 5-8
[9] Docket No. 04-3011, p. 76, paragraph. 285
[10] In Decision No. 64172, page 34, lines 16-17, the Commission authorized the rates shown in Attachment 1
[11] First Revised Proposed Tariff Sheet A.C.C. Sheet No. 98, Item 1 (see Attachment 3)

Customer per Month values proposed by Southwest and sponsored by Mr. Gieseking in this Case are merely margin values created by Southwest for Southwest's purposes, and should be rejected by the Commission. It should be noted that the establishment of the CMT would create an unprecedented, inequitable and drastic rate making change for Arizona's rate payers served by Southwest. I will address these aspects of the proposed CMT later in my Testimony. Suffice it to say at this juncture, that Mr. Gieseking's proposed CMT-driven residential rate adjustments are based on, in part, creative average margin per customer per month rates which have, at best, only a coincidental relationship to Commission-authorized margin rates.

2) Balancing Account Balances

A disturbing issue embedded in the proposed Conservation Margin Tracker is its inequitable focus on residential customers. The potential inequities are troubling in that: A) residential customers would be the only classes required to pay full margin through the proposed decoupling mechanism; B) residential customers would be the only classes asked to bear additional carrying costs associated with a perceived shortfall of sales; C) residential customers would be the only classes asked to forego the benefits of full rate case review and proceedings regarding full margin recovery; and, D) residential customers would be inequitably separated from other customer classes, through the exclusive assignment of CMT-driven revenue requirements to the residential classes. I will expand on Items A-D later in my Testimony.

3) Increasing Sales to Residential Customers

The current Commission-authorized margin rates are based upon adjusted calendar Test Year 1999 billing determinants. Using data filed by Robert A. Mashas, Exhibit No. RAM-1, pages 4 and 5, the approximate number of residential customers and therms can be estimated for the years 1999–August, 2004. Exhibit 1 illustrates why it is incorrect for Mr. Gieseking to state that residential sales are decreasing (see Fn. No. 8). The Exhibit

clearly demonstrates that since 1987, total residential sales have maintained an erratic but overall positive slope during the period depicted. The slope is statistically measured at 2.29. It is significant to note that since 1999, which is the latest general rate case test year submitted by Southwest in an Arizona general rate case, annual total residential sales have never dropped below test year volumes. By comparison, Exhibit 2 demonstrates another important aspect of the claims that residential sales per customer are decreasing. The rate of increase in total number of residential customers as shown in Exhibit 2 is much greater than the rate of increase in total residential sales as depicted in Exhibit 1. In fact, the measured slope equals 17.11. Consequently, it is mathematically impossible for the average use per residential customer to remain constant or increase when the increase in total number of residential customers is sloping approximately 7.5 times more than the increase in total residential sales over a comparable period of time. One may conclude from the data that the average usage of new residential customers is less than the average usage of existing residential customers. However, one may <u>not</u> conclude from the data that Southwest failed to earn its authorized rate-of-return because residential sales dropped below Test Year sales. In other words, when Mr. Gieseking uses the three words "gas sales volume" and "use per customer" in the same sentence,[12] he inadvertently misleads readers by inferring that the decline in average use per residential customer is driven by residential customers using less gas, when in fact, the declining average use per residential customer is clearly the result of much higher rates of increases in number of customers than rates of decreases in sales. The significance of this distinction is potentially far reaching in its impact upon the merits of implementing the proposed CMT. Exhibit 3 demonstrates that, except in a year following a year of extraordinarily cold weather (e.g. 1999), the CMT is likely to be positive. The primary reason for this phenomenon is the inescapable conclusion that, as was just discussed, as the number of customers continues

[12] EBG, p. 5, ll. 23-27

to increase at a rate far greater than changes in usage patterns, all other things being equal, the CMT-generated Rate Adjustment will be an increase borne inequitably and solely by residential rate payers. It is also important not to lose sight of the perspective that this conclusion is due, in large part, to the decoupling of margin recovery from sales, and to use the words of Mr. Gieseking, to "... re-couple residential margin recovery to the number of customers served each month."[13]

4) <u>CMT-Like Mechanism</u>

Southwest appeared before the Public Utilities Commission of Nevada during a general rate case proceeding in 2004. By Docket No. 04-3011 dated August 30, 2004, the Nevada Commission clearly and explicitly rejected the Margin per Customer Balancing Provision ("MCB") sponsored by Mr. Gieseking in that Proceeding. The Nevada Commission viewed the proposed MCB as being too drastic of a change to Southwest's billing practices as a reason to support their decision not to accept the proposed MCB.[14] The CMT proposed for Arizona residential ratepayers in this Proceeding also represents a significant change from current practices, and should likewise not be accepted by this Commission. The Nevada Commission also cited the lack of compelling evidence to establish the MCB as another reason to reject the proposed MCB. A review of Southwest's position as summarized in pages 72 and 73 of Docket No. 04-3011, makes it clear that Mr. Gieseking has not introduced any new evidence in the Arizona Case which would compel this Commission to accept the CMT as proposed. Staff recognizes that the California Public Utilities Commission and Oregon Public Utility Commission approved decoupling-like rate mechanisms similar in nature to the CMT proposed by Southwest in this Rate Case. However, Staff would be remiss if it failed to point out that neither the California or Nevada Commissions allow the rate mechanism to apply to only residential customers; and in California, a similar mechanism was implemented in the 1970s.

[13] EBG, p. 5, ll. 6-8
[14] Docket No. 04-3011, p. 76, para. 285

Therefore, the Core Fixed Cost Adjustment Mechanism proposed by Southwest in California was simply accepted without objections by the Office of Rate Payer Advocates, because other gas local distribution companies serving customers located in California were already operating under similar rate mechanisms at the time of Southwest's application. Staff respects the California and Oregon decisions, but they are based upon parameters that are different than the conditions that exist in Arizona. Furthermore, the CMT proposed for Arizona is similar in nature to the MCB mechanism proposed for Nevada, and that proposal was rejected by the Nevada Commission. Staff therefore recommends that the Arizona Commission also reject the proposed CMT decoupling mechanism.

Q. Will you please restate the four inequities mentioned earlier in your Testimony under Item No. 2) Balancing Account Balances?

A. Yes, the four inequities mentioned in Item No. 2 are:

A) Residential customers would be the only classes required to pay full margin through the proposed decoupling mechanism.

B) Residential customers would be the only classes required to bear additional carrying costs associated with a perceived shortfall in sales.

C) Residential customers would be the only classes required to forego the benefits of full rate case review and proceedings regarding full margin recovery.

D) Residential customers would be inequitably separated from other customer classes through the exclusive assignment of CMT-driven increased revenue requirements to the residential classes.

Q. Will you please expand on the four inequities outlined in your previous answer?

A. Yes.

A) Full Margin Requirements: I find Southwest's words on this matter to be somewhat misleading in light of Mr. Gieseking's repeated use of the words "more gradual"[15] when discussing Southwest's movement toward cost-based rates for residential customers. Apparently, Southwest views the assignment of approximately 80 percent of total requested increased revenue requirements to residential classes, and the resultant 60 percent increase to the Rate of Return Ratio to, for example, the Single Family Residential class as a gradual movement of rates. In the past, the Commission has not separated return-related issues from the traditional rate making process. The acceptance of the proposed CMT would create a radical change in the existing rate making process. Consider, for example, the residential revenue/risk/return-on-equity equation. The introduction of what is essentially a "guaranteed revenue stream" should be accompanied by a reasonable reduction in the assumed risk and related return to investors. There is no evidence in the record which demonstrates that Southwest has adjusted the proposed return-on-equity downward to more evenly balance the potential impact of the proposed CMT on revenues that would be collected from residential customers. If the proposed CMT is accepted by the Commission, Mr. Frank J. Hanley (FJH) proposes using 11.70 percent cost of common equity.[16] All other things being equal, gross revenue requirements would only decrease approximately $1.7 million. According to Southwest's data, approximately 80 percent of the proposed total increase in Arizona margin revenues will be derived from residential customers (revised Schedule H-1, Sheet 2). Therefore one could reasonably assume that the residential classes would receive a revenue requirement reduction of approximately 80 percent of the estimated $1.7 million, or about $1.4 million. Based on Mr. Robert A. Mashas' data (RAM-1, pp.4-5), however, residential customers would be facing a CMT recovery in the amount of $11.9 million (plus carrying charges) in the year 2005. As a reminder, it was pointed out in Staff's Testimony under Section 3)

[15] EBG p. 5, l. 2 and p. 18, l. 15
[16] FJH, p. 8, ll. 18-20

Increasing Sales to Residential Customers, that the proposed CMT will likely be positive in the foreseeable future. Based on the example above, the revenue/risk adjustment being proposed by Southwest would result in a $10.5 million revenue impact on Arizona residential rate payers - with little or no risk to Southwest's equity investors. Examples such as the one outlined above, in part, convinces Staff to recommend the Commission's rejection of the CMT proposed by Southwest in this Proceeding.

B) Additional Carrying Costs: Under the proposed CMT, Southwest would apply a CMT-generated Rate Adjustment per therm which would include a short term rate carrying charge adder. In his Direct Testimony, Mr. Gieseking brushes over the additional carrying costs, which are never quantified in this Case and will be borne exclusively by residential customers, by stating that "The mechanics of the CMT are described in the proposed tariff sheets filed as part of Southwest's Application." (GEB Direct Testimony, p. 18, ll. 1-3). Based on Phoenix data sponsored by Mr. Robert A. Mashas (RAM-1, Sheet 4), Staff estimates that the CMT, excluding the proposed additional carrying costs, would have been approximately 10 percent and 16 percent of Commodity Tariff Rates applicable in 2003 and 2004, respectively. In the past, the Commission has not sanctioned a Special Supplementary Tariff provision that would create a new rate making component outside the purview of a rate case proceeding, especially when the component would have the potential to be an average increase of approximately 13 percent in commodity rates. Also, in a time of escalating short term interest rates, Staff believes that it would be inappropriate for the Commission to authorize a proposal that potentially exposes residential rate payers to an additional inequitable economic burden through higher interest rates.

C) Rate Increases Without Full Rate Case Review: As was just pointed out in Item B) "Additional Carrying Costs", it appears that the CMT has the potential of reaching the 10-15 percent range of total Commodity Tariff Rates. This is a significant increase to be

passed on to residential customers without the benefit of evidentiary proceedings and review. We should not expect residential rate payers to willingly accept rates that are created outside the realm of an equitable rate making forum, especially when they are the only class of customers being asked to bear such an unreasonable burden. The movement towards equitable gradualism in authorizing rate increases does not support increases which have the potential to: a) impact only the Residential rate classes; b) be implemented without the benefit of a full evidentiary rate case Commission review; and, c) likely be in at least the 10+ percent increase range.

D) Inequitable Separation From Other Customer Classes: It is totally inappropriate to single out the residential class due to its declining average sales per customer profile. Comparing 2004 to 2002 for example, the General Service – Large class's average sales per customer rebound of 96 percent was less than the Residential Gas Service rebound of 98 percent. Furthermore, during the three year period 2002–2004, the combined General Service Classes had usage profiles nearly identical to the profiles of the combined Residential Classes. That is, 2003 versus 2002 total average sales per customer were in the 94-95 percent range for both classes, and in 2004, both classes rebounded to approximately 98 percent of 2002 total average sales per customer (see Tabulation 1). Also, it has already been demonstrated under Section 3) Increasing Sales to Residential Customers in this Testimony that the declining average use per residential customer is not driven by decreases in sales per customer. Finally, there is no evidence presented in Mr. Gieseking's Direct Testimony filed in this Case to justify excluding non-residential rate payers from the proposed CMT. The findings discussed in this Section alone are sufficient unto themselves to justify the Commission's rejection of the CMT as proposed by Southwest.

Q. Will you please summarize your recommendation regarding the Conservation Margin Tracker proposed by Southwest.

A. Yes. The CMT proposed by Southwest should not be accepted by the Commission for the following reasons:

1. Although not specifically addressed in my Testimony, the Joint Statement of the American Gas Association and the Natural Resources Defense Council is cited, for example, by Mr. Steven M. Fetter (SMF),[17] and the National Association of Regulatory Utility Commissioners' ("NARUC") Resolution is cited by Mr. Edward B. Gieseking (EBG)[18] as corroborating evidence supporting the acceptance of sales decoupling mechanisms similar in nature to the CMT proposed in this Case. Staff supports the Joint Statement and Resolution referenced above but would be remiss if it failed to point out that each initiative contains language that is much broader in meaning than is inferred by Messrs. Fetter and Gieseking. Mr. Fetter embraces the Joint Statement, but focuses on the innovative programs approach in his testimony.[19] Yet the Statement explicitly recommends "utility rate proposals" as another, equally weighted and viable alternative to help utilities recover authorized fixed costs. It should be noted that the words "modest automatic rate true-ups" are also a part of the wording in the Joint Statement. I find it hard to believe that residential ratepayers would consider paying an <u>additional</u> $144 million (plus carrying charges) over the last 11 years[20] to Southwest a modest true-up. Furthermore, Mr. Gieseking embraces the NARUC Resolution paragraph that encourages State Commissions to consider recommendations contained in the Joint Statement, but chooses to ignore the paragraph which recognizes that the best approach towards promoting energy efficiency programs may likely depend on local issues, preferences and conditions.

[17] SMF,p. 6, ll. 12-25 and p.7, ll.1-12
[18] EBG, p. 22, ll. 24-27 and p.23, ll. 1-3
[19] SMF,p. 8, ll. 1-14
[20] SWG's Response to Staff's Data Request No. STAFF-JJD-8-12

Therefore, the NARUC Resolution recognizes that there may be solutions other than simply accepting CMT-like mechanisms when considering utility arguments, such as, it being unfair to expect utilities to implement conservation programs without margin erosion protection.[21] A case in point is contained in Staff's testimony, which clearly demonstrates that local conditions (i.e. extraordinary increases in the number of residential customers) dominate in driving down average residential usage per customer in Arizona – not conservation as stated by Mr. Gieseking.[22]

2. The nature of the proposed CMT in singling out the Residential class is extremely inequitable, because the General Service class has a usage profile that is nearly identical to the profile of the Residential class.
3. If the CMT was accepted in this Rate Case as filed, a drastic new Adjustment Rate, including additional Carrying Charges, would be created and perpetuated outside the scope of general rate case scrutiny and proceedings. In addition, the CMT would be inequitably borne exclusively by the Residential Classes to the benefit of Southwest's equity investors.
4. Staff's Testimony establishes a definite link between increasing number of residential customers and decreasing average sales per residential customer. This inverse relationship practically guarantees that proposed CMT Adjustment Rates will be adders to residential rates in the foreseeable future. Furthermore, residential customers would bear a double burden in years with severe low temperatures, because they would be forced to pay bills containing high consumption and CMT Rate adjustments. Also, there is a possibility over time that the CMT could discourage conservation due to lower usage contributing to higher subsequent CMT rates.
5. Similar decoupling mechanisms have been rejected or accepted under different circumstances in other States. And in the State of Nevada, where the proposed Margin

[21] EBG, p. 21, ll. 16-27 and p.22, ll. 1-10
[22] EGB, p. 4, ll. 3-9

per Customer Balancing Provision ("MCB") would have had conditions very similar to the ones being proposed for Arizona in the CMT,[23] the Nevada Commission concluded that it would be more prudent to try other more recognized alternatives before implementing such a drastic change to Southwest's billing practices.

For the reasons summarized above, Staff recommends that the Commission not accept the Conservation Margin Tracker as proposed by Southwest in this Rate Case.

Q Does this conclude your Direct Testimony regarding the proposed Conservation Margin Tracker?

A. Yes it does.

[23]Both the MCB and CMT apply only to residential customers, include added carrying charges, do not include reasonable adjustments to the cost of equity, and exclude access to the evidentiary checks and balances embodied in a general rate case.

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

CURRENT TARIFF SHEET

Fifty-Eighth Revised A.C.C. Sheet No. 11
Canceling Fifty-Seventh Revised A.C.C. Sheet No. 11

Attachment 1

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

Description	Base Tariff Rate Margin	Base Tariff Rate Gas Cost	2/ Rate Adjustment	Monthly Gas Cost Adjustment	Currently Effective Tariff Rate
G-5 – Residential Gas Service					
Basic Service Charge per Month	$ 8.00				$ 8.00
Commodity Charge per Therm:					
Summer (May–October):					
First 20 Therms	$ .48762	$ .37034	$ .01073	$ .16402	$ 1.03271
Over 20 Therms	.40344	.37034	.01073	.16402	.94853
Winter (November–April):					
First 40 Therms	$ .48762	$ .37034	$ .01073	$ .16402	$ 1.03271
Over 40 Therms	.40344	.37034	.01073	.16402	.94853
G-10 – Low-Income Residential Gas Service					
Basic Service Charge per Month	$ 7.00				$ 7.00
Commodity Charge per Therm:					
Summer (May–October):					
First 20 Therms	$ .48762	$ .37034	$ .00486	$ .16402	$ 1.02684
Over 20 Therms	.40344	.37034	.00486	.16402	.94266
Winter (November–April):					
First 40 Therms	$ .28225	$ .37034	$ .00486	$ .16402	$ .82147
Next 110 Therms	.21491	.37034	.00486	.16402	.75413
Over 150 Therms	.40344	.37034	.00486	.16402	.94266
G-15 – Special Residential Gas Service for Air Conditioning					
Basic Service Charge per Month	$ 8.00				$ 8.00
Commodity Charge per Therm:					
Summer (May–October):					
First 20 Therms	$ .48762	$ .37034	$ .00486	$ .16402	$ 1.02684
Over 20 Therms	.19125	.37034	.00486	.16402	.73047
Winter (November–April):					
First 40 Therms	$ .48762	$ .37034	$ .00486	$ .16402	$ 1.02684
Over 40 Therms	.40344	.37034	.00486	.16402	.94266
G-16 – Special Residential Gas Service for Electric Generation					
Basic Service Charge per Month	$ 8.00				$ 8.00
Commodity Charge per Therm:					
Summer (May–October):					
First 20 Therms	$ .48762	$ .37034	$ .00486	$ .16402	$ 1.02684
Over 20 Therms	.19125	.37034	.00486	.16402	.73047
Winter (November–April):					
First 40 Therms	$ .48762	$ .37034	$ .00486	$ .16402	$ 1.02684
Over 40 Therms	.40344	.37034	.00486	.16402	.94266
G-20 – Master-Metered Mobile Home Park Gas Service					
Basic Service Charge per Month	$ 50.00				$ 50.00
Commodity Charge per Therm:					
All Usage	$ .31415	$ .37034	$ .01073	$ .16402	$ .85924
G-25 – General Gas Service					
Basic Service Charge per Month:					
Small	$ 20.00				$ 20.00
Medium	90.00				$ 90.00
Large	500.00				$500.00
Commodity Charge per Therm:					
Small, All Usage	$ .38024	$ .37034	$ .00000	$ .16402	$ .91460
Medium, All Usage	.27211	.37034	.00000	.16402	.80647
Large, All Usage	.08548	.37034	.00000	.16402	.61984
Demand Charge per Month–Large:					
Demand Charge 3/	$ .072695				$ .072695

Issued On August 18, 2004
Docket No. G-00000C-98-0568

Issued by
John P. Hester
Vice President

Effective August 27, 2004
Decision No. 62994

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

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 Margin, LIRA and DSM components of the commodity charge per therm, and Demand Charge, if applicable, of the Currently Effective Tariff Rate for each meter included in the transportation service agreement, plus an amount of $.00475 per therm for distribution system 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 $.01247 per therm to recover LIRA program costs.

(b) For all rate schedules, the Rate Adjustment includes $.00724 per therm to recover DSM Program costs. This charge shall be updated annually effective May 1.

(c) For Schedule Nos. G-5, G-6 and G-20, the Rate Adjustment includes $.00000 per therm to recover/refund CMT under- or over-collections.

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

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

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

Margin per Customer Balancing Provision Average Margin per Customer per Month

	G-5	G-6	G-20
January	$ 46.66	$ 34.25	$ 330.91
February	41.78	31.46	254.39
March	38.55	29.12	232.19
April	23.77	20.63	213.12
May	21.03	18.78	213.84
June	19.52	17.68	239.06
July	18.76	17.17	387.47
August	18.26	16.80	766.25
September	18.40	16.97	913.96
October	18.89	17.42	753.71
November	21.11	19.39	615.01
December	40.01	30.71	467.66

SPECIAL SUPPLEMENTARY TARIFF
CONSERVATION MARGIN TRACKER
(Continued

N

CONSERVATION MARGIN TRACKING BALANCING ACCOUNT

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

1. A debit or credit entry equal to the 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 on Sheet No. 13 of this Arizona Gas Tariff, and the actual number of customers during the month.

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 CMTBA Adjustment.

3. A debit or credit entry for carrying charges equal to the previous month's ending balance in the account, multiplied by a carrying charge rate based on the non-financial three-month commercial paper rate for each month contained in the Federal Reserve Statistical Release, G-13, or its successor publication.

TIMING AND MANNER OF FILING

The Utility shall file its CMTBA annually with the Commission in accordance with all statutory and regulatory requirements.

N

Southwest Gas Corporation Average Sales per Customer Data*

Residential Service Classes:

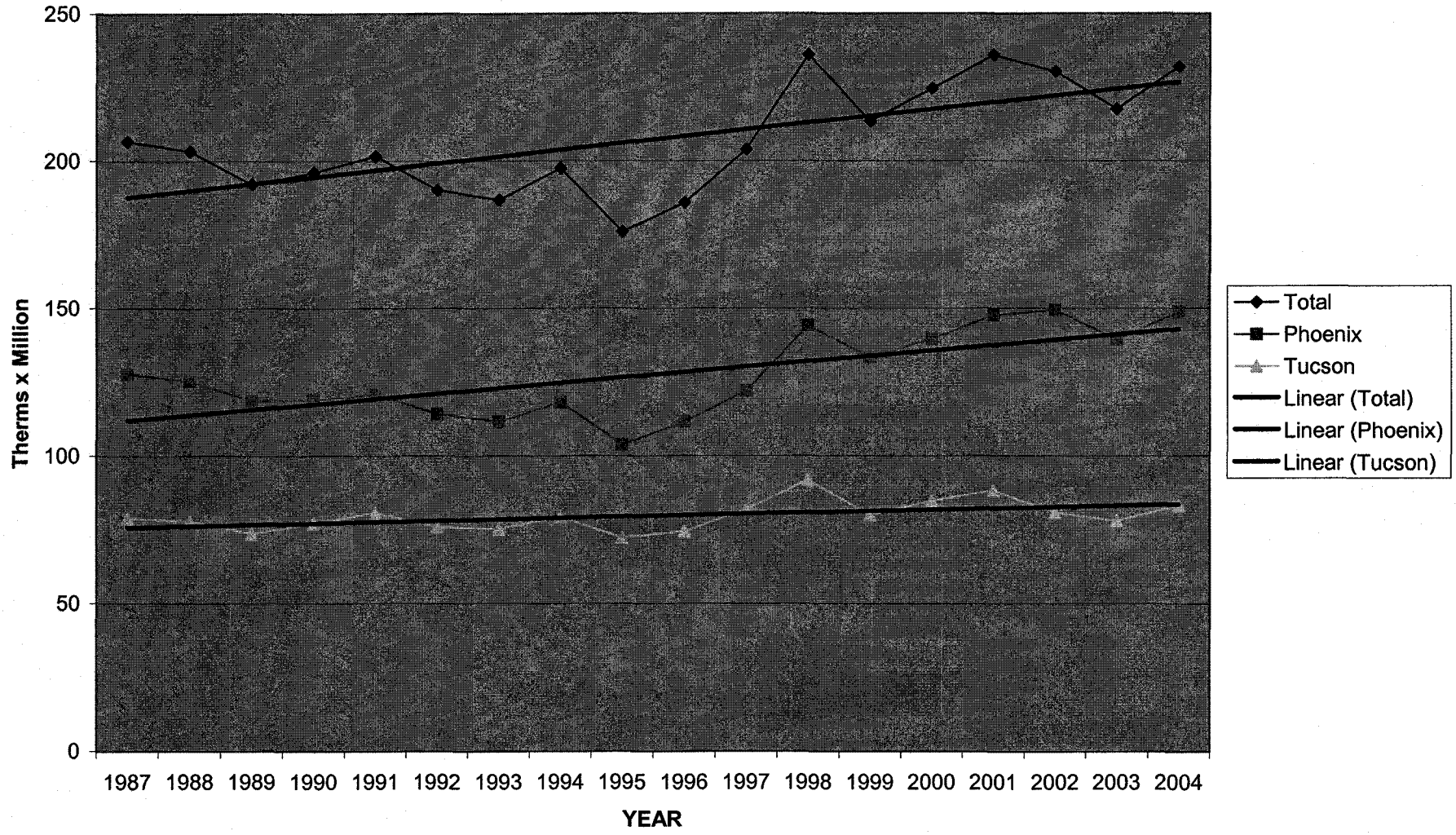
	August 2004				December 2003			December 2002		
	Average Number of Customers	Total Sales	Average Sales per Customer	% of 2002	Average Number of Customers	Total Sales	Average Sales per Customer	Average Number of Customers	Total Sales	Average Sales per Customer
RGS	771,088	267,837,474	347	98	744,407	246,908,831		720,061	254,771,067	354
LIRGS	30,973	10,695,648			29,765	9,961,331		24,862	8,574,479	
ACRGS	157	228,821			163	238,377		185	271,105	
MMMHPGS	191	2,519,499			191	2,517,554		199	2,784,158	
Totals	802,409	281,281,442	351		774,526	259,626,093	335	745,307	266,400,809	357
	Percent of 2002---------->		98%				94%			100%

General Service Classes:

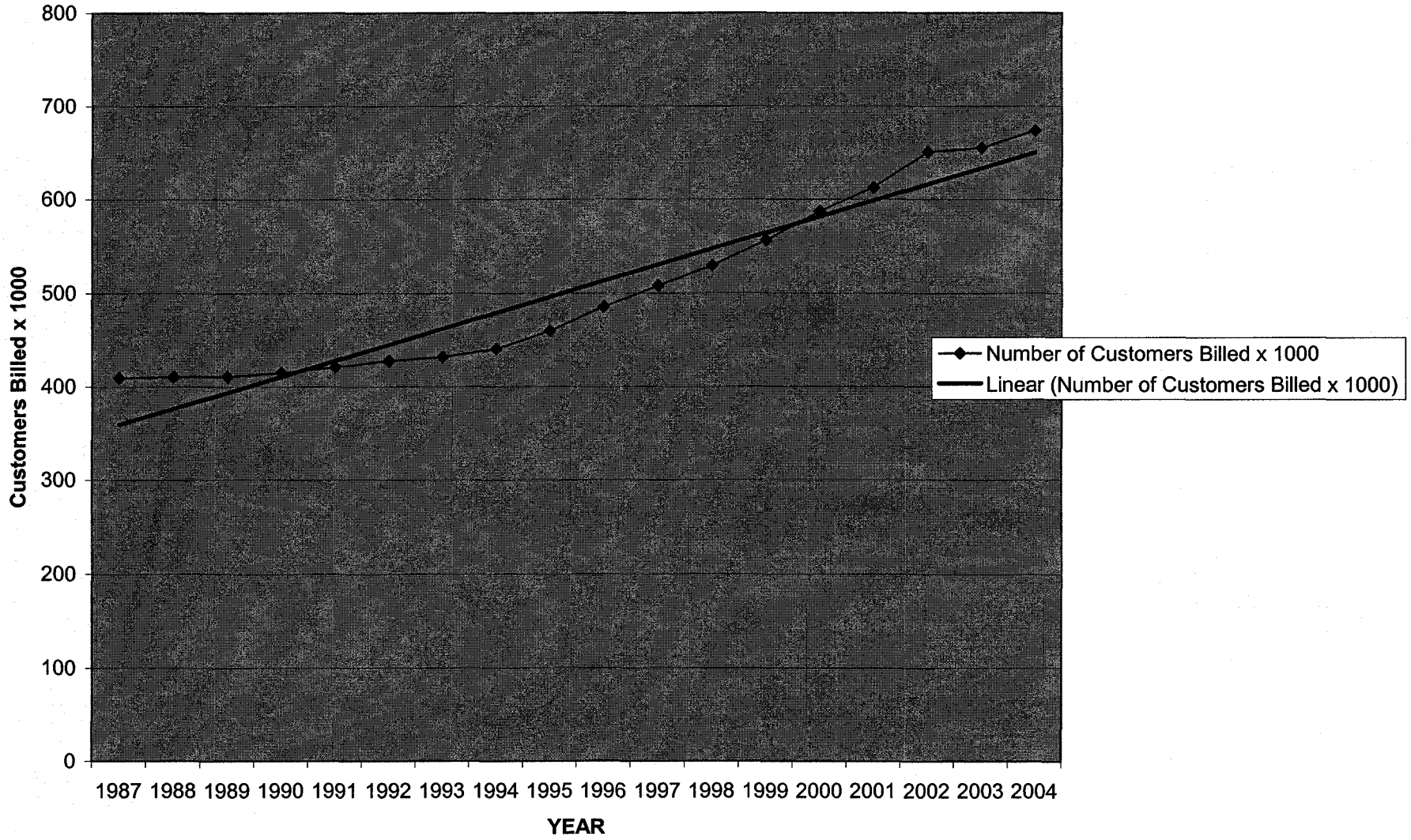
	August 2004				December 2003			December 2002		
	Average Number of Customers	Total Sales	Average Sales per Customer	% of 2002	Average Number of Customers	Total Sales	Average Sales per Customer	Average Number of Customers	Total Sales	Average Sales per Customer
Small	32,597	47,557,432			32,401	45,446,868		32,425	47,337,222	
Medium	6,785	136,866,745			6,731	132,727,148		6,622	133,223,203	
Large	105	44,280,034	421,715	96	104	42,716,175		118	51,611,995	437,390
Totals	39,487	228,704,211	5,792		39,236	220,890,191	5,630	39,165	232,172,420	5,928
	Percent of 2002---------->		98%				95%			100%

*Source: Southwest Gas Corporation, Schedule E-7, Sheets 1, 2, and 3

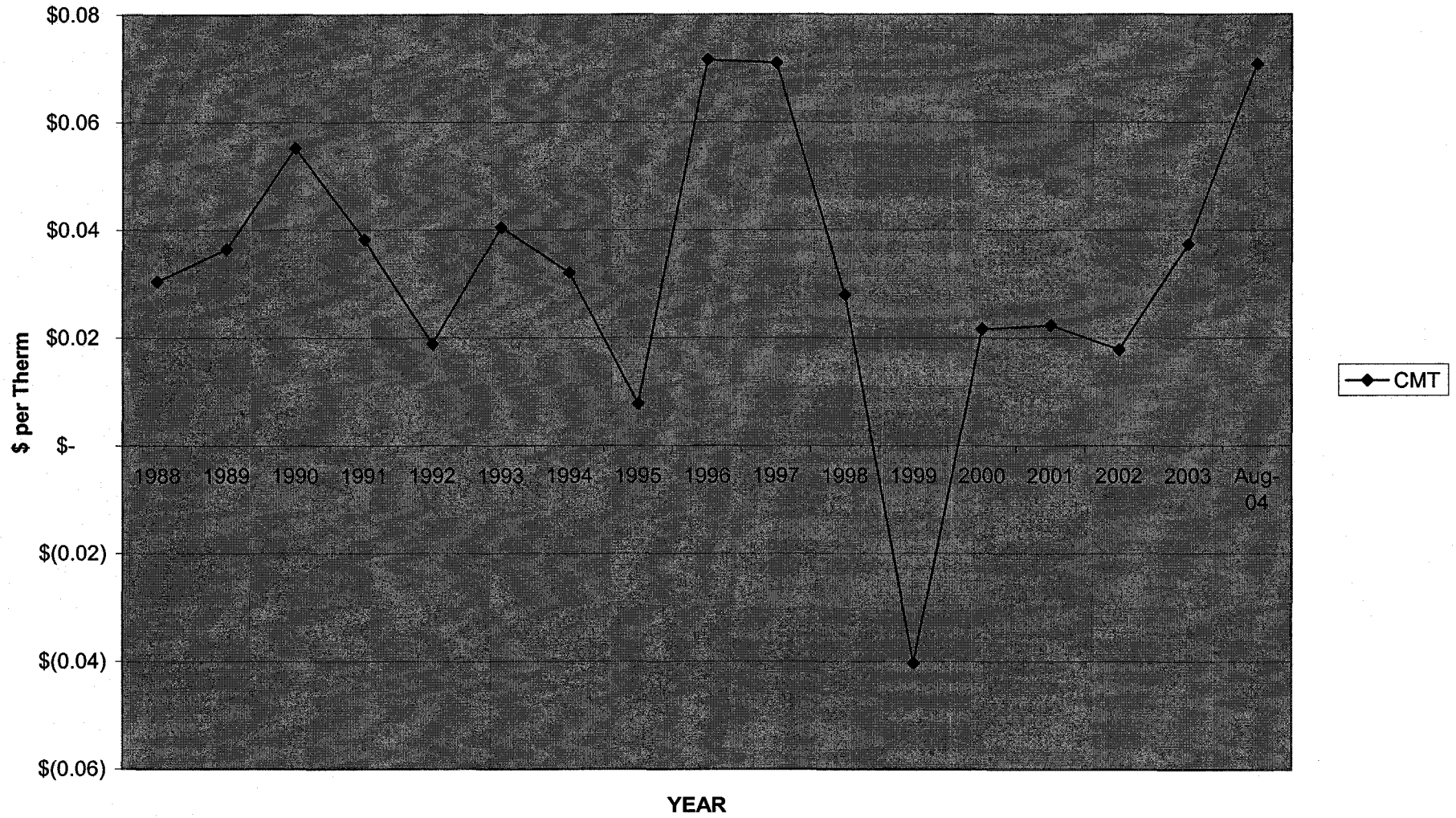
Arizona Residential Sales Trended
(Based on RAM-1)



Average Number of Residential Customers Billed Trended
(Total Arizona System Based on RAM-1)



Estimated CMT*
(Based on RAM-1)



*Includes 1-Year Lag; Excludes Carrying Charges

IRVINE

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. G-01551A-04-0876

DIRECT

TESTIMONY

OF

STEVE IRVINE

PUBLIC UTILITIES ANALYST II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 26, 2005

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-04-0876

On December 9, 2004, Southwest Gas Corporation ("Southwest") filed an application with the Arizona Corporation Commission ("Commission") for an increase in its rates throughout the State of Arizona. The application seeks among other things approval for its proposed Demand Side Management ("DSM") programs. Southwest proposed continuation of two existing DSM programs and implementation of seven new DSM programs. Southwest proposes specific funding levels for each program that collectively total $4,385,000.

As Southwest has provided only brief descriptions of the proposed programs, Staff recommends that Southwest submit within 120 days of a decision in this matter to the Commission for approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs. Staff recommends the filing include responses to specific criteria described by Staff in this testimony. Staff recommends that the DSM plan be filed under a new docket number and that for the purposes of compliance verification notice of the filing be made in this docket. Staff recommends approval at this time of a total DSM budget of $4,335,000.

Staff further recommends that the DSM adjustor mechanism be used to fund the newly proposed programs and that future filings for changes to the DSM adjustor level seek Commission approval rather than Staff approval. Staff also recommends that the DSM adjustor be applied to all rate classes.

Finally Staff recommends that semi-annual DSM Progress Reports shall be certified by an Officer of the Company and its existing filing practices shall continue.

INTRODUCTION

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

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

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

A. In my capacity as a Public Utilities Analyst, I review monthly filings of purchased power adjustors and purchased gas adjustors. My duties also include processing of applications for rate increases, adjustor credits and surcharges, borderline agreements, tariff compliance filings, and various applications of other types.

Q. Please describe your educational background and professional experience.

A. In 1994, I graduated from Arizona State University, receiving a Bachelor of Science degree in Business Marketing. In 1997, I received a Masters degree in Public Administration from Arizona State University. I have been employed by the Commission since May of 2001. I have worked in the Utilities Division since September of 2002.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. G-01551A-04-0876?

A. Yes.

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

A. My testimony will present Staff's evaluation of Southwest Gas Corporation's ("Southwest") proposal for its Demand Side Management ("DSM") programs.

Q. Will your testimony include discussion of Southwest's proposal for a Conservation Margin Tracker?

A. No. The Conservation Margin Tracker will be addressed in the testimony of Staff witness William Musgrove.

Q. Please provide a brief history of Southwest's DSM programs.

A. Prior to Decision No. 60352 of August 29, 1997, Southwest was divided into two divisions in Arizona, the Southern and Central Division. Decision No. 60352 consolidated the divisions. Prior to consolidation the Southern Division had the Southern Arizona Seniors program and the Energy Advantage Plus Program. The Central Division had a low income weatherization program and the Energy Advantage Home program. These programs involved weatherization repairs or upgrades to existing homes and improvements to the construction of new homes to improve energy efficiency. Prior to Decision No. 60352 the costs for these programs were recovered in rate base. Decision No. 60352 created a DSM Adjustor Mechanism for cost recovery of DSM projects. That Decision also required that all future DSM programs be filed for Staff pre-approval and capped DSM expenditures at $1,000,000. Additionally, it extended semi-annual reporting requirements for all the DSM programs; previously only the Southern Division DSM programs had reporting requirements. The DSM program cap was raised subsequently to $1,125,000 and later $1,250,000 to accommodate funding for a Low Income Energy Conservation program and increased spending in the Seniors program.

CURRENT PROGRAMS

Q. What DSM programs does Southwest currently have?

A. Currently Southwest has two Demand Side Management programs. Both programs are meant to improve energy performance in residential housing and consequently reduce customer bills. The programs are Low-Income Energy Conservation ("LIEC") and Energy Advantage Plus ("EAP").

Q. Please describe the LIEC program.

A. The LIEC program is designed for low income customers. Customers with a household income up to 125 percent of the Federal poverty guideline are eligible for the program. The program provides weatherization improvements and repairs to increase energy efficiency for homes of eligible customers. Multi-family housing projects are also eligible for LIEC program benefits. The LIEC program is administered through the Arizona Department of Commerce - Energy Office ("Energy Office") as part of the Energy Office's broader low income weatherization activities. The Energy Office administers its program with funds provided by Southwest, Federal funding, and funding from other sources. The Energy Office contracts with local community agencies for implementation of the weatherization measures. The program is beneficial as the repairs and improvements made to the homes increase energy efficiency and results in lower bills for the residents. These same efficiencies reduce the system load.

Q. Please describe the EAP program.

A. The EAP program is designed to improve energy performance in new residential homes. The program promotes to builders and homebuyers energy efficiency through improvements to a home's thermal shell and use of high efficiency equipment such as

furnaces and other heating appliances. In the past, a portion of the EAP funds were used to advertise the program and offer incentives to builders to participate. Decision No. 67878 of June 2005 reduced funding for the EAP program from $900,000 to $250,000 to reflect elimination of the advertising and builder incentive portion of the program. Southwest no longer views incentives and advertising as necessary given the extent of builder's current participation in the program. The program is beneficial as it promotes the design and construction of homes that are more energy efficient than homes that would have been built otherwise. The increased energy efficiency that results from the program reduces customers' bills and system load.

COST RECOVERY MECHANISM AND REPORTING

Q. Please describe Southwest's current cost recovery mechanism for DSM.

A. Costs for the current DSM programs are recovered through an adjustor mechanism. The adjustor mechanism was approved in Decision No. 60352 of August 1997. Most recently the adjustor was reset on March 23, 2005, to a credit of $0.00054. Southwest currently submits proposals for changes to the adjustor level yearly for Staff approval.

Q. Does Staff have recommendations regarding approval of changes to the DSM adjustor?

A. Yes. Southwest has proposed that the number of DSM programs increase from two to nine and has proposed increasing DSM funding from its current $600,000 level to $4,385,000. These represent significant increases in Southwest's DSM efforts. Accordingly, Staff recommends that in the future proposed changes to the DSM adjustor level be filed for Commission approval.

Q. In addition to proposals for changes to the adjustor mechanism, does Southwest submit other reports related to its DSM program?

A. Yes. Southwest currently submits a semi-annual Demand Side Management Progress Report. A redacted version is filed in Docket Control and a confidential version is submitted to Staff. The report details information such as budget, costs, and program activities. In order to encourage accuracy in reporting, Staff recommends that in the future the semi-annual DSM Progress Reports be certified by an Officer of the Company and that existing filing practices continue.

Q. Is the existing DSM adjustor an appropriate mechanism to fund costs for the new DSM programs that Southwest has proposed?

A. Yes. The current DSM adjustor is an appropriate mechanism to fund the new DSM programs that Southwest has proposed. The current DSM adjustor is already in place and would serve as a single consolidated mechanism for recovery of the DSM costs. Staff recommends that the existing DSM adjustor be used to fund all of Southwest's DSM programs, including new programs that may be adopted.

Q. Does Staff have additional recommendations regarding the DSM recovery mechanism?

A. Yes. In the past DSM costs have only been recovered from residential customers. Now that new programs are being proposed for commercial and industrial customers Southwest proposes that the DSM adjustor be recovered from all customer classes. Staff agrees that with approval of the new DSM programs it would be appropriate to recover the DSM adjustor cost from each of the rate classes. Consequently, Staff recommends that Southwest's DSM adjustor be applied to all of Southwest's customer classes.

PROPOSED PROGRAMS

Q. What are the new DSM programs that Southwest is proposing?

A. Southwest has proposed the following new residential programs: Multi-Family New Construction, Residential Energy Conservation, and Energy Star® Appliances. Southwest has proposed the following new Commercial and Industrial programs: Food Service Equipment, Efficient Commercial Building Design, Technology Information Center, and Distributed Generation.

Q. Please describe the Multi-Family New Construction program as it is proposed.

A. The Multi-Family New Construction program is designed to provide to renters and condominium owners benefits similar to those provided in the EAP program. Much as it does in the EAP program, Southwest will work with designers and developers of multi-family new construction primarily in Maricopa and Pima Counties to improve the energy efficiency of multi-family residences. Improvements will be achieved through upgrades to more efficient appliances and improvements to the building envelope. The program is designed to reduce customers' bills and system load much as it does in the EAP program.

Q. Please describe the Residential Energy Conservation Program as it is proposed.

A. The Residential Energy Conservation program will provide education and incentives to those who wish to undertake energy-saving measures in their homes. Southwest will promote in-store training at home improvement stores to teach weatherization techniques such as installation of insulation, weatherstripping, and caulking. The program will also offer rebates on selected energy efficiency products to promote their use. The program promotes energy efficiency to homeowners who may not be eligible for participation in the LIEC program, EAP program, or Multi-Family New Construction program. The

goals are to help homeowners improve the energy efficiency of their own homes consequently reducing their bills and system load.

Q. Please describe the Energy Star® Appliance program as it is proposed.

A. The Energy Star® Appliance program will promote purchases of high-efficiency appliances such as furnaces, water heaters, and washing machines. Southwest will promote the products through provision of educational materials at the point of purchase, training of retailers, and price incentives for selected appliances. The program is meant to increase the use of more energy efficient appliances. The program benefits any individual or organization that purchases Energy Star® Appliances. Use of these appliances will result in energy cost savings for the users and reduced system load.

Q. Please describe the Food Service Equipment Program as it is proposed.

A. The Food Service Equipment program will promote efficiencies in restaurants and commercial food service facilities. Southwest will provide information regarding high-efficiency equipment used in food service through training at its Food Service Center in Tempe and through other informational material. Rebates will be offered for high-efficiency natural gas appliances such as water booster heaters for dishwashers, gas cooking appliances, energy-efficient washing equipment, and high-efficiency hot water heaters. The program is meant to increase heating efficiency in a number of food service processes. These heating efficiencies will result in lower operating costs for food service providers and reduce load on Southwest's gas system.

Q. Please describe the Efficient Commercial Building Design program as it is proposed.

A. The Efficient Commercial Building Design program promotes energy-saving measures in the design and construction of new commercial buildings. This is achieved by providing professionals involved in the design of new buildings with educational materials and workshops which provide instruction on improved construction techniques, building materials, and energy-efficient equipment. Financial incentives will also be provided to encourage participation. The program is meant to result in the construction of more energy efficient commercial buildings. Improvements in the energy performance of commercial buildings will result in cost savings for the buildings' owners or operators and reduced system load.

Q. Please describe the Technology Information Center program as it is proposed.

A. The Technology Information Center program will serve as an informational resource for industrial and commercial customers. The center will provide information related to energy-efficiency through a variety of media such as a call center, newsletters, and the internet. The program is meant to provide technical instruction to a variety of commercial and industrial customers. Many of these customers will be owners or operators of existing commercial and industrial facilities and are not eligible for the benefits of the Efficient Commercial Building Design program.

Q. Please describe the Distributed Generation program as it is proposed.

A. The Distributed Generation program encourages projects that demonstrate either combined heat and power or peak-shaving concepts in industrial applications. It is difficult to evaluate how such a program would benefit in management of gas load vs. electric load until further detail about the program is developed. Staff has approved of

distributed generation as a DSM program for both gas and electric utilities in Staff's First Draft of Proposed DSM Rules – April 15, 2005, and will give further consideration to Southwest's proposal in this matter when details of the program are filed.

FUNDING LEVELS AND APPROVAL

Q. What are the funding levels of Southwest's current DSM programs?

A. Funding levels for Southwest's current DSM programs are shown in Table I below.

Table I
CURRENT FUNDING LEVELS

Low Income Energy Conservation *(Residential)*	$350,000
Energy Advantage Plus *(Residential)*	$250,000

Q. What are the funding levels that Southwest proposes for its new DSM programs?

A. Funding levels that Southwest proposes for its new DSM programs are shown in Table II below.

Table II
FUNDING LEVELS PROPOSED BY SOUTHWEST

Low Income Energy Conservation *(Residential)*	$500,000
Energy Advantage Plus *(Residential)*	$250,000
Multi-Family New Construction *(Residential)*	$1,200,000
Residential Energy Conservation *(Residential)*	$200,000
Energy Star® Appliances *(Residential)*	$800,000
Food Service Equipment *(Commercial and Industrial)*	$500,000
Efficient Commercial Building Design *(Commercial and Industrial)*	$500,000
Technology Information Center *(Commercial and Industrial)*	$35,000
Distributed Generation *(Commercial and Industrial)*	$400,000

Q. Please comment on these proposed funding levels.

A. Southwest has included brief descriptions of its newly proposed programs in its direct testimony. Southwest has not included in its proposal detailed descriptions of the new

programs or cost benefit analyses of the programs. At this time Staff does not have sufficient information regarding each of the newly proposed programs to make recommendations regarding funding levels for each of the programs. Staff finds Southwest's proposal reasonable as a whole, but cannot make specific recommendations regarding each new program until more specific information is provided.

Q. What recommendations does Staff have regarding funding of Southwest's DSM programs?

A. In order to allow consideration of the proposed programs in an informed manner, Staff recommends that within 120 days of a decision in this matter Southwest submit to the Commission for approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs. Staff recommends that the DSM plan be filed under a new docket number and that for purposes of compliance verification notice of the filing be made in this docket.

Q. What information should Southwest be required to provide when it submits its DSM program for approval?

A. The following is a list of DSM evaluation topics that Southwest should be required to provide:

1. Description of the program.
2. Objectives and rationale for the program.
3. Market segment at which the program is aimed, including geographic limitations.
4. Estimated level of program participation.
5. Estimate of baseline (when applicable).
6. Estimated societal benefits and savings from the program.
7. Estimated societal costs of the programs.
8. Marketing and delivery strategy.
9. Utility costs and budget.
10. Implementation schedule.
11. Monitoring and evaluation plan.
12. Proposed performance incentives.

Q. How will this information help in consideration of program approval?

A. This information, among other things, will help in describing the nature of the programs, their goals, who they may benefit, what benefits they may provide, how the program will be measured, and whether benefits can be expected.

Q. Does Staff's recommendation that within 120 days of a decision in this matter Southwest submit to the Commission for approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs include submitting for consideration the existing EAP and LIEC programs?

A. Yes. While these programs have been approved in the past, Staff finds that it will be beneficial to include these programs when considering Southwest's entire DSM program. Inclusion of these existing programs in Southwest's filing for approval will allow the Commission to consider the funding levels of each of the proposed DSM programs concurrently. This will facilitate reallocation of funding among the various programs should the Commission choose to do so. Additionally, it will allow the Commission to consider funding for the EAP and LIEC programs in light of the most recent analysis of the programs available.

Q. What should be the status of the existing EAP and LIEC programs while the Commission is considering Southwest's entire DSM program?

A. In order to provide continuity of benefits, Staff recommends that the EAP and LIEC programs continue as previously approved and at their current funding levels until the Commission examines the detailed plans for the DSM programs and issues a decision in the matter.

Q. What other recommendations does Staff have regarding funding of Southwest's DSM programs?

A. The new programs and funding levels greatly increase Southwest's DSM efforts. Staff recommends approval of the total combined funding level at this time as proposed by Southwest with the exception of a reduction related to the spending proposed for bill assistance as a component of the LIEC program.

Q. Please describe the basis for Staff's exception to Southwest's proposal for bill assistance as a component of the LIEC program.

A. Southwest has proposed that $50,000 of LIEC funds be used annually for customer bill assistance. In response to a data request from Staff on the matter Southwest has indicated it has had discussions with Arizona community service organizations regarding the possibility of their administration of the bill assistance program. Exactly who might administer the program is not yet formally established. Southwest currently has a Low Income Rate Assistance program ("LIRA") which provides a 20 percent discount on the commodity portion of the winter bills of eligible customers. While the LIRA program exists to provide rate assistance, currently no rate assistance is provided to Southwest customers through third parties. Consequently, Southwest's proposal for $50,000 in spending for rate assistance administered through the third parties would be a new rate assistance program for Southwest. Southwest has not included in its application details about how such a program would operate. Most significantly, the proposed program is a rate assistance program and is not a DSM program. Staff recommends that the Commission not approve Southwest's request to include $50,000 in rate assistance as a part of its DSM program. As Staff is not recommending approval of the rate assistance

portion of Southwest's DSM proposal, Staff recommends that Southwest's proposal for total DSM spending be reduced by $50,000.

Q. What DSM funding level is Staff recommending for Southwest?

A. Staff recommends that Southwest's total annual DSM budget be $4,335,000.

Q. What effects would the cost of the new programs have on customer bills?

A. The average monthly use of Southwest's residential customers in the test year was 29 therms. The new DSM program recommendations, excluding the proposed $50,000 spending for bill assistance within the LIEC program, will result in costs of $0.2075 per average monthly residential bill. This is an increase of $0.0628 monthly over the DSM program costs for average residential customers during the test year. While the DSM costs at either Southwest's or Staff's recommended funding level are a significant increase over the existing funding level, the impact of the funding increase is reduced as DSM costs will be recovered from all customer classes rather than only from residential customers as was done previously. In the 2004 test year, average residential customer therm use in January was 72 therms. The new DSM program recommendations, again excluding the proposed $50,000 spending for bill assistance within the LIEC program, will result in costs of $0.5152 per bill at the 72 therm use level. This is an increase in January of $0.1559 over the DSM program costs for residential customers during the test year.

The monthly increase in DSM cost to residential customers at various therm levels is demonstrated in Table III and Table IV. Both tables demonstrate DSM costs that result from implementation of Staff's proposed $4,335,000 program funding level. These costs

are compared to the Test Year DSM Cost of $0.00499 per therm monthly. Table III makes a comparison based on average and median residential therm use in January of the test year. A January comparison is made as January is typically the peak therm use month. Table IV makes a comparison based on average monthly and median monthly residential therm use from the entire test year.

Table III
DSM COSTS
January Therm Use

	Therm Level	Test Year DSM Cost	DSM Cost Given Staff's Proposed DSM Funding Level	Difference
Low Use Customer 50% of average	36	$0.1796	$0.2576	$0.0780
Median Use Customer	58	$0.2894	$0.4151	$0.1257
Average Use Customer	72	$0.3593	$0.5152	$0.1559
High Use Customer 150% of average	108	$0.5389	$0.7729	$0.2340

Table IV
DSM COSTS
Monthly Average and Median Therm Use

	Therm Level	Test Year DSM Cost	DSM Cost Given Staff's Proposed DSM Funding Level	Difference
Low Use Customer 50% of average	15	$0.0724	$0.1038	$0.0314
Median Use Customer	16	$0.0798	$0.1145	$0.0347
Average Use Customer	29	$0.1447	$0.2075	$0.0628
High Use Customer 150% of average	44	$0.2171	$0.3113	$0.0942

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please provide a summary of each of Staff's recommendations regarding DSM.

A. Staffs recommendations are as follows:

1. Proposed changes to the DSM adjustor level shall be filed for Commission approval.
2. Future semi-annual DSM Progress Reports shall be certified by an Officer of the Company and its existing filing practices shall continue.
3. The existing DSM adjustor shall be used to fund all of Southwest's DSM programs, including new programs that may be adopted.
4. Southwest's DSM adjustor shall be applied to all of Southwest's customer classes.
5. Within 120 days of a decision in this matter Southwest shall submit to the Commission for approval a DSM plan that includes detailed descriptions of each of the proposed DSM programs.
6. The DSM plan shall be filed under a new docket number.
7. Notice of filing of the DSM plan shall be made in this docket.
8. Southwest shall provide in its DSM plan, at a minimum, an evaluation of each of the proposed programs using the twelve DSM evaluation topics discussed in this report.
9. The EAP and LIEC programs shall continue as previously approved and at their current funding levels until the Commission examines the detailed plans for the DSM programs and issues a decision in the matter.
10. Southwest's total annual DSM budget should be established at $4,335,000.

Q. Does this conclude your testimony?

A. Yes it does.

BAHL

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-01551A-04-0876

DIRECT

TESTIMONY

OF

PREM K. BAHL

ELECTRIC UTILITIES ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 26, 2005

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-04-0876

In this testimony, Utilities Division Staff ("Staff") discusses its review of Southwest Gas Corporation's ("Southwest," "SWG" or "Company") Class Cost of Service Study ("CCOSS") for the rate case filed with the Arizona Corporation Commission ("Commission"), and presents the results of Staff's analysis.

Based on its review of Southwest's CCOSS, Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that Southwest performed the CCOSS consistent with the methodology generally accepted in the industry, and developed the allocation factors appropriately. Except as noted, the CCOSS model ("Model") utilized by Southwest is consistent with what was approved by the Commission in its last rate case in Decision No. 64172. The Company has, however, made one change in allocating costs of Distribution Mains to demand-related and customer-related expenses as compared to its allocation of such costs in the last rate case. Based on Staff's review of Southwest's study concerning this change, Staff concurs with the results of the analysis the Company has made as discussed in Item 4 below.

2. Staff further concludes that, based on its evaluation of the Model utilized by Southwest, the results are satisfactory.

3. Staff recommends the Commission approve Southwest's Cost of Service Study methodology for use in this case and future cases.

4. Staff further recommends that the Commission approve the Company's allocation factor for Distribution Mains in the ratio of 60 percent customer-related costs to 40 percent demand-related costs, as opposed to a 50 percent split between the two costs approved in the last rate case.

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EXHIBIT 1

Southwest Gas Corporation
Embedded Class Cost of Service
Functionalization of Costs (RevReq)
Test Year Ending August 31, 2004

EXHIBIT 2

Southwest Gas Corporation
Class Cost of Service Study Allocations (CCOSS)
Test Year Ending August 31, 2004

EXHIBIT 3

Southwest Gas Corporations
Class Cost of Service Study Allocation Factors
Test Year Ending August 31, 2004

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Prem K. Bahl. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

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

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer.

Q. Please describe your educational background.

A. I graduated from the South Dakota State University with a Masters degree in Electrical Engineering in May 1972. I received my Professional Engineering ("P.E.") License in the state of Arizona in 1978. My Bachelor of Science degree in Electrical Engineering was from the Agra University, India in 1957.

Q. Please describe your pertinent work experience.

A. I worked at the Arizona Corporation Commission from 1988 to 1998 as a Utilities Consultant, and have been re-employed at the Commission as an Electric Utilities Engineer since June 2002. During this time period of thirteen years, I conducted engineering evaluations for electric utility rate cases and financing cases. I have inspected several utility power plants, including the Palo Verde Nuclear Generating Station. I was involved with the development of retail competition in Arizona and of DesertStar, an Independent System Operator ("ISO"). DesertStar was later renamed as WestConnect, a Regional Transmission Operator ("RTO"), approved by Federal Energy Regulatory Commission ("FERC") for the southwest region. I was Chairman of the System Reliability Working Group, which evaluated the impact of competition on system

reliability and recommended the establishment of the Arizona Independent System Administrator ("AZISA") as an interim organization until commercial operation of DesertStar was implemented. Since rejoining the Commission, I have reviewed utilities' load curtailment plans, coordinated with the Commission consultants to hold two workshops to report on the second Biennial Transmission Assessment ("BTA") 2002-2011, and the third BTA 2004-2013, in the state of Arizona; and worked on the compliance of power plant and line siting cases, such as the Harquahala, Panda Gila River, Red Hawk plants, the 138 kV Sandario Project and the 138 kV Robert Bills-Wilmot Transmission Line and Substation Project. I have performed engineering evaluations and conducted analyses of financing applications and of cost of service studies performed by jurisdictional electric cooperatives, such as Sulphur Springs Valley Electric Cooperative; Trico Electric Cooperative; Duncan Valley Electric Cooperative; Graham County Electric Cooperative and Graham County Gas Division. I have also analyzed the most recent financing application of Salt River Project.

From July 2001 to June 2002, I had my own consulting engineering firm, named P. K. Bahl & Associates. During this time, I was involved with deregulation of electric power industry, and formation of RTO West and the MidWest ISO.

From July 1998 to August 2000, I worked as Chief Engineer at the Residential Utility Consumer Office. During this time period, I performed many of the duties I performed at the Commission. I was also involved with the Distributed Generation Work Group that looked at the impact of development of distributed generation in Arizona on system reliability, and modifications of interconnection standards currently specified by the jurisdictional utilities. I was a member of the AZISA Board of Directors from September 1999 to June 2000. I was involved in the deliberations of the Market Interface Committee

of the North American Electric Reliability Council. I also published and presented a number of technical papers at national and international conferences regarding formation of ISOs and RTOs; transmission issues and distributed generation. In April 2005, I chaired a national conference on "Western Power Supply" in Los Angeles, California.

Prior to my employment with the Commission, I had worked as an electrical engineer with electric utilities and consulting firms in the transmission and generation planning areas for approximately twenty eight years, including ten years experience at the Punjab State Electricity Board ("PSEB") in India from 1960 to 1970. I worked as Executive Engineer at the PSEB from 1968 to 1970 prior to coming to the USA in 1970.

Q. As part of your assigned duties at the Commission, did you perform a Cost of Service analysis of the application that is the subject of this proceeding?

A. Yes, I did.

Q. Is your testimony herein based on that analysis?

A. Yes, it is.

Q. What is the purpose of Staff's prefiled testimony?

A. The purpose of Staff's testimony is to discuss its review of Southwest Gas Corporation ("Southwest," "SWG"or "Company") Class Cost of Service Study ("CCOSS") for this rate case, and present the results of this review.

II. COST OF SERVICE STUDY - REVIEW PROCESS

Q. What does the CCOSS signify?

A. There are three steps to take in performing a CCOSS. They are: 1) functionalization; 2) classification; and 3) allocation. First, the CCOSS enables us to determine the system's cost of service by classifying the utility's costs (investments and expenses) by function, such as distribution-related and customer-related functions. Second, the study breaks down these costs by customer classification to reflect as closely as possible the cost causation by respective customer classes. Third, the results of the CCOSS provide a benchmark for the revenues needed from each customer category by appropriately allocating the revenue requirement for each customer class.

Q. What are the basic components of Southwest's Class Cost of Service Study model?

A. Southwest's Class Cost of Service Study ("CCOSS") model ("Model") uses test year account data to functionalize, classify and allocate the costs of providing service to different categories of customers. Since Southwest has no production, storage or transmission, the Model assigns investments in plant and operating expenses only to two functional categories: distribution and customer accounting. Functionalization is done in part of the Model called "RevReq," attached to my testimony as Exhibit 1.

Next, the Model utilizes the process of classifying costs, which assigns costs to demand, customer, or commodity related components. Based on certain assumptions, the Model allocates costs to different classes of customers depending on their contribution to system coincident peak demand ("CP") and non-coincident peak demand ("NCP"), and to their usage of the amount of gas ("Commodity"). Certain costs are a function of the number of customers regardless of the consumption of gas by them. Furthermore, the Model assigns certain costs that are customer-weighted, depending upon the resources and the amount of

time needed to serve such customers. These resources include both personnel and monetary factors. The classifying process is done in the part of the Model called "Allocation Factors," attached to my testimony as Exhibit 3.

The final step is cost allocation to various classes of customers. The cost allocation is determined by applying the above noted Allocation Factors to the functionalized costs shown in Exhibit 1. This is accomplished in the portion of the Model called "CCOSS", attached to my testimony as Exhibit 2.

Q. Does CCOSS (Exhibit 2) reflect rate of return by customer classes?

A. Yes, the rate of return on Staff's proposed revenues by customer classes is reflected in Exhibit 2 on pages 7, 14, 21 and 28.

Q. Is there a standard CCOSS model?

A. There is no standard methodology for designing a CCOSS, but it is generally advisable to consider a range of alternatives to identify which allocations are more reasonable than others. For that reason, the CCOSS results should be used as a general guide only and as one of many considerations in designing rates.

Q. What was the process Staff used in reviewing SWG's CCOSS?

A. First, I reviewed the Model used by SWG in developing various allocation factors in the CCOSS. Second, I reviewed the Test Year (for the twelve months ending August 31, 2004) rate base, revenues and operating expenses, adjusted by the Company's Pro Forma adjustments, in the filed rate case, and matched them with the appropriate schedules contained in the Application. Third, I incorporated the rate base, revenues and operating expense adjustments of Staff witness, Dennis Rogers, in the CCOSS.

Q. Did Staff conduct a separate independent CCOSS?

A. No. After studying SWG's Model, I concluded that the best method for review would be to verify the reasonableness of SWG's CCOSS and then make the appropriate Staff adjustments. The accuracy of the Model was established by the fact that all adjustments flowed through to the relevant G-Schedules[1]. When adjustments properly flow through to the relevant schedules, this is a check on the Model's reliability and accuracy. The results of Staff's CCOSS analysis are attached to this testimony as "Embedded Class Cost of Service Functionalization of Costs (RevReq)" under Exhibit 1, and "Class Cost of Service Study Allocations (CCOSS)"under Exhibit 2.

III. COST ALLOCATION OF DISTRIBUTION MAINS

Q. What was the Company's rationale for allocating the cost of Distribution Mains[2] to Customers and Demand in the ratio of 60 percent to 40 percent, respectively, for the Test Year ending August 2004, and why is it different from the 50/50 ratio approved by the Commission in Southwest's last rate case?

A. According to the Work Papers provided by Southwest in this rate filing, the Company performed a minimum system study, which determined what portions of the costs for Distribution Mains would be included even under a zero-demand condition. Since these minimum costs are a function of the number of customers added to the system, regardless of their gas consumption or gas requirements, these costs are customer-related. The remaining costs are attributed to demand. It is the result of this minimum system study, which indicates that 60 percent of the costs for Distribution Mains are customer related

[1] The G-Schedules refer to the CCOSS analysis in accordance with the Arizona Administrative Code Title 14, Chapter 2, Regulation R14-2-103.

[2] Distribution Mains are laterals from the El Paso Natural Gas Corporation transmission pipeline for supply of gas to the end-use customers via the distribution service lines.

and 40 percent of the costs are demand related. Staff reviewed this study and concurs with the study results.

Q Does Staff agree with the Company's proposed allocation of costs for Distribution Mains for purposes of this case?

A. Yes. Staff recommends the Commission approve the Company's proposed allocation of costs for Distribution Mains as 60 percent customer-related and 40 percent demand-related, as opposed to the 50 percent split approved in the last rate case.

IV. CONCLUSIONS AND RECOMMENDATIONS

Q. Based upon your testimony, what are Staff's conclusions and recommendations regarding Southwest's CCOSS?

A. Based on its review of Southwest's CCOSS, Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that SWG performed the CCOSS consistent with the methodology generally accepted in the industry, and developed allocation factors that are appropriate and reasonable.

2. Staff further concludes that, based on the evaluation of the CCOSS Model utilized and the assumptions made by SWG in developing the various allocation factors, the results of CCOSS are satisfactory.

3. Staff recommends that SWG continue to utilize the current CCOSS Model for allocating expenditures associated with Distribution Mains and Operating Expenses for Distribution Mains and Services in future rate cases.

4. Staff further recommends that the Commission approve Southwest's CCOSS cost allocations based on the allocation factors developed in this rate filing, including allocation of Distribution Mains as 60 percent customer-related and 40 percent demand-related.

Q. Does this conclude your pre-filed testimony?

A. Yes it does.

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description		Amount
	(a)	(b)		(c)
		Net Plant in Service		
		Direct		
		Intangible		
1	301	Organization	$	42,653
2	302	Franchise & Consent		1,185,155
3	303	Misc. Intangible		278,178
		Total Intangible	$	1,505,987
		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	$	351,685
21	374.2	Rights of Way		445,985
22	375	Structures		47,682
23	376	Mains		516,273,775
24	378	Measuring & Reg. Station		23,180,184
25	380	Services		305,210,571
26	381	Meters		125,828,203
27	385	Industrial Meas. & Reg. Sta.		3,942,124
28	386	Other Prop. on Cust. Premises		

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description	Amount
	(a)	(b)	(c)
29	387	Other Equipment	(39,455)
30		Total Distribution	$ 975,240,755
31		Total Trans., Dist., Prod.	$ 975,240,755
		General	
1	389	Land & Land Rights	$ 6,454,589
2	390.1	Structures & Improvements	19,010,773
3	390.2	Struct. & Imp.-Leasehold	405,811
4	391.0	Office Furn. & Equip.	4,193,220
5	391.1	Office Furn. & Computer Equip.	7,310,243
6	392.1	Transp. Equip.-Light	25,153,605
7	392.0	Transp. Equip.-Heavy	
8	393	Stores Equipment	467,851
9	394	Tools, Shop, & Garage Equip.	7,534,959
10	395	Laboratory Equip.	575,431
11	396	Power Operated Equip.	2,688,717
12	397.1	Comm. Equip.-General	(108,682)
13	397.2	Comm. Equip.-Telemetering	128,122
14	398	Miscellaneous Equip.	811,368
15		Total General	$ 74,626,005

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description	Amount
	(a)	(b)	(c)

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description		Amount
	(a)	(b)		(c)
		Systems Allocable		
		Intangible		
16	301	Organization	$	35,594
17	302	Franchise & Consent		-
18	303	Miscellaneous Intang.		26,080,382
19		Total Intangible	$	26,115,976
		General		
20	389	Land & Land Rights	$	225,313
21	390.10	Structures & Improvements		4,759,482
22	390.20	Struct. & Imp.-Leasehold		143,546
23	391.00	Office Furn. & Equip.		3,394,106
24	391.10	Office Furn. & Computer Equip.		1,741,593
25	392.11	Transp. Equip.-Light		1,320,722
26	392.12	Transp. Equip.-Heavy		83,950
27	392.22	Aircraft-Left Engine		
28	392.23	Aircraft-Right Engine		
29	393	Stores Equipment		16,762
30	394	Tools, Shop, & Garage Equip.		255,878
31	395	Laboratory Equip.		107,340
32	397.0	Comm. Equip.-General		1,200,989
33	397.2	Telemetering Equipment		338,566
34	398	Miscellaneous Equip.		600,283
35		Total General	$	14,188,530
36		Total Net Plant-Direct	$	1,051,372,747
37		Total Net Plant-Systems Alloc.	$	40,304,506
38		Total Net Plant	$	1,091,677,252
39		Cash Working Capital	$(	11,082,156)
40		Materials and Supplies		9,222,489
41		Prepayments		2,740,815
42		Gas Plant Acquisition Adjustment		-
43		Customer Deposits	(	23,912,141)
44		Customer Advances	(	7,027,372)
45		Deferred Taxes	(	136,691,328)
46		Deferred Gain Headquarters Bldg.		-

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description	Amount
	(a)	(b)	(c)
47		Total Rate Base	$ 924,927,560

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description		Amount
	(a)	(b)		(c)
		Depreciation Expense & Amortization		
		Direct		
		Intangible		
1	301	Organization	$	-
2	302	Franchise & Consent		77,626
3	303	Misc. Intangible		132,362
4		Total Intangible Dep. Exp.	$	209,988
		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		15,501
23	375	Structures		1,271
24	376	Mains		30,164,518
25	378	Measuring & Reg. Station		1,007,546
26	380	Services		27,761,544
27	381	Meters		3,104,837
28	385	Industrial Meas. & Reg. Sta.		281,378
29	386	Other Prop. on Cust. Premises		

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description		Amount
	(a)	(b)		(c)
30	387	Other Equipment		24,340
31		Total Distribution Dep. Exp.	$	62,360,935
		General		
1	389	Land & Land Rights	$	-
2	390.1	Structures & Improvements		483,646
3	390.2	Struct. & Imp.-Leasehold		62,345
4	391	Office Furn. & Equip.		132,400
5	391	Office Furn. & Computer Equip.		1,262,320
6	392	Transp. Equip.		2,329,207
7	393	Stores Equipment		10,024
8	394	Tools, Shop, & Garage Equip.		106,156
9	395	Laboratory Equip.		16,715
10	396	Power Operated Equip.		147,733
11	397.1	Comm. Equip.-General		197,463
12	397.2	Comm. Equip.-Telemetering		34,683
13	398	Miscellaneous Equip.		38,242
14		Total General Dep. Exp.	$	4,820,934
		Systems Allocable		
		Intangible		
15	301	Organization	$	-
16	302	Franchise & Consent		-
17	303	Miscellaneous Intang.		4,593,633
18		Total Intangible Dep. Exp.	$	4,593,633
		General		
19	389	Land & Land Rights	$	-
20	390.1	Structures		170,308
21	390.2	Structures - Leasehold Improvements		17,118
22	391	Office Furniture & Equipment		364,407
23	391.1	Computer Equipment		1,262,257
24	392.11	Transportation Equipment - Light		140,516
25	392.12	Transportation Equipment - Heavy		4,614
26	393	Stores Equipment		2,225
27	394	Tools, Shop, & Garage Equipment		26,648
28	395	Laboratory Equipment		7,385
29	396	Power Operated Equipment		

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description		Amount
	(a)	(b)		(c)
30	397.1	Communication Equipment		225,680
31	397.2	Telemetering Equipment		92,988
32	398	Miscellaneous Equipment		59,842
33		Total General Dep. Exp.	$	2,373,988
		System Allocable Amortization		
34		Miscellaneous Intangible	$	-
35		Structures-Leasehold Improvements		-
36		Total System Allocable Amortization	$	-
37		Total Depreciation Exp.-Direct	$	67,391,857
38		Total Dep. Exp.-Systems Alloc.	$	6,967,621
39		Amortization-Limited Term Gas Plant	$	-
40		Amortization-Gas Plant Acquisition	(	52,996)
41		Amortization of PBOP Costs		337,524
42		Amortization of Service Investigation		-
43		Amortization of TRIMP Costs		0
44	407	Amortization of SOX Implementation		0

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description		Amount
	(a)	(b)		(c)
45		Total Depreciation Expense	$	74,644,007
		Operation and Maintenance Expense		
		Gas Supply Expense		
1	800	Natural Gas Wellhead Purchases	$	-
2	803	Natural Gas Transmission Line Purch.		-
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		675,355
7		Materials & Expenses		57,202
8		Total Gas Supply Expense	$	732,557
		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		-

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description	Amount
	(a)	(b)	(c)
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	-

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description		Amount
	(a)	(b)		(c)
43		Total Transmission Expense	$	-
		Distribution Expenses		
1	870	Operation Supervision & Eng.		
2		Labor & Labor Loading	$	7,265,470
3		Materials & Expenses		1,144,604
4	871	Distribution Load Dispatching		
5		Labor & Labor Loading		525,437
6		Materials & Expenses		128,930
7	874	Mains & Svcs. Expense		
8		Labor & Labor Loading		5,194,376
9		Materials & Expenses		4,392,768
10	875	Meas. & Reg. Sta. Exp.-Gen.		
11		Labor & Labor Loading		1,951,603
12		Materials & Expenses		777,755
13	878	Meter & House Reg. Exp.		
14		Labor & Labor Loading		5,759,636
15		Materials & Expenses		875,104
16	879	Customer Installation Exp.		
17		Labor & Labor Loading		6,806,932
18		Materials & Expenses		1,043,174
19	880	Other Expenses		
20		Labor & Labor Loading		6,252,765
21		Materials & Expenses		4,262,589
22	881	Rents		1,980,383
23		Total Distribution-Operations	$	48,361,527
24	885	Maint. Supervision & Eng.		
25		Labor & Labor Loading	$	2,358,410
26		Materials & Expenses		254,842
27	886	Maint. of Structures & Imp.		
28		Labor & Labor Loading		13,595
29		Materials & Expenses		50,707
30	887	Maint. of Mains		
31		Labor & Labor Loading		7,455,894
32		Materials & Expenses		5,406,561
33	889	Maint. of Meas. & Reg. Sta-Gen		
34		Labor & Labor Loading		1,111,026

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description	Amount
	(a)	(b)	(c)
35		Materials & Expenses	829,877
36	892	Maint. of Services	
37		Labor & Labor Loading	5,283,687
38		Materials & Expenses	2,909,486
39	893	Maint of Meter & House Reg.	
40		Labor & Labor Loading	1,119,529
41		Materials & Expenses	805,373
42	894	Maint of Other Equip.	
43		Labor & Labor Loading	149,359
44		Materials & Expenses	44,303
45		Total Distribution-Maintenance	$ 27,792,650

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description		Amount
	(a)	(b)		(c)
46		Total Distribution O & M	$	76,154,176
		Customer Accounts Expenses		
1	901	Supervision		
2		Labor & Labor Loading	$	3,551,712
3		Materials & Expenses		218,328
4	902	Meter Reading Exp.		
5		Labor & Labor Loading		5,097,814
6		Materials & Expenses		1,285,812
7	903	Customer Records & Collections		
8		Labor & Labor Loading		14,059,043
9		Materials & Expenses		6,602,396
10	903	Customer Records & Collections - LCS		
11		Labor & Labor Loading - LCS		1,077,228
12		Materials & Expenses - LCS		47,923
13	904	Uncollectible Accounts Exp.		1,559,656
14	905	Misc. Customer Accounts Exp.		
15		Labor & Labor Loading		370,493
16		Materials & Expenses		21,199
17		Total Customer Accounts Expenses	$	33,891,603
		Customer Service & Info. Exp.		
18	908	Customer Assistance Exp.		
19		Labor & Labor Loading	$	273,679
20		Materials & Expenses		248,457
21	909	Info. & Instructional Exp.		
22		Labor & Labor Loading		-
23		Materials & Expenses		-
24	910	Misc. C.S. & I. Expense		
25		Labor & Labor Loading		768
26		Materials & Expenses		23,832
27		Total Customer Service & Info. Exp.	$	546,736
		Sales Expense		
28	911	Supervision		
29		Labor & Labor Loading	$	-
30		Materials & Expenses		-
31	912	Demonstrating & Selling Exp.		

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description	Amount
	(a)	(b)	(c)
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	$ 111,325,072
1	925	Administrative & General Expense	$ 48,271,016
2		Interest on Customer Deposits	717,364
3	408	Taxes other than Income	31,717,579
4		Interest Expense	38,754,465
5		South Georgia - State	77,020
6		Investment Tas Credit (I T C)	(528,352)
7		South Georgia - Federal	288,233

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description		Amount
	(a)	(b)		(c)
8		Regulatory Amortization		-
9		SIT Rate		6.9680%
10		FIT Rate		32.5612%
		Rate Base		
11		Direct Net Plant	$	1,051,372,747
12		Systems Allocable Net Plant		40,304,506
13		Cash Working Capital	(	11,082,156)
14		Materials & Supplies		9,222,489
15		Prepayments		2,740,815
16		Gas Plant Acquisition Adjustment		-
17		Customer Deposits	(	23,912,141)
18		Customer Advances	(	7,027,372)
19		Deferred Taxes	(	136,691,328)
20		Deferred Gain Hdqtrs Bldg		-
21		Total Rate Base	$	924,927,560
22		Net Operating Margin	$	352,069,751
23		Special Contract & Optional		7,611,429
24		Late Charges		1,386,957
25		Service Establishment Charges		6,950,610
26		Reconnect / Reread Charges		547,658
27		Other Revenue - Labor		1,705
28		Other Revenue - Parts & Material		5,764
29		Other Revenue - Field Collection Fee		388,540
30		Other Revenue - Returned Item Fee		135,450
31		Other Revenue - Rental Income		767,198
32		Total Revenue	$	369,865,063
		Operating Deductions		
33		O & M	$(	111,325,072)
34		A & G	(	48,271,016)
35		Depreciation Expense	(	74,644,007)
36		Interest on Customer Deposits	(	717,364)
37		Taxes other than Income	(	31,717,579)

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
FUNCTIONALIZATION OF COSTS (RevReq)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Acct No.	Description		Amount
	(a)	(b)		(c)
		State Income Tax		
1		Taxable Income before Interest Exp.	$	103,190,025
2		Interest Expense	(	38,754,465)
3		State Taxable Income	$	64,435,560
4		State Income Tax @ 6.9680%	$	4,489,870
5		South Georgia		77,020
6		State Income Tax	$	4,566,890
		Federal Income Tax		
7		Taxable Income before Interest Exp.	$	103,190,025
8		Interest Expense	(	38,754,465)
9		Federal Taxable Income	$	64,435,560
10		Federal Income Tax @ 32.5612%	$	20,980,992
11		I T C	(	528,352)
12		South Georgia		288,233
13		Total Federal Income Tax	$	20,740,873
14		Regulatory Amortization		-
15		Net Income	$	77,882,263
		Rate of Return on Rate Base		8.42%

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Net Plant in Service - Direct														
		Intangible														
1	301	Organization	1.1	$ 42,653	$ 5,064	$ 25,996	$ 528	$ 252	$ 1,521	$ 31	$ 42	$ 34	$ 5	$ 75	$ 1,576	$ 7
2	302	Franchise & Consent	1.1	1,185,155	140,722	722,332	14,665	6,990	42,267	863	1,177	934	133	2,076	43,797	206
3	303	Misc. Intangible	1.1	278,178	33,030	169,545	3,442	1,641	9,921	203	276	219	31	487	10,280	48
4		Total Intangible		$ 1,505,987	$ 178,817	$ 917,873	$ 18,635	$ 8,883	$ 53,709	$ 1,097	$ 1,496	$ 1,187	$ 170	$ 2,638	$ 55,653	$ 262
5		Allocation Percentage	Intang. Plant	100.00%	11.87%	60.95%	1.24%	0.59%	3.57%	0.07%	0.10%	0.08%	0.01%	0.18%	3.70%	0.02%
		Production														
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission														
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution														
26	374	Land & Land Rights	1.0	$ 351,685	$ 194,604	$ -	$ -	$ 9,667	$ -	$ -	$ 1,628	$ -	$ -	$ 2,871	$ -	$ -
27	374	Rights of Way	1.0	445,985	246,785	-	-	12,259	-	-	2,065	-	-	3,640	-	-
28	375	Structures	1.0	47,682	26,385	-	-	1,311	-	-	221	-	-	389	-	-
29	376	Mains - Demand	1.0	208,461,866	115,351,773	-	-	5,729,984	-	-	965,044	-	-	1,701,513	-	-
30	376	Mains - Customer	5.0	307,811,910	-	271,168,317	-	-	22,011,408	-	-	67,379	-	-	5,883,789	-
31	376	Mains - Commodity	3.0	1	-	-	0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	23,180,184	-	-	10,313,459	-	-	606,897	-	-	93,846	-	-	144,913
33	380	Services - Demand	1.0	0	0	-	-	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	305,210,571	-	238,209,289	-	-	5,448,226	-	-	306,762	-	-	23,189,801	-
35	381	Meters	6.0	125,828,203	-	85,015,123	-	-	7,320,940	-	-	394,459	-	-	6,966,167	-
36	385	Industrial Meas. & Reg. Sta.	3.0	3,942,124	-	-	1,753,952	-	-	103,211	-	-	15,960	-	-	24,644
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(39,455)	(21,832)	-	-	(1,084)	-	-	(183)	-	-	(322)	-	-
39		Total Distribution		$ 975,240,756	$ 115,797,715	$ 594,392,729	$ 12,067,411	$ 5,752,136	$ 34,780,573	$ 710,108	$ 968,775	$ 768,600	$ 109,806	$ 1,708,091	$ 36,039,757	$ 169,557
40		Allocation Percentage	Dist. Plant	100.00%	11.87%	60.95%	1.24%	0.59%	3.57%	0.07%	0.10%	0.08%	0.01%	0.18%	3.70%	0.02%
41	389-398	Total General Plant	1.1	$ 74,626,005	$ 8,860,910	$ 45,483,287	$ 923,406	$ 440,157	$ 2,661,430	$ 54,338	$ 74,131	$ 58,814	$ 8,402	$ 130,704	$ 2,757,784	$ 12,975
42		Total Net Plant-Direct		$ 1,051,372,747	$ 124,837,442	$ 640,793,889	$ 13,009,452	$ 6,201,175	$ 37,495,712	$ 765,543	$ 1,044,402	$ 828,601	$ 118,378	$ 1,841,433	$ 38,853,194	$ 182,794
		Systems Allocable Plant														
43	301-303	Intangible Plant	1.1	$ 26,115,976	$ 3,100,947	$ 15,917,245	$ 323,153	$ 154,036	$ 931,389	$ 19,016	$ 25,943	$ 20,582	$ 2,940	$ 45,741	$ 965,109	$ 4,541
44	389-398	General Plant	1.1	$ 14,188,530	$ 1,684,712	$ 8,647,669	$ 175,566	$ 83,686	$ 506,014	$ 10,331	$ 14,094	$ 11,182	$ 1,598	$ 24,851	$ 524,333	$ 2,467
45		Total Systems Allocable		40,304,506	4,785,659	24,564,914	498,719	237,723	1,437,403	29,347	40,037	31,765	4,538	70,592	1,489,442	7,007
46		Total Net Plant		$ 1,091,677,253	$ 129,623,101	$ 665,358,803	$ 13,508,170	$ 6,438,898	$ 38,933,115	$ 794,890	$ 1,084,439	$ 860,365	$ 122,916	$ 1,912,024	$ 40,342,636	$ 189,801

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service			Multi-Family Residential			MMMHP Gas Service			Small General Gas Service		
					Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Other Rate Base Items														
1		Cash Working Capital	11.2	(11,082,156)	(558,222)	(7,108,793)	(392,055)	(27,729)	(516,528)	(23,070)	(4,670)	(15,310)	(3,567)	(8,234)	(442,306)	(5,509)
2		Materials & Supplies	1.1	9,222,489	1,095,056	5,620,951	114,117	54,396	328,907	6,715	9,161	7,268	1,038	16,153	340,815	1,603
3		Prepayments	1.1	2,740,815	325,438	1,670,480	33,914	16,166	97,747	1,996	2,723	2,160	309	4,800	101,286	477
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	(23,912,141)	-	(21,263,793)	-	-	(1,726,035)	-	-	(5,284)	-	-	(461,380)	-
6		Customer Advances	8.0	(7,027,372)	-	(6,249,068)	-	-	(507,252)	-	-	(1,553)	-	-	(135,592)	-
7		Deferred Taxes	1.1	(136,691,328)	(16,230,396)	(83,311,050)	(1,691,388)	(806,229)	(4,874,902)	(99,530)	(135,785)	(107,728)	(15,391)	(239,409)	(5,051,391)	(23,765)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		924,927,560	114,254,977	554,717,531	11,572,759	5,675,502	31,735,052	681,000	955,868	739,919	105,305	1,685,334	34,694,068	162,607

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service			Multi-Family Residential			MMMHP Gas Service			Small General Gas Service		
					Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Direct Depreciation Expense														
1	301-303	Intangible	Intang. Plant	$ 209,988	$ 24,933	$ 127,984	$ 2,598	$ 1,239	$ 7,489	$ 153	$ 209	$ 165	$ 24	$ 368	$ 7,760	$ 37
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 62,360,935	$ 7,404,586	$ 38,007,934	$ 771,640	$ 367,815	$ 2,224,014	$ 45,407	$ 61,947	$ 49,147	$ 7,021	$ 109,222	$ 2,304,531	$ 10,842
5	389-398	General	1.1	$ 4,820,934	$ 572,426	$ 2,938,278	$ 59,653	$ 28,435	$ 171,932	$ 3,510	$ 4,789	$ 3,799	$ 543	$ 8,444	$ 178,156	$ 838
6		Total Direct Dep. Exp.		$ 67,391,857	$ 8,001,945	$ 41,074,196	$ 833,892	$ 397,489	$ 2,403,435	$ 49,070	$ 66,945	$ 53,112	$ 7,588	$ 118,034	$ 2,490,448	$ 11,717
		Systems Allocable Depreciation Expense														
7	301-303	Intangible	Intang. Plant	$ 4,593,633	$ 545,437	$ 2,799,741	$ 56,841	$ 27,094	$ 163,825	$ 3,345	$ 4,563	$ 3,620	$ 517	$ 8,046	$ 169,756	$ 799
8	389-398	General	1.1	$ 2,373,988	$ 281,882	$ 1,446,906	$ 29,375	$ 14,002	$ 84,665	$ 1,729	$ 2,358	$ 1,871	$ 267	$ 4,158	$ 87,730	$ 413
		System Allocable Amortization														
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
10		*Structures-Leasehold Improvements*	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		6,967,621	827,318	4,246,647	86,216	41,096	248,490	5,073	6,921	5,491	785	12,203	257,487	1,211
13		Total Depreciation Expense		74,359,478	8,829,264	45,320,843	920,108	438,585	2,651,925	54,144	73,866	58,604	8,372	130,237	2,747,934	12,928
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(6,293)	(32,300)	(656)	(313)	(1,890)	(39)	(53)	(42)	(6)	(93)	(1,958)	(9)
16		Amortization of PBOP Costs	1.1	337,524	40,077	205,715	4,176	1,991	12,037	246	335	266	38	591	12,473	59
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	0	0	0	0	0	0	0	0	0	0	0	0	0
19		Amortization of SOX Implementation	1.1	0	0	0	0	0	0	0	0	0	0	0	0	0
20		Total Depreciation & Amortization Expense		$ 74,644,007	$ 8,863,048	$ 45,494,258	$ 923,628	$ 440,263	$ 2,662,072	$ 54,351	$ 74,149	$ 58,828	$ 8,404	$ 130,736	$ 2,758,449	$ 12,978

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Operation and Maintenance Expense														
		Gas Supply Expense														
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch.	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--(Cr	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	675,355	-	-	300,483	-	-	17,682	-	-	2,734	-	-	4,222
7		Materials & Expenses	3.0	57,202	-	-	25,451	-	-	1,498	-	-	232	-	-	358
8		Total Gas Supply Expense		$ 732,557	$ -	$ -	$ 325,934	$ -	$ -	$ 19,180	$ -	$ -	$ 2,966	$ -	$ -	$ 4,580
		Transmission Expenses														
9	850	Operation Supervision & Engin.														
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch														
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.														
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station														
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
22	856	Mains Expense														
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.														
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.														
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains														
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.														
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.														
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Distribution Expenses														
1	870	Operation Supervision & Eng.														
2		Labor & Labor Loading	5.5	$ 7,265,470	$ 356,242	$ 4,162,897	$ 398,395	$ 17,696	$ 307,819	$ 23,444	$ 2,980	$ 13,172	$ 3,625	$ 5,255	$ 301,996	$ 5,598
3		Materials & Expenses	5.5	1,144,604	56,122	655,824	62,763	2,788	48,494	3,693	470	2,075	571	828	47,577	882
4	871	Distribution Load Dispatching														
5		Labor & Labor Loading	3.0	525,437	-	-	233,780	-	-	13,757	-	-	2,127	-	-	3,285
6		Materials & Expenses	3.0	128,930	-	-	57,364	-	-	3,376	-	-	522	-	-	806
7	874	Mains & Svcs. Expense														
8		Labor & Labor Loading	4.4	5,194,376	729,388	3,220,876	0	36,232	173,632	0	6,102	2,366	0	10,759	183,837	0
9		Materials & Expenses	4.4	4,392,768	616,827	2,723,822	0	30,640	146,836	0	5,160	2,001	0	9,099	155,467	0
10	875	Meas. & Reg. Sta. Exp.-Gen.														
11		Labor & Labor Loading	3.0	1,951,603	-	-	868,318	-	-	51,096	-	-	7,901	-	-	12,201
12		Materials & Expenses	3.0	777,755	-	-	346,043	-	-	20,363	-	-	3,149	-	-	4,862
13	878	Meter & House Reg. Exp.														
14		Labor & Labor Loading	6.0	5,759,636	-	3,891,466	-	-	335,107	-	-	18,056	-	-	318,868	-
15		Materials & Expenses	6.0	875,104	-	591,259	-	-	50,915	-	-	2,743	-	-	48,448	-
16	879	Customer Installation Exp.														
17		Labor & Labor Loading	6.0	6,806,932	-	4,599,065	-	-	396,041	-	-	21,339	-	-	376,849	-
18		Materials & Expenses	6.0	1,043,174	-	704,815	-	-	60,694	-	-	3,270	-	-	57,753	-
19	880	Other Expenses														
20		Labor & Labor Loading	5.5	6,252,765	306,587	3,582,647	342,864	15,229	264,913	20,176	2,565	11,336	3,120	4,522	259,902	4,818
21		Materials & Expenses	5.5	4,262,589	209,004	2,442,336	233,735	10,382	180,595	13,754	1,749	7,728	2,127	3,083	177,178	3,284
22	881	Rents	5.5	1,980,383	97,103	1,134,700	108,592	4,823	83,904	6,390	812	3,590	988	1,432	82,316	1,526
23		Total Distribution-Operations		$ 48,361,527	$ 2,371,273	$ 27,709,709	$ 2,651,855	$ 117,791	$ 2,048,949	$ 156,049	$ 19,838	$ 87,676	$ 24,130	$ 34,978	$ 2,010,190	$ 37,261
		Operation and Maintenance Expense														
		Distribution Expenses														
24	885	Maint. Supervision & Eng.														
25		Labor & Labor Loading	6.6	$ 2,358,410	$ 274,624	$ 1,364,035	$ 81,511	$ 13,642	$ 76,139	$ 4,797	$ 2,298	$ 1,505	$ 742	$ 4,051	$ 82,655	$ 1,145
26		Materials & Expenses	6.6	254,842	29,675	147,393	8,808	1,474	8,227	518	248	163	80	438	8,931	124
27	886	Maint. of Structures & Imp.														
28		Labor & Labor Loading	1.0	13,595	7,523	-	-	374	-	-	63	-	-	111	-	-
29		Materials & Expenses	1.0	50,707	28,059	-	-	1,394	-	-	235	-	-	414	-	-
30	887	Maint. of Mains														
31		Labor & Labor Loading	2.2	7,455,894	1,665,881	3,916,143	0	82,751	317,883	0	13,937	973	0	24,573	84,972	0
32		Materials & Expenses	2.2	5,406,561	1,207,996	2,839,749	0	60,006	230,510	0	10,106	706	0	17,819	61,617	0
33	889	Maint. of Meas. & Reg. Sta-Gen														
34		Labor & Labor Loading	3.0	1,111,026	-	-	494,324	-	-	29,089	-	-	4,498	-	-	6,946
35		Materials & Expenses	3.0	829,877	-	-	369,234	-	-	21,728	-	-	3,360	-	-	5,188
36	892	Maint. of Services														
37		Labor & Labor Loading	3.3	5,283,687	0	4,123,786	-	0	94,318	-	0	5,311	-	0	401,453	-
38		Materials & Expenses	3.3	2,909,486	0	2,270,782	-	0	51,936	-	0	2,924	-	0	221,062	-
39	893	Maint.of Meter & House Reg.														
40		Labor & Labor Loading	6.0	1,119,529	-	756,404	-	-	65,136	-	-	3,510	-	-	61,980	-
41		Materials & Expenses	6.0	805,373	-	544,146	-	-	46,858	-	-	2,525	-	-	44,588	-
42	894	Maint of Other Equip.														
43		Labor & Labor Loading	6.6	149,359	17,392	86,385	5,162	864	4,822	304	146	95	47	257	5,235	73
44		Materials & Expenses	6.6	44,303	5,159	25,623	1,531	256	1,430	90	43	28	14	76	1,553	22
45		Total Distribution-Maintenance		$ 27,792,650	$ 3,236,308	$ 16,074,447	$ 960,570	$ 160,760	$ 897,260	$ 56,525	$ 27,075	$ 17,739	$ 8,741	$ 47,738	$ 974,044	$ 13,497
46		Total Distribution O & M		$ 76,154,176	$ 5,607,581	$ 43,784,156	$ 3,612,425	$ 278,551	$ 2,946,209	$ 212,574	$ 46,914	$ 105,415	$ 32,871	$ 82,715	$ 2,984,235	$ 50,758

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
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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	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Customer Accounts Expenses														
1	901	Supervision														
2		Labor & Labor Loading	10.1	$ 3,551,712	$ -	$ 2,849,463	$ -	$ -	$ 231,299	$ -	$ -	$ 4,986	$ -	$ -	$ 150,389	$ -
3		Materials & Expenses	10.1	218,328	-	175,160	-	-	14,218	-	-	307	-	-	9,245	-
4	902	Meter Reading Exp.														
5		Labor & Labor Loading	13.0	5,097,814	-	4,067,662	-	-	330,183	-	-	7,491	-	-	222,411	-
6		Materials & Expenses	13.0	1,285,812	-	1,025,979	-	-	83,282	-	-	1,889	-	-	56,098	-
7	903	Customer Records & Collections														
8		Labor & Labor Loading	13.0	14,059,043	-	11,218,029	-	-	910,598	-	-	20,660	-	-	613,379	-
9		Materials & Expenses	13.0	6,602,396	-	5,268,201	-	-	427,634	-	-	9,702	-	-	288,055	-
10	903	Customer Records & Collections - LCS														
11		Labor & Labor Loading - LCS	13.0	1,077,228	-	859,545	-	-	69,772	-	-	1,583	-	-	46,998	-
12		Materials & Expenses - LCS	13.0	47,923	-	38,239	-	-	3,104	-	-	70	-	-	2,091	-
13	904	Uncollectible Accounts Exp.	4.0	1,559,656	-	1,373,986	-	-	111,530	-	-	341	-	-	29,813	-
14	905	Misc. Customer Accounts Exp.														
15		Labor & Labor Loading	10.1	370,493	-	297,238	-	-	24,128	-	-	520	-	-	15,688	-
16		Materials & Expenses	10.1	21,199	-	17,007	-	-	1,381	-	-	30	-	-	898	-
17		Total Customer Accounts Expenses		$ 33,891,603	$ -	$ 27,190,508	$ -	$ -	$ 2,207,128	$ -	$ -	$ 47,580	$ -	$ -	$ 1,435,064	$ -
		Customer Service & Info. Exp.														
18	908	Customer Assistance Exp.														
19		Labor & Labor Loading	13.0	$ 273,679	$ -	$ 218,374	$ -	$ -	$ 17,726	$ -	$ -	$ 402	$ -	$ -	$ 11,940	$ -
20		Materials & Expenses	13.0	248,457	-	198,250	-	-	16,092	-	-	365	-	-	10,840	-
21	909	Info. & Instructional Exp.														
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense														
25		Labor & Labor Loading	13.0	768	-	613	-	-	50	-	-	1	-	-	34	-
26		Materials & Expenses	13.0	23,832	-	19,016	-	-	1,544	-	-	35	-	-	1,040	-
27		Total Customer Service & Info. Exp.		$ 546,736	$ -	$ 436,253	$ -	$ -	$ 35,412	$ -	$ -	$ 803	$ -	$ -	$ 23,853	$ -
		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		$ 111,325,072	$ 5,607,581	$ 71,410,917	$ 3,938,358	$ 278,551	$ 5,188,749	$ 231,753	$ 46,914	$ 153,798	$ 35,837	$ 62,715	$ 4,443,152	$ 55,337
39		Allocation Percentage	Total O&M	100.00%	5.04%	64.15%	3.54%	0.25%	4.66%	0.21%	0.04%	0.14%	0.03%	0.07%	3.99%	0.05%
		Other Operating Deductions														
40		Administrative & General Expense	Total O&M	48,271,016	2,431,470	30,964,072	1,707,689	120,781	2,249,863	100,489	20,342	66,688	15,539	35,866	1,926,569	23,994
41		Interest on Customer Deposits	8.0	717,364	-	637,914	-	-	51,781	-	-	159	-	-	13,841	-
42		Taxes Other Than Income	1.1	31,717,579	3,766,068	19,331,327	392,466	187,076	1,131,162	23,095	31,507	24,997	3,571	55,552	1,172,114	5,514
43		Total Allocated Operating Deductions		$ 192,031,031	$ 11,805,120	$ 122,344,229	$ 6,038,513	$ 586,408	$ 8,621,556	$ 355,337	$ 98,763	$ 245,641	$ 54,947	$ 174,133	$ 7,555,677	$ 84,846
		Tax Adjustments														
44		Interest Expense	1.1	38,754,465	4,601,611	23,620,190	479,539	228,580	1,382,123	28,219	38,498	30,543	4,363	67,877	1,432,161	6,738
45		State South Georgia	1.1	77,020	9,145	46,942	953	454	2,747	56	77	61	9	135	2,846	13
46		Investment Tax Credit	1.1	(528,352)	(62,735)	(322,022)	(6,538)	(3,116)	(18,843)	(385)	(525)	(416)	(59)	(925)	(19,525)	(92)
47		Federal South Georgia	1.1	288,233	34,224	175,673	3,567	1,700	10,279	210	286	227	32	505	10,652	50

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Summary of Allocated Cost of Service														
		Rate Base														
1		Direct Net Plant		$ 1,051,372,747	$ 124,837,442	$ 640,793,889	$ 13,009,452	$ 6,201,175	$ 37,495,712	$ 765,543	$ 1,044,402	$ 828,601	$ 118,378	$ 1,841,433	$ 38,853,194	$ 182,794
2		Systems Allocable Net Plant		40,304,506	4,785,659	24,564,914	498,719	237,723	1,437,403	29,347	40,037	31,765	4,538	70,592	1,489,442	7,007
3		Cash Working Capital	1.1	(11,082,156)	(558,222)	(7,108,793)	(392,055)	(27,729)	(516,528)	(23,070)	(4,670)	(15,310)	(3,567)	(8,234)	(442,306)	(5,509)
4		Materials & Supplies	1.1	9,222,489	1,095,056	5,620,951	114,117	54,396	328,907	6,715	9,161	7,268	1,038	16,153	340,815	1,603
5		Prepayments	1.1	2,740,815	325,438	1,670,480	33,914	16,166	97,747	1,996	2,723	2,160	309	4,800	101,286	477
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	(23,912,141)	-	(21,263,793)	-	-	(1,726,035)	-	-	(5,284)	-	-	(461,380)	-
8		Customer Advances	8.0	(7,027,372)	-	(6,249,068)	-	-	(507,252)	-	-	(1,553)	-	-	(135,592)	-
9		Deferred Taxes	1.1	(136,691,328)	(16,230,396)	(83,311,050)	(1,691,388)	(806,229)	(4,874,902)	(99,530)	(135,785)	(107,728)	(15,391)	(239,409)	(5,051,391)	(23,765)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$ 924,927,560	$ 114,254,977	$ 554,717,531	$ 11,572,759	$ 5,675,502	$ 31,735,052	$ 681,000	$ 955,868	$ 739,919	$ 105,305	$ 1,685,334	$ 34,694,068	$ 162,607
12		Net Operating Margin	Direct	$ 352,069,751	$ 123,877,754	$ 72,702,524	$ -	$ 7,548,076	$ 5,876,225	$ -	$ 770,456	$ 113,400	$ -	$ 1,439,375	$ 3,975,660	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 7,611,429	$ 3,090,716	$ 1,813,908	$ -	$ 188,322	$ 146,610	$ -	$ 19,223	$ 2,829	$ -	$ 35,912	$ 99,192	$ -
14		Late Charges	Direct	$ 1,386,957	$ 563,191	$ 330,531	$ -	$ 34,316	$ 26,715	$ -	$ 3,503	$ 516	$ -	$ 6,544	$ 18,075	$ -
15		Service Establishment Charges	Direct	$ 6,950,610	$ 2,822,382	$ 1,656,426	$ -	$ 171,972	$ 133,882	$ -	$ 17,554	$ 2,584	$ -	$ 32,794	$ 90,580	$ -
16		Reconnect / Reread Charges	Direct	$ 547,658	$ 222,383	$ 130,514	$ -	$ 13,550	$ 10,549	$ -	$ 1,383	$ 204	$ -	$ 2,584	$ 7,137	$ -
17		Other Revenue - Labor	Direct	$ 1,705	$ 693	$ 406	$ -	$ 42	$ 33	$ -	$ 4	$ 1	$ -	$ 8	$ 22	$ -
18		Other Revenue - Parts & Material	Direct	$ 5,764	$ 2,341	$ 1,374	$ -	$ 143	$ 111	$ -	$ 15	$ 2	$ -	$ 27	$ 75	$ -
19		Other Revenue - Field Collection Fee	Direct	$ 388,540	$ 157,772	$ 92,594	$ -	$ 9,613	$ 7,484	$ -	$ 981	$ 144	$ -	$ 1,833	$ 5,063	$ -
20		Other Revenue - Returned Item Fee	Direct	$ 135,450	$ 55,001	$ 32,280	$ -	$ 3,351	$ 2,609	$ -	$ 342	$ 50	$ -	$ 639	$ 1,765	$ -
21		Other Revenue - Rental Income	Direct	$ 767,198	$ 311,530	$ 182,834	$ -	$ 18,982	$ 14,778	$ -	$ 1,938	$ 285	$ -	$ 3,620	$ 9,998	$ -
22		Total Revenue		369,865,063	131,103,763	76,943,391	-	7,988,369	6,218,996	-	815,398	120,015	-	1,523,336	4,207,567	-
23		O & M		(111,325,072)	(5,607,581)	(71,410,917)	(3,938,358)	(278,551)	(5,188,749)	(231,753)	(46,914)	(153,798)	(35,837)	(82,715)	(4,443,152)	(55,337)
24		A & G	Total O&M	(48,271,016)	(2,431,470)	(30,964,072)	(1,707,689)	(120,781)	(2,249,863)	(100,489)	(20,342)	(66,688)	(15,539)	(35,866)	(1,926,569)	(23,994)
25		Depreciation Expense		(74,644,007)	(8,863,048)	(45,494,258)	(923,628)	(440,263)	(2,662,072)	(54,351)	(74,149)	(58,828)	(8,404)	(130,736)	(2,758,449)	(12,978)
26		Interest on Customer Deposits	8.0	(717,364)	-	(637,914)	-	-	(51,781)	-	-	(159)	-	-	(13,841)	-
27		Taxes other than Income	1.1	(31,717,579)	(3,766,068)	(19,331,327)	(392,466)	(187,076)	(1,131,162)	(23,095)	(31,507)	(24,997)	(3,571)	(55,552)	(1,172,114)	(5,514)
		State Income Tax														
28		Taxable Income before Interest Exp.		$ 103,190,025	$ 110,435,595	$(90,895,097)	$(6,962,142)	$ 6,961,698	$(5,064,633)	$(409,688)	$ 642,486	$(184,454)	$(63,351)	$ 1,218,468	$(6,106,559)	$(97,824)
29		Interest Expense	1.1	(38,754,465)	(4,601,611)	(23,620,190)	(479,539)	(228,580)	(1,382,123)	(28,219)	(38,498)	(30,543)	(4,363)	(67,877)	(1,432,161)	(6,738)
30		State Taxable Income		$ 64,435,560	$ 105,833,984	$(114,515,287)	$(7,441,681)	$ 6,733,118	$(6,446,755)	$(437,906)	$ 603,989	$(214,997)	$(67,715)	$ 1,150,591	$(7,538,720)	$(104,562)
31		State Income Tax		4,489,870	7,374,512	(7,979,425)	(518,536)	469,164	(449,210)	(30,513)	42,086	(14,981)	(4,718)	80,173	(525,298)	(7,286)
32		South Georgia	1.1	77,020	9,145	46,942	953	454	2,747	56	77	61	9	135	2,846	13
33		State Income Tax		4,566,890	7,383,657	(7,932,483)	(517,583)	469,618	(446,463)	(30,457)	42,162	(14,920)	(4,710)	80,308	(522,452)	(7,272)
		Federal Income Tax														
34		Taxable Income before Interest Exp.		103,190,025	110,435,595	(90,895,097)	(6,962,142)	6,961,698	(5,064,633)	(409,688)	642,486	(184,454)	(63,351)	1,218,468	(6,106,559)	(97,824)
35		Interest Expense	1.1	(38,754,465)	(4,601,611)	(23,620,190)	(479,539)	(228,580)	(1,382,123)	(28,219)	(38,498)	(30,543)	(4,363)	(67,877)	(1,432,161)	(6,738)
36		Federal Taxable Income		64,435,560	105,833,984	(114,515,287)	(7,441,681)	6,733,118	(6,446,755)	(437,906)	603,989	(214,997)	(67,715)	1,150,591	(7,538,720)	(104,562)
37		Federal Income Tax		$ 20,980,992	$ 34,460,815	$(37,287,552)	$(2,423,101)	$ 2,192,384	$(2,099,141)	$(142,588)	$ 196,666	$(70,006)	$(22,049)	$ 374,646	$(2,454,698)	$(34,047)
38		I T C	1.1	(528,352)	(62,735)	(322,022)	(6,538)	(3,116)	(18,843)	(385)	(525)	(416)	(59)	(925)	(19,525)	(92)
39		South Georgia	1.1	288,233	34,224	175,673	3,567	1,700	10,279	210	286	227	32	505	10,652	50
40		Total Federal Income Tax		$ 20,740,873	$ 34,432,304	$(37,433,900)	$(2,426,072)	$ 2,190,968	$(2,107,704)	$(142,762)	$ 196,427	$(70,195)	$(22,076)	$ 374,226	$(2,463,571)	$(34,088)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Net Income		$ 77,882,263	$ 68,619,634	$(45,528,714)	$(4,018,487)	$ 4,301,113	$(2,510,465)	$(236,468)	$ 403,896	$(99,339)	$(36,566)	$ 763,934	$(3,120,536)	$(56,463)
43		Rate of Return on Rate Base		8.42%	60.06%	(8.21%)	(34.72%)	75.78%	(7.91%)	(34.72%)	42.25%	(13.43%)	(34.72%)	45.33%	(8.99%)	(34.72%)
44		Rate of Return by Class Total				2.80%			4.08%			14.88%			(6.60%)	

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Net Plant in Service - Direct										
		Intangible										
1	301	Organization	1.1	$ 595	$ 1,584	$ 84	$ 2,121	$ 1,145	$ 278	$ 793	$ 143	$ 168
2	302	Franchise & Consent	1.1	16,536	44,020	2,341	58,939	31,822	7,726	22,038	3,965	4,668
3	303	Misc. Intangible	1.1	3,881	10,332	550	13,834	7,469	1,813	5,173	931	1,096
4		Total Intangible		$ 21,012	$ 55,936	$ 2,975	$ 74,894	$ 40,436	$ 9,818	$ 28,004	$ 5,038	$ 5,932
5		Allocation Percentage	Intang. Plant	1.40%	3.71%	0.20%	4.97%	2.69%	0.65%	1.86%	0.33%	0.39%
		Production										
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission										
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-
16	367	*Mains - Demand*	1.0	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution										
26	374	Land & Land Rights	1.0	$ 22,868	$ -	$ -	$ 81,506	$ -	$ -	$ 30,476	$ -	$ -
27	374	Rights of Way	1.0	28,999	-	-	103,360	-	-	38,648	-	-
28	375	Structures	1.0	3,100	-	-	11,051	-	-	4,132	-	-
29	376	Mains - Demand	1.0	13,554,761	-	-	48,312,628	-	-	18,064,891	-	-
30	376	Mains - Customer	5.0	-	5,810,706	-	-	2,492,628	-	-	60,962	-
31	376	Mains - Commodity	3.0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	-	-	1,646,541	-	-	5,433,608	-	-	3,283,214
33	380	Services - Demand	1.0	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	-	23,028,521	-	-	11,352,122	-	-	935,661	-
35	381	Meters	6.0	-	7,383,848	-	-	12,340,615	-	-	2,265,918	-
36	385	Industrial Meas. & Reg. Sta.	3.0	-	-	280,018	-	-	924,063	-	-	558,358
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(2,565)	-	-	(9,144)	-	-	(3,419)	-	-
39		Total Distribution		$ 13,607,163	$ 36,223,075	$ 1,926,560	$ 48,499,401	$ 26,185,365	$ 6,357,672	$ 18,134,728	$ 3,262,541	$ 3,841,572
40		Allocation Percentage	Dist. Plant	1.40%	3.71%	0.20%	4.97%	2.69%	0.65%	1.86%	0.33%	0.39%
41	389-398	Total General Plant	1.1	$ 1,041,228	$ 2,771,811	$ 147,421	$ 3,711,203	$ 2,003,720	$ 486,493	$ 1,387,680	$ 249,652	$ 293,959
42		Total Net Plant-Direct		$ 14,669,403	$ 39,050,822	$ 2,076,956	$ 52,285,498	$ 28,229,521	$ 6,853,982	$ 19,550,413	$ 3,517,231	$ 4,141,464
		Systems Allocable Plant										
43	301-303	Intangible Plant	1.1	$ 364,386	$ 970,018	$ 51,591	$ 1,298,766	$ 701,218	$ 170,252	$ 485,630	$ 87,368	$ 102,873
44	389-398	General Plant	1.1	$ 197,967	$ 527,000	$ 28,029	$ 705,605	$ 380,964	$ 92,496	$ 263,838	$ 47,466	$ 55,890
45		Total Systems Allocable		562,353	1,497,018	79,620	2,004,371	1,082,182	262,748	749,468	134,833	158,764
46		Total Net Plant		$ 15,231,757	$ 40,547,840	$ 2,156,576	$ 54,289,869	$ 29,311,703	$ 7,116,730	$ 20,299,880	$ 3,652,064	$ 4,300,227

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service			Large General Gas Service			Transportation Eligible Service		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Other Rate Base Items										
1		Cash Working Capital	11.2	(65,596)	(483,501)	(62,591)	(233,799)	(440,547)	(206,553)	(87,421)	(57,050)	(124,808)
2		Materials & Supplies	1.1	128,678	342,548	18,219	458,641	247,625	60,122	171,493	30,853	36,328
3		Prepayments	1.1	38,242	101,801	5,414	136,303	73,591	17,868	50,966	9,169	10,796
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	-	(455,649)	-	-	-	-	-	-	-
6		Customer Advances	8.0	-	(133,908)	-	-	-	-	-	-	-
7		Deferred Taxes	1.1	(1,907,202)	(5,077,085)	(270,030)	(6,797,755)	(3,670,183)	(891,102)	(2,541,793)	(457,283)	(538,441)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		13,425,878	34,842,047	1,847,588	47,853,259	25,522,189	6,097,066	17,893,125	3,177,753	3,684,103

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service			Large General Gas Service			Transportation Eligible Service		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Direct Depreciation Expense										
1	301-303	Intangible	Intang. Plant	$ 2,930	$ 7,800	$ 415	$ 10,443	$ 5,638	$ 1,369	$ 3,905	$ 702	$ 827
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 870,098	$ 2,316,253	$ 123,192	$ 3,101,253	$ 1,674,401	$ 406,536	$ 1,159,610	$ 208,620	$ 245,646
5	389-398	General	1.1	$ 67,265	$ 179,063	$ 9,524	$ 239,748	$ 129,443	$ 31,428	$ 89,646	$ 16,128	$ 18,990
6		Total Direct Dep. Exp.		$ 940,293	$ 2,503,116	$ 133,131	$ 3,351,444	$ 1,809,482	$ 439,333	$ 1,253,160	$ 225,451	$ 265,463
		Systems Allocable Depreciation Expense										
7	301-303	Intangible	Intang. Plant	$ 64,093	$ 170,620	$ 9,075	$ 228,445	$ 123,340	$ 29,946	$ 85,419	$ 15,367	$ 18,095
8	389-398	General	1.1	$ 33,123	$ 88,176	$ 4,690	$ 118,060	$ 63,742	$ 15,476	$ 44,145	$ 7,942	$ 9,351
		System Allocable Amortization										
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		97,217	258,796	13,764	346,505	187,082	45,422	129,564	23,309	27,446
13		Total Depreciation Expense		1,037,509	2,761,912	146,895	3,697,949	1,996,563	484,755	1,382,724	248,760	292,910
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(739)	(1,968)	(105)	(2,636)	(1,423)	(345)	(985)	(177)	(209)
16		Amortization of PBOP Costs	1.1	4,709	12,537	667	16,785	9,063	2,200	6,276	1,129	1,330
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	0	0	0	0	0	0	0	0	0
19		Amortization of SOX Implementation	1.1	0	0	0	0	0	0	0	0	0
20		Total Depreciation & Amortization Expense		$ 1,041,479	$ 2,772,480	$ 147,457	$ 3,712,098	$ 2,004,203	$ 486,610	$ 1,388,015	$ 249,712	$ 294,030

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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Operation and Maintenance Expense										
		Gas Supply Expense										
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch.	3.0	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--(Cr	3.0	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	-	-	47,972	-	-	158,308	-	-	95,657
7		Materials & Expenses	3.0	-	-	4,063	-	-	13,409	-	-	8,102
8		Total Gas Supply Expense		$ -	$ -	$ 52,035	$ -	$ -	$ 171,717	$ -	$ -	$ 103,759
		Transmission Expenses										
9	850	Operation Supervision & Engin.										
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch										
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.										
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
18	853	Compressor Station										
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-
22	856	Mains Expense										
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.										
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.										
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains										
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.										
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.										
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Distribution Expenses										
1	870	Operation Supervision & Eng.										
2		Labor & Labor Loading	5.5	$ 41,861	$ 313,996	$ 63,604	$ 149,204	$ 418,684	$ 209,893	$ 55,790	$ 72,104	$ 126,826
3		Materials & Expenses	5.5	6,595	49,467	10,020	23,506	65,960	33,067	8,789	11,359	19,980
4	871	Distribution Load Dispatching										
5		Labor & Labor Loading	3.0	-	-	37,323	-	-	123,166	-	-	74,422
6		Materials & Expenses	3.0	-	-	9,158	-	-	30,222	-	-	18,261
7	874	Mains & Svcs. Expense										
8		Labor & Labor Loading	4.4	85,709	182,355	0	305,488	87,543	0	114,227	6,302	0
9		Materials & Expenses	4.4	72,482	154,214	0	258,345	74,033	0	96,599	5,329	0
10	875	Meas. & Reg. Sta. Exp.-Gen.										
11		Labor & Labor Loading	3.0	-	-	138,627	-	-	457,470	-	-	276,423
12		Materials & Expenses	3.0	-	-	55,246	-	-	182,312	-	-	110,160
13	878	Meter & House Reg. Exp.										
14		Labor & Labor Loading	6.0	-	337,987	-	-	564,877	-	-	103,720	-
15		Materials & Expenses	6.0	-	51,353	-	-	85,826	-	-	15,759	-
16	879	Customer Installation Exp.										
17		Labor & Labor Loading	6.0	-	399,444	-	-	667,591	-	-	122,579	-
18		Materials & Expenses	6.0	-	61,216	-	-	102,309	-	-	18,786	-
19	880	Other Expenses										
20		Labor & Labor Loading	5.5	36,026	270,229	54,738	128,407	360,325	180,637	48,014	62,053	109,148
21		Materials & Expenses	5.5	24,560	184,219	37,316	87,537	245,638	123,142	32,732	42,303	74,408
22	881	Rents	5.5	11,410	85,587	17,337	40,669	114,123	57,211	15,207	19,654	34,570
23		Total Distribution-Operations		$ 278,644	$ 2,090,065	$ 423,368	$ 993,157	$ 2,786,908	$ 1,397,120	$ 371,358	$ 479,947	$ 844,199
		Operation and Maintenance Expense										
		Distribution Expenses										
24	885	Maint. Supervision & Eng.										
25		Labor & Labor Loading	6.6	$ 32,271	$ 82,677	$ 13,013	$ 115,021	$ 52,446	$ 42,944	$ 43,008	$ 5,786	$ 25,949
26		Materials & Expenses	6.6	3,487	8,934	1,406	12,429	5,667	4,640	4,647	625	2,804
27	886	Maint. of Structures & Imp.										
28		Labor & Labor Loading	1.0	884	-	-	3,151	-	-	1,178	-	-
29		Materials & Expenses	1.0	3,297	-	-	11,752	-	-	4,394	-	-
30	887	Maint. of Mains										
31		Labor & Labor Loading	2.2	195,754	83,917	0	697,719	35,998	0	260,889	880	0
32		Materials & Expenses	2.2	141,949	60,851	0	505,943	26,103	0	189,181	638	0
33	889	Maint. of Meas. & Reg. Sta-Gen										
34		Labor & Labor Loading	3.0	-	-	78,919	-	-	260,433	-	-	157,364
35		Materials & Expenses	3.0	-	-	58,948	-	-	194,529	-	-	117,543
36	892	Maint. of Services										
37		Labor & Labor Loading	3.3	0	398,661	-	0	196,524	-	0	16,198	-
38		Materials & Expenses	3.3	0	219,524	-	0	108,217	-	0	8,919	-
39	893	Maint of Meter & House Reg.										
40		Labor & Labor Loading	6.0	-	65,696	-	-	109,798	-	-	20,161	-
41		Materials & Expenses	6.0	-	47,261	-	-	78,987	-	-	14,503	-
42	894	Maint of Other Equip.										
43		Labor & Labor Loading	6.6	2,044	5,236	824	7,284	3,321	2,720	2,724	366	1,643
44		Materials & Expenses	6.6	606	1,553	244	2,161	985	807	808	109	487
45		Total Distribution-Maintenance		$ 380,292	$ 974,311	$ 153,355	$ 1,355,459	$ 618,046	$ 506,073	$ 506,828	$ 68,186	$ 305,791
46		Total Distribution O & M		$ 658,936	$ 3,064,376	$ 576,723	$ 2,348,616	$ 3,404,954	$ 1,903,193	$ 878,186	$ 548,133	$ 1,149,989

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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Customer Accounts Expenses										
1	901	Supervision										
2		Labor & Labor Loading	10.1	$ -	$ 184,772	$ -	$ -	$ 105,183	$ -	$ -	$ 2,572	$ -
3		Materials & Expenses	10.1	-	11,358	-	-	6,466	-	-	158	-
4	902	Meter Reading Exp.										
5		*Labor & Labor Loading*	13.0	-	274,561	-	-	157,043	-	-	3,841	-
6		Materials & Expenses	13.0	-	69,252	-	-	39,611	-	-	969	-
7	903	Customer Records & Collections										
8		Labor & Labor Loading	13.0	-	757,200	-	-	433,102	-	-	10,592	-
9		Materials & Expenses	13.0	-	355,596	-	-	203,393	-	-	4,974	-
10	903	Customer Records & Collections - LCS										
11		Labor & Labor Loading - LCS	13.0	-	58,018	-	-	33,185	-	-	812	-
12		Materials & Expenses - LCS	13.0	-	2,581	-	-	1,476	-	-	36	-
13	904	Uncollectible Accounts Exp.	4.0	-	29,442	-	-	12,630	-	-	309	-
14	905	Misc. Customer Accounts Exp.										
15		Labor & Labor Loading	10.1	-	19,274	-	-	10,972	-	-	268	-
16		Materials & Expenses	10.1	-	1,103	-	-	628	-	-	15	-
17		Total Customer Accounts Expenses		$ -	$ 1,763,158	$ -	$ -	$ 1,003,687	$ -	$ -	$ 24,547	$ -
		Customer Service & Info. Exp.										
18	908	Customer Assistance Exp.										
19		Labor & Labor Loading	13.0	$ -	$ 14,740	$ -	$ -	$ 8,431	$ -	$ -	$ 206	$ -
20		Materials & Expenses	13.0	-	13,382	-	-	7,654	-	-	187	-
21	909	Info. & Instructional Exp.										
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense										
25		Labor & Labor Loading	13.0	-	41	-	-	24	-	-	1	-
26		Materials & Expenses	13.0	-	1,284	-	-	734	-	-	18	-
27		Total Customer Service & Info. Exp.		$ -	$ 29,446	$ -	$ -	$ 16,843	$ -	$ -	$ 412	$ -
		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		$ 658,936	$ 4,856,980	$ 628,758	$ 2,348,616	$ 4,425,484	$ 2,074,910	$ 878,186	$ 573,092	$ 1,253,748
39		Allocation Percentage	Total O&M	0.59%	4.36%	0.56%	2.11%	3.98%	1.86%	0.79%	0.51%	1.13%
		Other Operating Deductions										
40		Administrative & General Expense	Total O&M	285,717	2,106,007	272,632	1,018,370	1,918,908	899,690	380,765	248,495	543,630
41		*Interest on Customer Deposits*	8.0	-	13,669	-	-	-	-	-	-	-
42		Taxes Other Than Income	1.1	442,543	1,178,076	62,657	1,577,337	851,622	206,769	589,792	106,107	124,939
43		Total Allocated Operating Deductions		$ 1,387,196	$ 8,154,733	$ 964,047	$ 4,944,322	$ 7,196,014	$ 3,181,369	$ 1,848,764	$ 927,694	$ 1,922,317
		Tax Adjustments										
44		Interest Expense	1.1	540,726	1,439,445	76,558	1,927,287	1,040,563	252,643	720,644	129,648	152,658
45		State South Georgia	1.1	1,075	2,861	152	3,830	2,068	502	1,432	258	303
46		Investment Tax Credit	1.1	(7,372)	(19,624)	(1,044)	(26,275)	(14,186)	(3,444)	(9,825)	(1,768)	(2,081)
47		Federal South Georgia	1.1	4,022	10,706	569	14,334	7,739	1,879	5,360	964	1,135

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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Summary of Allocated Cost of Service										
		Rate Base										
1		Direct Net Plant		$ 14,669,403	$ 39,050,822	$ 2,076,956	$ 52,285,498	$ 28,229,521	$ 6,853,982	$ 19,550,413	$ 3,517,231	$ 4,141,464
2		Systems Allocable Net Plant		562,353	1,497,018	79,620	2,004,371	1,082,182	262,748	749,468	134,833	158,764
3		Cash Working Capital	1.1	(65,596)	(483,501)	(62,591)	(233,799)	(440,547)	(206,553)	(87,421)	(57,050)	(124,808)
4		Materials & Supplies	1.1	128,678	342,548	18,219	458,641	247,625	60,122	171,493	30,853	36,328
5		Prepayments	1.1	38,242	101,801	5,414	136,303	73,591	17,868	50,966	9,169	10,796
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	-	(455,649)	-	-	-	-	-	-	-
8		Customer Advances	8.0	-	(133,908)	-	-	-	-	-	-	-
9		Deferred Taxes	1.1	(1,907,202)	(5,077,085)	(270,030)	(6,797,755)	(3,670,183)	(891,102)	(2,541,793)	(457,283)	(538,441)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$ 13,425,878	$ 34,842,047	$ 1,847,588	$ 47,853,259	$ 25,522,189	$ 6,097,066	$ 17,893,125	$ 3,177,753	$ 3,684,103
12		Net Operating Margin	Direct	$ 16,136,803	$ 4,213,440	$ -	$ 38,942,928	$ 7,300,460	$ -	$ 14,970,291	$ 885,300	$ -
13		*Special Contract & Optional Margin*	Net Op. Marg.	$ 402,609	$ 105,124	$ -	$ 971,615	$ 182,144	$ -	$ 373,505	$ 22,088	$ -
14		Late Charges	Direct	$ 73,364	$ 19,156	$ -	$ 177,048	$ 33,190	$ -	$ 68,060	$ 4,025	$ -
15		Service Establishment Charges	Direct	$ 367,655	$ 95,997	$ -	$ 887,260	$ 166,331	$ -	$ 341,077	$ 20,170	$ -
16		Reconnect / Reread Charges	Direct	$ 28,969	$ 7,564	$ -	$ 69,910	$ 13,106	$ -	$ 26,874	$ 1,589	$ -
17		Other Revenue - Labor	Direct	$ 90	$ 24	$ -	$ 218	$ 41	$ -	$ 84	$ 5	$ -
18		Other Revenue - Parts & Material	Direct	$ 305	$ 80	$ -	$ 736	$ 138	$ -	$ 283	$ 17	$ -
19		Other Revenue - Field Collection Fee	Direct	$ 20,552	$ 5,366	$ -	$ 49,598	$ 9,298	$ -	$ 19,066	$ 1,128	$ -
20		Other Revenue - Returned Item Fee	Direct	$ 7,165	$ 1,871	$ -	$ 17,290	$ 3,241	$ -	$ 6,647	$ 393	$ -
21		Other Revenue - Rental Income	Direct	$ 40,581	$ 10,596	$ -	$ 97,934	$ 18,359	$ -	$ 37,648	$ 2,226	$ -
22		Total Revenue		17,078,091	4,459,217	-	41,214,538	7,726,309	-	15,843,535	936,941	-
23		O & M		(658,936)	(4,856,980)	(628,758)	(2,348,616)	(4,425,484)	(2,074,910)	(878,186)	(573,092)	(1,253,748)
24		A & G	Total O&M	(285,717)	(2,106,007)	(272,632)	(1,018,370)	(1,918,908)	(899,690)	(380,785)	(248,495)	(543,630)
25		Depreciation Expense		(1,041,479)	(2,772,480)	(147,457)	(3,712,098)	(2,004,203)	(486,610)	(1,388,015)	(249,712)	(294,030)
26		Interest on Customer Deposits	8.0	-	(13,669)	-	-	-	-	-	-	-
27		Taxes other than Income	1.1	(442,543)	(1,178,076)	(62,657)	(1,577,337)	(851,622)	(206,769)	(589,792)	(106,107)	(124,939)
		State Income Tax										
28		Taxable Income before Interest Exp.		$ 14,649,415	$(6,467,995)	$(1,111,504)	$ 32,558,117	$(1,473,909)	$(3,667,979)	$ 12,606,756	$(240,465)	$(2,216,347)
29		Interest Expense	1.1	(540,726)	(1,439,445)	(76,558)	(1,927,287)	(1,040,563)	(252,643)	(720,644)	(129,648)	(152,658)
30		State Taxable Income		$ 14,108,689	$(7,907,441)	$(1,188,063)	$ 30,630,831	$(2,514,472)	$(3,920,622)	$ 11,886,111	$(370,113)	$(2,369,005)
31		State Income Tax		983,093	(550,990)	(82,784)	2,134,356	(175,208)	(273,189)	828,224	(25,789)	(165,072)
32		South Georgia	1.1	1,075	2,861	152	3,830	2,068	502	1,432	258	303
33		State Income Tax		984,168	(548,130)	(82,632)	2,138,187	(173,140)	(272,687)	829,656	(25,532)	(164,769)
		Federal Income Tax										
34		Taxable Income before Interest Exp.		14,649,415	(6,467,995)	(1,111,504)	32,558,117	(1,473,909)	(3,667,979)	12,606,756	(240,465)	(2,216,347)
35		Interest Expense	1.1	(540,726)	(1,439,445)	(76,558)	(1,927,287)	(1,040,563)	(252,643)	(720,644)	(129,648)	(152,658)
36		Federal Taxable Income		14,108,689	(7,907,441)	(1,188,063)	30,630,831	(2,514,472)	(3,920,622)	11,886,111	(370,113)	(2,369,005)
37		Federal Income Tax		$ 4,593,958	$(2,574,758)	$(386,847)	$ 9,973,766	$(818,742)	$(1,276,602)	$ 3,870,260	$(120,513)	$(771,376)
38		I T C	1.1	(7,372)	(19,624)	(1,044)	(26,275)	(14,186)	(3,444)	(9,825)	(1,768)	(2,081)
39		*South Georgia*	1.1	4,022	10,706	569	14,334	7,739	1,879	5,360	964	1,135
40		Total Federal Income Tax		$ 4,590,608	$(2,583,676)	$(387,322)	$ 9,961,825	$(825,189)	$(1,278,167)	$ 3,865,795	$(121,316)	$(772,322)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-
42		Net Income		$ 9,074,639	$(3,336,189)	$(641,550)	$ 20,458,106	$(475,579)	$(2,117,125)	$ 7,911,304	$(93,616)	$(1,279,256)
43		Rate of Return on Rate Base		67.59%	(9.58%)	(34.72%)	42.75%	(1.86%)	(34.72%)	44.21%	(2.95%)	(34.72%)
44		Rate of Return by Class Total			10.17%			22.48%			26.41%	

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
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Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Net Plant in Service - Direct													
		Intangible													
1	301	Organization	1.1	$ 6	$ 8	$ 4	$ 1	$ 1	$ 0	$ 11	$ 20	$ 4	$ 1	$ 3	$ 0
2	302	Franchise & Consent	1.1	154	229	100	33	21	10	309	545	103	15	81	4
3	303	Misc. Intangible	1.1	36	54	23	8	5	2	73	128	24	4	19	1
4		Total Intangible		$ 196	$ 291	$ 127	$ 42	$ 27	$ 13	$ 393	$ 692	$ 131	$ 19	$ 103	$ 6
5		Allocation Percentage	Intang. Plant	0.01%	0.02%	0.01%	0.00%	0.00%	0.00%	0.03%	0.05%	0.01%	0.00%	0.01%	0.00%
		Production													
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission													
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-	-	-	-
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution													
26	374	Land & Land Rights	1.0	$ 213	$ -	$ -	$ 46	$ -	$ -	$ 428	$ -	$ -	$ 21	$ -	$ -
27	374	Rights of Way	1.0	271	-	-	58	-	-	542	-	-	27	-	-
28	375	Structures	1.0	29	-	-	6	-	-	58	-	-	3	-	-
29	376	Mains - Demand	1.0	126,518	-	-	27,295	-	-	253,522	-	-	12,468	-	-
30	376	Mains - Customer	5.0	-	13,339	-	-	7,843	-	-	9,626	-	-	39,215	-
31	376	Mains - Commodity	3.0	-	-	0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	-	-	70,276	-	-	6,976	-	-	72,658	-	-	3,050
33	380	Services - Demand	1.0	0	-	-	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	-	166,779	-	-	7,273	-	-	174,727	-	-	16,202	-
35	381	Meters	6.0	-	8,304	-	-	2,377	-	-	263,826	-	-	11,225	-
36	385	Industrial Meas. & Reg. Sta.	3.0	-	-	11,951	-	-	1,186	-	-	12,357	-	-	519
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(24)	-	-	(5)	-	-	(48)	-	-	(2)	-	-
39		Total Distribution		$ 127,007	$ 188,422	$ 82,227	$ 27,400	$ 17,493	$ 8,163	$ 254,502	$ 448,179	$ 85,015	$ 12,516	$ 66,642	$ 3,569
40		*Allocation Percentage*	*Dist. Plant*	0.01%	0.02%	0.01%	0.00%	0.00%	0.00%	0.03%	0.05%	0.01%	0.00%	0.01%	0.00%
41	389-398	Total General Plant	1.1	$ 9,719	$ 14,418	$ 6,292	$ 2,097	$ 1,339	$ 625	$ 19,475	$ 34,295	$ 6,505	$ 958	$ 5,100	$ 273
42		Total Net Plant-Direct		$ 136,922	$ 203,131	$ 88,646	$ 29,539	$ 18,859	$ 8,800	$ 274,369	$ 483,166	$ 91,652	$ 13,493	$ 71,845	$ 3,848
		Systems Allocable Plant													
43	301-303	Intangible Plant	1.1	$ 3,401	$ 5,046	$ 2,202	$ 734	$ 468	$ 219	$ 6,815	$ 12,002	$ 2,277	$ 335	$ 1,785	$ 96
44	389-398	General Plant	1.1	$ 1,848	$ 2,741	$ 1,196	$ 399	$ 255	$ 119	$ 3,703	$ 6,520	$ 1,237	$ 182	$ 970	$ 52
45		Total Systems Allocable		5,249	7,787	3,398	1,132	723	337	10,518	18,522	3,513	517	2,754	148
46		Total Net Plant		$ 142,171	$ 210,918	$ 92,045	$ 30,672	$ 19,582	$ 9,137	$ 284,887	$ 501,688	$ 95,165	$ 14,011	$ 74,599	$ 3,995

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service			CNG - Small			CNG - Large			CNG - Residential		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Other Rate Base Items													
1		Cash Working Capital	11.2	(612)	(1,907)	(2,671)	(132)	(367)	(265)	(1,227)	(7,088)	(2,762)	(60)	(913)	(116)
2		Materials & Supplies	1.1	1,201	1,782	778	259	165	77	2,407	4,238	804	118	630	34
3		Prepayments	1.1	357	530	231	77	49	23	715	1,260	239	35	187	10
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
7		Deferred Taxes	1.1	(17,802)	(26,410)	(11,525)	(3,840)	(2,452)	(1,144)	(35,671)	(62,816)	(11,916)	(1,754)	(9,341)	(500)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		125,315	184,913	78,857	27,035	16,977	7,828	251,111	437,281	81,530	12,350	65,163	3,423

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Direct Depreciation Expense													
1	301-303	Intangible	Intang. Plant	$ 27	$ 41	$ 18	$ 6	$ 4	$ 2	$ 55	$ 97	$ 18	$ 3	$ 14	$ 1
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 8,121	$ 12,048	$ 5,258	$ 1,752	$ 1,119	$ 522	$ 16,274	$ 28,658	$ 5,436	$ 800	$ 4,261	$ 228
5	389-398	General	1.1	$ 628	$ 931	$ 406	$ 135	$ 86	$ 40	$ 1,258	$ 2,215	$ 420	$ 62	$ 329	$ 18
6		Total Direct Dep. Exp.		$ 8,777	$ 13,020	$ 5,682	$ 1,893	$ 1,209	$ 564	$ 17,587	$ 30,970	$ 5,875	$ 865	$ 4,605	$ 247
		Systems Allocable Depreciation Expense													
7	301-303	Intangible	Intang. Plant	$ 598	$ 888	$ 387	$ 129	$ 82	$ 38	$ 1,199	$ 2,111	$ 400	$ 59	$ 314	$ 17
8	389-398	General	1.1	$ 309	$ 459	$ 200	$ 67	$ 43	$ 20	$ 620	$ 1,091	$ 207	$ 30	$ 162	$ 9
		System Allocable Amortization													
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		907	1,346	587	196	125	58	1,818	3,202	607	89	476	26
13		Total Depreciation Expense		9,684	14,367	6,270	2,089	1,334	622	19,405	34,172	6,482	954	5,081	272
14		*Amortization-Limited Term Gas Plant*	1.1	-	-	-	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(7)	(10)	(4)	(1)	(1)	(0)	(14)	(24)	(5)	(1)	(4)	(0)
16		Amortization of PBOP Costs	1.1	44	65	28	9	6	3	88	155	29	4	23	1
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	0	0	0	0	0	0	0	0	0	0	0	0
19		Amortization of SOX Implementation	1.1	0	0	0	0	0	0	0	0	0	0	0	0
20		Total Depreciation & Amortization Expense		$ 9,721	$ 14,422	$ 6,294	$ 2,097	$ 1,339	$ 625	$ 19,479	$ 34,303	$ 6,507	$ 958	$ 5,101	$ 273

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Operation and Maintenance Expense													
		Gas Supply Expense													
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch.	3.0	-	-	-	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--(Cr	3.0	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	-	-	2,047	-	-	203	-	-	2,117	-	-	89
7		Materials & Expenses	3.0	-	-	173	-	-	17	-	-	179	-	-	8
8		Total Gas Supply Expense		$ -	$ -	$ 2,221	$ -	$ -	$ 220	$ -	$ -	$ 2,296	$ -	$ -	$ 96
		Transmission Expenses													
9	850	Operation Supervision & Engin.													
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch													
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.													
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station													
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-	-	-	-
22	856	Mains Expense													
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.													
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.													
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-	-	-	-
33	862	*Maint. of Struct. & Imp.*	1.0	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains													
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.													
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.													
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Distribution Expenses													
1	870	Operation Supervision & Eng.													
2		Labor & Labor Loading	5.5	$ 391	$ 809	$ 2,715	$ 84	$ 119	$ 269	$ 783	$ 8,606	$ 2,807	$ 39	$ 513	$ 118
3		Materials & Expenses	5.5	62	127	428	13	19	42	123	1,356	442	6	81	19
4	871	Distribution Load Dispatching													
5		Labor & Labor Loading	3.0	-	-	1,593	-	-	158	-	-	1,647	-	-	69
6		Materials & Expenses	3.0	-	-	391	-	-	39	-	-	404	-	-	17
7	874	Mains & Svcs. Expense													
8		Labor & Labor Loading	4.4	800	1,139	0	173	96	0	1,603	1,166	0	79	350	0
9		Materials & Expenses	4.4	677	963	0	146	81	0	1,356	986	0	67	296	0
10	875	Meas. & Reg. Sta. Exp.-Gen.													
11		Labor & Labor Loading	3.0	-	-	5,917	-	-	587	-	-	6,117	-	-	257
12		Materials & Expenses	3.0	-	-	2,358	-	-	234	-	-	2,438	-	-	102
13	878	Meter & House Reg. Exp.													
14		Labor & Labor Loading	6.0	-	380	-	-	109	-	-	12,076	-	-	514	-
15		Materials & Expenses	6.0	-	58	-	-	17	-	-	1,835	-	-	78	-
16	879	Customer Installation Exp.													
17		Labor & Labor Loading	6.0	-	449	-	-	129	-	-	14,272	-	-	607	-
18		Materials & Expenses	6.0	-	69	-	-	20	-	-	2,187	-	-	93	-
19	880	Other Expenses													
20		Labor & Labor Loading	5.5	336	696	2,336	73	102	232	674	7,407	2,415	33	442	101
21		Materials & Expenses	5.5	229	475	1,593	49	70	158	459	5,049	1,647	23	301	69
22	881	Rents	5.5	107	221	740	23	32	73	213	2,346	765	10	140	32
23		Total Distribution-Operations		$ 2,601	$ 5,386	$ 18,070	$ 561	$ 793	$ 1,794	$ 5,212	$ 57,286	$ 18,682	$ 256	$ 3,415	$ 784
		Operation and Maintenance Expense													
		Distribution Expenses													
24	885	Maint. Supervision & Eng.													
25		Labor & Labor Loading	6.6	$ 301	$ 466	$ 555	$ 65	$ 40	$ 55	$ 604	$ 846	$ 574	$ 30	$ 149	$ 24
26		Materials & Expenses	6.6	33	50	60	7	4	6	65	91	62	3	16	3
27	886	Maint. of Structures & Imp.													
28		Labor & Labor Loading	1.0	8	-	-	2	-	-	17	-	-	1	-	-
29		Materials & Expenses	1.0	31	-	-	7	-	-	62	-	-	3	-	-
30	887	Maint. of Mains													
31		Labor & Labor Loading	2.2	1,827	193	0	394	113	0	3,661	139	0	180	566	0
32		Materials & Expenses	2.2	1,325	140	0	286	82	0	2,655	101	0	131	411	0
33	889	Maint. of Meas. & Reg. Sta-Gen													
34		Labor & Labor Loading	3.0	-	-	3,368	-	-	334	-	-	3,483	-	-	146
35		Materials & Expenses	3.0	-	-	2,516	-	-	250	-	-	2,601	-	-	109
36	892	Maint. of Services													
37		Labor & Labor Loading	3.3	0	2,887	-	0	126	-	0	3,025	-	0	280	-
38		Materials & Expenses	3.3	0	1,590	-	0	69	-	0	1,666	-	0	154	-
39	893	Maint of Meter & House Reg.													
40		Labor & Labor Loading	6.0	-	74	-	-	21	-	-	2,347	-	-	100	-
41		Materials & Expenses	6.0	-	53	-	-	15	-	-	1,689	-	-	72	-
42	894	Maint of Other Equip.													
43		Labor & Labor Loading	6.6	19	30	35	4	3	3	38	54	36	2	9	2
44		Materials & Expenses	6.6	6	9	10	1	1	1	11	16	11	1	3	0
45		Total Distribution-Maintenance		$ 3,550	$ 5,491	$ 6,545	$ 766	$ 475	$ 650	$ 7,113	$ 9,974	$ 6,767	$ 350	$ 1,762	$ 284
46		Total Distribution O & M		$ 6,150	$ 10,877	$ 24,615	$ 1,327	$ 1,268	$ 2,444	$ 12,324	$ 67,259	$ 25,450	$ 606	$ 5,177	$ 1,068

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Customer Accounts Expenses													
1	901	Supervision													
2		Labor & Labor Loading	10.1	$ -	$ 853	$ -	$ -	$ 249	$ -	$ -	$ 406	$ -	$ -	$ 412	$ -
3		Materials & Expenses	10.1	-	52	-	-	15	-	-	25	-	-	25	-
4	902	Meter Reading Exp.													
5		Labor & Labor Loading	13.0	-	1,280	-	-	371	-	-	606	-	-	588	-
6		Materials & Expenses	13.0	-	323	-	-	93	-	-	153	-	-	148	-
7	903	Customer Records & Collections													
8		Labor & Labor Loading	13.0	-	3,531	-	-	1,022	-	-	1,672	-	-	1,622	-
9		Materials & Expenses	13.0	-	1,658	-	-	480	-	-	785	-	-	762	-
10	903	Customer Records & Collections - LCS													
11		Labor & Labor Loading - LCS	13.0	-	271	-	-	78	-	-	128	-	-	124	-
12		Materials & Expenses - LCS	13.0	-	12	-	-	3	-	-	6	-	-	6	-
13	904	Uncollectible Accounts Exp.	4.0	-	68	-	-	40	-	-	49	-	-	199	-
14	905	Misc. Customer Accounts Exp.													
15		Labor & Labor Loading	10.1	-	89	-	-	26	-	-	42	-	-	43	-
16		Materials & Expenses	10.1	-	5	-	-	1	-	-	2	-	-	2	-
17		Total Customer Accounts Expenses		$ -	$ 8,142	$ -	$ -	$ 2,380	$ -	$ -	$ 3,876	$ -	$ -	$ 3,932	$ -
		Customer Service & Info. Exp.													
18	908	Customer Assistance Exp.													
19		Labor & Labor Loading	13.0	$ -	$ 69	$ -	$ -	$ 20	$ -	$ -	$ 33	$ -	$ -	$ 32	$ -
20		Materials & Expenses	13.0	-	62	-	-	18	-	-	30	-	-	29	-
21	909	Info. & Instructional Exp.													
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense													
25		Labor & Labor Loading	13.0	-	0	-	-	0	-	-	0	-	-	0	-
26		Materials & Expenses	13.0	-	6	-	-	2	-	-	3	-	-	3	-
27		Total Customer Service & Info. Exp.		$ -	$ 137	$ -	$ -	$ 40	$ -	$ -	$ 65	$ -	$ -	$ 63	$ -
		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		$ 6,150	$ 19,157	$ 26,836	$ 1,327	$ 3,687	$ 2,664	$ 12,324	$ 71,200	$ 27,746	$ 606	$ 9,172	$ 1,165
39		Allocation Percentage	Total O&M	0.01%	0.02%	0.02%	0.00%	0.00%	0.00%	0.01%	0.06%	0.02%	0.00%	0.01%	0.00%
		Other Operating Deductions													
40		Administrative & General Expense	Total O&M	2,667	8,306	11,636	575	1,599	1,155	5,344	30,873	12,031	263	3,977	505
41		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Taxes Other Than Income	1.1	4,131	6,128	2,674	891	569	265	8,277	14,576	2,765	407	2,167	116
43		Total Allocated Operating Deductions		$ 12,948	$ 33,591	$ 41,146	$ 2,793	$ 5,855	$ 4,085	$ 25,945	$ 116,649	$ 42,541	$ 1,276	$ 15,317	$ 1,786
		Tax Adjustments													
44		Interest Expense	1.1	5,047	7,488	3,268	1,089	695	324	10,113	17,810	3,378	497	2,648	142
45		State South Georgia	1.1	10	15	6	2	1	1	20	35	7	1	5	0
46		Investment Tax Credit	1.1	(69)	(102)	(45)	(15)	(9)	(4)	(138)	(243)	(46)	(7)	(36)	(2)
47		Federal South Georgia	1.1	38	56	24	8	5	2	75	132	25	4	20	1

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
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Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Summary of Allocated Cost of Service													
		Rate Base													
1		Direct Net Plant		$ 136,922	$ 203,131	$ 88,646	$ 29,539	$ 18,859	$ 8,800	$ 274,369	$ 483,166	$ 91,652	$ 13,493	$ 71,845	$ 3,848
2		Systems Allocable Net Plant		5,249	7,787	3,398	1,132	723	337	10,518	18,522	3,513	517	2,754	148
3		Cash Working Capital	1.1	(612)	(1,907)	(2,671)	(132)	(367)	(265)	(1,227)	(7,088)	(2,762)	(60)	(913)	(116)
4		Materials & Supplies	1.1	1,201	1,782	778	259	165	77	2,407	4,238	804	118	630	34
5		Prepayments	1.1	357	530	231	77	49	23	715	1,260	239	35	187	10
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
8		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Deferred Taxes	1.1	(17,802)	(26,410)	(11,525)	(3,840)	(2,452)	(1,144)	(35,671)	(62,818)	(11,916)	(1,754)	(9,341)	(500)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$ 125,315	$ 184,913	$ 78,857	$ 27,035	$ 16,977	$ 7,828	$ 251,111	$ 437,281	$ 81,530	$ 12,350	$ 65,163	$ 3,423
12		Net Operating Margin	Direct	$ 139,816	$ 27,400	$ -	$ 24,257	$ 5,280	$ -	$ 252,636	$ 55,080	$ -	$ 10,607	$ 10,560	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 3,488	$ 684	$ -	$ 605	$ 132	$ -	$ 6,303	$ 1,374	$ -	$ 265	$ 263	$ -
14		Late Charges	Direct	$ 636	$ 125	$ -	$ 110	$ 24	$ -	$ 1,149	$ 250	$ -	$ 48	$ 48	$ -
15		Service Establishment Charges	Direct	$ 3,186	$ 624	$ -	$ 553	$ 120	$ -	$ 5,756	$ 1,255	$ -	$ 242	$ 241	$ -
16		Reconnect / Reread Charges	Direct	$ 251	$ 49	$ -	$ 44	$ 9	$ -	$ 454	$ 99	$ -	$ 19	$ 19	$ -
17		Other Revenue - Labor	Direct	$ 1	$ 0	$ -	$ 0	$ 0	$ -	$ 1	$ 0	$ -	$ 0	$ 0	$ -
18		Other Revenue - Parts & Material	Direct	$ 3	$ 1	$ -	$ 0	$ 0	$ -	$ 5	$ 1	$ -	$ 0	$ 0	$ -
19		Other Revenue - Field Collection Fee	Direct	$ 178	$ 35	$ -	$ 31	$ 7	$ -	$ 322	$ 70	$ -	$ 14	$ 13	$ -
20		Other Revenue - Returned Item Fee	Direct	$ 62	$ 12	$ -	$ 11	$ 2	$ -	$ 112	$ 24	$ -	$ 5	$ 5	$ -
21		Other Revenue - Rental Income	Direct	$ 352	$ 69	$ -	$ 61	$ 13	$ -	$ 635	$ 139	$ -	$ 27	$ 27	$ -
22		Total Revenue		147,972	28,998	-	25,672	5,588	-	267,373	58,293	-	11,226	11,176	-
23		O & M		(6,150)	(19,157)	(26,836)	(1,327)	(3,687)	(2,664)	(12,324)	(71,200)	(27,746)	(606)	(9,172)	(1,165)
24		A & G	Total O&M	(2,667)	(8,306)	(11,636)	(575)	(1,599)	(1,155)	(5,344)	(30,873)	(12,031)	(263)	(3,977)	(505)
25		Depreciation Expense		(9,721)	(14,422)	(6,294)	(2,097)	(1,339)	(625)	(19,479)	(34,303)	(6,507)	(958)	(5,101)	(273)
26		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Taxes other than Income	1.1	(4,131)	(6,128)	(2,674)	(891)	(569)	(265)	(8,277)	(14,576)	(2,765)	(407)	(2,167)	(116)
		State Income Tax													
28		Taxable Income before Interest Exp.		$ 125,303	$(19,014)	$(47,440)	$ 20,781	$(1,606)	$(4,709)	$ 221,948	$(92,659)	$(49,048)	$ 8,992	$(9,241)	$(2,059)
29		Interest Expense	1.1	(5,047)	(7,488)	(3,268)	(1,089)	(695)	(324)	(10,113)	(17,810)	(3,378)	(497)	(2,648)	(142)
30		State Taxable Income		$ 120,256	$(26,502)	$(50,708)	$ 19,693	$(2,301)	$(5,034)	$ 211,834	$(110,469)	$(52,427)	$ 8,494	$(11,890)	$(2,201)
31		State Income Tax		8,379	(1,847)	(3,533)	1,372	(160)	(351)	14,761	(7,697)	(3,653)	592	(828)	(153)
32		South Georgia	1.1	10	15	6	2	1	1	20	35	7	1	5	0
33		State Income Tax		8,389	(1,832)	(3,527)	1,374	(159)	(350)	14,781	(7,662)	(3,646)	593	(823)	(153)
		Federal Income Tax													
34		Taxable Income before Interest Exp.		125,303	(19,014)	(47,440)	20,781	(1,606)	(4,709)	221,948	(92,659)	(49,048)	8,992	(9,241)	(2,059)
35		Interest Expense	1.1	(5,047)	(7,488)	(3,268)	(1,089)	(695)	(324)	(10,113)	(17,810)	(3,378)	(497)	(2,648)	(142)
36		Federal Taxable Income		120,256	(26,502)	(50,708)	19,693	(2,301)	(5,034)	211,834	(110,469)	(52,427)	8,494	(11,890)	(2,201)
37		Federal Income Tax		$ 39,157	$(8,629)	$(16,511)	$ 6,412	$(749)	$(1,639)	$ 68,976	$(35,970)	$(17,071)	$ 2,766	$(3,871)	$(717)
38		I T C	1.1	(69)	(102)	(45)	(15)	(9)	(4)	(138)	(243)	(46)	(7)	(36)	(2)
39		South Georgia	1.1	38	56	24	8	5	2	75	132	25	4	20	1
40		Total Federal Income Tax		$ 39,125	$(8,676)	$(16,531)	$ 6,405	$(754)	$(1,641)	$ 68,913	$(36,080)	$(17,092)	$ 2,763	$(3,888)	$(718)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-	-	-	-
42		Net Income		$ 77,788	$(8,507)	$(27,382)	$ 13,002	$(693)	$(2,718)	$ 138,254	$(48,917)	$(28,310)	$ 5,636	$(4,530)	$(1,189)
43		Rate of Return on Rate Base		62.07%	(4.60%)	(34.72%)	48.09%	(4.08%)	(34.72%)	55.06%	(11.19%)	(34.72%)	45.64%	(6.95%)	(34.72%)
44		Rate of Return by Class Total			10.77%			18.50%			7.93%			(0.10%)	

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
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Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service Demand	Electric Generation Gas Service Customer	Electric Generation Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Net Plant in Service - Direct													
		Intangible													
1	301	Organization	1.1	$ 98	$ 8	$ 29	$ 60	$ 9	$ 6	$ 33	$ 265	$ 42	$ 1	$ 1	$ 0
2	302	Franchise & Consent	1.1	2,720	236	817	1,677	256	160	903	7,354	1,157	21	25	5
3	303	Misc. Intangible	1.1	638	55	192	394	60	38	212	1,726	272	5	6	1
4		*Total Intangible*		$ 3,456	$ 299	$ 1,038	$ 2,131	$ 325	$ 204	$ 1,148	$ 9,345	$ 1,471	$ 26	$ 32	$ 7
5		Allocation Percentage	Intang. Plant	0.23%	0.02%	0.07%	0.14%	0.02%	0.01%	0.08%	0.62%	0.10%	0.00%	0.00%	0.00%
		Production													
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission													
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-	-	-	-
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution													
26	374	Land & Land Rights	1.0	$ 3,761	$ -	$ -	$ 2,319	$ -	$ -	$ 1,249	$ -	$ -	$ 29	$ -	$
27	374	Rights of Way	1.0	4,769	-	-	2,941	-	-	1,584	-	-	36	-	-
28	375	Structures	1.0	510	-	-	314	-	-	169	-	-	4	-	-
29	376	Mains - Demand	1.0	2,229,318	-	-	1,374,784	-	-	740,412	-	-	16,954	-	-
30	376	Mains - Customer	5.0	-	8,200	-	-	12,923	-	-	215,238	-	-	10,339	-
31	376	Mains - Commodity	3.0	-	-	0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	-	-	574,275	-	-	112,694	-	-	813,954	-	-	3,822
33	380	Services - Demand	1.0	0	-	-	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	-	124,593	-	-	117,964	-	-	2,122,074	-	-	10,575	-
35	381	Meters	6.0	-	61,074	-	-	79,774	-	-	3,714,554	-	-	-	-
36	385	*Industrial Meas. & Reg. Sta.*	3.0	-	-	97,664	-	-	19,165	-	-	138,425	-	-	650
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(422)	-	-	(260)	-	-	(140)	-	-	(3)	-	-
39		Total Distribution		$ 2,237,937	$ 193,867	$ 671,938	$ 1,380,098	$ 210,662	$ 131,859	$ 743,275	$ 6,051,866	$ 952,379	$ 17,020	$ 20,914	$ 4,472
40		Allocation Percentage	Dist. Plant	0.23%	0.02%	0.07%	0.14%	0.02%	0.01%	0.08%	0.62%	0.10%	0.00%	0.00%	0.00%
41	389-398	Total General Plant	1.1	$ 171,248	$ 14,835	$ 51,417	$ 105,606	$ 16,120	$ 10,090	$ 56,876	$ 463,092	$ 72,877	$ 1,302	$ 1,600	$ 342
42		Total Net Plant-Direct		$ 2,412,641	$ 209,001	$ 724,393	$ 1,487,835	$ 227,107	$ 142,153	$ 801,298	$ 6,524,304	$ 1,026,726	$ 18,348	$ 22,546	$ 4,821
		Systems Allocable Plant													
43	301-303	Intangible Plant	1.1	$ 59,930	$ 5,192	$ 17,994	$ 36,958	$ 5,641	$ 3,531	$ 19,904	$ 162,063	$ 25,504	$ 456	$ 560	$ 120
44	389-398	General Plant	1.1	$ 32,559	$ 2,821	$ 9,776	$ 20,079	$ 3,065	$ 1,918	$ 10,814	$ 88,047	$ 13,856	$ 248	$ 304	$ 65
45		Total Systems Allocable		92,489	8,012	27,770	57,036	8,706	5,449	30,718	250,110	39,360	703	864	185
46		*Total Net Plant*		$ 2,505,130	$ 217,013	$ 752,163	$ 1,544,872	$ 235,813	$ 147,602	$ 832,016	$ 6,774,413	$ 1,066,085	$ 19,052	$ 23,411	$ 5,006

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
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Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service			Small Essential Agr. User Gas Service			Natural Gas Engine Gas Service			Street Lighting Gas Service		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Other Rate Base Items													
1		Cash Working Capital	11.2	(10,788)	(2,335)	(21,830)	(6,653)	(4,341)	(4,284)	(3,583)	(109,303)	(30,942)	(82)	(1,889)	(145)
2		Materials & Supplies	1.1	21,163	1,833	6,354	13,051	1,992	1,247	7,029	57,230	9,006	161	198	42
3		Prepayments	1.1	6,289	545	1,888	3,879	592	371	2,089	17,008	2,677	48	59	13
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
7		Deferred Taxes	1.1	(313,673)	(27,173)	(94,180)	(193,437)	(29,527)	(18,482)	(104,179)	(848,239)	(133,487)	(2,386)	(2,931)	(627)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		2,208,121	189,883	644,395	1,361,712	204,530	126,454	733,372	5,891,110	913,340	16,793	18,847	4,289

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
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Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service			Small Essential Agr. User Gas Service			Natural Gas Engine Gas Service			Street Lighting Gas Service		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Direct Depreciation Expense													
1	301-303	Intangible	Intang. Plant	$ 482	$ 42	$ 145	$ 297	$ 45	$ 28	$ 160	$ 1,303	$ 205	$ 4	$ 5	$ 1
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 143,103	$ 12,397	$ 42,967	$ 88,249	$ 13,471	$ 8,432	$ 47,528	$ 386,981	$ 60,899	$ 1,088	$ 1,337	$ 286
5	389-398	General	1.1	$ 11,063	$ 958	$ 3,322	$ 6,822	$ 1,041	$ 652	$ 3,674	$ 29,916	$ 4,708	$ 84	$ 103	$ 22
6		Total Direct Dep. Exp.		$ 154,648	$ 13,397	$ 46,433	$ 95,369	$ 14,557	$ 9,112	$ 51,362	$ 418,201	$ 65,812	$ 1,176	$ 1,445	$ 309
		Systems Allocable Depreciation Expense													
7	301-303	Intangible	Intang. Plant	$ 10,541	$ 913	$ 3,165	$ 6,501	$ 992	$ 621	$ 3,501	$ 28,506	$ 4,486	$ 80	$ 99	$ 21
8	389-398	General	1.1	$ 5,448	$ 472	$ 1,636	$ 3,360	$ 513	$ 321	$ 1,809	$ 14,732	$ 2,318	$ 41	$ 51	$ 11
		System Allocable Amortization													
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		15,989	1,385	4,801	9,860	1,505	942	5,310	43,238	6,804	122	149	32
13		Total Depreciation Expense		170,637	14,782	51,233	105,229	16,062	10,054	56,673	461,438	72,616	1,298	1,595	341
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(122)	(11)	(37)	(75)	(11)	(7)	(40)	(329)	(52)	(1)	(1)	(0)
16		Amortization of PBOP Costs	1.1	775	67	233	478	73	46	257	2,095	330	6	7	2
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	0	0	0	0	0	0	0	0	0	0	0	0
19		Amortization of SOX Implementation	1.1	0	0	0	0	0	0	0	0	0	0	0	0
20		Total Depreciation & Amortization Expense		$ 171,290	$ 14,838	$ 51,430	$ 105,631	$ 16,124	$ 10,092	$ 56,890	$ 463,204	$ 72,894	$ 1,303	$ 1,601	$ 342

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
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Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service			Small Essential Agr. User Gas Service			Natural Gas Engine Gas Service			Street Lighting Gas Service		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Operation and Maintenance Expense													
		Gas Supply Expense													
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch.	3.0	-	-	-	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--(Cr	3.0	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	-	-	16,732	-	-	3,283	-	-	23,715	-	-	111
7		Materials & Expenses	3.0	-	-	1,417	-	-	278	-	-	2,009	-	-	9
8		Total Gas Supply Expense		$ -	$ -	$ 18,149	$ -	$ -	$ 3,561	$ -	$ -	$ 25,723	$ -	$ -	$ 121
		Transmission Expenses													
9	850	Operation Supervision & Engin.													
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch													
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.													
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station													
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-	-	-	-
22	856	Mains Expense													
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.													
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.													
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains													
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.													
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.													
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service			Small Essential Agr. User Gas Service			Natural Gas Engine Gas Service			Street Lighting Gas Service		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Distribution Expenses													
1	870	Operation Supervision & Eng.													
2		Labor & Labor Loading	5.5	$ 6,885	$ 2,271	$ 22,183	$ 4,246	$ 2,834	$ 4,353	$ 2,287	$ 120,373	$ 31,442	$ 52	$ 65	$ 148
3		Materials & Expenses	5.5	1,085	358	3,495	669	447	686	360	18,964	4,953	8	10	23
4	871	Distribution Load Dispatching													
5		Labor & Labor Loading	3.0	-	-	13,017	-	-	2,554	-	-	18,450	-	-	87
6		Materials & Expenses	3.0	-	-	3,194	-	-	627	-	-	4,527	-	-	21
7	874	Mains & Svcs. Expense													
8		Labor & Labor Loading	4.4	14,096	840	0	8,693	828	0	4,682	14,779	0	107	132	0
9		Materials & Expenses	4.4	11,921	710	0	7,351	700	0	3,959	12,498	0	91	112	0
10	875	Meas. & Reg. Sta. Exp.-Gen.													
11		Labor & Labor Loading	3.0	-	-	48,350	-	-	9,488	-	-	68,529	-	-	322
12		Materials & Expenses	3.0	-	-	19,268	-	-	3,781	-	-	27,310	-	-	128
13	878	Meter & House Reg. Exp.													
14		Labor & Labor Loading	6.0	-	2,796	-	-	3,652	-	-	170,029	-	-	-	-
15		Materials & Expenses	6.0	-	425	-	-	555	-	-	25,834	-	-	-	-
16	879	Customer Installation Exp.													
17		Labor & Labor Loading	6.0	-	3,304	-	-	4,316	-	-	200,946	-	-	-	-
18		Materials & Expenses	6.0	-	506	-	-	661	-	-	30,795	-	-	-	-
19	880	Other Expenses													
20		Labor & Labor Loading	5.5	5,925	1,954	19,091	3,654	2,439	3,746	1,968	103,595	27,059	45	56	127
21		Materials & Expenses	5.5	4,039	1,332	13,015	2,491	1,663	2,554	1,342	70,622	18,447	31	38	87
22	881	Rents	5.5	1,877	619	6,047	1,157	773	1,187	623	32,811	8,570	14	18	40
23		Total Distribution-Operations		$ 45,828	$ 15,114	$ 147,661	$ 28,261	$ 18,866	$ 28,977	$ 15,221	$ 801,247	$ 209,288	$ 349	$ 430	$ 983
		Operation and Maintenance Expense													
		Distribution Expenses													
24	885	Maint. Supervision & Eng.													
25		*Labor & Labor Loading*	6.6	$ 5,307	$ 423	$ 4,539	$ 3,273	$ 444	$ 891	$ 1,763	$ 11,247	$ 6,433	$ 40	$ 51	$ 30
26		Materials & Expenses	6.6	574	46	490	354	48	96	190	1,215	695	4	6	3
27	886	Maint. of Structures & Imp.													
28		Labor & Labor Loading	1.0	145	-	-	90	-	-	48	-	-	1	-	-
29		Materials & Expenses	1.0	542	-	-	334	-	-	180	-	-	4	-	-
30	887	Maint. of Mains													
31		Labor & Labor Loading	2.2	32,195	118	0	19,854	187	0	10,693	3,108	0	245	149	0
32		Materials & Expenses	2.2	23,346	86	0	14,397	135	0	7,754	2,254	0	178	108	0
33	889	Maint. of Meas. & Reg. Sta-Gen													
34		Labor & Labor Loading	3.0	-	-	27,525	-	-	5,401	-	-	39,013	-	-	183
35		Materials & Expenses	3.0	-	-	20,560	-	-	4,035	-	-	29,140	-	-	137
36	892	Maint. of Services													
37		Labor & Labor Loading	3.3	0	2,157	-	0	2,042	-	0	36,737	-	0	183	-
38		Materials & Expenses	3.3	0	1,188	-	0	1,125	-	0	20,229	-	0	101	-
39	893	Maint of Meter & House Reg.													
40		Labor & Labor Loading	6.0	-	543	-	-	710	-	-	33,049	-	-	-	-
41		Materials & Expenses	6.0	-	391	-	-	511	-	-	23,775	-	-	-	-
42	894	Maint of Other Equip.													
43		Labor & Labor Loading	6.6	336	27	287	207	28	56	112	712	407	3	3	2
44		Materials & Expenses	6.6	100	8	85	61	8	17	33	211	121	1	1	1
45		Total Distribution-Maintenance		$ 62,546	$ 4,987	$ 53,487	$ 38,571	$ 5,238	$ 10,496	$ 20,773	$ 132,539	$ 75,810	$ 476	$ 602	$ 356
46		Total Distribution O & M		$ 108,374	$ 20,101	$ 201,147	$ 66,832	$ 24,104	$ 39,473	$ 35,994	$ 933,786	$ 285,098	$ 824	$ 1,032	$ 1,339

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service			Small Essential Agr. User Gas Service			Natural Gas Engine Gas Service			Street Lighting Gas Service		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Customer Accounts Expenses													
1	901	Supervision													
2		Labor & Labor Loading	10.1	$ -	$ 346	$ -	$ -	$ 2,010	$ -	$ -	$ 16,922	$ -	$ -	$ 1,849	$
3		*Materials & Expenses*	10.1	-	21	-	-	124	-	-	1,040	-	-	114	-
4	902	Meter Reading Exp.													
5		Labor & Labor Loading	13.0	-	517	-	-	3,032	-	-	25,436	-	-	2,792	-
6		Materials & Expenses	13.0	-	130	-	-	765	-	-	6,416	-	-	704	-
7	903	Customer Records & Collections													
8		Labor & Labor Loading	13.0	-	1,425	-	-	8,362	-	-	70,150	-	-	7,699	-
9		Materials & Expenses	13.0	-	669	-	-	3,927	-	-	32,944	-	-	3,615	-
10	903	Customer Records & Collections - LCS													
11		Labor & Labor Loading - LCS	13.0	-	109	-	-	641	-	-	5,375	-	-	590	-
12		Materials & Expenses - LCS	13.0	-	5	-	-	29	-	-	239	-	-	26	-
13	904	Uncollectible Accounts Exp.	4.0	-	42	-	-	65	-	-	1,091	-	-	52	-
14	905	Misc. Customer Accounts Exp.													
15		Labor & Labor Loading	10.1	-	36	-	-	210	-	-	1,765	-	-	193	-
16		Materials & Expenses	10.1	-	2	-	-	12	-	-	101	-	-	11	-
17		Total Customer Accounts Expenses		$ -	$ 3,302	$ -	$ -	$ 19,176	$ -	$ -	$ 161,479	$ -	$ -	$ 17,645	$
		Customer Service & Info. Exp.													
18	908	Customer Assistance Exp.													
19		Labor & Labor Loading	13.0	$ -	$ 28	$ -	$ -	$ 163	$ -	$ -	$ 1,366	$ -	$ -	$ 150	$
20		Materials & Expenses	13.0	-	25	-	-	148	-	-	1,240	-	-	136	-
21	909	Info. & Instructional Exp.													
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense													
25		Labor & Labor Loading	13.0	-	0	-	-	0	-	-	4	-	-	0	-
26		Materials & Expenses	13.0	-	2	-	-	14	-	-	119	-	-	13	-
27		Total Customer Service & Info. Exp.		$ -	$ 55	$ -	$ -	$ 325	$ -	$ -	$ 2,728	$ -	$ -	$ 299	$
		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		$ 108,374	$ 23,458	$ 219,296	$ 66,832	$ 43,605	$ 43,034	$ 35,994	$ 1,097,993	$ 310,821	$ 824	$ 18,976	$ 1,460
39		Allocation Percentage	Total O&M	0.10%	0.02%	0.20%	0.06%	0.04%	0.04%	0.03%	0.99%	0.28%	0.00%	0.02%	0.00%
		Other Operating Deductions													
40		Administrative & General Expense	Total O&M	46,991	10,171	95,088	28,979	18,907	18,660	15,607	476,094	134,773	357	8,228	633
41		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Taxes Other Than Income	1.1	72,784	6,305	21,853	44,885	6,851	4,288	24,173	196,824	30,974	554	680	145
43		Total Allocated Operating Deductions		$ 228,149	$ 39,934	$ 336,237	$ 140,696	$ 69,364	$ 65,982	$ 75,774	$ 1,770,911	$ 476,569	$ 1,735	$ 27,885	$ 2,238
		Tax Adjustments													
44		*Interest Expense*	1.1	88,932	7,704	26,702	54,843	8,371	5,240	29,537	240,491	37,846	676	831	178
45		State South Georgia	1.1	177	15	53	109	17	10	59	478	75	1	2	0
46		Investment Tax Credit	1.1	(1,212)	(105)	(364)	(748)	(114)	(71)	(403)	(3,279)	(516)	(9)	(11)	(2)
47		Federal South Georgia	1.1	661	57	199	408	62	39	220	1,789	281	5	6	1

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE STUDY (CCOSS)
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Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service Demand	Electric Generation Gas Service Customer	Electric Generation Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Summary of Allocated Cost of Service													
		Rate Base													
1		Direct Net Plant		$ 2,412,641	$ 209,001	$ 724,393	$ 1,487,835	$ 227,107	$ 142,153	$ 801,298	$ 6,524,304	$ 1,026,726	$ 18,348	$ 22,546	$ 4,821
2		Systems Allocable Net Plant		92,489	8,012	27,770	57,036	8,706	5,449	30,718	250,110	39,360	703	864	185
3		Cash Working Capital	1.1	(10,788)	(2,335)	(21,830)	(6,653)	(4,341)	(4,284)	(3,583)	(109,303)	(30,942)	(82)	(1,889)	(145)
4		Materials & Supplies	1.1	21,163	1,833	6,354	13,051	1,992	1,247	7,029	57,230	9,006	161	198	42
5		Prepayments	1.1	6,289	545	1,888	3,879	592	371	2,089	17,008	2,677	48	59	13
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
8		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Deferred Taxes	1.1	(313,673)	(27,173)	(94,180)	(193,437)	(29,527)	(18,482)	(104,179)	(848,239)	(133,487)	(2,386)	(2,931)	(627)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$ 2,208,121	$ 189,883	$ 644,395	$ 1,361,712	$ 204,530	$ 126,454	$ 733,372	$ 5,891,110	$ 913,340	$ 16,793	$ 18,847	$ 4,289
12		Net Operating Margin	Direct	$ 1,340,792	$ 64,560	$ -	$ 573,347	$ 32,625	$ -	$ 3,443,622	$ 289,800	$ -	$ 47,592	$ -	$
13		Special Contract & Optional Margin	Net Op. Marg.	$ 33,452	$ 1,611	$ -	$ 14,305	$ 814	$ -	$ 85,917	$ 7,230	$ -	$ 1,187	$ -	$
14		Late Charges	Direct	$ 6,096	$ 294	$ -	$ 2,607	$ 148	$ -	$ 15,656	$ 1,318	$ -	$ 216	$ -	$
15		Service Establishment Charges	Direct	$ 30,548	$ 1,471	$ -	$ 13,063	$ 743	$ -	$ 78,458	$ 6,603	$ -	$ 1,084	$ -	$
16		Reconnect / Reread Charges	Direct	$ 2,407	$ 116	$ -	$ 1,029	$ 59	$ -	$ 6,182	$ 520	$ -	$ 85	$ -	$
17		Other Revenue - Labor	Direct	$ 7	$ 0	$ -	$ 3	$ 0	$ -	$ 19	$ 2	$ -	$ 0	$ -	$
18		Other Revenue - Parts & Material	Direct	$ 25	$ 1	$ -	$ 11	$ 1	$ -	$ 65	$ 5	$ -	$ 1	$ -	$
19		Other Revenue - Field Collection Fee	Direct	$ 1,708	$ 82	$ -	$ 730	$ 42	$ -	$ 4,386	$ 369	$ -	$ 61	$ -	$
20		Other Revenue - Returned Item Fee	Direct	$ 595	$ 29	$ -	$ 255	$ 14	$ -	$ 1,529	$ 129	$ -	$ 21	$ -	$
21		Other Revenue - Rental Income	Direct	$ 3,372	$ 162	$ -	$ 1,442	$ 82	$ -	$ 8,660	$ 729	$ -	$ 120	$ -	$
22		Total Revenue		1,419,003	68,326	-	606,791	34,528	-	3,644,495	306,705	-	50,368	-	-
23		O & M		(108,374)	(23,458)	(219,296)	(66,832)	(43,605)	(43,034)	(35,994)	(1,097,993)	(310,821)	(824)	(18,976)	(1,460)
24		A & G	Total O&M	(46,991)	(10,171)	(95,088)	(28,979)	(18,907)	(18,660)	(15,607)	(476,094)	(134,773)	(357)	(8,228)	(633)
25		Depreciation Expense		(171,290)	(14,838)	(51,430)	(105,631)	(16,124)	(10,092)	(56,890)	(463,204)	(72,894)	(1,303)	(1,601)	(342)
26		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Taxes other than Income	1.1	(72,784)	(6,305)	(21,853)	(44,885)	(6,851)	(4,288)	(24,173)	(196,824)	(30,974)	(554)	(680)	(145)
		State Income Tax													
28		Taxable Income before Interest Exp.		$ 1,019,564	$ 13,554	$(387,666)	$ 360,464	$(50,960)	$(76,075)	$ 3,511,831	$(1,927,410)	$(549,463)	$ 47,330	$(29,485)	$(2,580)
29		Interest Expense	1.1	(88,932)	(7,704)	(26,702)	(54,843)	(8,371)	(5,240)	(29,537)	(240,491)	(37,846)	(676)	(831)	(178)
30		State Taxable Income		$ 930,632	$ 5,850	$(414,368)	$ 305,622	$(59,331)	$(81,314)	$ 3,482,295	$(2,167,902)	$(587,309)	$ 46,654	$(30,317)	$(2,758)
31		State Income Tax		64,846	408	(28,873)	21,296	(4,134)	(5,666)	242,646	(151,059)	(40,924)	3,251	(2,112)	(192)
32		South Georgia	1.1	177	15	53	109	17	10	59	478	75	1	2	0
33		State Income Tax		65,023	423	(28,820)	21,405	(4,118)	(5,656)	242,705	(150,581)	(40,848)	3,252	(2,111)	(192)
		Federal Income Tax													
34		Taxable Income before Interest Exp.		1,019,564	13,554	(387,666)	360,464	(50,960)	(76,075)	3,511,831	(1,927,410)	(549,463)	47,330	(29,485)	(2,580)
35		Interest Expense	1.1	(88,932)	(7,704)	(26,702)	(54,843)	(8,371)	(5,240)	(29,537)	(240,491)	(37,846)	(676)	(831)	(178)
36		Federal Taxable Income		930,632	5,850	(414,368)	305,622	(59,331)	(81,314)	3,482,295	(2,167,902)	(587,309)	46,654	(30,317)	(2,758)
37		Federal Income Tax		$ 303,025	$ 1,905	$(134,923)	$ 99,514	$(19,319)	$(26,477)	$ 1,133,877	$(705,895)	$(191,235)	$ 15,191	$(9,871)	$(898)
38		I T C	1.1	(1,212)	(105)	(364)	(748)	(114)	(71)	(403)	(3,279)	(516)	(9)	(11)	(2)
39		South Georgia	1.1	661	57	199	408	62	39	220	1,789	281	5	6	1
40		Total Federal Income Tax		$ 302,474	$ 1,857	$(135,089)	$ 99,174	$(19,371)	$(26,509)	$ 1,133,694	$(707,385)	$(191,469)	$ 15,187	$(9,877)	$(899)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-	-	-	-
42		Net Income		$ 652,067	$ 11,274	$(223,758)	$ 239,885	$(27,471)	$(43,910)	$ 2,135,432	$(1,069,444)	$(317,145)	$ 28,891	$(17,498)	$(1,469)
43		Rate of Return on Rate Base		29.53%	5.94%	(34.72%)	17.62%	(13.43%)	(34.72%)	291.18%	(18.15%)	(34.72%)	172.04%	(92.84%)	(34.72%)
44		Rate of Return by Class Total			14.45%			9.95%			9.93%			24.80%	

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE ALLOCATION FACTORS
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Description	Allocation Factor No.	Total	Residential Gas Service			Multi-Family Residential			MMMHP Gas Service			Small General Gas Service		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	CP Demand		1,384,417	766,063			38,053			6,409			11,300		
		1	100.0000%	55.334712%	0.000000%	0.000000%	2.748697%	0.000000%	0.000000%	0.462936%	0.000000%	0.000000%	0.816223%	0.000000%	0.000000%
2	NCP Demand		1,534,800	766,063			38,053			6,409			11,300		
		2	100.0000%	49.912903%	0.000000%	0.000000%	2.479374%	0.000000%	0.000000%	0.417576%	0.000000%	0.000000%	0.736247%	0.000000%	0.000000%
3	Throughput		605,776,598	0		269,525,564	0		15,860,260			2,452,509			3,787,060
		3	100.0000%	0.000000%	0.000000%	44.492568%	0.000000%	0.000000%	2.618170%	0.000000%	0.000000%	0.404854%	0.000000%	0.000000%	0.625158%
4	Customers		863,424		760,637			61,743			189			16,504	
		4	100.0000%	0.000000%	88.095460%	0.000000%	0.000000%	7.150928%	0.000000%	0.000000%	0.021890%	0.000000%	0.000000%	1.911488%	0.000000%
5	*Customers With Mains*		863,424	0	760,637	0	0	61,743	0	0	189	0	0	16,504	0
		5	100.0000%	0.000000%	88.095460%	0.000000%	0.000000%	7.150928%	0.000000%	0.000000%	0.021890%	0.000000%	0.000000%	1.911488%	0.000000%
6	Meters for Customers		1,125,795		760,637			65,501			3,529			62,327	
		6	100.0000%	0.000000%	67.564442%	0.000000%	0.000000%	5.818203%	0.000000%	0.000000%	0.313490%	0.000000%	0.000000%	5.536253%	0.000000%
7	Service Lines for Customers		974,582		760,637			17,397			980			74,048	
		7	100.0000%	0.000000%	78.047523%	0.000000%	0.000000%	1.785071%	0.000000%	0.000000%	0.100508%	0.000000%	0.000000%	7.597968%	0.000000%
8	Res., MMMHP & Small, Medium GS		855,373	0	760,637	0	0	61,743	0	0	189	0	0	16,504	0
		8	100.0000%	0.000000%	88.924673%	0.000000%	0.000000%	7.218237%	0.000000%	0.000000%	0.022096%	0.000000%	0.000000%	1.929480%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		9	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,163	0	0	0	0	0	0	0	0	0	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		953,272	0	760,637	0	0	61,743	0	0	1,401	0	0	41,590	0
		13	100.0000%	0.000000%	79.792269%	0.000000%	0.000000%	6.476958%	0.000000%	0.000000%	0.146949%	0.000000%	0.000000%	4.362879%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors														
	Net Production, Transmission, & Distribution Plant		975,240,756	115,797,715	594,392,729	12,067,411	5,752,136	34,780,573	710,108	968,775	768,600	109,806	1,708,091	36,039,757	169,557
16		1.1	100.0000%	11.873757%	60.948307%	1.237378%	0.589817%	3.566358%	0.072814%	0.099337%	0.078811%	0.011259%	0.175146%	3.695473%	0.017386%
	Distribution Mains		516,273,776	115,351,773	271,168,317	0	5,729,984	22,011,408	0	965,044	67,379	0	1,701,513	5,883,789	0
17		2.2	100.0000%	22.343140%	52.524132%	0.000000%	1.109873%	4.263515%	0.000000%	0.186925%	0.013051%	0.000000%	0.329576%	1.139664%	0.000000%
	Distribution Services		305,210,571	0	238,209,289	0	0	5,448,226	0	0	306,762	0	0	23,189,801	0
18		3.3	100.0000%	0.000000%	78.047523%	0.000000%	0.000000%	1.785071%	0.000000%	0.000000%	0.100508%	0.000000%	0.000000%	7.597968%	0.000000%
	Distribution Mains & Services		821,484,347	115,351,774	509,377,607	0	5,729,984	27,459,634	0	965,044	374,141	0	1,701,513	29,073,589	0
19		4.4	100.0000%	14.041871%	62.006977%	0.000000%	0.697516%	3.342685%	0.000000%	0.117476%	0.045545%	0.000000%	0.207127%	3.539153%	0.000000%
	Allocable Distribution Operating Expenses		27,455,714	1,346,214	15,731,303	1,505,506	66,872	1,163,226	88,592	11,263	49,775	13,699	19,858	1,141,221	21,154
20		5.5	100.0000%	4.903221%	57.297010%	5.483397%	0.243563%	4.236734%	0.322671%	0.041021%	0.181292%	0.049895%	0.072326%	4.156590%	0.077046%
	Allocable Distribution Maintenance Expenses		24,985,736	2,909,458	14,451,011	863,558	144,524	806,641	50,816	24,341	15,948	7,858	42,916	875,671	12,134
21		6.6	100.0000%	11.644476%	57.837043%	3.456203%	0.578428%	3.228407%	0.203381%	0.097419%	0.063828%	0.031449%	0.171764%	3.504683%	0.048563%
	Transmission Operating Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
22		7.7	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Mains		0	0	0	0	0	0	0	0	0	0	0	0	0
23		8.8	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
24		9.9	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Customer Accounting Expense		29,729,871	0	23,851,640	0	0	1,936,103	0	0	41,737	0	0	1,258,845	0
25		10.1	100.0000%	0.000000%	80.227862%	0.000000%	0.000000%	6.512315%	0.000000%	0.000000%	0.140388%	0.000000%	0.000000%	4.234276%	0.000000%
	Total O & M Expense		111,325,072	5,607,581	71,410,917	3,938,358	278,551	5,188,749	231,753	46,914	153,798	35,837	82,715	4,443,152	55,337
		11.2	100.0000%	5.037123%	64.146302%	3.537710%	0.250214%	4.660899%	0.208177%	0.042141%	0.138152%	0.032191%	0.074301%	3.991151%	0.049708%

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Line No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	CP Demand		90,019			320,849			119,971		
		1	6.502274%	0.000000%	0.000000%	23.175763%	0.000000%	0.000000%	8.665801%	0.000000%	0.000000%
2	NCP Demand		90,019			320,849			119,971		
		2	5.865167%	0.000000%	0.000000%	20.904954%	0.000000%	0.000000%	7.816708%	0.000000%	0.000000%
3	Throughput				43,029,696			141,998,559			85,801,495
		3	0.000000%	0.000000%	7.103229%	0.000000%	0.000000%	23.440747%	0.000000%	0.000000%	14.163884%
4	Customers			16,299			6,992			171	
		4	0.000000%	1.887746%	0.000000%	0.000000%	0.809789%	0.000000%	0.000000%	0.019805%	0.000000%
5	Customers With Mains		0	16,299	0	0	6,992	0	0	171	0
		5	0.000000%	1.887746%	0.000000%	0.000000%	0.809789%	0.000000%	0.000000%	0.019805%	0.000000%
6	Meters for Customers			66,064			110,413			20,273	
		6	0.000000%	5.868198%	0.000000%	0.000000%	9.807511%	0.000000%	0.000000%	1.800803%	0.000000%
7	Service Lines for Customers			73,533			36,249			2,988	
		7	0.000000%	7.545126%	0.000000%	0.000000%	3.719439%	0.000000%	0.000000%	0.306562%	0.000000%
8	Res., MMMHP & Small, Medium GS		0	16,299							
		8	0.000000%	1.905514%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0
		9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0
		10	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0
		11	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		0	0	0	0	6,992	0	0	171	0
		12	0.000000%	0.000000%	0.000000%	0.000000%	97.612704%	0.000000%	0.000000%	2.387296%	0.000000%
13	Weighted Customers for Meter Reading		0	51,342	0	0	29,366	0	0	718	0
		13	0.000000%	5.385858%	0.000000%	0.000000%	3.080591%	0.000000%	0.000000%	0.075341%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0
		14	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0
		15	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors										
	Net Production, Transmission, & Distribution Plant		13,607,163	36,223,075	1,926,560	48,499,401	26,185,365	6,357,672	18,134,728	3,262,541	3,841,572
16		1.1	1.395262%	3.714270%	0.197547%	4.973070%	2.685015%	0.651908%	1.859513%	0.334537%	0.393910%
	Distribution Mains		13,554,761	5,810,706	0	48,312,628	2,492,628	0	18,064,891	60,962	0
17		2.2	2.625499%	1.125509%	0.000000%	9.357947%	0.482811%	0.000000%	3.499091%	0.011808%	0.000000%
	Distribution Services		0	23,028,521	0	0	11,352,122	0	0	935,661	0
18		3.3	0.000000%	7.545126%	0.000000%	0.000000%	3.719439%	0.000000%	0.000000%	0.306562%	0.000000%
	Distribution Mains & Services		13,554,761	28,839,227	0	48,312,628	13,844,750	0	18,064,891	996,623	0
19		4.4	1.650033%	3.510624%	0.000000%	5.881138%	1.685333%	0.000000%	2.199055%	0.121320%	0.000000%
	Allocable Distribution Operating Expenses		158,191	1,186,568	240,354	563,833	1,582,178	793,170	210,827	272,475	479,267
20		5.5	0.576168%	4.321752%	0.875423%	2.053610%	5.762655%	2.888908%	0.767879%	0.992415%	1.745599%
	Allocable Distribution Maintenance Expenses		341,885	875,910	137,867	1,218,564	555,627	454,962	455,641	61,300	274,907
21		6.6	1.368320%	3.505641%	0.551782%	4.877040%	2.223775%	1.820888%	1.823606%	0.245339%	1.100257%
	Transmission Operating Expense		0	0	0	0	0	0	0	0	0
22		7.7	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Mains		0	0	0	0	0	0	0	0	0
23		8.8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0
24		9.9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Customer Accounting Expense		0	1,546,650	0	0	880,439	0	0	21,532	0
25		10.1	0.000000%	5.202344%	0.000000%	0.000000%	2.961463%	0.000000%	0.000000%	0.072427%	0.000000%
	Total O & M Expense		658,936	4,856,980	628,758	2,348,616	4,425,484	2,074,910	878,186	573,092	1,253,748
		11.2	0.591902%	4.362881%	0.564795%	2.109691%	3.975281%	1.863830%	0.788849%	0.514791%	1.126204%

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Line No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	CP Demand		840			181			1,684			83		
		1	0.060691%	0.000000%	0.000000%	0.013093%	0.000000%	0.000000%	0.121615%	0.000000%	0.000000%	0.005981%	0.000000%	0.000000%
2	NCP Demand		5,469			614			14,805			265		
		2	0.356347%	0.000000%	0.000000%	0.040034%	0.000000%	0.000000%	0.964630%	0.000000%	0.000000%	0.017238%	0.000000%	0.000000%
3	Throughput				1,836,544			182,313			1,898,808			79,719
		3	0.000000%	0.000000%	0.303172%	0.000000%	0.000000%	0.030096%	0.000000%	0.000000%	0.313450%	0.000000%	0.000000%	0.013160%
4	Customers			37			22			27			110	
		4	0.000000%	0.004334%	0.000000%	0.000000%	0.002548%	0.000000%	0.000000%	0.003127%	0.000000%	0.000000%	0.012740%	0.000000%
5	Customers With Mains		0	37	0	0	22	0	0	27	0	0	110	0
		5	0.000000%	0.004334%	0.000000%	0.000000%	0.002548%	0.000000%	0.000000%	0.003127%	0.000000%	0.000000%	0.012740%	0.000000%
6	Meters for Customers			74			21			2,360			100	
		6	0.000000%	0.006599%	0.000000%	0.000000%	0.001889%	0.000000%	0.000000%	0.209672%	0.000000%	0.000000%	0.008921%	0.000000%
7	Service Lines for Customers			533			23			558			52	
		7	0.000000%	0.054644%	0.000000%	0.000000%	0.002383%	0.000000%	0.000000%	0.057248%	0.000000%	0.000000%	0.005308%	0.000000%
8	Res., MMMHP & Small, Medium GS													
		8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		10	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		11	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		0	0	0	0	0	0	0	0	0	0	0	0
		12	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		0	239	0	0	69	0	0	113	0	0	110	0
		13	0.000000%	0.025114%	0.000000%	0.000000%	0.007270%	0.000000%	0.000000%	0.011896%	0.000000%	0.000000%	0.011539%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		14	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		15	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors													
	Net Production, Transmission, & Distribution Plant		127,007	188,422	82,227	27,400	17,493	8,163	254,502	448,179	85,015	12,516	66,642	3,569
16		1.1	0.013023%	0.019321%	0.008431%	0.002810%	0.001794%	0.000837%	0.026096%	0.045956%	0.008717%	0.001283%	0.006833%	0.000366%
	Distribution Mains		126,518	13,339	0	27,295	7,843	0	253,522	9,626	0	12,468	39,215	0
17		2.2	0.024506%	0.002584%	0.000000%	0.005287%	0.001519%	0.000000%	0.049106%	0.001864%	0.000000%	0.002415%	0.007596%	0.000000%
	Distribution Services		0	166,779	0	0	7,273	0	0	174,727	0	0	16,202	0
18		3.3	0.000000%	0.054644%	0.000000%	0.000000%	0.002383%	0.000000%	0.000000%	0.057248%	0.000000%	0.000000%	0.005308%	0.000000%
	Distribution Mains & Services		126,518	180,118	0	27,295	15,116	0	253,522	184,353	0	12,468	55,417	0
19		4.4	0.015401%	0.021926%	0.000000%	0.003323%	0.001840%	0.000000%	0.030861%	0.022441%	0.000000%	0.001518%	0.006746%	0.000000%
	Allocable Distribution Operating Expenses		1,477	3,058	10,258	319	450	1,018	2,959	32,522	10,606	146	1,939	445
20		5.5	0.005378%	0.011138%	0.037364%	0.001160%	0.001639%	0.003709%	0.010776%	0.118453%	0.038631%	0.000530%	0.007062%	0.001622%
	Allocable Distribution Maintenance Expenses		3,191	4,936	5,884	688	427	584	6,394	8,966	6,084	314	1,584	255
21		6.6	0.012772%	0.019757%	0.023551%	0.002755%	0.001709%	0.002338%	0.025592%	0.035885%	0.024349%	0.001259%	0.006338%	0.001022%
	Transmission Operating Expense		0	0	0	0	0	0	0	0	0	0	0	0
22		7.7	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Mains		0	0	0	0	0	0	0	0	0	0	0	0
23		8.8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0	0	0	0
24		9.9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Customer Accounting Expense		0	7,142	0	0	2,088	0	0	3,400	0	0	3,449	0
25		10.1	0.000000%	0.024023%	0.000000%	0.000000%	0.007022%	0.000000%	0.000000%	0.011436%	0.000000%	0.000000%	0.011602%	0.000000%
	Total O & M Expense		6,150	19,157	26,836	1,327	3,687	2,664	12,324	71,200	27,746	606	9,172	1,165
		11.2	0.005525%	0.017208%	0.024106%	0.001192%	0.003312%	0.002393%	0.011071%	0.063957%	0.024923%	0.000544%	0.008239%	0.001046%

SOUTHWEST GAS CORPORATION
CLASS COST OF SERVICE ALLOCATION FACTORS
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Description	Allocation Factor No.	Electric Generation Gas Service			Small Essential Agr. User Gas Service			Natural Gas Engine Gas Service			Street Lighting Gas Service		
			Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	CP Demand		14,805			9,130			4,917			113		
		1	1.069413%	0.000000%	0.000000%	0.659489%	0.000000%	0.000000%	0.355179%	0.000000%	0.000000%	0.008133%	0.000000%	0.000000%
2	NCP Demand		45,747			9,130			105,993			113		
		2	2.980643%	0.000000%	0.000000%	0.594871%	0.000000%	0.000000%	6.905971%	0.000000%	0.000000%	0.007336%	0.000000%	0.000000%
3	Throughput				15,007,742			2,945,076			21,271,370			99,883
		3	0.000000%	0.000000%	2.477438%	0.000000%	0.000000%	0.486165%	0.000000%	0.000000%	3.511422%	0.000000%	0.000000%	0.016488%
4	Customers			23			36			604			29	
		4	0.000000%	0.002664%	0.000000%	0.000000%	0.004198%	0.000000%	0.000000%	0.069925%	0.000000%	0.000000%	0.003359%	0.000000%
5	Customers With Mains		0	23	0	0	36	0	0	604	0	0	29	0
		5	0.000000%	0.002664%	0.000000%	0.000000%	0.004198%	0.000000%	0.000000%	0.069925%	0.000000%	0.000000%	0.003359%	0.000000%
6	Meters for Customers			546			714			33,234			0	
		6	0.000000%	0.048537%	0.000000%	0.000000%	0.063399%	0.000000%	0.000000%	2.952084%	0.000000%	0.000000%	0.000000%	0.000000%
7	Service Lines for Customers			398			377			6,776			34	
		7	0.000000%	0.040822%	0.000000%	0.000000%	0.038650%	0.000000%	0.000000%	0.695282%	0.000000%	0.000000%	0.003465%	0.000000%
8	Res., MMMHP & Small, Medium GS													
		8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		10	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		11	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		0	0	0	0	0	0	0	0	0	0	0	0
		12	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		0	97	0	0	567	0	0	4,757	0	0	522	0
		13	0.000000%	0.010134%	0.000000%	0.000000%	0.059479%	0.000000%	0.000000%	0.498966%	0.000000%	0.000000%	0.054759%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		14	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		15	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors													
	Net Production, Transmission, & Distribution Plant		2,237,937	193,867	671,938	1,380,098	210,662	131,859	743,275	6,051,866	952,379	17,020	20,914	4,472
16		1.1	0.229475%	0.019879%	0.068900%	0.141514%	0.021601%	0.013521%	0.076214%	0.620551%	0.097656%	0.001745%	0.002144%	0.000459%
	Distribution Mains		2,229,318	8,200	0	1,374,784	12,923	0	740,412	215,238	0	16,954	10,339	0
17		2.2	0.431809%	0.001588%	0.000000%	0.266290%	0.002503%	0.000000%	0.143415%	0.041691%	0.000000%	0.003284%	0.002003%	0.000000%
	Distribution Services		0	124,593	0	0	117,964	0	0	2,122,074	0	0	10,575	0
18		3.3	0.000000%	0.040822%	0.000000%	0.000000%	0.038650%	0.000000%	0.000000%	0.695282%	0.000000%	0.000000%	0.003465%	0.000000%
	Distribution Mains & Services		2,229,318	132,793	0	1,374,784	130,888	0	740,412	2,337,312	0	16,954	20,914	0
19		4.4	0.271377%	0.016165%	0.000000%	0.167354%	0.015933%	0.000000%	0.090131%	0.284523%	0.000000%	0.002064%	0.002546%	0.000000%
	Allocable Distribution Operating Expenses		26,017	8,580	83,830	16,044	10,711	16,450	8,641	454,882	118,817	198	244	558
20		5.5	0.094761%	0.031252%	0.305327%	0.058437%	0.039011%	0.059916%	0.031472%	1.656786%	0.432758%	0.000721%	0.000889%	0.002032%
	Allocable Distribution Maintenance Expenses		56,229	4,483	48,085	34,675	4,709	9,436	18,675	119,153	68,153	428	541	320
21		6.6	0.225044%	0.017943%	0.192449%	0.138781%	0.018847%	0.037766%	0.074743%	0.476883%	0.272769%	0.001711%	0.002167%	0.001281%
	Transmission Operating Expense		0	0	0	0	0	0	0	0	0	0	0	0
22		7.7	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Mains		0	0	0	0	0	0	0	0	0	0	0	0
23		8.8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0	0	0	0
24		9.9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Customer Accounting Expense		0	2,896	0	0	16,821	0	0	141,650	0	0	15,478	0
25		10.1	0.000000%	0.009742%	0.000000%	0.000000%	0.056579%	0.000000%	0.000000%	0.476458%	0.000000%	0.000000%	0.052062%	0.000000%
	Total O & M Expense		108,374	23,458	219,296	66,832	43,605	43,034	35,994	1,097,993	310,821	824	18,976	1,460
		11.2	0.097349%	0.021071%	0.196987%	0.060033%	0.039169%	0.038656%	0.032332%	0.986294%	0.279202%	0.000740%	0.017046%	0.001311%

GRAY

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION – APPLICATION FOR AN INCREASE IN GAS IN GAS RATES.	)	DOCKET NO. G-01551A-04-0876

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 26, 2005

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INTRODUCTION

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

A. My name is Robert G. Gray. I am a Rate Analyst 5 employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Senior Rate Analyst.

A. In my capacity as a Rate Analyst 5, I conduct analysis and provide recommendations to the Commission on electricity and natural gas matters. A copy of my resume is attached as Exhibit RGG-1.

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

A. Issues I will address include the rate design, the purchased gas adjustor, the base cost of gas, Gas Technology Institute funding, and some gas procurement issues regarding Southwest Gas Corporation ("Southwest"), and other issues. My testimony takes into consideration the revenue requirement testimony of Staff Witness James Dorf and the cost of service testimony of Staff Witness Prem Bahl.

Q. Will you be filing supplemental rate design schedules?

A. Yes. As explained below, I based my rate design on a total margin of $369,145,782. I recently learned that due to a calculation error for an operating income item, Staff's revenue requirements number would be amended. This error was discovered two business days before Staff's Direct Testimony was to be filed. While not a substantial change, it does affect the rate design schedules attached to my testimony. Because it will take time to adjust my schedules to reflect the amended revenue requirements number, I will be filing supplemental rate design schedules.

GAS TECHNOLOGY INSTITUTE FUNDING

Q. What is the Gas Technology Institute ("GTI")?

A. GTI (formerly known as the Gas Research Institute) is a non-profit entity which is involved in research, development, and training related to energy markets. GTI is headquartered in Des Plaines, Illinois, with offices in Washington, D.C. and Houston, Texas, and a test facility near Tulsa, Oklahoma. Examples of GTI efforts include the development of technologies for coal bed methane and shale natural gas production, improvements in polyethylene plastic pipe, development of "smart pigs" for pipeline inspections, development of high efficiency burner systems, natural gas vehicle development, and the development of products and processes to reduce the environmental impact of natural gas operations and use.

Q. Why is GTI of interest in this proceeding?

A. Traditionally GTI had been funded through a surcharge on interstate natural gas sales authorized by the Federal Energy Regulatory Commission ("FERC"). In 1997 FERC issued an opinion approving GTI's (then GRI) budget of $164 million for 1998. A 1998 FERC-approved settlement agreement stipulates that FERC-approved funding for GTI through the interstate natural gas sales surcharge would be phased out between 1999 and 2004. The 1998 settlement agreement contemplates that GTI would seek voluntary funding for its activities to replace the historical FERC-approved funding. As of 2005, GTI receives no funding through the FERC-approved surcharge.

Since the 1998 settlement agreement, GTI has sought voluntary funding via state public utility commissions and the local distribution companies they regulate. As of March 2005, GTI receives approximately $12 million in funding from 16 states via this voluntary contribution method. The 16 states are Alabama, Delaware, Florida, Idaho, Illinois,

Kentucky, Mississippi, New Jersey, New Hampshire, New York, North Carolina, Oregon, Utah, Virginia, Washington, and Wyoming. Additionally, there are on-going proceedings related to GTI funding in the following states: Illinois, Pennsylvania, Minnesota, New Mexico, Massachusetts, Michigan, and Tennessee.

Q. Does Southwest currently collect any money to fund GTI research activities?

A. Not as of the beginning of 2005. Through the end of 2004 the FERC approved GTI funding was reflected in El Paso's billing for interstate pipeline services to Southwest, which was then passed along to Southwest's customers through the PGA mechanism along with all other FERC mandated interstate pipeline charges. But as of January 2005, no GTI funding is reflected in El Paso's billing to Southwest, per the phase-out of the FERC approved surcharge.

Q. Please discuss the importance of research and development efforts in the natural gas industry.

A. The natural gas industry has come under a great deal of pressure in recent years as natural gas prices have risen significantly and have become more volatile, the supply/demand balance of the North American natural gas market has tightened, policymakers have struggled to balance the need for additional domestic supplies with environmental concerns, national and state efforts to ensure pipeline safety have increased, and interest in energy efficiency and conservation have been redoubled. On-going research and development efforts are needed in the natural gas industry to address these broad issues and work toward more efficient and safe production, distribution, and consumption of natural gas. GTI has been a central player in addressing a broad spectrum of needed research and development activities in the natural gas industry.

Q. How are the GTI research programs which are funded in this manner structured?

A. GTI has two primary sets of programs which are funded in this manner, the Operations Technology Development ("OTD") program and the Utilization Technology Development ("UTD") program. Schedule RGG-2 contains documents describing the OTD and UTD programs. The OTD program focuses on enhancing distribution system integrity and safety and lowering O&M costs. Specific OTD activities include pipe and leak locating and detection, reduced construction costs, gas main integrity, reduced rehabilitation costs, and new pipe materials and coatings. The UTD program focuses on developing increased-efficiency and safety end-use equipment for residential, commercial, and industrial gas customers. Specific UTD activities include developing high-efficiency gas equipment in traditional residential/commercial markets (space heating, water heating, cooking, venting safety, low-income customer R&D) and industrial markets (melting, process heating, boilers, CHP).

Q. What are the financial mechanics of a utility participating in GTI funding for the OTD and UTD programs?

A. OTD program funding is assessed on a basis of $0.50 per meter annually, with a minimum of $250,000 annually and a maximum of $750,000 annually. UTD funding is assessed on a basis of $0.40 per meter annually, with a maximum of $250,000 annually.

Q. Please estimate the approximately cost of Southwest Gas participating in the OTD and UTD programs.

A. Based on test year data Southwest has approximately 863,424 bills per month. Using this as an approximate estimate of the number of meters, OTD funding (at $0.50 per meter annually) would be at a level of $431,712. UTD funding (at $0.40 per meter) would reach

the $250,000 annual maximum. The total anticipated annual funding from Southwest for GTI funding for the OTD and UTD programs would be $681,712.

Q. Please estimate the approximate bill impacts of the level of funding identified in the previous question.

A. If the estimated annual cost of $681,712 were spread across all customer classes (excluding G-30 and B-1), the cost would be approximately $0.00113 per therm. For an average residential customer using 30 therms, this would increase their bill by approximately three cents per month.

Q. Please discuss how the funds collected by Southwest would be spent by GTI.

A. One of the benefits of participating in GTI research and development projects is that the participating utilities can choose which specific programs their funds will be directed towards.

Q. Please discuss why Arizona ratepayers might want to participate in funding GTI's research activities.

A. The natural gas research and development efforts at GTI address a wide variety of important areas where improved technology, methods, and processes can provide for safer and more efficient production, distribution, and consumption of natural gas at a time when natural gas prices are at historic highs. Given the number of states that currently fund or are considering funding GTI research, a wide variety of research activities will likely be undertaken regardless of whether Arizona chooses to fund GTI research and development activities or not. However, the larger and more important question is whether Arizona's funding of GTI research and development activities is in the larger public interest.

Weighed in this broader context, Arizona's funding of GTI research and development activities is in the best interests of Arizona, particularly given its relatively small cost.

A good example of this is in the area of pipeline safety related work at GTI. Arizona's reliance on natural gas has grown dramatically in recent years and given the dearth of in-state supplies of natural gas (and similarly for other fuels such as gasoline), Arizona is heavily dependent on the interstate pipeline systems to reliably deliver such fuels in a reliable fashion. As the gasoline crisis in the summer of 2003 showed, a major disruption in such interstate pipeline systems can have a significant impact on welfare of Arizonans. GTI has a variety of pipeline safety related research and development efforts. If GTI is funded through Southwest, some portion of that funding could be directed to GTI's pipeline safety efforts to enhance the development of new technologies and processes in the area of pipeline safety. Given the relatively small cost of GTI funding and the long term benefits of GTI research and development activities in a variety of natural gas related areas, funding of GTI's programs through Southwest is in the public interest.

Q. Have you discussed the possibility of Southwest funding GTI research and development efforts with the Commission's pipeline safety section?

A. Yes, I discussed the matter with Robert Miller, Staff's pipeline safety witness in this proceeding. Mr. Miller indicated he was supportive of funding GTI efforts and that he is actually involved in a GTI research project currently in coordination with the City of Mesa, looking at issues related to plastic piping.

Q. What are your recommendations regarding GTI funding?

A. I recommend that Southwest participate in funding GTI's OTD and UTD programs at a level of $681,712 annually and that the costs of this funding be recovered on a per therm basis from all of Southwest's sales customers, excluding G-30 and B-1 customers.

Q. Do you have further recommendations regarding GTI funding?

A. Yes. I recommend that each year 30 days prior to Southwest notifying GTI which programs it will participate in, Southwest should file its proposed list of programs to fund, with a short description of each program, with Docket Control, providing the Commission an opportunity to provide any input it wishes to Southwest on its choice of programs to fund. I further recommend that Southwest reset the GTI surcharge annually beginning with the April billing cycle, based upon prior calendar year sales and any over or undercollection from the prior calendar year and that the GTI surcharge be reflected in the Rate Adjustment column of its Statement of Rates, with a separate footnote identifying the current level of the GTI surcharge.

Q. Are there additional GTI research and development efforts, beyond the OTD and UTD programs, which could be funded if there was a desire to further support GTI's efforts?

A. Yes. GTI has a number of other natural gas industry research and development efforts which could be funded. Schedule RGG-2, pages one and two, is a copy of the 2005 allocation form, listing a variety of other research and development projects beyond the OTD and UTD programs.

BASE COST OF GAS

Q. What is the function of the base cost of gas in setting the rates Southwest's customers pay?

A. The base cost of gas is used as an estimate of the typical cost of natural gas to Southwest and is included in Southwest's base rates. Currently customers served on Schedules G-60, Cogeneration Gas Service, and G-80, Natural Gas Engine Service are served under a separate cost of gas which is reset twice annually, before the summer and winter seasons based upon specific gas purchases for these customer classes. All other core customers are served under Southwest's purchased gas adjustor ("PGA") mechanism. The base cost of gas accounts for both the commodity cost and the cost of transporting the natural gas from its source to Southwest's distribution system. Southwest uses a PGA mechanism to account for the changing cost of natural gas. Southwest currently uses a 12 month rolling average PGA mechanism, whereby a new PGA rate is calculated each month. Each month Southwest calculates its average cost of natural gas, on a per therm basis, for the most recent 12 months. The monthly PGA rate is then derived by subtracting the base cost of gas from the 12 month average cost of gas. Therefore, over time, the PGA rate and the base cost of gas should typically in combination account for the total cost of natural gas for Southwest. The PGA rate is banded, meaning that each new month when the PGA rate is set it cannot be set at a rate that is more than $0.10 per therm different than the rate that was in place in any of the previous 12 months.

Q. Please discuss how the cost of gas fits into Southwest's overall rate structure.

A. Southwest's rate structure contains two basic categories of costs. One is the cost of gas, which is currently captured in Southwest's tariffs through the base cost of gas, the monthly PGA rate, and any temporary PGA surcharge or credit which may be in effect. The second category is referred to herein as the margin and captures all of Southwest's

costs other than the cost of gas, including such things as the costs for Southwest's distribution infrastructure, personnel, metering, billing, etc. In Southwest's rates the margin is recovered through the monthly basic service charge, the margin rate, and miscellaneous other charges.

Q. How does the level of the base cost of gas impact Southwest customers' natural gas bills?

A. Because the monthly PGA rate is set off of the base cost of gas, in general the level of the base cost of gas does not cause any increase or decrease in the natural gas bills of Southwest's customers. To the extent the base cost of gas is set at a higher level, the monthly PGA rate will in general move in the opposite direction an equal amount, resulting in the customer seeing the same overall cost of gas. For example, hypothetically, if the base cost of gas was set at $0.40 per therm and the company's actual 12 month average cost of gas was $0.60 per therm, the monthly PGA rate would be $0.20 per therm. But the customer would be paying a total gas cost of $0.60 per therm (the base cost plus the monthly PGA rate). If the base cost of gas was increased to $0.50 per therm, then, using the same actual average cost of gas of $0.60 per therm, the monthly PGA rate would be set at $0.10 per therm. So the cost of gas to the customer is the same in both examples, there is just $0.10 per therm more in the monthly PGA rate in the first example and $0.10 per therm more in the base cost of gas in the second example. The overall cost of gas is the same, $0.60 per therm, in both examples.

The only case in which a different base cost of gas might result in a different customer bill is if the base cost of gas is increased or decreased to such an extent that the $0.10 per therm band on the monthly PGA rate does not allow the monthly PGA rate to make the equal and opposite adjustment in comparison to the change in the base cost of gas. In

such a case, there would be a short term impact on customer bills, perhaps for 6-12 months, while the monthly PGA rate gradually is able to fully adjust within the $0.10 per therm band. And even in this case over a longer period of time, Southwest's customers would eventually pay the same total cost of gas whether the base cost of gas changes or not. But the potential for short term impacts on customer bills should be carefully considered. A proposed solution to this potential issue is provided later in this section.

Q. What is Southwest's current base cost of gas?

A. Southwest's current base cost of gas is $0.37034 per therm. This base cost of gas was set in Southwest's last rate proceeding (Decision Number 64172, October 30, 2001).

Q. Has Southwest proposed a change in the base cost of gas?

A. Yes. In Southwest's application the Company has proposed an increase in the base cost of gas to $0.53436 per therm.

Q. What is the basis for Southwest's proposed base cost of gas?

A. In response to Staff Data Request BGG-7-23, Southwest indicated that its proposed base cost of gas reflected the current base cost of gas and the monthly PGA rate effective during September 2004 of $0.16402.

Q. Please discuss the market cost of natural gas in recent years.

A. Natural gas market prices were relatively low and stable through most of the 1990s. The primary cause of these relatively low and stable prices was the "gas bubble" which was caused by there being more natural gas supply than demand. However, in recent years natural gas prices have been much higher and more volatile. While there is some disagreement over the exact impacts of various factors on natural gas market prices, there

is broad agreement that a number of factors have fundamentally tightened the supply/demand equation, resulting in higher prices and more exposure to price volatility. Such factors include the gradual decline of traditional North American supply basin production, various limitations on new drilling in many parts of North America, increased demand for natural gas (particularly for electric generation), and at times low natural gas storage inventory levels. With continued reliance on natural gas for most new electric generation at present and in the near term future, as well as other factors, it appears likely that the natural gas market will continue to see high and volatile natural gas prices in the future.

Regarding recent natural gas prices, prices remained at relatively high levels through 2004 and 2005, but there were no major price spikes during that period. San Juan basin prices dropped to roughly $5.50 per MMBtu (1 MMBtu equals 10 therms) in the first few months of 2005, then bumped up to between $6.00 and $6.50 per MMBtu in late March and April before recently settling down between $5.50 and $6.00. As of May 2005, the Energy Information Administration's short term outlook projects wellhead prices averaging $6.20 per mcf (approximately equal to one MMBtu) in 2005 and $6.73 per mcf in 2006.

Q. Does Staff agree with Southwest's proposed base cost of gas?

A. If the Commission is to adopt a new base cost of gas, given the information available at this time, Southwest's proposed base cost of gas of $0.53436 per therm appears reasonable. However, as I discuss in the following pages, I believe the Commission should consider a new approach to the base cost of gas which will make Southwest's customer bills simpler and easier to understand for customers.

Q. Please discuss the place of the base cost of gas in Southwest's overall rate and cost structure.

A. The base cost of gas is currently included along with the margin within the tariffed rate per therm for each rate class. The monthly PGA rate is a separate line item. Traditionally in a natural gas company rate proceeding, the Commission addresses potential rate increases or decreases, but such increases or decreases address basically all costs apart from the cost of gas component, which is treated separately through the on-going functioning of the PGA mechanism. The margin rate is set to recover all these other costs, which include such things as metering, billing, customer service, personnel, facility costs, etc. When rates change in a rate proceeding it is only the margin rate component, consisting of the tariffed rate(s) and the basic service charge which change. Therefore the margin rate change for a given customer class is always much higher than the percentage increase in an actual customer bill, as the cost of gas component is treated as a constant in the rate proceeding.

Having the tariffed rate consist of both a margin component and a base cost of gas component can be a significant source of confusion, particularly on the part of customers trying to understand their changing natural gas bills.

Q. Does the inclusion of the base cost of gas within the tariffed rate as is currently done create any difficulties?

A. Yes. Under the current way rates are reflected in Southwest's tariffs, the cost of gas component is split apart, with the base cost of gas shown in one place and the other components shown elsewhere. Inherently the current way rates are structured is confusing for customers, as they are unable to look at their bill and determine what part of their bill reflects the commodity cost. Over the years I have personally spoken to a good number of

gas customers in Arizona who have expressed their frustration in their natural gas bill being difficult to understand. Particularly during a time when natural gas prices have been changing significantly and at times quickly, it is of interest to have natural gas bills be as understandable as possible for customers.

Q. Does Staff have any recommendations regarding the base cost of gas which could alleviate at least some customer confusion?

A. Yes. Staff recommends that the base cost of gas be set at zero, effectively eliminating the base cost of gas component, and that the monthly PGA rate now include the previously separate base cost of gas amount. This proposal would create a single line item on the customer bill which would represent the full commodity cost they are paying (absent a temporary surcharge or credit). So a customer could look at their bill and see the changing commodity cost component, an action customers cannot do at this time. Another benefit would be that it would be easier for customers and others to understand the portion of customer rates which is being dealt with in a rate proceeding, as the margin rate would be represented clearly and separately on a customer bill from gas cost component(s). Therefore a customer could directly see the margin rate change reflected in a new tariffed rate, made by the Commission in the rate proceeding. Such a change would also likely result in some simplification in the accounting necessary to be done in regard to the cost of gas in a rate proceeding and tracking of the PGA mechanism.

Q. Please discuss Staff's sample bills under the current and proposed treatment of the base cost of gas contained in Schedule RGG-4.

A. Schedule RGG-4 provides a hypothetical sample bill calculation showing the difference between a currently structured customer bill and what a customer bill would look like if the base cost of gas was set at zero and the full cost of gas was reflected in the monthly

PGA rate. The final amount paid by the customer is no different, just how the cost components are shown. Under the current bill structure example, the customer sees a tariffed rate of $0.85 per therm and a monthly PGA rate of $0.12 per therm, for a total per therm rate of $0.97. Under the proposed structure scenario, the customer sees a tariffed rate of $0.30 per therm and a monthly PGA rate of $0.67 per therm, again for a total per therm rate of $0.97. The difference is that under the current structure, the customer cannot tell that the total gas cost component on the bill is $0.67 per therm ($0.55 base cost of gas and $0.12 monthly PGA rate), whereas under the proposed structure the customer can clearly see that the total gas cost component on the bill is $0.67 per therm.

Q. Has Southwest expressed a view on the idea of setting the base cost of gas to zero as described above?

A. Yes. In response to a Staff data request, Southwest indicated that it believed that overall it is advantageous to combine the base cost of gas with the monthly PGA rate.

Q. Are there any drawbacks to setting the base cost of gas to zero and effectively combining it with the monthly PGA rate, creating a single gas cost component?

A. The only drawback Staff is aware of is that if such a change were to take place, some amount of customer confusion is likely in the short term, as is the case anytime there is a noticeable change to how customer bills are represented. However, a well-designed customer education effort to inform customers of this change would likely reduce customer confusion and in the longer term such a change would make customer bills more understandable and would reduce customer confusion. Staff recommends that if the recommendation to set the base cost of gas to zero is accepted that Southwest create specific customer education materials to explain this change. An example of possible

information to be provided to customers would be to show a side-by-side bill comparison under the old and proposed new structures.

Q. For customers who receive this proposed new way of showing the cost of gas on their bill, is there a way they can compare their current bill to last year's bill under the old way of showing the cost of gas?

A. Yes. For customers to see what their new bill would look like if it had the same structure as last year's bill, all they would have to do is subtract the currently effective base cost of gas of $0.37034 per therm from the monthly PGA rate on their new bill and add it to the margin rate. Doing this will in effect turn their new bill structure into the bill structure previously used by Southwest.

Q. Has Staff discussed this proposal with the Commission's Consumer Services section?

A. Yes. The Consumer Services section indicated that they favored the proposal, as in the long term they felt it would make customer bills more understandable and therefore reduce inquiries.

Q. If the Commission sets the base cost of gas to zero as Staff is recommending, is there any action which would need to be taken in regard to the $0.10 per therm band on the monthly PGA rate?

A. Yes. Obviously zeroing out the base cost of gas will cause the monthly PGA rate component to increase a great deal above its current level, well beyond what a typical application of the $0.10 per therm band would enable the monthly PGA rate to reflect. To address this sizable shift in the monthly PGA rate and allow the PGA mechanism including the $0.10 per therm band to continue functioning on a consistent manner, Staff recommends that when applying the $0.10 per therm band for the first twelve months

following the implementation of new rates that Southwest compare the new monthly PGA rate to the sum of the base cost of gas and the monthly PGA rate in prior months. This will provide a consistent benchmark for applying the $0.10 per therm band while transitioning to a zero base cost of gas. By the thirteenth month, the new "combined" PGA rate will have been in effect a year, making a comparison to the last twelve months an apples to apples comparison.

Q. Please discuss the way Staff represents Southwest's cost of gas in Staff's rate design schedules.

A. When discussing rate design and representing impacts of various rate design characteristics, Staff shows the base cost of gas as being set at Southwest's proposed level of $0.53436 per therm. The reason Staff does this is for comparability, so Staff's proposed rate design schedules can be more easily compared to those put forth by other parties. If the proposed zero base cost of gas was included in the rate design schedules, there would be no impact on the calculations of customer bill impact. The changes would be that the revenue column would become unnecessary, as that column merely capture the combined effect of the changes in margin rates and the amount recovered by the cost of gas. For the customer bill impact comparisons, the only effect would be that the amount shown in the base cost of gas column would be moved to the monthly PGA rate column.

PURCHASED GAS ADJUSTOR

Q. Please discuss the functioning of the PGA mechanism in recent years.

A. At the time the currently effective PGA mechanism was implemented in June 1999, natural gas prices had been relatively low and stable for a number of years. Shortly following implementation, significant changes took place in natural gas markets, leading to higher and more volatile natural gas prices which have made the last five years difficult

for regulators, local distribution companies, and consumers of natural gas. Recent years have also provided a stern test of various aspects of the PGA mechanism. Staff believes that in general the PGA mechanism as currently designed and operated has worked well, given the difficult circumstances of recent years. A PGA mechanism by nature determines the manner in which costs are passed through to customers, including such issues as timing and structure of such pass throughs. In a market where the underlying commodity cost has risen from around $2.50 per mmbtu to $6.00 or so in recent years, any PGA mechanism is going to reflect those higher costs which will be passed through to customers in some fashion, the only variance being the manner in which the rising costs are passed along to customers. No PGA structure can change or mitigate the underlying fact that natural gas prices have increased dramatically in recent years. Staff believes that the current PGA mechanism reasonably balances the interest in shielding customers from price volatility with the competing desire to at least to some extent send a price signal to customers regarding the changing level of the underlying commodity costs.

Q. Do you have any recommendations regarding Southwest's PGA mechanism?

A. Yes.

Q. Should the Commission continue to use the PGA mechanism currently in effect for Southwest?

A. Yes. With the exception of several limited modifications in the PGA bank balance trigger level and the interest rate applied to the bank balance, both of which are discussed later, Staff believes the existing PGA mechanism should be retained.

Q. Please discuss the trigger level on Southwest's PGA mechanism.

A. When the Commission established the rolling average PGA mechanism in decision number 61225 (October 30, 1998), the Commission set a trigger level on the Southwest's PGA bank balance such that if the balance became overcollected by $22.4 million or more, Southwest was required to take certain actions to address the undercollected bank balance. At the time the $22.4 million trigger level was set, it was contemplated that the trigger level might be adjusted in the future due to changing conditions such as customer growth or simply because a different level might be considered to be better at some later time.

Q. Have circumstances changed since Southwest's PGA bank balance trigger level was set at $22.4 million?

A. Yes. The $22.4 million trigger level was set on the basis of consumption levels for Southwest in 1996 and 1997. The average annual consumption for Southwest over 1996 and 1997 was multiplied by $0.05 per therm, resulting in the $22.4 million trigger level. The average consumption in those two years for Southwest was approximately 447 million therms. Since that time Southwest has seen growth in consumption to an average of approximately 516 million therms in 2003 and 2004. Additionally both the price and volatility of natural gas prices have increased enormously. Such changes suggest that the level of Southwest's trigger level should be revisited, taking into careful consideration the impacts which a change in the trigger level might have. Given greater consumption and higher and more volatile prices it reasonably follows that if the trigger is adjusted, it would be adjusted to a higher level.

Q. Please discuss issues which should be considered in resetting the trigger level.

A. It is important to note that there is no one "right" trigger level, with all other trigger levels being wrong. By its nature the level at which the trigger is set at is rather artificial. At the time the current trigger level was set in the 1998-1999 timeframe, it seemed like a reasonable level given current circumstances.

Given the higher natural gas prices which are prevalent now, the annual cost of gas for a utility, even absent any load growth, has increased a lot in recent years. For Southwest, the average annual cost of gas in 1996 and 1997 was approximately $134 million. This had increased to an average annual cost of gas in 2003 and 2004 of $267 million. Such a sizable increase creates difficulties in dealing with gas costs on both a company and customer basis.

Possible issues to be considered when resetting the trigger level include:

1. The size of balances (whether over-collected or under-collected) which may be carried by the company for an indeterminate period of time and any resulting financial impacts.
2. Possible increases in the amount of interest accumulated on the on-going balance.
3. Longer periods of time elapsing between when given costs are caused and when they are recovered from a company's ratepayers, potentially raising concerns of whether the cost causer is paying the costs.
4. The likelihood of less frequent filings for PGA credits or surcharges, which could have positive and negative aspects.

Additionally it should be noted that under the existing PGA mechanism there is nothing which prohibits Southwest or another local distribution company from filing with the

Commission for a PGA credit or surcharge at any time if the company believes such an action is warranted. In actuality Southwest's currently effective $0.02 per therm PGA surcharge resulted from a filing that Southwest made prior to reaching the trigger on the PGA bank balance.

Q. Please discuss potential methods for adjusting Southwest's PGA bank balance trigger level.

A. Applying the same method which was used in creating the original trigger, namely multiplying usage in the last two calendar years by $0.05 per therm would yield a new trigger level of $25.8 million based on 2003 and 2004 usage, a $3.4 million increase over the current trigger level. This method would capture the increase in core customer usage Southwest has experienced, but would not address the higher total gas costs being seen by Southwest.

If there was a desire to fully reflect the increase in total gas costs being experienced by Southwest, the trigger could be increased by the percentage increase gas costs have grown, almost 99 percent, from 1996 and 1997 to 2003 and 2004. Applying that percentage to the existing trigger level would result in a trigger level of $44.5 million, a very sizable increase over the existing trigger.

Another possibility would be to find some new trigger level that would capture the growth in usage and would provide some level of recognition of the higher natural gas costs without increasing the trigger level on the scale shown in the example which fully captures increased annual gas costs. For example, the $3.4 million increase which is reflective of usage growth could be doubled, taking the trigger level to $29.2 million.

Q. What trigger level does Staff recommend adopting for Southwest Gas?

A. Staff recommends that Southwest's trigger level for the PGA bank balance be increased from the current $22.4 million level to $29.2 million. Such an increase will provide some level of additional flexibility to absorb higher usage and higher natural gas costs in the PGA bank balance. This increase is also small enough that it wouldn't represent an enormous potentially new exposure for customers or the company if a positive or negative balance were to be carried for some period of time within the balance. In summary, an increase of the PGA bank balance trigger level to $29.2 million appears to be a reasonable balance between the different issues to be considered when resetting the trigger level.

Q. Please discuss the current interest rate being applied to Southwest's PGA bank balance.

A. Since establishment of the 12 month rolling average PGA mechanism in 1999, the interest rate applied to Southwest's balance has been the Federal Reserve's monthly, three month, commercial, non-financial paper rate. Recently an issue has arisen with this particular interest rate, as there was not a rate published for February. This was due to the fact that there were no published daily rates, from which the monthly rate is calculated. At the time the solution which was used was to apply the previous month's rate, with the understanding that the situation would be monitored to see if there would be an on-going problem with this particular interest rate. Since February 2005 it appears that there may be a continued problem which may result in there being further months when the Federal Reserve doesn't publish the currently used rate. For example, in April 2005, there was only one day when the interest rate was published, so therefore the monthly rate for April 2005 was based upon that one day. Absent that one day being published, April 2005 would have been another month where the interest rate currently being applied to Southwest's PGA bank balance was not published.

Q. Given these circumstances, does Staff believe that the Commission should consider use of a different interest rate to be applied to Southwest's PGA bank balance?

A. Yes. Staff believes it would be prudent to identify another interest rate to be applied to the PGA bank balance so that the problem of months with no published information for the current interest rate in a given month can be avoided.

Q. Please discuss the general issue of applying interest rates to the PGA bank balances.

A. Prior to the Commission's establishment of the 12 month rolling PGA mechanism in 1999, there was no application of interest to PGA bank balances. The decision to adopt the monthly, three month, non-financial, commercial paper rate as the proper rate to apply to PGA bank balances was the result of a working group process involving Staff, the Residential Utility Consumer Office ("RUCO"), Arizona LDCs, and other interested parties. At the time the monthly, three month, non-financial, commercial paper rate was generally hovering slightly above six percent. In recent years the currently applied interest rate has dropped to low levels, at times near one percent, reflecting the prevailing low interest rate climate. This recently low interest rate has been an issue which certain utilities have expressed a concern about given the tendency for LDCs to often have under-collected PGA bank balances in recent years and the carrying costs which may be incurred in relation to under-collected PGA bank balances. It has been my general observation that utilities do not show the same interest regarding a low interest rate when PGA bank balances are positive, thus benefiting the utility. Therefore it is important to view the setting of interest rates for the PGA bank balance and in other areas with a longer term view than simply what current market conditions may be.

Q. Does Staff have any recommendations regarding the interest rate to be applied to Southwest's PGA bank balance?

A. Yes. Staff recommends that the interest rate to be applied to Southwest's PGA bank balance be switched to the monthly one-year nominal Treasury constant maturities rate, contained in the Federal Reserve's H.15 statistical release or its successor.

Q. Please discuss this interest rate.

A. The monthly one-year nominal Treasury constant maturities rate is a rate which has been published since 1953 and there has never been a month where the monthly rate has not been published. A comparison of this interest rate to the currently applicable interest rate in recent years shows that this new rate is usually very similar but slightly higher than the currently applicable rate, with the differential ranging as high as approximately 0.8 percent in a few months, but typically 0.4 percent or less. For April 2005, the currently applicable interest rate is 2.97 percent while the proposed new interest rate would be 3.32 percent. Therefore adoption of this new interest rate would not represent a large shift from the existing interest rate regime, while also showing at least a small movement toward addressing the utilities' concern about the interest rate being too low. Additionally the Commission adopted the annual one-year nominal Treasury constant maturities rate as the appropriate interest rate to apply to Arizona Public Service Company's power supply adjustor rate in its recently concluded rate proceeding (Decision Number 67744, dated April 7, 2005).

Q. Has Staff estimated the potential impact of the use of the proposed new interest rate in comparison the the currently applied interest rate?

A. Yes. Staff started with a hypothetical $20 million PGA bank balance, and applied the 3.32 percent rate (proposed rate as of April 2005) in one case and the 2.97 percent rate

(currently applicable rate as of April 2005) in another case. For purposes of comparing the impact of the different interest rates, no other inputs were made to the PGA bank balance outside the additional interest accrued each month and its cumulative effect on the PGA bank balance. In the first case, the ending PGA bank balance was $20,602,153, and in the second case the PGA bank balance was $20,674,198, resulting in a cumulative difference after twelve months of $72,045. While not an insignificant amount of money, this differential is very small in comparison to the PGA bank balance being dealt with and is even very much smaller than the month to month changes that are typically seen in the PGA bank balance.

Q. Does Staff have any further recommendations regarding the interest rate to be applied to the PGA bank balance?

A. Yes. Staff recommends that if for some reason in the future the then applicable interest rate becomes unavailable for one or more months, the previous month's interest rate would apply to the month(s) where no interest rate is available. Further, Staff recommends that if the then applicable interest rate becomes unavailable on a recurrent basis, Southwest may file with the Commission to replace the interest rate with another interest rate, with the underlying presumption being that any replacement interest rate would be similar in nature to the then applicable rate.

Q. Does Staff have any recommendations regarding Southwest's monthly PGA report?

A. Yes. Staff recommends that a Southwest Officer certify, under oath, through an affidavit attached to each adjustor report that all information provided in the adjustor report is true and accurate to the best of his or her information and belief. This recommendation is consistent with actions taken by the Commission in other recent natural gas and electric cases dealing with adjustor mechanisms, including Graham Utilities Inc.'s recent natural

gas rate case (Docket No. G-02527A-04-0301). Staff further recommends that on the page where Southwest lists its purchases, that the term purchases be split into groups showing fixed price contracts and other contracts which vary such as index contracts. Staff further recommends that Southwest begin specifically identifying in its monthly PGA reports what the average and median usage levels are for its G-5 and G10 schedules for that given month.

GAS PROCUREMENT

Q. Please discuss the areas which you will address in your review of Southwest's gas procurement activities.

A. As part of Staff's overall review of Southwest's gas procurement activities, I provide a high level overview of Southwest's procurement activities during the test year. Additionally, I selected two months, January 2004 and July 2004 to review all individual purchases in those two months to assess whether the purchases appear reasonable given prices and market conditions at the time.

Q. Please describe in general terms Southwest's purchases of natural gas during the test year.

A. During the period of September 2003 to August 2004, Southwest purchased approximately 538 million therms for its core customers at a total cost of approximately $251 million, an average cost of $0.466 per therm. The average cost by month varied from $0.458 per therm in November 2003 to $0.553 per therm in August 2004. Transportation costs for interstate pipeline service ranged from $2.73 million in December 2003 to $1.96 million in November 2003. Purchased volumes varied from 21.9 million therms in October 2003 to 82.6 million therms in February 2004. During the test year the

monthly PGA rate increased from $0.09061 per therm in September 2003 to $0.16402 in July 2004.

Q. Please describe in general terms Southwest's spot market natural gas purchases in January 2004.

A. Southwest spot market deliveries in January 2004 represented 343 different purchases from 17 different suppliers resulting in total scheduled volumes of 553,498 decatherms. 36 purchases were based upon a fixed price, while 307 purchases were index based. Of the index based purchases, 268 were based upon indices in the San Juan supply basin (either El Paso – San Juan or Bondad) and 37 were based upon indices in the Permian supply basin (either El Paso – Permian or Waha). All referenced indices were from the Gas Daily publication. Prices paid for spot purchases in January 2004 ranged from $4.93 to $6.805 per decatherm.

Q. Please describe in general terms Southwest's spot market natural gas purchases in July 2004.

A. Southwest spot market deliveries in July 2004 represented 147 different purchases from 12 different suppliers resulting in total scheduled volumes of 886,826 decatherms. With the exception of six small purchases which were based on a fixed price, all the July 2004 spot market purchases were index based. Referenced indices were from the Gas Daily and Inside FERC publications. All but two of the index based purchases were based on San Juan basin indices, with the other two purchases referencing a Gas Daily Permian basin index. Prices paid for spot purchases in July 2004 ranged from $4.825 to $5.92 per decatherm.

Q. Did Staff independently verify that the prices reflected in index based purchases in January and July 2004 actually match the prices Southwest shows having paid under the index based purchases?

A. While the Commission does not hold a subscription to Inside FERC – Natural Gas Markets, the Commission does subscribe to Gas Daily. A review of Southwest's index based purchases which reference Gas Daily show that in all such cases Southwest's reported prices match the Gas Daily indices referenced in said purchases.

Q. Were there any spot market purchases where the price varied noticeably from the supply basin indices?

A. Yes, there were a small number of such instances representing a very small portion of Southwest's overall purchases. There were eight purchases in January and June 2004 where the prices paid were somewhat higher than the published supply basin indices for that given day. In response to a data request Southwest indicated that all eight of these purchases were made in a scheduling cycle later than cycle one. I have reviewed information from Southwest's scheduling records to confirm that these purchases were made in later cycles. There are a total of four scheduling cycles in each gas day and most if not all gas is typically scheduled during the first cycle, which is the cycle where prices are tied to the given basin indices. When a shipper schedules gas in later cycles, it may have to pay more for the gas, as there is typically thin trading in later cycles, the ability to move gas is often limited on the pipeline due to earlier cycle nominations, and often such a need is generated by unexpected weather or system conditions which also may lead to other shippers pursuing additional gas supplies.

Q. Please describe in general terms Southwest's fixed price natural gas purchases in January 2004.

A. Southwest fixed price deliveries in January 2004 represented 17 different purchases from 8 different suppliers resulting in total scheduled volumes of 5,473,532 decatherms. The lengths of the contracts which these purchases were made under range from 1-5 months, generally covering the winter heating season. Prices paid for fixed purchases in January 2004 ranged from $3.91 to $5.40 per decatherm.

Additionally, in January 2004, Southwest had 11 term purchases from 9 different suppliers resulting in total scheduled volumes of 2,356,732 decatherms. These term purchases were made for 4-5 months and were indexed to San Juan and Permian basin indices published in Gas Daily and Inside FERC Natural Gas Markets. Prices paid for term purchases in January 2004 ranged from $4.93 to $6.805 per decatherm.

Q. Please describe in general terms Southwest's fixed price natural gas purchases in July 2004.

A. Southwest fixed price deliveries in July 2004 represented 7 different purchases from 4 different suppliers resulting in total scheduled volumes of 1,906,989 decatherms. The lengths of the contracts which these purchases were made under range from 5-7 months, generally running from spring to fall. Prices paid for fixed purchases in July 2004 ranged from $4.01 to $4.39 per decatherm.

Q. Please discuss existing Commission policy regarding longer term, fixed price gas supply contracts.

A. In Decision Number 61225 (October 30, 1998) the Commission specifically identified price stability as one of the goals of the gas procurement process for Arizona local

distribution companies ("LDCs"), including Southwest. In this Decision the Commission further directed Arizona LDCs, including Southwest, to pursue longer term, fixed price supply options as part of their gas supply portfolio. To date the Commission has not mandated any specific percentages which must be purchased under long term contracts. Southwest has indicated at times in the past that it generally targets approximately 50 percent of its gas supply to be purchased through fixed price, longer term contracts with balance of its gas supply purchased through spot market purchases.

Q. Please discuss the role such longer term, fixed price contracts play in Southwest's gas supply portfolio.

A. The primary function which these contracts play is that they introduce some price stability into Southwest's overall supply portfolio, thereby at least partially blunting the impact of natural gas price movements in the marketplace. It is important to note that the purpose of such longer term, fixed price contracts is not to reduce the cost of natural gas in and of itself, but rather to reduce price volatility in Southwest's gas supply portfolio, thereby reducing the fluctuations in natural gas prices which Southwest's customers face. Over time it is to be expected that such fixed price contracts will at times end up being higher priced than actual market prices and at times end up being lower prices that actual spot market prices. In recent years natural gas prices have generally been increasing. In such an environment, prices which have been locked in for a period of time generally result in lower than market prices over the term of the contract. Therefore Southwest's longer term, fixed price purchases in recent years have generally saved money over a situation where Southwest had bought all of its supplies based upon spot market indices. This has been a beneficial side effect of the longer term, fixed price contracts, but it should be recognized that at points where natural gas market prices may be in decline that such

purchases will result in higher than spot market prices, tying back to the recognized goal of such contracts of introducing a measure of price stability.

Q. Are Southwest's purchases of natural gas under longer term, fixed price contracts which you have reviewed consistent with the Commission's policy regarding such purchases?

A. Yes. It is clear that Southwest purchases a significant portion of its natural gas supplies through fixed price, longer term contracts and that such contracts have introduced a measure of price stability to Southwest's gas supply portfolio. As part of its gas procurement efforts, Southwest should further explore opportunities to provide price stability to its core customers.

RATE DESIGN

Q. What total margin target have you designed your proposed rates to meet?

A. The rates I am proposing are designed to provide a total margin to Southwest of $369,145,782. The details of my rate design proposals, customer bill impact estimates, and other related details are contained in Schedule RGG-3. As I stated above, since the revenue requirements number was amended, and since it takes time to adjust the rate design to reflect the amended revenue requirements number, I will be filing supplemental rate design schedules.

Q. Has Southwest made any proposals related to the rates to be paid by Southwest's customers?

A. Yes. Southwest has proposed a wide variety of changes to its rate schedules involving both the tariffed rates and the terms of service. Southwest has further provided two rate

design proposals, dependent upon whether its request for the conservation margin tracker ("CMT") is granted or not.

Q. Please discuss the factors which Staff considers in regard to rate design for Southwest.

A. Staff considered a number of factors in creating its rate design. These factors include cost of service, the desire to encourage energy conservation, the need to use gradualism in cases where rates are being changed so that customers are not hit by large rate increases, customer equity issues within and between rate classes, efforts to make rates and bills easier for customers to understand, revenue impacts on the Company, and other policy considerations. Given the number of various considerations which go into designing rates, some of which are not easily quantifiable, it is understandable why it is commonly said that rate design is more of an art than a science.

Residential Rates

Q. Please describe Southwest's proposed changes to its residential rate schedules.

A. Southwest proposes to split the existing G-5, Residential Gas Service tariff ("G-5 tariff") into a single family and a multi-family tariff ("proposed G-6 tariff"). Southwest would also eliminate the G-15, Special Residential Gas Service for Air Conditioning ("G-15 tariff") and G-16, Special Residential Gas Service for Electric Generation ("G-16 tariff") tariffs, merging existing G-15 customers into the otherwise applicable residential tariff. Southwest would eliminate the G-10, Low Income Residential Gas Service ("G-10 tariff"), merging the low income discount features into the other residential tariffs, replacing the current 20 percent discount in the winter months on the first 150 therms with a 15 percent discount year round. Southwest also shrinks the size of the first block in the G-5 tariff and the proposed G-6 tariff would have a smaller first block than the G-5 tariff.

Southwest also proposes to change November from being considered a winter season month to being considered a summer season month. Regarding actual rates for residential customers, both of the rate design proposals by Southwest represent a very sizable shift to frontloading costs in the customer charge and the first block of usage.

G-5, Residential Gas Service

Q. Please discuss Southwest's proposal to significantly increase the customer charge and first usage block for residential customers.

A. Southwest's rate design proposals would increase the residential customer charge from the current $8.00 to either $12.00 or $16.00, depending upon whether the conservation margin tracker is adopted. Under Southwest's current G-5 tariff, the first usage block is priced approximately $0.08 per therm higher than the second usage block. Southwest's rate design proposals would increase the differential to between $0.50 and $0.60 per therm. It is understandable that from the Company's financial viewpoint, a heavy frontloading of costs into the customer charge and first usage block is desirable. Such a rate design would increase the certainty of the Company's revenue, as the customer charge and usage in the first block are less impacted by fluctuations in weather and other factors. However, the Company's interest must be balanced by the significant impacts of such a rate design on bills residential customers would face, and other considerations.

Q. Please discuss Staff's general concerns with Southwest's proposed front-loading of costs in the residential customer charge and first usage block.

A. Any time such large changes in rate structure are proposed by a utility, the potential impacts on customers must be carefully considered. Generally speaking when large shifts such as this are undertaken, some customers bear much more of the brunt of the rate increase than other customers do. The proposed large increases in the customer charge

and the first usage block would hit low usage residential customers particularly hard, while high usage customers would see relatively small bill increases. Additionally, having a differential in excess of $0.50 per therm between the first and second usage blocks in a declining block rate structure raises the question of whether the customers will be provided with a disincentive to conserve natural gas. Under the current G-5 tariff, the second usage block is approximately $0.08 per therm cheaper than the first usage block. Given fluctuations in natural gas prices and the resulting changes in the monthly PGA rate as well as PGA surcharges and credits which may be in place at the time, the current differential is not likely to be large enough for a significant percentage of customers to notice the differential and then change their behavior as a result. However, to the extent there is some level of declining block rate structure, the potential exists for customers to notice and possibly use more of the commodity being priced than if the commodity was structured with a flat rate. Southwest's proposed differential in excess of $0.50 per therm between the first and second usage blocks would dwarf the changes which customers are likely to see through the PGA mechanism over any short term time frame. Such a large differential between the first and second usage blocks is likely to result in some amount of customers noting the significantly less expensive price per therm in the second block and therefore some customers might consume more therms as their consumption moves into the second block.

To the extent there is a need or desire to increase the customer charge and first block per therm rate, a much more gradual movement would be warranted to protect customers from possible rate shock. Another possibility is to move in the other direction, reducing or eliminating the declining block characteristic of the residential rate structure and moving to either a flat rate or even possibly an inclining block rate structure.

Q. Please discuss other factors that the Commission may wish to consider in addressing the issue of a declining block rate structure for Southwest's residential customers.

A. By nature using a declining block rate structure is more complicated than the more commonly used flat rate structure. For a residential customer, it makes their bill more difficult to understand, as instead of having a single tariff rate multiplied by their therm consumption, the bill reflects the different rates in each block, each applied to the applicable portion of the usage. Use of a single flat rate would be simpler for the customer to understand. Additionally, apart from Southwest's residential tariffs, no other Southwest tariff employs a declining block rate structure. Use of a declining block is also more difficult to administer. Apart from Southwest, none of the other Arizona LDCs have a declining block rate structure for their residential customers. Also, in Southwest's last rate proceeding before the Commission, there was some interest expressed in seeing the declining block rate structure eliminated or even moved to an inclining block rate structure to promote energy conservation.

When looking at the overall residential rate design, even if the Commission were to move to a flat tariffed per therm rate for residential customers, the continuing existence of a basic service charge in essence still creates some semblance of a declining block rate structure. The basic service charge could be viewed as a first block in the declining block rate structure, with no usage associated with the application of the basic service charge block of the rate structure.

Q. What are Staff's recommendations regarding a declining block rate structure in the future?

A. While Staff is not recommending movement to a flat rate structure for Southwest's residential rates at this time, Staff is recommending a smaller block differential at this time

as well as smaller first blocks in the summer and winter, as the first step toward a flat rate structure for residential customers. Staff anticipates in the next Southwest rate proceeding before the Commission that Staff will propose elimination of the declining block rate structure for residential customers, eliminating a possible disincentive for energy conservation. Such a movement in rate design will eliminate any possible rate design disincentive for customers to conserve which a declining block rate structure could provide and would present a simpler, more understandable rate design for residential customers.

Q. Please discuss Staff's view of Southwest's proposal to split the residential rate class into separate single family and multi-family classes.

A. Southwest has proposed splitting the current G-5 tariff into a single family residential tariff and a multi-family residential tariff. Southwest's proposed multi-family residential customer class is only a very small segment of the overall residential customer class. While there appear to be some differences between single family and multi-family residential customers, there is no compelling reason to split the existing residential customer class into subclasses.

Q. What are Staff's recommendations regarding rates for the G-5 tariff?

A. Staff recommends that the basic service charge be increased from $8.00 to $9.50. Staff further recommends that the first summer usage block be reduced from 20 therms to 15 therms and that the first winter usage block be reduced from 40 therms to 35 therms. Staff recommends that the per therm rate for the first block be increased from $0.48762 per therm to $0.54 per therm and the per therm rate for the second block be increased from $0.40344 per therm to $0.49 per therm. This would result in a reduction of the differential between the two blocks from $0.08418 per therm currently to $0.05 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-5 tariff rates?

A. An average G-5 customer using 72 therms in January would see their bill increase from $84.04 to $90.16, a 7.3 percent increase. A median G-5 customer using 58 therms in January would see their bill increase from $69.91 to $74.81, a 7.0 percent increase. A G-5 customer using the annual average consumption of 29 therms would see their bill increase from $39.71 to $42.73 under winter rates, a 7.6 percent increase.

G-10, Low Income Residential Gas Service

Q. Please identify Southwest's proposals regarding the G-10 tariff for low income customers.

A. Southwest indicated that it was concerned regarding the possible rate impacts on low income customers and that it crafted its rate proposals to address this. Southwest indicated that its billing system no longer requires the low income discount tariff to be listed as a separate tariff and therefore the low income discount tariff should be discontinued, with the low income discount functions being folded into the other residential tariffs. Further, Southwest proposes to retain the existing $7.00 customer charge. Also, Southwest proposes to replace the existing 20 percent discount on the first 150 therms consumed each month during the winter months with a 15 percent discount year round with no consumption limit.

Q. Does Staff agree that the G-10 tariff should be discontinued and its discount functions be folded into the other residential tariffs?

A. No. Typically Arizona utilities which offer a low income discount tariff have done so through a separate, stand-alone tariff such as the current G-10 tariff. Southwest's changing billing system capabilities provides an unpersuasive reason to no longer have a stand alone low income discount tariff. On balance, Staff believes that retaining a

separate low income tariff is preferable. Having a separate tariff will likely provide a higher profile to the low income discount opportunity than to have it provided through certain clauses of the other residential tariffs. For example, if a customer were to look at Southwest's tariffs on the Company website or at the ACC offices, having the low income discount listed as a separate tariff would seem to make it more noticeable. Additionally, having multiple customer charges and rates listed on the other residential tariffs, indicating what the rates are for both non-low income and low income customers will likely be confusing to customers. Therefore, Staff recommends that the G-10 tariff be retained as a separate tariff.

Q. Please discuss Southwest's rate recommendations in regard to the G-10 customer charge.

A. Southwest's proposal to retain the $7.00 customer charge for low income customers served on the G-10 tariff is reasonable and should be adopted.

Q. Please discuss Southwest's rate recommendations in regard to the rate discount provisions.

A. Southwest's proposal spreads a lower percentage rate discount over the entire year, rather than providing a higher rate discount on the first 150 therms of consumption during the winter months. This proposal raises the question of what manner of timing for discounts is most beneficial to customers? In general in recent seasons of high natural gas prices, most of the concern at the Commission has been targeted at the winter months where customer usage and therefore bills are at their highest levels. As such, it seems preferable to retain a system where the discounts continue to be targeted at the high usage winter months. Provision of a discount during the summer months would certainly be of some benefit to customers, but to a lesser extent than focusing the impact of the discounts on the

high usage winter months. Staff believes that retention of the discount in only the winter months is preferable.

Q. How are low income rate assistance ("LIRA") customer discounts accounted for by Southwest?

A. LIRA discount dollars are recovered through a LIRA surcharge which is currently applied to other residential customer classes. The LIRA surcharge is reset annually by Southwest as part of one of its monthly PGA filings.

Q. Please discuss the issues which Staff considered in designing its proposed G-10 tariff.

A. Over the past decade the Commission has been proactive in establishing discount tariffs for low income utility customers in Arizona and for LDCs in Arizona. These tariffs have helped provide some amount of buffering for these customers from the significant increases in natural gas commodity costs in recent years, though even with such discounts low income customers are also paying much higher natural gas bills than they did when commodity prices were much lower. Similarly low income discount tariffs have been introduced for electric utilities to help buffer the impact of high air conditioning bills in the summer months. For a utility such as Southwest, which provides a percentage discount to low income customers, as commodity costs and overall tariff rates increase, the size of the discount customers receive also increases. Under Southwest's rate effective for June 2005, a customer using 150 therms would receive a discount of $30.95, assuming such usage is in a winter month when the discount applies. This is a significantly higher discount than a customer with the same usage level was receiving 5-6 years ago.

One issue that must be balanced is the desire to provide significant relief to low income customers, while not placing too much of a burden on other residential customers who are

also facing higher natural gas bills, and who have to pay for every dollar which is provided to LIRA customers in the form of a discount.

Q. How does Southwest's current discount level compare with other major natural gas and electric utilities in Arizona regulated by the Commission?

A. Southwest's current discount level provides the highest overall rate discounts of any major electric or natural gas utility in Arizona. Further, Southwest's discount tariff is the only discount tariff of any major electric or gas utility in Arizona that does not have a cap on benefit levels. The other major LDC in Arizona, UNS Gas, provides a $0.15 per therm discount on the first 100 therms of usage in winter months, setting an effective cap of $15.00 for a monthly customer discount. For electric utilities, Tucson Electric Power provides a flat $8.00 per customer per month discount, UNS Electric provides a declining block discount, with the final discount block providing a $8.00 per customer per month discount, and APS also provides a declining block discount with the final discount block providing a $13.00 per customer per month discount. Compared to these other discounts, Southwest's maximum discount level as of June 2005 effective rates results in a discount of as high as $30.95 in a winter month which far exceeds the possible highest discount for other major Arizona utilities. Additionally, customers taking service on the G-10 tariff receive a discounted basic service charge and receive a discount on the service establishment charge.

Q. In light of these circumstances, what are Staff's recommendations regarding Southwest's G-10 tariff?

A. Staff recommends that the basic service charge continue to be $7.00 and the discount provided by the G-10 tariff remain at the current 20 percent level for the first 150 therms in the winter months. Given the large size of discounts which can be achieved under the

existing discount structure and the desire to balance the discount level with the impact a higher discount level would have on other residential customers who would bear that additional burden, Staff believes that the current discount level is equitable and does in fact provide a significant benefit to low income customers who take service under the G-10 tariff.

Q. What are the customer bill impacts of Staff's recommendations for the G-10 tariff, in conjunction with Staff recommended residential rates for the G-5 tariff?

A. An average G-10 customer using 70 therms in January would see their bill increase from $66.22 to $69.77, a 5.4 percent increase. A median G-10 customer using 64 therms in January would see their bill increase from $61.37 to $64.51, a 5.1 percent increase. A G-10 customer using the annual average consumption of 29 therms per month would see their bill increase from $32.37 to $33.59 under winter rates, a 3.8 percent increase. The maximum discount available for a customer who uses 150 therms in a winter month increases from $30.95 under current rates to $33.23 under proposed rates.

Q. Please briefly discuss the other relief that Staff is proposing to provide low income customers.

A. As previously noted, Staff agrees with Southwest's proposal to keep the monthly customer charge for the G-10 tariff at the current $7.00 level, a savings of $1.00 over the current G-5 customer charge of $8.00, and a $2.50 savings over the Staff proposed monthly customer charge of $9.50. Additionally, Staff is proposing to keep the service establishment charge for G-10 customers at the current levels of $24.00 for normal service and $32.00 for expedited service, a savings of $9.00 and $15.00 respectively over the service establishment charges Staff has proposed for other residential customers.

Additionally, as discussed in Staff Witness Steve Irvine's testimony, Staff is recommending increased funding for the low income weatherization program.

Q. Does Staff have any further recommendations regarding Southwest's LIRA tariff?

A. Yes. Southwest provides quarterly reports to the Commission regarding LIRA tariff activity such as participation and discount levels. The current reports provide some financial information regarding discounts provided under the LIRA tariff, but not a complete accounting of LIRA bank balance activity. Staff recommends that within 90 days of the date of the final order in this proceeding, in addition to LIRA program information currently contained in the LIRA reports, Southwest begin including in its LIRA reports a complete accounting of the LIRA bank balance for the most recent 12 month period, including individual listing of all inputs into the LIRA bank balance each month.

G-15, Special Residential Gas Service for Air Conditioning

Q. Does Staff agree that the G-15 tariff should be eliminated, with customers migrated to the other residential tariffs as proposed by Southwest?

A. No. A review of the billing frequency analysis ("BFA") for G-15 customers indicates that typical usage is significantly higher than general residential usage, as would be expected from customers who use natural gas for air conditioning. Given the significantly different usage patterns of G-15 customers, it seems reasonable to continue the G-15 tariff as a separate tariff for customers who have natural gas air conditioning.

Q. What are Staff's recommendations regarding rates for the G-15 tariff?

A. The G-15 tariff has typically reflected the same residential rate components as the G-5 tariff, with the exception of the second summer usage block which is priced lower to

account for significant summer usage for air conditioning consumption. Staff recommends that the G-15 tariff continue to reflect the G-5 tariff rates with the exception of the second summer usage block. For the second summer usage block, Staff recommends an increase from $0.19125 per therm to $0.28 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-15 tariff rates?

A. An average G-15 customer using 150 therms in January would see their bill increase from $162.77 to $175.89, a 8.1 percent increase. A median G-15 customer using 113 therms in January would see their bill increase from $125.43 to $135.09, a 7.7 percent increase. A G-15 customer using the annual average consumption of 119 therms would see their bill increase from $131.48 to $141.92 under winter rates, a 7.9 percent increase.

G-16, Special Residential Gas Service for Electric Generation

Q. Does Staff agree with Southwest's proposal to eliminate the G-16 tariff?

A. Yes. Southwest has indicated that no customers have taken service on this tariff, which was introduced as a result of Southwest's last general rate proceeding in Arizona. Therefore no customers will be impacted by the elimination of this tariff and residential electric generation customers could now take service under the G-60 cogeneration tariff, which Southwest is proposing to make available to smaller electric generators. Schedule G-60 appears to be more favorable to residential electric generators anyway, so to the extent residential electric generation customers begin to seek service from Southwest, they would likely prefer the G-60 tariff to the G-16 tariff. The current rates under the G-16 tariff are identical to those offered under the current G-15 tariff. It appears that any prospective customers for residential electric generation could be accommodated under Southwest's other residential tariffs. Additionally, Southwest could file to implement a

new tariff for residential electric generation service at some point in the future if the need for such a tariff develops.

G-20, Master Metered Mobile Home Park Gas Service

Q. What are Staff's recommendations regarding rates for the G-20 tariff?

A. Staff recommends that the basic service charge be increased from $50.00 to $60.00. Staff further recommends that the per therm rate be increased from $0.31415 per therm to $0.376 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-20 tariff rates?

A. An average G-20 customer using 2522 therms in January would see their bill increase from $2370.44 to $2536.43, a 7.0 percent increase. A median G-20 customer using 700 therms in January would see their bill increase from $694.06 to $747.15, a 7.7 percent increase. A G-20 customer using the annual average consumption of 1081 therms would see their bill increase from $1044.61 to $1121.47, a 7.4 percent increase.

G-25, General Gas Service

Q. Southwest has proposed to create a new G-25 subclass for the smallest commercial customers. Does Staff agree with this recommendation?

A. No. Under Southwest's proposal and proposed rates, the members of this new smallest commercial class would see a much larger rate increase than if they had remained part of the current small commercial customer class presently in existence. While addition of a fourth subclass in the G-25 tariff is not necessarily objectionable, it should be done in a way which would not substantially disadvantage those customers who would be moved

into the new customer class. I recommend that the current usage levels for small, medium, and large G-25 customer groupings be retained.

Q. Southwest has proposed to change the formula for calculating the demand charge for large G-25 customers from using the customer's coincident peak to using the noncoincident peak. What is Staff's recommendation regarding this proposed change?

A. While there may be some merit in trying to address a linkage to system costs through a shift to use of the noncoincident peak in calculating the demand charge, such a shift can and would have a significant bill impact on customers who have a very different coincident and noncoincident peak. Some customers may have structured their consumption and operations such that they reduce consumption on what is likely to be Southwest's peak month. Movement to a noncoincident peak calculation would result in large bill increases for customers who have low coincident peaks and high noncoincident peaks. Such a result is not worth the benefits that the Company believes accrue from moving to the noncoincident method which the company believes is more aligned with actual cost causation. Staff recommends that the demand charge for large G-25 customers continue to be calculated using the coincident peak.

Q. What are Staff's recommendations regarding rates for the G-25, Small segment of the G-25 tariff?

A. Staff recommends that the basic service charge be increased from $20.00 to $24.00. Staff further recommends that the per therm rate be increased from $0.38024 per therm to $0.44700 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-25, Small tariff rates?

A. An average small G-25 customer using 223 therms in January would see their bill increase from $239.93 to $258.80, a 7.9 percent increase. A median small G-25 customer using 113 therms in January would see their bill increase from $131.44 to $142.98, a 8.8 percent increase. A small G-25 customer using the annual average consumption of 122 therms would see their bill increase from $140.31 to $152.46, a 8.7 percent increase.

Q. What are Staff's recommendations regarding rates for the G-25, Medium segment of the G-25 tariff?

A. Staff recommends that the basic service charge be increased from $90.00 to $105.00. Staff further recommends that the per therm rate be increased from $0.27211 per therm to $0.305 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-25, Medium tariff rates?

A. An average medium G-25 customer using 2,682 therms in January would see their bill increase from $2444.90 to $2548.11, a 4.2 percent increase. A median medium G-25 customer using 1,791 therms in January would see their bill increase from $1662.57 to $1736.48, a 4.5 percent increase. A medium G-25 customer using the annual average consumption of 1,690 therms would see their bill increase from $1573.89 to $1644.47, a 4.5 percent increase.

Q. What are Staff's recommendations regarding rates for the G-25, Large segment of the G-25 tariff?

A. Staff recommends that the basic service charge be increased from $500.00 to $540.00. Staff further recommends that the per therm rate be increased from $0.08548 per therm to $0.10 per therm. Staff also recommends that the demand charge be increased from $0.072695 per therm to $0.07700 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-25, Large tariff rates?

A. An average large G-25 customer using 51,574 therms in January would see their bill increase from $40600.22 to $41652.09, a 2.6 percent increase. A median large G-25 customer using 36,000 therms in January would see their bill increase from $28491.00 to $29237.32, a 2.6 percent increase. A large G-25 customer using the annual average consumption of 42,048 therms would see their bill increase from $33,193.49 to $34,058.46, a 2.6 percent increase.

G-35, Gas Service to Armed Forces

Q. Southwest has proposed elimination of the G-35 tariff, with customers being migrated to the otherwise applicable tariff, the G-25 General Service tariff. Does Staff agree with this recommendation?

A. No. In a data response Southwest provided an estimate showing that current G-35 customers would save money by being switched to the G-25 tariff, based upon Southwest's estimate of what it would have proposed for G-35 rates. However, a comparison of currently effective rates shows that current G-35 customers overall pay $18,016 less under the current G-35 tariff than under the current G-25 tariff. Therefore, any savings G-35 customers show under Southwest's proposed G-25 and hypothetical G-

35 reflects the fact that Southwest's proposed increase for the G-25 tariff is less than what it would have proposed for the G-35 tariff. The overall difference between what current G-35 customers pay under the current G-35 tariff compared to what they would pay under the current G-25 tariff is not enormously different, so future savings are dependent on how much increase is allocated to the G-25 versus G-35 tariffs. Given that the current G-35 tariff appears to be more favorable to current G-35 customers than the current G-25 tariff by a small margin, Staff recommends retaining a separate G-35 tariff. Staff further recommends that customers served under the G-35 tariff be provided the option of taking service under the G-25 tariff instead. If the G-25 tariff is truly more beneficial to G-35 customers, they will naturally migrate to it and possibly in Southwest's next rate proceeding there will be no customers taking service on the G-35 tariff. It is worth noting that the Department of Defense, the sole customer taking service under the G-35 tariff, is an intervenor in this proceeding.

Q. What are Staff's recommendations regarding rates for the G-35 tariff?

A. Staff recommends that the basic service charge be increased from $350.00 to $370.00. Staff further recommends that the per therm rate be increased from $0.18966 per therm to $0.215 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-35 tariff rates?

A. An average G-35 customer using 67,261 therms in January would see their bill increase from $53,862.18 to $55,586.57, a 3.2 percent increase. A median medium G-35 customer using 63,500 therms in January would see their bill increase from $50,869.97 to $52,499.06, a 3.2 percent increase. A G-35 customer using the annual average

consumption of 33,008 therms would see their bill increase from $26,610.83 to $27,467.26, a 3.2 percent increase.

G-40, Air Conditioning Gas Service

Q. Southwest has proposed implementing a single basic service charge for this tariff, rather than what the customer's otherwise applicable basic service charge would be. Does Staff agree with this recommendation?

A. No. Southwest has a number of tariffs where the basic service charge is set by what it would be on the customer's otherwise applicable tariff, and this is the only tariff where Southwest is proposing this change. Staff sees no reason why the current provision should be changed and it seems reasonable to have a larger basic service charge for a large commercial customer taking service under this tariff compared to a small commercial customer taking service under this tariff.

Q. What are Staff's recommendations regarding rates for the G-40 tariff?

A. Staff recommends that the otherwise applicable basic service charge continue to be applied to G-40 customers. Staff further recommends that the per therm rate be increased from $0.07613 per therm to $0.09500 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-40 tariff rates?

A. A median G-40 customer using 175 therms in January would see their bill increase from $139.36 to $146.66, a 5.2 percent increase. A medium G-40 customer using an annual average of 3,826 therms would see their bill increase from $2,699.56 to $2,786.76, a 3.2 percent increase. A small customer using the the annual median average monthly usage of 540 therms would see their bill increase from $388.31 to $402.50, a 3.7 percent increase.

G-45, Street Lighting Gas Service

Q. What are Staff's recommendations regarding rates for the G-45 tariff?

A. The G-45 tariff does not have a basic service charge. Staff recommends that the per therm rate be increased from $0.47648 per therm to $0.54 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-45 tariff rates?

A. A G-45 customer using the annual average monthly usage of 287 therms would see their bill increase from $310.65 to $328.88, a 5.9 percent increase.

G-55, Gas Service for Compression on Customer's Premises

Q. What are Staff's recommendations regarding rates for the G-55 tariff?

A. Staff recommends that the small basic service charge be increased from $20.00 to $24.00, the large basic service charge be increased from $170.00 to $185.00, and the residential basic service charge be increased from $8.00 to $9.50. Staff further recommends that the per therm rate be increased from $0.13305 per therm to $0.165 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-55 tariff rates?

A. A residential G-55 customer using the January median usage of 62 therms would see their bill increase from $53.82 to $57.30, a 6.5 percent increase. A residential G-55 customer using the annual median monthly usage of 65 therms would see an increase in their bill from $56.03 to $59.61, a 6.4 percent increase.

G-60, Cogeneration Gas Service

Q. Southwest has made a number of proposals regarding the cogeneration tariff. Please describe these proposed changes.

A. Southwest has proposed that the G-60 tariff be made available to all electric generation customers, with the exception being customers of 5 megawatts ("MW") or greater, who would have to either take transportation service or if eligible service under the G-30 tariff. Additionally, Southwest has proposed to apply its general monthly PGA rate to G-60 customers, rather than having the cost of gas reset twice a year (along with G-80 tariff customers).

Q. Does Staff agree with Southwest's proposal to make the G-60 tariff available to smaller electric generation customers, such a residential customers who would previously have taken service under the G-16 tariff?

A. Yes.

Q. Please discuss the proposed limit on customers greater than 5 MW or greater customers.

A. Southwest's has legitimate concerns regarding the possibility of significant new electric generation loads straining its system and impacting service to other core customers, especially in light of the growing operational restrictions on the El Paso interstate pipeline system. At the same time it is disconcerting to impose a provision on a tariff which in effect bars a certain portion of the customers in Southwest's service territory who would likely take service under that tariff from taking such service due to their size. Southwest has indicated in a data request that there are no customers above 5 MW currently taking service under the G-60 tariff. Rather than banning customers above 5 MW from taking service under the G-60 tariff, Staff recommends that Southwest develop and propose

provisions for the G-60 tariff which would provide sufficient protections for the system and other core customers from the potential impacts of 5 MW or larger electric generators.

Q. Does Staff agree with Southwest's proposal to apply the monthly PGA rate to G-60 customers rather than resetting their cost of gas twice a year as is currently done for G-60 and G-80 customers?

A. Yes. As a general principal it is simpler to administer Southwest's tariffs with a single cost of gas for all customer classes and applying the monthly PGA rate to the G-60 tariff would move in that direction. Also, the Commission held a proceeding, including a workshop in the Tucson office, to address the issue of gas cost calculations for the G-60 and G-80 tariffs. G-80 tariff customers were vocal regarding the need to have their gas cost reset twice a year, as it allowed them to know what their utility costs would be when they planned their spring planting. No G-60 customers participated in that proceeding, which changed the way their gas cost was set. Additionally, there would seem to be an economic interest in having a gas cost for electric generation customers that shows gas cost movement on a monthly basis for customers who are using that gas to generate electricity.

Q. What are Staff's recommendations regarding rates for the G-60 tariff?

A. Staff recommends that the otherwise applicable general service and essential agricultural basic service charges continue to be applied to G-60 customers. Staff further recommends that the per therm rate be increased from $0.08934 per therm to $0.11000 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-60 tariff rates?

A. A medium G-60 customer using the January median usage of 6,500 therms would see their bill increase from $4,609.26 to $4,758.55, a 3.2 percent increase. A medium G-60 customer using the annual average median monthly usage of 5,250 therms would see their bill increase from $3,740.17 to $3,863.63, a 3.3 percent increase.

G-75, Small Essential Agricultural User Gas Service

Q. Southwest has proposed freezing the G-75 tariff so no new customers could take service under the tariff. New customers who would previously have taken service under the G-75 tariff would now take service under the G-25, General Service tariff. Does Staff agree with freezing the G-75 tariff to new customers?

A. No. Agricultural customers who are eligible for the G-75 tariff may now choose to take service under either the G-25 or G-75 tariff. Elimination of the G-75 tariff for new customers would remove such an option for these agricultural customers. Absent a powerful reason to take this service option away from these customers, the G-75 tariff should be retained.

Q. What are Staff's recommendations regarding rates for the G-75 tariff?

A. Staff recommends that the basic service charge be increased from $75.00 to $90.00. Staff further recommends that the per therm rate be increased from $0.19468 per therm to $0.22500 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-75 tariff rates?

A. An average G-75 customer using 10,192 therms in January would see their bill increase from $8,234.82 to $8,507.88, a 3.3 percent increase. A median G-75 customer using 2,125 therms in January would see their bill increase from $1,776.30 to $1,845.10, a 3.9 percent increase. A G-75 customer using the annual average consumption of 9,774 therms would see their bill increase from $7,900.16 to $8,162.64, a 3.3 percent increase.

G-80, Natural Gas Engine Gas Service

Q. What are Staff's recommendations regarding rates for the G-80 tariff?

A. Staff recommends that the off-peak basic service charge remain at zero and that the on-peak basic service charge be increased from $80.00 to $95.00. Staff further recommends that the per therm rate be increased from $0.16189 per therm to $0.18000 per therm.

Q. What are the estimated customer bill impacts from Staff's proposed G-80 tariff rates?

A. An average G-80 customer using 2,936 therms in January would see their bill increase from $2,194.77 to $2,251.20, a 2.6 percent increase. A G-80 customer using the annual median monthly consumption of 678 therms would see their bill increase from $568.36 to $592.92, a 4.3 percent increase.

T-1, Transportation of Customer Secured Natural Gas

Q. Southwest has proposed to eliminate tariff sheet fourteen, which lists the various charges related to taking transportation service from Southwest. Does Staff agree with Southwest's proposal?

A. Yes. Most of the information contained on tariff sheet fourteen is also shown in the Statement of Rates tariff pages and therefore sheet fourteen is primarily duplicative. The limited amount of information which is not captured elsewhere in the Statement of Rates, for example the shrinkage rate, will be captured in the footnotes on tariff sheet thirteen.

OTHER ISSUES

Q. Are there any other issues you wish to address in your testimony?

A. Yes.

Q. Does Staff have any recommendations regarding interest rates for the demand side management ("DSM") adjustor and LIRA tariff bank balance?

A. Yes. As with the PGA bank balance, Southwest should also use the monthly one-year nominal Treasury constant maturities rate, contained in the Federal Reserve's H.15 statistical release or its successor, for its DSM adjustor bank balance and the bank balance related to the LIRA tariff.

Q. In your discussions with the Commission's Consumer Services section, did they express a concern regarding the service window currently used by Southwest?

A. Yes. Consumer Services has received a number of customer contacts expressing concern with the fact that Southwest currently asks customers to be available at the service location for most or all of a day if a Southwest technician is scheduled to provide service to that customer. It is burdensome for the customer to be required to be at the service

location for such a long period of time. In contrast the typical practice for other major Arizona electric and gas utilities is to provide the customer with a four hour window during which the utility technician will provide the scheduled service to the customer. The length of the service window is not established by Commission rule or tariff provision. Rather, the service window length is set according to each Company's practice. Given on-going customer concerns and the divergence of Southwest's current practice from that of other Arizona utilities, Staff requests that Southwest consider adoption of a four hour service window as standard company practice and in its rebuttal testimony address whether it could move to using a four hour service window.

Q. Please discuss Southwest's participation in the Energy Share program.

A. Southwest currently participates in the Energy Share program. Energy Share involves the utility providing customers with the opportunity to make voluntary contributions which are then administered to help utility customers who due to financial difficulties are having a problem paying their utility bills. The Salvation Army administers these funds. Other Arizona utilities involved in the Energy Share program include Arizona Public Service Company ("APS") and Salt River Project. Southwest currently provides its customers with the opportunity to participate in the Energy Share program via a bill insert with an information card customers can return indicating they wish to participate and what amount they wish to donate on a monthly basis or on a one time basis. Some other utilities, including APS, also have a box on the customer bill each month where customers may choose to donate to the Energy Share program as they pay their monthly bill. Currently Southwest does not have this option on its customer bill.

Q. Does Staff have any recommendations regarding Southwest's participation in the Energy Share program?

A. Yes. Staff recommends that, at the time Southwest's new rates from this rate proceeding are reflected on customer bills, Southwest provide a place on its customer bill which would allow customers to elect to make a donation to the Energy Share program. This additional opportunity for customers to make a voluntary donation should provide some level of additional funding for the Energy Share program. Such additional funding would be particularly welcome given the high natural gas prices utility customers have faced in recent years.

Q. Please discuss Southwest's proposal to extend the period over which it would hold customer deposits from 12 months to 24 months.

A. Southwest's proposed tariff sheets include a change which would allow Southwest to hold customer deposits for 24 months, rather than the current 12 month period. In response to a data request, Southwest indicated that it was proposing this change to assist in reducing the level of uncollected dollars. By comparison, UNS Gas, the other major LDC in Arizona uses a 12 month period as do Arizona Public Service Company and Tucson Electric Power Company. Further, Commission Rule R14-2-303.B.4 states in regard to natural gas LDCs in Arizona that "each utility's refund policy shall include provisions for residential deposits and accrued interest to be refunded or Letter of Guarantee or surety bond to expire after 12 months of service if the customer has not been delinquent more than twice in the payment of utility bills."

Q. Does Staff have any recommendations regarding Southwest's proposal to change the period of time customer deposits can be held from 12 to 24 months?

A. Yes. Based upon prevailing practice and Commission rules, Staff recommends that the current 12 month provision be retained. Southwest has not made a compelling case that the period should be extended to 24 months.

Q. Does Staff have any recommendations regarding Southwest's proposal for subsequent customer requested meter tests?

A. Yes. Southwest has added a provision to its Other Service Charges sheet providing for a default $25.00 charge for subsequent customer requested meter tests, but allowing the Company to charge the customer the actual costs incurred by the utility to perform the meter test for customers using more than 180,000 therms. Southwest has not provided a rationale for including this new open-ended provision and it is unclear when another meter test is considered a subsequent test or not, as there is no specific time frame cited. As currently framed this provision is not acceptable and should be rejected.

Q. Please discuss Southwest's recommendation to reduce the interest paid on customer deposits from six percent to three percent.

A. Southwest's proposed tariff sheets include a change in the customer deposit rate from the current six percent to a proposed three percent level. It appears that this recommendation is based upon consideration of the relatively low interest rates that are currently prevalent in financial markets. However, if interest rates rise significantly, a three percent interest level would not appear to be very equitable to customers whose money the utility holds. The Commission continues to use a six percent interest rate for a wide variety of other utilities.

Q. Does Staff have any recommendations regarding the interest rate to be applied to customer deposits?

A. Yes. Staff recommends that the interest rate for customer deposits be retained at the current six percent level.

Q. Please discuss the impact which the El Paso pipeline rate case, filed June 30, 2005, may have on Southwest Gas' rates.

A. Although there are no issues to specifically address in Southwest's rate proceeding related to the El Paso rate case, it is worth noting the potential impacts of the case on Southwest's customers. The recently initiated El Paso rate case contains a number of issues that may have a significant impact on Southwest's rates and its ability to access natural gas supplies and deliver them to Arizona consumers. El Paso costs are flowed through Southwest's PGA mechanism as part of the overall cost of gas. Southwest will certainly see an increase in rates due to the resetting of its billing determinants from their present 1996 level. Additionally, there are a number of areas which seem to indicate Southwest's rates per volume of throughput on El Paso's system will rise substantially while at the same time Southwest will see reduced operational flexibility on the El Paso system. So Southwest faces rate increases on both a higher volume basis and a higher rate basis with reduced operational flexibility. At this early stage of the El Paso rate case it is very difficult to assess what all of the impacts will be, but it seems likely there will be a substantial rate increase. Such an increase in the cost of interstate pipeline service costs and their flow through to Southwest's ratepayers will be in addition to any changes in the cost of the natural gas commodity cost as well as any increase which may result from Southwest's current rate proceeding before the ACC.

Q. Does Staff have any recommendations regarding Southwest's activities before the FERC in relation to natural gas service in Arizona?

A. Yes. To assist the Commission in monitoring natural gas matters of interest at the FERC, Staff recommends that anytime Southwest initiates participation in a new natural gas docket at the FERC which relates to its service in Arizona, Southwest be required to provide Staff with a copy of their initial filing in that docket. This will ensure that Staff is aware on a timely basis of any natural gas matters Southwest is involved in at the FERC which relate to Arizona.

Q. Does Staff have any recommendations regarding Southwest's bill format?

A. Yes. A review of Southwest's bill indicates that two cost line items, "Base Tariff Rate" and "Rate Adjustment" do not have a corresponding explanation on the reverse side of the bill. Staff recommends that Southwest provide an explanation of each of these two line items on the reverse side of its bill. Additionally, a portion of the bill contains information regarding customer bill issues for California and Nevada customers. It does not appear that this information is necessary for Arizona customers and Staff recommends that Southwest remove California and Nevada information from the reverse side of its bill and rework it to reflect Arizona specific information to more better use of such space for explaining the bill to Arizona customers. Such an approach will likely provide better and more detailed information to Arizona consumers.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. My testimony contains the following recommendations, listed by general subject:

Gas Technology Institute Funding

1. Staff recommends that the OTD and UTD programs be funded at a level of $681,712, to be recovered from all Southwest customers except G-30 and B-1 customers through a GTI surcharge.
2. Staff further recommends that at least 30 days prior to Southwest notifying GTI of its program funding selections, that Southwest file its list of proposed GTI projects to fund, with a short description of each project, with Docket Control.
3. Staff further recommends that the GTI surcharge be reset annually beginning with the April billing cycle, based upon prior calendar year sales and prior year recoveries, and that the GTI surcharge be reflected in the Rate Adjustment column of its Statement of Rates, with a separate footnote identifying the current level of the GTI surcharge.

Base Cost of Gas

4. Staff recommends that the base cost of gas be set at zero.
5. Staff further recommends that Southwest develop specific customer education materials to explain the changes resulting from setting the base cost of gas at zero.
6. Staff further recommends that when applying the $0.10 per therm band for the first twelve months following the implementation of new rates that Southwest compare the new monthly PGA rate to the sum of the current base cost of gas and the monthly PGA rate in prior months when the base cost of gas was not zero.

Purchased Gas Adjustor

7. Staff recommends that the current PGA mechanism should be retained, with adjustments to the interest rate and bank balance trigger.
8. Staff further recommends that the PGA bank balance trigger be set at $29.2 million.

9. Staff further recommends that the monthly one-year nominal Treasury constant maturities rate, contained in the Federal Reserve's H.15 statistical release or its successor be applied to the PGA bank balance.

10. Staff further recommends that if for some reason in the future the then applicable interest rate becomes unavailable for one or more months, the previous month's interest rate would apply to the month(s) where no interest rate is available. Further, Staff recommends that if the then applicable interest rate becomes unavailable on a recurrent basis, Southwest may file with the Commission to replace the interest rate with another interest rate, with the underlying presumption being that any replacement interest rate would be similar in nature to the then applicable rate.

11. Staff further recommends that a Southwest Officer certify, under oath, through an affidavit attached to each monthly PGA report that all information provided in the adjustor report is true and accurate to the best of his or her information and belief.

12. Staff further recommends that in Southwest's monthly PGA report, on the page where Southwest lists its purchases, that the term purchases be split into groups showing fixed price contracts and other contracts which vary such as index contracts.

13. Staff further recommends that Southwest begin specifically identifying in its monthly PGA reports what the average and median usage levels are for its G-5 and G10 schedules for that given month.

Rate Design

14. Staff recommends that the basic service charges, tariffed rates, and other charges as discussed in the rate design section of my testimony and on Schedule RGG-3 be adopted.

15. Staff further recommends that within 90 days of the date of the final order in this proceeding, in addition to LIRA program information currently contained in the LIRA reports, that Southwest begin including in its LIRA reports a complete accounting of the LIRA bank balance for the most recent 12 month period, including individual listing of all inputs into the LIRA bank balance each month.
16. Staff further recommends that the G-16, Special Residential Gas Service for Electric Generation, be eliminated.
17. Staff further recommends that Schedule G-35 customers be given the option to take service on either Schedule G-35 or Schedule G-25.
18. Staff further recommends that Schedule G-60 be made available to smaller electric generation customers, as proposed by Southwest.
19. Staff further recommends that Southwest develop and propose provisions for Schedule G-60 which would provide sufficient protections for the system and other core customers from the potential impacts of 5 MW or larger electric generators, rather than banning such customers from taking service under Schedule G-60.
20. Staff further recommends that the monthly PGA rate be applied to Schedule G-60 customers.

Other Issues

21. Staff recommends that the monthly one-year nominal Treasury constant maturities rate, contained in the Federal Reserve's H.15 statistical release or its successor, be applied to Southwest's DSM adjustor bank balance and the bank balance for the LIRA tariff.
22. Staff further recommends that, at the time Southwest's new rates from this rate proceeding are reflected on customer bills, Southwest provide a place on its

customer bill which would allow customers to elect to make a donation to the Energy Share program.

23. Staff further recommends that the current 12 month period for retaining customer deposits be retained.

24. Staff further recommends that the proposal as currently structured to allow Southwest to charge actual costs for subsequent customer requested meter tests for customers above 180,000 therms not be adopted.

25. Staff further recommends that the current six percent interest rate applied to customer deposits be retained.

26. Staff further recommends that anytime Southwest initiates participation in a new natural gas docket at FERC which relates to its service in Arizona, Southwest be required to provide Staff with a copy of their initial filing in that docket.

27. Staff further recommends that Southwest rework the information on the back of its Arizona customer bill to explain all tariffed rate components as well as to reflect Arizona specific information rather than California and Nevada information, to improve the quality of information provided to Arizona customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Schedule RGG1-1

RESUME

ROBERT G. GRAY

Education

B.A. Geography, University of Minnesota-Duluth (1988)

M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Senior Economist (August 1997 - present), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses of issues related to the natural gas and electric utilities. Prepare recommendations and present written and oral testimony before the Commission on various utility industry issues. Represent the ACC in natural gas proceedings at the Federal Energy Regulatory Commission and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas. Conduct working group/workshop activities including organizing meetings, moderating meetings, and analyzing and reporting working group findings.

Testimony

Resource Planning for Electric Utilities, (Docket No. 0000-90-088), Arizona Corporation Commission, 1990.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-92-073), Arizona Corporation Commission, 1993.

Resource Planning for Electric Utilities, (Docket No. 0000-93-052), Arizona Corporation Commission, 1993.

Arizona Public Service Company, Rate Settlement (Docket No. E-1345-94-120), Arizona Corporation Commission, 1994.

U S West Communications, Rate Case (Docket No. E-1051-93-183), Arizona Corporation Commission, 1995.

Schedule RGG1-2

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-95-433), Arizona Corporation Commission, 1996.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. U-1551-96-596), Arizona Corporation Commission, 1997.

Black Mountain Gas Company - Northern States Power Company, Merger (Docket Nos. G-03493A-98-0017, G-01970A-98-0017), Arizona Corporation Commission, 1998.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-98-0695, G-03493A-98-0705), Arizona Corporation Commission, 1999.

Graham County Utilities Company Rate Case (Docket No. G-02527A-00-0378), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Cave Creek Division Rate Case (Docket No. G-03703A-00-0283), Arizona Corporation Commission, 2000.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. G-01551A-00-0309), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-01-0263), Arizona Corporation Commission, 2001.

Duncan Rural Services – Natural Gas Rate Case (Docket No. G-02528A-01-0561), Arizona Corporation Commission, 2001.

Toltec Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Y-01-0112), September 2001.

Lap Paz Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000AA-01-0116), December 2001.

Bowie Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000BB-01-0118), December 2001.

Southwest Gas Corporation, Acquisition of Black Mountain Gas Company (Docket No. G-01551A-02-0425), Arizona Corporation Commission, 2002.

Wellton-Mohawk Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Z-01-0114), February 2003.

Arizona Public Service Company, Rate Proceeding (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004.

Graham County Utilities Company Rate Case (Docket No. G-02527A-04-0301), Arizona Corporation Commission, 2004.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A., Vol. 27A, 1993, pp. 1-12.

(with David Berry) Staff Guidelines on Photovoltaics Versus Line Extensions. Arizona Corporation Commission, January 28, 1993.

(with Ray Williamson, Robert Hammond, Frank Mancini, and James Arwood) The Solar Electric Option (Instead of Power Line Extension). A joint publication of the Arizona Corporation Commission and the Arizona Department of Commerce Energy Office, August, 1993.

(with David Berry, Kim Clark, Barbara Keene, Jesse Tsao, Ray Williamson, Randall Sable, Roni Washington, Wilfred Shand, and Prem Bahl) Staff Report on Resource Planning. (Docket No. U-0000-93-052) Arizona Corporation Commission, 1993.

Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

Staff Report on Purchased Gas Adjustor Mechanisms, (Docket No. G-00000C-98-0568) Arizona Corporation Commission, October 19, 1998.

Staff Report on the Rolling Average PGA Mechanism, (Docket No. G-00000C-98-0568),Arizona Corporation Commission, September 6, 2000.

Staff Report on the Use of a Circuit-Breaker in Adjustor Mechanisms, Arizona Corporation Commission, September 3, 2003.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. G-01551A-04-0192), Arizona Corporation Commission, June 2, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. E-01345A-04-0273), Arizona Corporation Commission, August 16, 2004.

Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition
1997	NARUC 6th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7th Annual Natural Gas Conference
1999 – 2005	NARUC Summer Committee Meetings
2001	Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2005	NARUC Winter Committee Meetings

Memberships

NARUC - Staff Subcommittee on Gas – Vice-Chair (2002 - 2004)
NARUC - Staff Subcommittee on Gas – Chair (2005 - current)

Schedule RGG2-1

Company Allocation Form (for 2005)

Company Name: _____

Company Address: _____

Customer Name: _____ Title: _____

Signature: _____ Date: _____

Phone: _____ FAX: _____ Email: _____

Estimated 2005 Client Funding $U.S._____

Other Sources (please specify) _____ $U.S._____

Please indicate the amount of client funding for 2005 that your company wishes to allocate among the

following R&D investment options. Collaborative Programs are subject to minimum allocations.

Investment Options (indicate allocation for each)

2005-2006 GTI Environmental Issues Collaborative (EIC) Programs
(Note: the EIC projects are two years in length; shown below is the annual contribution)

- Hydrocarbon Degradation Products in Sedimentary Environments ($45,000) _____
- Developing Rapid Quantitative PCB Analysis in the Field ($38,333) _____
- Implications of the PCB Mega Rule on Natural Gas T&D ($30,000) _____
- Sources of Indoor Air VOCs near Former MGP Sites ($30,600) _____
- Linking MGP Fuels to MGP By-Products with Stable C and H2 Isotopes ($56,667) _____
- External Corrosion Survey of Natural Gas Pipelines ($10,000) _____
- Internal Corrosion Survey of Natural Gas Pipelines ($10,000) _____
- Effect of Petroleum-Based Hydrocarbons on PE Structural Integrity ($43,750) _____

2005 GTI Collaborative Projects

- Distributed Energy Collaborative Program ($60,000) _____
- Ergonomics Handbook and Tool Development ($24,000) _____
- National Accounts Energy Alliance ($15,000) _____
- Keyhole Technology Program ($25,000) _____
- Gas Technology AdvisorTM Food Service Module ($25,000) _____

GTI/EPRI Joint Projects

- GTI/EPRI Sediment Specific Research Program ($50,000 per yr for 2 yrs) _____

Other Program Options

- GTI 2005 SMP Emerging Technology (Contact Ron Snedic GTI for dollar level) _____
- Operations Technology Development (Contact Ron Snedic GTI for dollar level) _____
- Utilization Technology Development (Contact Ron Snedic GTI for dollar level) _____

Schedule RGG2-2

• Operator Qualifications (Contact your Strategic Account Manager (SAM) for dollar level) _____
• Technology Deployment and Implementation (Contact your SAM for dollar level) _____
• APGA Research Foundation (Contact Bob Beauregard, APGA, for dollar level) _____
• Please put in my company's hold account for future investment _____
Total $U.S._____
Please return this completed form (FAX preferred) to:

Ron Edelstein Phone:847/768-0898
GTI FAX: 847/483-1306
1700 South Mount Prospect Road E-mail: ron.edelstein@gastechnology.org
Des Plaines, IL 60018 Rev. 7 - 5/27/05

Operations Technology Development An LDC Partnership Program

An LDC Partnership Concept

For many years, natural gas local distribution companies (LDCs), both public and investor owned, have recognized the importance and value of supporting multi-faceted technology developments for their customers and their own infrastructure operation. The resulting technological advances have primarily provided improvements in the quality of service, reduced costs, greater efficiency, greater integrity and safety, and enhanced environmental characteristics. The LDCs have also recognized the importance of leveraging their investments with each other, as well as with others that have similar interests, to minimize the risks associated with any innovative product development. Given this need and the loss of the FERC funding mechanism that supported a major R&D gas industry program over the last 25 years, LDCs are pursuing funding alternatives to continue supporting critical technology developments.

One of these alternatives is to create an entity where utilities can come together as partners and have the lead in jointly funding potential technology development solutions to common issues. The concept is not new. Gas Technology Institute (GTI) has, on a smaller scale, developed and evolved a program called SMP that allows utilities to come together as partners and decide which projects best address their mid-to longer-term needs. SMP has two decision-making bodies comprised of utilities representatives: an executive committee that focuses on strategic issues, and a technical committee that makes decisions on which projects to fund. Under the proposed partnership program, a similar structure would exist, but would stand on its own with no employees, contracting all of its administrative and program requirements. The scope of the program would include near-, mid-, and longer-term technology developments. Utilities would nominate from their company participants for each

committee. The participants would vote with their funds by choosing which projects best address their customers' and utility operations' needs.

With GTI's history, current management capabilities, and technology strength primarily supported by LDCs for the past 60 years, a group of LDCs approached GTI in 2002 to work with them on further developing the concept. The primary areas to focus on were Gas operations, End Use and Environmental Science. Operations was identified as the first area to address.

After several individual meetings and two group meetings with LDCs, GTI is in the process of rolling out the "Operations Technology Development Inc., An LDC Partnership Program" in 2003.

Background and LDC Needs

LDCs have traditionally placed great importance on the safety and reliability of the operation of the gas distribution network. Throughout the United States, LDCs provide natural gas service to over 50 million residential, commercial, and industrial customers. These end-users of natural gas receive safe, reliable gas service through the focused efforts of the gas company, and through the use of new technologies that enhance field operations.

The development and implementation of new technology for gas industry field operations whether new tools, equipment, processes or procedures, has allowed the industry to continually improve operations while reducing operating costs. Since 1995, the gas industry has reduced its annual costs for operations and maintenance from $3.2 billion to $2.8 billion. Although significant, additional development and implementation of new technology can further enhance these savings while having a positive impact on safety, operating efficiency, labor requirements, reliability and integrity.

Today, LDCs continue to support the continued need to develop technology solutions for the natural gas industry and the gas consumer, but place a stronger emphasis on working collaboratively. This is especially apparent in the distribution operations area. There are numerous benefits to working collaboratively to develop technology solutions for LDCs including: the leveraging of funds (no single LDC is responsible to carry the entire financial burden), the ability to gain the interest of a commercializer based on broad industry support, and the belief that input from numerous sources will result in a stronger solution. There is also

a significant benefit to working collaboratively on programs or projects that can impact regulatory issues such as pipeline integrity.

Operations Technology Development Program Overview

To fully address the need for an industry-led collaborative program to pursue the technology development needs of LDCs, GTI, working with over 20 utilities has put in place an organization called "Operations Technology Development Inc, *An LDC Partnership Program*, " or simply OTD. This program will develop, test, and implement new technology, providing solutions to a wide range of issues relating to gas operations and its infrastructure. It is designed to provide new tools, equipment, software, processes or procedures that will enhance safety, increase operating efficiency, reduce operating costs, and help maintain system reliability and integrity.

Program Size and Scope

The program seeks the long-term participation of 15 to 25 gas companies. The funding level for OTD is between $250,000 and $750,000 per company per year. No company can pay more than $750,000 or less than $250,000 to be a participant. Each participating company will vote with their funds when selecting projects of interest. The minimum amount determined to sustain a viable gas operations technology development program today is approximately $15 million/year. The goal is to at least secure $7.5 million/year from the LDCs and leverage the funds with other organizations.

The OTD program will focus its research and technology development efforts on distribution and transmission activities identified by the participants. The R&D program may include short-term or quick-response research, engineering, or testing activities; mid-term research projects (3-5 years to implementation); or long-term research (greater than 5 years to implementation). The initial areas of gas operations that could be addressed in the program are listed below. This list will most likely change and potentially grow based on the OTD participant's input.

- Pipe Location
    - Plastic pipe location
    - Cast iron pipe joint location

  - Facilities mapping systems coupled with global positioning systems to provide improved locating and mapping accuracy
- Leak Detection and Location
  - Improved walking leak survey equipment to detect leaks without false positives
  - Improved productivity through the use of remote leak detection systems
  - Acoustic systems to pinpoint leaks
- Pipe Materials, Repair, and Rehabilitation
  - Studies and evaluations to provide guidance on maximizing the life of Aldyl-A plastic piping systems
  - Methods to stop the flow of gas in plastic gas systems without using squeeze-off
  - The development of a service-applied main stopper
  - Improved sealing methods and materials for cast iron pipe
- No-dig Technologies
  - Tools and procedures for small-opening field work
  - Cured-in-place liners for main and service rehabilitation
  - Connection of services to lined mains without excavation
  - Materials and Failure Testing
- Excavation and Restoration
  - One-step pavement restoration
  - Advanced methods for shoring
- Third Party Damage Prevention and Detection
  - Systems to detect and provide real-time reporting of activity over a pipeline before damage occurs
  - Systems that detect third party damage
- Corrosion and Coating Damage Prevention / Detection
  - Systems that detect wall loss with no excavation
  - Systems that detect wall loss with micro-excavation
  - The development of a new technology that will facilitate direct examination of pipes and pipe coatings with micro-excavation
  - Remote cathodic protection monitoring
  - Improved field-applied coatings
  - NDE sensors for un-piggable pipelines

- System Automation and Infrastructure Security
  - Utility Infrastructure Security tools and procedures
  - Development of remote monitoring and control systems using the latest computer chip and memory technologies
  - The development of Palm[R]-based software systems for automated field data acquisition that will download to, or communicate with office computers
  - The development of systems to predict gas pipe failure

Project Funding

A participating LDC has the option to fund or not fund an individual development. The program will operate on a "customer choice" basis, with the LDC investing in the projects they wish to fund. Once participating companies elect to move a project forward and the scope of work is finalized, the project participants may elect to seek additional project co-founders outside of the Partnership. The additional co-founders solicited may include DOE, DOT, gas utilities, and product manufacturers/developers.

Funding Procedure

Companies participating in the OTD program can provide their funding through one of two arrangements. A company may place their full amount of funding for a year or longer in a "hold account". Participants will draw down funds from their hold account and apply them to selected projects. Each company will receive a quarterly accounting on the status of their hold account. Information included in this report could include the participant's opening balance, projects being funded, funds applied monthly to specific projects, and remaining balance. LDC participants will decide and finalize the measures once the program is initiated.

Alternatively, participating company may elect to receive quarterly invoices for their participation. Payments received will be deposited into their hold account.

For either funding procedure, a participating company will be asked to commit to a specific level of total annual funding based on the funding formula to allow for appropriate long-term planning.

UTD

Utilization
Technology
Development

2004 Offering

Based on extensive feedback from, and discussion with, the gas industry, there is an urgent need for investment in advanced utilization technology to address gas consumer needs for increased-efficiency and lower cost equipment. To address this, **Utilization Technology Development, NFP** (UTD) has been formed as a not-for-profit corporation, directed by participating companies, to manage a gas-focused technology program for the benefit of the investors and their customers. The program managed by UTD encompasses technology development and demonstration activities targeted to the residential, commercial, and industrial market segments. The technology portfolio will include increased-efficiency gas equipment and appliances, industrial process and combustion systems, distributed energy, and combined heat and power (CHP) systems. Participating companies in UTD will define the program structure and content, which may include a *Base Program* that supports cross-cutting activities such as technology transfer, analysis, and codes and standards, and a *Project Portfolio* that supports individual technology development projects selected by investing utilities on behalf of their customers. It is anticipated the selected projects will address near-term technology and technical analyses needs, including tools and information to help a utility and their customers in selecting increased-efficiency, cost-effective gas options. UTD will support technology development initiatives in areas dictated by participants. The company will work with research partners and other industry organizations to aggressively leverage gas utility investments with supplemental program funding from federal and state governments. sources and other industry stakeholders.

Background

- UTD is being formed based on extensive input from natural gas utilities and GTI's Public Interest Advisory Committee. Over the last half of 2003, interested companies have provided input via two customer group meetings and numerous individual utility meetings. The intent of this communication has been to develop a mechanism to leverage investments in utilization research, development and demonstration (RD&D) to maximize the benefit to these companies and their ratepayers.

Throughout the meetings, it became clear that marketing managers at today's natural gas utilities operate in a difficult business environment. Among the challenges they face are very high and volatile energy prices; environmental regulations; the influence of mergers and acquisitions; and the uncertain progress of corporate unbundling and retail competition. These utilities are often hampered in their struggle by a shortage of end-use technologies and information to enable them to offer end-users a compelling value proposition.

In parallel with these market and business challenges, utilization RD&D programs have declined substantially over the past five years. While several factors are driving this, there is an increased awareness of the severity of overall program reduction and the consequences of continued declines in direct industry investment and involvement. Scenarios extrapolating this trend of declining utilization RD&D support are characterized by reduced gas ratepayer benefits and additional consequences for gas industry participants. There is a growing awareness and sense of urgency among utilities towards maintaining an adequate level of utilization research and technology develop-ment programs. Key considerations include maintaining program continuity and development momentum from traditional Federal Energy Regulatory Commission (FERC)-funded programs.

Gas Technology Institute (GTI) recently commissioned a study to assess current research needs for gas companies and their customers. The following needs and opportunities were identified:

- **Better end-use technologies:** Gas utilities struggle to find firm ground on which to offer their products—that is, end uses in which the customer feel the gas value proposition offers clear benefits. Utilities and their customers are looking for new technology and more sophisticated products to lower energy bills, lower equipment first costs, and meet increasingly stringent environmental regulations.
- **Residential segments:** To counter the impact of rising energy costs, increased-efficiency, lower emissions gas equipment must be developed to ensure that existing and new homes and multifamily buildings continue to choose natural gas options (for space and water heating and other applications) which offer the consumer clear benefits. Codes and standards issues, such as venting and indoor air quality, also must continue to be addressed.
- **Commercial segments:** Several traditional natural gas product segments, including food service and heating, are being displaced by electric technologies. This can reduce product options for customers and increase their life-cycle cost for energy systems. Increased-efficiency gas equipment can be the answer.
- **Industrial segments:** In today's tough economy, utilities are willing to work with industrial customers to help them become more efficient, and less polluting and thereby stay solvent, even at the expense of gas throughput.
- **Distributed energy:** Utilities agreed that fuel cells, microturbines, and advanced engines represent a huge opportunity for customers and gas utilities, although the technology is not yet competitive economically, and important technical and other barriers remain.
- **Integrated cooling and power packages:** Gas cooling continues to attract managerial interest due to its potential to balance gas loads and reduce gas-fired peak electricity loads. The new opportunity may be for a packaged, off-the-shelf system integrating power generation and cooling technology.
- **Information needs:** Utilities, decision makers, and customers continue to look for technical information on end-use technology, particularly in light of reductions in utility-based marketing and technical support. Specific value is seen in more case studies; an "Emerging Technology" newsletter; material in electronic format for their websites; and quantitative information on the costs and economic benefits to customers of installing advanced gas equipment.

Vision

To address these urgent needs, GTI and several leading gas utilities have worked together to define and launch a not-for-profit corporation, **Utilization Technology Development, NFP** (UTD), that builds and manages an investor-driven collaborative RD&D program. This collaborative program, guided by direct industry involvement and perspective, can contribute to a healthy scenario for the industry and provide sustained benefits for the gas consumer. The program provides a "bridge" from traditional industry programs supported by the FERC funding mechanism to one funded through a broader collaborative amongst the gas industry, government and other interested stakeholders.

UTD will address the needs identified by participating companies and provide an opportunity to address the significant gap in product-versus-potential in the marketplace. UTD will identify and advance technologies and best practices for a robust gas product portfolio and provide near-term impact by delivering advanced technologies that offer the consumer lower energy bills, lower first costs, environmental benefits, and other advantages. Sustained impact through an extended time horizon is anticipated through targeted programs aimed at staged implementation schedules.

UTD will coordinate activities with other industry organizations (e.g., Energy Solutions Center, and American Gas Association's Building Energy Codes and Standards Committee) to provide the best value to its investors.

Value To Investors

UTD will provide participants with information, tools, and products to aid their customers in value-driven gas markets. This includes an understanding of opportunities, an assessment of the implementation barriers, and assistance with the deployment to achieve sustained market impact.

Specific utility needs addressed include:

- **Identification and assessment** of barriers and relevant technologies for near-term implementation
- Development of **advanced increased-efficiency technologies** to broaden the gas product portfolio
- An **industry forum** that enables peer networking and opportunities for shared-learning from the varied experiences of other utilities
- **Validation** of performance, operating characteristics, and emissions for developed and emerging technology
- Substantial **funding leverage** and market impact through collaboration with other gas companies and subsequent partnering with public and private funding partners.

A benefits analysis tool is being developed that will assist in characterizing public benefits expected from individual projects being considered. This tool will be available for participants to use when prioritizing and selecting projects.

A gas utility has many options for investing in technology programs, but what drives allocation towards the optimal portfolio? While the answer is dependant on factors unique for each company, in general, a balanced perspective and portfolio provides risk reduction, security, and benefits under a range of scenarios. Among other criteria, consideration must include: immediate versus long term impact; basic research vs. applied research vs. technology development vs. product development vs. demonstration; and, residential through large industrial market segments. Achieving the optimal balance within a diverse technology program for the gas industry and its customers is a primary objective of UTD.

Program Description

The founding members of UTD will determine the program structure. Initial discussions with potential investors suggest that the program may be structured into two elements, one that supports cross-cutting, industry-wide activities, and one more focused on project activities. The allocation and balance of funds to and within these "Base" or "Program" elements will be determined by program participants.

- **Base Program.** The base program will be designed to support cross-cutting programs of broad benefit to the industry and its customers. *Base Program* components and specific projects will be finalized through discussion with investors, but are anticipated to include:
  - Application and technology analysis
  - Deployment
  - Codes and standards
  - Technology transfer
- **Project Portfolio.** Individual projects will be proposed to participants for funding consideration and allocation. The funding process is characterized in Appendix A. Participants will determine and apply their own prioritization criteria in selecting projects to support. The slate of projects to be undertaken will be based upon final funding amounts received. Specific projects that comprise the final *Project Portfolio* will not be defined until the participants meet and allocate their funds to projects of direct interest to them and their customers. Appendix B includes paragraph summaries of candidate projects for 2004. Additional projects will be defined and presented to participants and considered at the first UTD meeting.

Deliverables

▼ The slate of deliverables for UTD will be finalized through guidance and recommendations of participants, but may include the following for the *Base Program* and *Project Portfolio* elements.

Base Program participants are anticipated to receive:

- Quarterly summary report via e-mail
  - Technology and market segment updates
  - Synopsis for all projects that UTD is supporting
  - UTD participation update
  - Leveraged funding update

Quarterly participant conference calls updating investors on overall UTD programs

- Codes and standards program reports
- Technology transfer support
- Deployment programs
- Participation in two meetings per year to review program results and to provide input on, and selection of, new projects
- Customized technology consulting services

The deliverables in the *Project Portfolio* will be based upon the final projects selected, but are expected to include:

- Detailed periodic reports; a final report; and relevant software for the projects a company is invested in
- Periodic project-specific teleconference or web-based conferences for projects a company is invested in
- Opportunities for field evaluation and demonstration in service territory for projects invested in
- The opportunity for intellectual property royalty or return, based upon any technology that may result from co-funding applied to the develop-ment of these respective systems
- Opportunities to participate in and/or guide the development of proposals for leveraged co-funding from state agencies, the U.S. Department of Energy (DOE), or other RD&D funding sources

Program Investment

▼ Investment in UTD is offered to gas companies on a per-meter basis. A portion of these funds will support UTD program management and G&A activities.

Funding commitment is for an initial two-year period, with annual approval thereafter.

The 2004-05 funding level is set at $0.40 per meter per year with minimum annual funding level of $100,000 and a maximum annual funding level of $250,000 for an individual company. At their discretion, individual companies can invest and direct additional funds towards projects of specific interest.

Companies with less than 250,000 meters can pool with other gas companies to meet the minimum investment level.

Non-gas utilities and other organizations may be allowed to participate upon approval of the UTD Board of Directors.

Schedule

▼ UTD is expected to begin with participant signups through 1Q04. Projects are expected to commence in 2Q04. The project deliverables will be forthcoming as the tasks are completed throughout 2004 and beyond.

UTD will be offered to new participants annually.

Appendix B – 2004 Candidate Projects

Base Program

Codes and Standards Program.

Technology Transfer Support.
Deployment Programs.

Technology and Application Information and Consulting Services.

Project Portfolio Candidates

Residential

Advanced Gas Water Heater Assessment.

Combo System Field Test.

Combination Gas Engine Heat Pump/Generator for CHP.

Smart Appliances Technology.

Reduced Cost Residential Desiccant Unit Development.

Residential and Commercial Heating Assessment.

Advanced Residential Gas Cooking.

Gas Cooling Technology and Market Assessment.

Residential Gas-fired Stirling Micro-CHP Feasibility Study.

Residential Micro-CHP Modeling and Validation.

Development and Testing of a 3-ton Stirling Engine Heat Pump/Air Conditioner.

Commercial

Commercial Gas Technology Advisor (GTA) Module Development.

Warewashing Equipment Advancement.

Ventilation System Development.

Commercial IC Engine Micro-CHP System Feasibility.

Online Novel Gas Applications Handbook.

Abridged Online Gas Engineers Handbook.

Load Management Through Distributed Natural Gas Storage.

Distributed Natural Gas to Hydrogen.

Industrial

VA IR Infrared Heating Product Development.

Industrial Gas Technology Advisor (GTA) Module Development.

LNG Interchangeability.

High-Efficiency Flexible Combined Heat and Power (CHP) Unit.

Ultra-Low NO_x Burner for CHP Applications.

Self-Powered Hydrogen Production Unit.

Firetube Boiler Retrofit.

Reduced Atmosphere Generator for Heat Treating.

Field Demonstration of Prototype Super Boiler.

Advanced Combustion System for Large Firetube Boilers.

Low NO_x Flexible Burner for Thermal Fluid Heaters.

Field Demonstration of PC Preheat Combustion System on a Utility Boiler.

Industrial Food Processing.

Advanced Sensors and Controls Development.

Industrial HVAC and CHP.

Selected Industrial Product Development.

Distributed Energy

Distributed Energy Strategic Service.

Upgraded Hour-By-Hour Building Analysis Software Tools.

Representation in Policy-Making Forums Related to Distributed Generation.

Distributed Energy Performance Testing and Improvement Program.

STM Stirling Engine Demonstration Testing Program.

Gate Station Energy Conversion System.

Diesel to Gas Engine Conversion Systems.

Vertical Markets and Packaged Systems.

Monitoring Equipment for DG Equipment.

Advanced Reciprocating Engine Technology Development.

Advanced Analytical Tools.

Bio-Power Evaluation.

CHP/Renewable Energy Technology Community Planning Tool.

Hydrogen-Fueled Natural Gas Technologies.

Gas Compressors.

Specialty Packaging.

Hybrid Gas Turbine Cycles.

VAM Power Generation.

Heat Recovery Containerized Design for Natural Gas Reciprocating Engines.

Schedule RGG-3, Rate Design Details and Customer Bill Impacts

Note:

When discussing rate design and representing impacts of various rate design characteristics, I show the base cost of gas as being set at Southwest's proposed level of $0.53436 per therm. The reason I do this is for comparability, so Staff's proposed rate design schedules can be more easily compared to those put forth by other parties. If the proposed zero base cost of gas was included in the rate design schedules, there would be no impact on the calculations of customer bill impact. The changes would be that the revenue column would become unnecessary, as that column merely capture the combined effect of the changes in margin rates and the amount recovered by the cost of gas. For the customer bill impact comparisons, the only effect would be that the amount shown in the base cost of gas column would be moved to the monthly PGA rate column.

Schedule RGG3-1

Comparison of Current Rates vs. Staff Proposed Rates

	Current Rates	Staff Proposed Rates	Percent Margin Increase	Percent Revenue Increase	Current Rates Median January Bill	Proposed Rates Median January Bill	Current Rates Median Annual Bill	Proposed Rates Median Annual Bill
Proposed Base Cost of Gas	$0.37034	$0.53436 per therm						
Assumed Monthly PGA Rate		$0.07157 per therm						
Rate Schedule G-5, Residential Gas Service			15.26%	8.84%	$69.91	$74.81	$25.50	$27.83
Median Usage - therms					58	58	16	16
Increase in Median Bill From Current to Proposed Rates						7.01%		9.16%
Basic Service Charge	$8.00	$9.50						
Summer First 20/15 therms	$0.48762	$0.54000 per therm						
Summer Over 20/15 therms	$0.40344	$0.49000 per therm						
Winter First 40/35 therms	$0.48762	$0.54000 per therm						
Winter Over 40/35 therms	$0.40344	$0.49000 per therm						
Rate Schedule G-10, Low Income Residential Gas Service			8.34%	4.76%	$61.37	$64.51	$21.87	$22.58
Median Usage - therms					64	64	17	17
Increase in Median Bill From Current to Proposed Rates						5.12%		3.27%
Basic Service Charge	$7.00	$7.00						
Summer First 20/15 therms	$0.48762	$0.54000 per therm						
Summer Over 20/15 therms	$0.40344	$0.49000 per therm						
Winter First 40/35 therms	$0.48762	$0.54000 per therm						
Winter Next 110/115 therms	$0.40344	$0.49000 per therm						
Winter Over 150 therms	$0.40344	$0.49000 per therm						
Rate Schedule G-15, Special Residential Gas Service for Air Conditioning			22.51%	9.56%	$125.43	$135.09	$64.86	$69.33
Median Usage - therms					113	113	53	53
Increase in Median Bill From Current to Proposed Rates						7.70%		6.90%
Basic Service Charge	$8.00	$9.50						
Summer First 20/15 therms	$0.48762	$0.54000 per therm						
Summer Over 20/15 therms	$0.19125	$0.28000 per therm						
Winter First 40/35 therms	$0.48762	$0.54000 per therm						
Winter Over 40/35 therms	$0.40344	$0.49000 per therm						
Rate Schedule G-20, Master-Metered Mobile Home Park Service			19.73%	7.95%	$694.06	$747.35	$350.87	$381.09
Median Usage - therms					700	700	327	327
Increase in Median Bill From Current to Proposed Rates						7.68%		8.61%
Basic Service Charge	$50.00	$60.00						
Commodity Charge, All Therms	$0.31415	$0.37600 per therm						

Schedule RGG3-2

Rate Schedule G-25, General Gas Service, Small			18.29%	9.25%	$131.44	$142.98	$53.53	$59.80
Median Usage - therms					113	113	34	34
Increase in Median Bill From Current to Proposed Rates						8.78%		11.71%
Basic Service Charge	$20.00	$24.00						
Commodity Charge, All therms	$0.38024	$0.44700 per therm						
Rate Schedule G-25, General Gas Service, Medium			12.84%	4.92%	$1,662.57	$1,736.48	$1,075.16	$1,127.06
Median Usage - therms					1791	1791	1122	1122
Increase in Median Bill From Current to Proposed Rates						4.45%		4.83%
Basic Service Charge	$90.00	$105.00						
Commodity Charge, All therms	$0.27211	$0.30500 per therm						
Rate Schedule G-25, General Gas Service, Large			11.20%	3.90%	$28,491.00	$29,237.32	$22,889.69	$23,494.66
Median Usage - therms					36000	36000	28796	28796
Increase in Median Bill From Current to Proposed Rates						2.62%		2.64%
Basic Service Charge	$500.00	$540.00						
Commodity Charge, All therms	$0.08548	$0.10000 per therm						
Demand Charge	$0.07270	$0.07700 per therm						
Rate Schedule G-35, Gas Service to Armed Forces			12.91%	3.54%	$50,869.97	$52,499.06	$13,079.44	$13,504.88
Median Usage - therms					63500	63500	16000	16000
Increase in Median Bill From Current to Proposed Rates						3.20%		3.25%
Basic Service Charge	$350.00	$370.00						
Commodity Charge, All therms	$0.18966	$0.21500 per therm						
Rate Schedule G-40, Air-Conditioning Gas Service			22.67%	4.66%	$139.36	$146.66	$388.31	$402.50
Median Usage - therms					175	175	540	540
Increase in Median Bill From Current to Proposed Rates						5.24%		3.65%
Basic Service Charge, General Service - Small	$20.00	$24.00						
Basic Service Charge, General Service - Medium	$90.00	$105.00						
Basic Service Charge, General Service - Large	$500.00	$540.00						
Basic Service Charge, Essential Agriculture	$75.00	$90.00						
Commodity Charge, All therms	$0.07613	$0.09500 per therm						

Schedule RGG3-3

Rate Schedule G-45, Street Lighting Gas Service			13.33%	6.28%			$310.65	$328.88
Median Usage (annual average usage used, see footnote) - therms							287	287
Increase in Median Bill From Current to Proposed Rates								5.87%
Commodity Charge, All therms	$0.47648	$0.54000 per therm						
Rate Schedule G-55, Gas Service for Compression on Customer's Premises			21.47%	5.08%	$53.82	$57.30	$56.03	$59.61
Median Usage - therms					62	62	65	65
Increase in Median Bill From Current to Proposed Rates						6.46%		6.39%
Basic Service Charge, General Service - Small	$20.00	$24.00						
Basic Service Charge, General Service - Large	$170.00	$185.00						
Basic Service Charge, General Service - Residential	$8.00	$9.50						
Commodity Charge, All therms	$0.13305	$0.16500 per therm						
Rate Schedule G-60, Cogeneration Gas Service			22.50%	3.36%	$4,609.26	$4,758.55	$3,740.17	$3,863.63
Median Usage - therms					6500	6500 0	5250	5250
Increase in Median Bill From Current to Proposed Rates						3.24%		3.30%
Basic Service Charge, General Service - Small	$20.00	$24.00						
Basic Service Charge, General Service - Medium	$90.00	$105.00						
Basic Service Charge, General Service - Large	$500.00	$540.00						
Basic Service Charge, Essential Agriculture	$75.00	$90.00						
Commodity Charge, All therms	$0.08934	$0.11000 per therm						
Rate Schedule G-75, Small Essential Agriculture User Gas Service			13.28%	4.97%	$1,776.30	$1,845.10	$835.58	$874.63
Median Usage - therms					2125	2125	950	950
Increase in Median Bill From Current to Proposed Rates						3.87%		4.67%
Basic Service Charge	$75.00	$90.00						
Commodity Charge, All therms	$0.19468	$0.22000 per therm						
Rate Schedule G-80, Natural Gas Engine Gas Service			9.49%	2.27%	$27.37	$27.91	$568.36	$592.92
Median Usage - therms					38	38	678	678
Increase in Median Bill From Current to Proposed Rates						1.96%		4.32%
Basic Service Charge, Off-Peak Season (Oct. - Mar)	$0.00	$0.00						
Basic Service Charge, On-Peak Season (Apr - Sep)	$80.00	$95.00						
Commodity Charge, All therms	$0.16189	$0.17600 per therm						
Cost of Gas	$0.55840	$0.55840 per therm						

Note: For schedule G-45, there is no basic service charge and only a flag usage charge, so G-45 customers see the same rate increase regardless of usage levels.
Current and Proposed rate calculations apply the proposed base cost of gas of $0.53436 per therm and a monthly PGA rate of $0.07157 per therm.
For residential rates classes, the winter rates are applied when calculating the annual median bill.
For schedule G-40, a median customer is assumed to be in the small category.
For schedule G-55, a median customer is assumed to be in the residential category.
For schedule G-60, a median cusomer is assumed to be in the medium category.
For schedule G-80, a the median customer calculations assume an on-peak season month for the annual median use calculation and an off-peak season month for the January median use calculation.

Schedule RGG3-4

Margin and Revenue from Staff Proposed Rates for Southwest Gas

			Current Rates Margin	Current Rates Revenue	Staff Proposed Rates Margin	Staff Proposed Rates Revenue	Percent Margin Increase	Percent Revenue Increase
Rate Schedule G-5, Residential Gas Service								
Basic Service Charge					$90,220,778	$90,220,778		
Summer	First	15 therms			$24,350,530	$24,350,530		
Summer	Over	15 therms			$6,953,650	$6,953,650		
Winter	First	35 therms			$67,893,860	$67,893,860		
Winter	First	35 therms			$43,907,496	$43,907,496		
Base Cost of Gas						$146,746,585		
Class Total			$202,442,141	$349,188,726	**$233,326,314**	**$380,072,899**	15.26%	8.84%
Rate Schedule G-10, Low Income Residential Gas Service								
Basic Service Charge					$2,588,285	$2,588,285		
Summer	First	15 therms			$978,159	$978,159		
Summer	Over	15 therms			$207,277	$207,277		
Winter	First	35 therms			$2,743,595	$2,743,595		
Winter	Next	115 therms			$1,504,087	$1,504,087		
Winter	Over	150 therms			$76,111	$76,111		
Base Cost of Gas						$5,632,178		
Class Total			$7,473,828	$13,106,007	$8,097,514	$13,729,692	8.34%	4.76%
Rate Schedule G-15, Special Residential Gas Service for Air Conditioning								
Basic Service Charge					$17,898	$17,898		
Summer	First	15 therms			$6,409	$6,409		
Summer	Over	15 therms			$28,575	$28,575		
Winter	First	35 therms			$15,663	$15,663		
Winter	First	35 therms			$40,007	$40,007		
Base Cost of Gas						$120,004		
Class Total			$88,610	$208,614	**$108,552**	**$228,557**	22.51%	9.56%
Rate Schedule G-20, Master-Metered Mobile Home Park Service								
Basic Service Charge					$136,080	$136,080		
Commodity Charge, All Therms					$922,143	$922,143		
Base Cost of Gas						$1,310,523		
Class Total			$883,856	$2,194,378	**$1,058,223**	**$2,368,746**	19.73%	7.95%

Schedule RGG3-5

Rate Schedule G-25, General Gas Service, Small						
Basic Service Charge			$9,444,408	$9,444,408		
Commodity Charge, All therms			$21,393,697	$21,393,697		
Base Cost of Gas				$25,476,513		
Class Total	$26,068,862	$51,545,375	**$30,838,105**	**$56,314,618**	18.29%	9.25%
Rate Schedule G-25, General Gas Service, Medium						
Basic Service Charge			$8,741,040	$8,741,040		
Commodity Charge, All therms			$42,787,078	$42,787,078		
Base Cost of Gas				$73,476,415		
Class Total	$45,665,407	$119,141,823	**$51,528,118**	**$125,004,533**	12.84%	4.92%
Rate Schedule G-25, General Gas Service, Large						
Basic Service Charge			$978,480	$978,480		
Commodity Charge, All therms			$7,366,782	$7,366,782		
Demand Charge			$6,719,806	$6,719,806		
Base Cost of Gas				$25,392,409		
Class Total	$13,547,232	$38,939,642	**$15,065,067**	**$40,457,477**	11.20%	3.90%
Rate Schedule G-30, Optional Gas Service	$5,476,592	$61,408,388	$5,476,592	$61,408,388		
Rate Schedule G-35, Gas Service to Armed Forces						
Basic Service Charge			$39,960	$39,960		
Commodity Charge, All therms			$681,274	$681,274		
Base Cost of Gas				$1,693,235		
Class Total	$638,779	$2,332,014	**$721,234**	**$2,414,469**	12.91%	3.54%
Rate Schedule G-40, Air-Conditioning Gas Service						
Basic Service Charge, General Service - Small			$7,608	$7,608		
Basic Service Charge, General Service - Medium			$2,520	$2,520		
Basic Service Charge, General Service - Large			$19,440	$19,440		
Basic Service Charge, Essential Agriculture			$1,080	$1,080		
Commodity Charge, All therms			$174,472	$174,472		
Base Cost of Gas				$645,312		
Class Total	$167,216	$812,528	**$205,120**	**$850,432**	22.67%	4.66%

Schedule RGG3-6

Rate Schedule G-45, Street Lighting Gas Service						
Commodity Charge, All therms			$53,937	$53,937		
Base Cost of Gas				$53,373		
Class Total	$47,592	$100,966	**$53,937**	**$107,310**	13.33%	6.28%
Rate Schedule G-55, Gas Service for Compression on Customer's Premises						
Basic Service Charge, General Service - Small			$6,336	$6,336		
Basic Service Charge, General Service - Large			$59,940	$59,940		
Basic Service Charge, General Service - Residential			$12,540	$12,540		
Commodity Charge, All therms			$356,539	$356,539		
Base Cost of Gas				$1,154,666		
Class Total	$358,420	$1,513,086	**$435,355**	**$1,590,021**	21.47%	5.08%
Rate Schedule G-60, Cogeneration Gas Service						
Basic Service Charge, General Service - Small			$1,440	$1,440		
Basic Service Charge, General Service - Medium			$8,820	$8,820		
Basic Service Charge, General Service - Large			$58,320	$58,320		
Basic Service Charge, Essential Agriculture			$2,160	$2,160		
Commodity Charge, All therms			$1,650,852	$1,650,852		
Base Cost of Gas				$8,019,537		
Class Total	$1,405,352	$9,424,889	**$1,721,592**	**$9,741,129**	22.50%	3.36%
Rate Schedule G-75, Small Essential Agriculture User Gas Service						
Basic Service Charge			$121,230	$121,230		
Commodity Charge, All therms			$2,767,432	$2,767,432		
Base Cost of Gas				$4,268,999		
Class Total	$2,549,950	$6,818,949	**$2,888,662**	**$7,157,661**	13.28%	4.97%
Rate Schedule G-80, Natural Gas Engine Gas Service						
Basic Service Charge, Off-Peak Season (Oct. - Mar)			$0	$0		
Basic Service Charge, On-Peak Season (Apr - Sep)			$344,185	$344,185		
Commodity Charge, All therms			$3,743,761	$3,743,761		
Base Cost of Gas				$11,877,933		
Class Total	$3,733,462	$15,611,395	**$4,087,946**	**$15,965,879**	9.49%	2.27%
Special Contract Service, B-1	$2,134,837	$2,134,837	$2,134,837	$2,134,837		
Other Operating Revenues	$10,183,883	$10,183,883	$11,398,614	$11,398,614		
Total Margin	$322,866,019		$369,145,780		14.33%	
Total Revenue		$684,665,499		$730,945,260		6.76%
Target Revenue Requirement			$369,145,782			
Difference			-$2			

Schedule RGG3-7

Rate Schedule G-5, Residential Gas Service

Current Rates			Bills	Therms	Current Rate	Revenue
Basic Service Charge			9,496,924		$8.00	$75,975,392
Commodity Charge						
Summer	First	20 therms		49,593,360	$0.48762	$24,182,714
Summer	Over	20 therms		9,691,281	$0.40344	$3,909,850
Winter	First	40 therms		136,597,796	$0.48762	$66,607,817
Winter	Over	40 therms		78,738,764	$0.40344	$31,766,367
Total - Excluding Cost of Gas						$202,442,141
Base Cost of Gas (per therm)				274,621,201	$0.53436	$146,746,585
(applies proposed base cost of gas for comparability)						
Total Revenue						$349,188,726

Proposed Rates			Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge			9,496,924		$9.50	$90,220,778	18.8%
Commodity Charge							
Summer	First	15 therms		45,093,574	$0.54000	$24,350,530	
Summer	Over	15 therms		14,191,122	$0.49000	$6,953,650	
Winter	First	35 therms		125,729,371	$0.54000	$67,893,860	
Winter	Over	35 therms		89,607,134	$0.49000	$43,907,496	
Total - Excluding Cost of Gas						$233,326,314	15.3%
Base Cost of Gas (per therm)				274,621,201	$0.53436	$146,746,585	
Total Revenue						$380,072,899	8.8%

Schedule RGG3-8

Customer Bill Impact - Summer Rates

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
5		$9.50	$2.67	$2.70	$0.36	$15.23	$13.47	13.1%
10	Aug. avg.	$9.50	$5.34	$5.40	$0.72	$20.96	$18.94	10.7%
15		$9.50	$8.02	$8.10	$1.07	$26.69	$24.40	9.4%
20		$9.50	$10.69	$10.55	$1.43	$32.17	$29.87	7.7%
25		$9.50	$13.36	$13.00	$1.79	$37.65	$34.92	7.8%
29	Annual avg.	$9.50	$15.50	$14.96	$2.08	$42.03	$38.96	7.9%
30		$9.50	$16.03	$15.45	$2.15	$43.13	$39.96	7.9%
40		$9.50	$21.37	$20.35	$2.86	$54.09	$50.06	8.0%
50		$9.50	$26.72	$25.25	$3.58	$65.05	$60.15	8.1%
60		$9.50	$32.06	$30.15	$4.29	$76.01	$70.25	8.2%
72		$9.50	$38.47	$36.03	$5.15	$89.16	$82.36	8.3%
75		$9.50	$40.08	$37.50	$5.37	$92.44	$85.39	8.3%
100		$9.50	$53.44	$49.75	$7.16	$119.84	$110.62	8.3%
125		$9.50	$66.80	$62.00	$8.95	$147.24	$135.85	8.4%
150		$9.50	$80.15	$74.25	$10.74	$174.64	$161.09	8.4%
200		$9.50	$106.87	$98.75	$14.31	$229.44	$211.56	8.5%
250		$9.50	$133.59	$123.25	$17.89	$284.23	$262.03	8.5%
300		$9.50	$160.31	$147.75	$21.47	$339.03	$312.49	8.5%
400		$9.50	$213.74	$196.75	$28.63	$448.62	$413.43	8.5%
500		$9.50	$267.18	$245.75	$35.79	$558.22	$514.37	8.5%

Schedule RGG3-9

Customer Bill Impact - Winter Rates

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Staff Proposed Rates - Total Bill	Current Rates - Total Bill	Percent Increase
5	$9.50	$2.67	$2.70	$0.36	$15.23	$13.47	13.1%
10	$9.50	$5.34	$5.40	$0.72	$20.96	$18.94	10.7%
15	$9.50	$8.02	$8.10	$1.07	$26.69	$24.40	9.4%
20	$9.50	$10.69	$10.80	$1.43	$32.42	$29.87	8.5%
25	$9.50	$13.36	$13.50	$1.79	$38.15	$35.34	8.0%
29 Annual avg.	$9.50	$15.50	$15.66	$2.08	$42.73	$39.71	7.6%
30	$9.50	$16.03	$16.20	$2.15	$43.88	$40.81	7.5%
40	$9.50	$21.37	$21.35	$2.86	$55.09	$51.74	6.5%
50	$9.50	$26.72	$26.25	$3.58	$66.05	$61.84	6.8%
60	$9.50	$32.06	$31.15	$4.29	$77.01	$71.93	7.1%
72 Jan avg.	$9.50	$38.47	$37.03	$5.15	$90.16	$84.04	7.3%
75	$9.50	$40.08	$38.50	$5.37	$93.44	$87.07	7.3%
100	$9.50	$53.44	$50.75	$7.16	$120.84	$112.30	7.6%
125	$9.50	$66.80	$63.00	$8.95	$148.24	$137.54	7.8%
150	$9.50	$80.15	$75.25	$10.74	$175.64	$162.77	7.9%
200	$9.50	$106.87	$99.75	$14.31	$230.44	$213.24	8.1%
250	$9.50	$133.59	$124.25	$17.89	$285.23	$263.71	8.2%
300	$9.50	$160.31	$148.75	$21.47	$340.03	$314.18	8.2%
400	$9.50	$213.74	$197.75	$28.63	$449.62	$415.12	8.3%
500	$9.50	$267.18	$246.75	$35.79	$559.22	$516.05	8.4%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-10

Rate Schedule G-10, Low Income Residential Gas Service

Current Rates			Bills	Therms	Current Rate	Revenue
Basic Service Charge			369,755		$7.00	$2,588,285
Commodity Charge						
Summer	First	20 therms		1,996,133	$0.48762	$973,354
Summer	Over	20 therms		238,288	$0.40344	$96,135
Winter	First	40 therms		5,526,657	$0.48762	$2,694,908
Winter	Next	110 therms		2,703,999	$0.40344	$1,090,901
Winter	Over	150 therms		74,968	$0.40344	$30,245
Total - Excluding Cost of Gas						$7,473,829
Base Cost of Gas (per therm)				10,540,045	$0.53436	$5,632,178
(applies proposed base cost of gas for comparability)						
Total Revenue (excluding Discount)						$13,106,008
Test Year Total Discount						$1,593,570
Total Revenue After Discount						$11,512,438

Proposed Rates			Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge			369,755		$7.00	$2,588,285	
Commodity Charge							
Summer	First	15 therms		1,811,406	$0.54000	$978,159	
Summer	Over	15 therms		423,015	$0.49000	$207,277	
Winter	First	35 therms		5,080,731	$0.54000	$2,743,595	
Winter	Next	115 therms		3,069,565	$0.49000	$1,504,087	
Winter	Over	150 therms		155,328	$0.49000	$76,111	
Total - Excluding Cost of Gas						$8,097,514	
Base Cost of Gas (per therm)				10,540,045	$0.53436	$5,632,178	
(applies proposed base cost of gas for comparability)							
Total Revenue						$13,729,692	

Schedule RGG3-11

Customer Bill Impact - Summer Rates

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Proposed Rates Total Bill	Current Rates Total Bill	Percent Increase
1		$7.00	$0.53	$0.54	$0.07	$8.15	$8.09	0.6%
2		$7.00	$1.07	$1.08	$0.14	$9.29	$9.19	1.1%
3		$7.00	$1.60	$1.62	$0.21	$10.44	$10.28	1.5%
4		$7.00	$2.14	$2.16	$0.29	$11.58	$11.37	1.8%
5		$7.00	$2.67	$2.70	$0.36	$12.73	$12.47	2.1%
6		$7.00	$3.21	$3.24	$0.43	$13.88	$13.56	2.3%
7		$7.00	$3.74	$3.78	$0.50	$15.02	$14.65	2.5%
8		$7.00	$4.27	$4.32	$0.57	$16.17	$15.75	2.7%
9		$7.00	$4.81	$4.86	$0.64	$17.31	$16.84	2.8%
10	Aug. avg.	$7.00	$5.34	$5.40	$0.72	$18.46	$17.94	2.9%
15		$7.00	$8.02	$8.10	$1.07	$24.19	$23.40	3.4%
20		$7.00	$10.69	$10.55	$1.43	$29.67	$28.87	2.8%
25		$7.00	$13.36	$13.00	$1.79	$35.15	$33.92	3.6%
29	Annual avg.	$7.00	$15.50	$14.96	$2.08	$39.53	$37.96	4.2%
30		$7.00	$16.03	$15.45	$2.15	$40.63	$38.96	4.3%
40		$7.00	$21.37	$20.35	$2.86	$51.59	$49.06	5.2%
50		$7.00	$26.72	$25.25	$3.58	$62.55	$59.15	5.7%
60		$7.00	$32.06	$30.15	$4.29	$73.51	$69.25	6.2%
72		$7.00	$38.47	$36.03	$5.15	$86.66	$81.36	6.5%
75		$7.00	$40.08	$37.50	$5.37	$89.94	$84.39	6.6%
100		$7.00	$53.44	$49.75	$7.16	$117.34	$109.62	7.0%
125		$7.00	$66.80	$62.00	$8.95	$144.74	$134.85	7.3%
150		$7.00	$80.15	$74.25	$10.74	$172.14	$160.09	7.5%
200		$7.00	$106.87	$98.75	$14.31	$226.94	$210.56	7.8%
250		$7.00	$133.59	$123.25	$17.89	$281.73	$261.03	7.9%
300		$7.00	$160.31	$147.75	$21.47	$336.53	$311.49	8.0%
400		$7.00	$213.74	$196.75	$28.63	$446.12	$412.43	8.2%
500		$7.00	$267.18	$245.75	$35.79	$555.72	$513.37	8.2%

Schedule RGG3-12

Customer Bill Impact - Winter Rates

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Proposed Rates Total Bill Before Discount	Proposed Rates Total Bill After Discount	Current Rates Total Bill Before Discount	Current Rates Total Bill After Discount	Percent Increase After Discount
1	$7.00	$0.53	$0.54	$0.07	$8.15	$7.92	$8.09	$7.87	0.5%
2	$7.00	$1.07	$1.08	$0.14	$9.29	$8.83	$9.19	$8.75	1.0%
3	$7.00	$1.60	$1.62	$0.21	$10.44	$9.75	$10.28	$9.62	1.3%
4	$7.00	$2.14	$2.16	$0.29	$11.58	$10.67	$11.37	$10.50	1.6%
5	$7.00	$2.67	$2.70	$0.36	$12.73	$11.58	$12.47	$11.37	1.8%
6	$7.00	$3.21	$3.24	$0.43	$13.88	$12.50	$13.56	$12.25	2.1%
7	$7.00	$3.74	$3.78	$0.50	$15.02	$13.42	$14.65	$13.12	2.2%
8	$7.00	$4.27	$4.32	$0.57	$16.17	$14.33	$15.75	$14.00	2.4%
9	$7.00	$4.81	$4.86	$0.64	$17.31	$15.25	$16.84	$14.87	2.5%
10	$7.00	$5.34	$5.40	$0.72	$18.46	$16.17	$17.94	$15.75	2.7%
15	$7.00	$8.02	$8.10	$1.07	$24.19	$20.75	$23.40	$20.12	3.1%
20	$7.00	$10.69	$10.80	$1.43	$29.92	$25.33	$28.87	$24.50	3.4%
25	$7.00	$13.36	$13.50	$1.79	$35.65	$29.92	$34.34	$28.87	3.6%
29 Annual avg.	$7.00	$15.50	$15.66	$2.08	$40.23	$33.59	$38.71	$32.37	3.8%
30	$7.00	$16.03	$16.20	$2.15	$41.38	$34.50	$39.81	$33.25	3.8%
40	$7.00	$21.37	$21.35	$2.86	$52.59	$43.47	$50.74	$41.99	3.5%
50	$7.00	$26.72	$26.25	$3.58	$63.55	$52.24	$60.84	$50.07	4.3%
60	$7.00	$32.06	$31.15	$4.29	$74.51	$61.00	$70.93	$58.14	4.9%
70 Jan avg.	$7.00	$37.41	$36.05	$5.01	$85.47	$69.77	$81.02	$66.22	5.4%
75	$7.00	$40.08	$38.50	$5.37	$90.94	$74.16	$86.07	$70.26	5.6%
100	$7.00	$53.44	$50.75	$7.16	$118.34	$96.07	$111.30	$90.44	6.2%
125	$7.00	$66.80	$63.00	$8.95	$145.74	$117.99	$136.54	$110.63	6.7%
150	$7.00	$80.15	$75.25	$10.74	$173.14	$139.91	$161.77	$130.82	7.0%
200	$7.00	$106.87	$99.75	$14.31	$227.94	$194.71	$212.24	$181.29	7.4%
250	$7.00	$133.59	$124.25	$17.89	$282.73	$249.50	$262.71	$231.76	7.7%
300	$7.00	$160.31	$148.75	$21.47	$337.53	$304.30	$313.18	$282.22	7.8%
400	$7.00	$213.74	$197.75	$28.63	$447.12	$413.89	$414.12	$383.16	8.0%
500	$7.00	$267.18	$246.75	$35.79	$556.72	$523.49	$515.05	$484.10	8.1%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-13

Rate Schedule G-15, Special Residential Gas Service for Air Conditioning

Current Rates			Bills	Therms	Current Rate	Revenue
Basic Service Charge			1,884		$8.00	$15,072
Commodity Charge						
Summer	First	20 therms		14,784	$0.48762	$7,209
Summer	Over	20 therms		99,140	$0.19125	$18,961
Winter	First	40 therms		32,391	$0.48762	$15,794
Winter	Over	40 therms		78,261	$0.40344	$31,574
Total - Excluding Cost of Gas						$88,610
Base Cost of Gas (per therm)				224,576	$0.53436	$120,004
(applies proposed base cost of gas for comparability)						
Total Revenue						$208,614

Proposed Rates			Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge			1,884		$9.50	$17,898	18.8%
Commodity Charge							
Summer	First	15 therms		11,869	$0.54000	$6,409	
Summer	Over	15 therms		102,055	$0.28000	$28,575	
Winter	First	35 therms		29,006	$0.54000	$15,663	
Winter	Over	35 therms		81,646	$0.49000	$40,007	
Total - Excluding Cost of Gas						$108,552	22.5%
Base Cost of Gas (per therm)				224,576	$0.53436	$120,004	
Total Revenue						$228,557	9.6%

Schedule RGG3-14

Customer Bill Impact - Summer Rates

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rat Total Bill	Percent Increase
			Staff Proposed Rates				
10	$9.50	$5.34	$5.40	$0.72	$20.96	$18.94	10.7%
20	$9.50	$10.69	$10.80	$1.43	$32.42	$29.87	8.5%
30	$9.50	$16.03	$13.60	$2.15	$41.28	$37.84	9.1%
40	$9.50	$21.37	$16.40	$2.86	$50.14	$45.81	9.4%
50	$9.50	$26.72	$19.20	$3.58	$59.00	$53.79	9.7%
60	$9.50	$32.06	$22.00	$4.29	$67.86	$61.76	9.9%
75	$9.50	$40.08	$26.20	$5.37	$81.14	$73.72	10.1%
100	$9.50	$53.44	$33.20	$7.16	$103.29	$93.65	10.3%
119 Annual avg.	$9.50	$63.59	$38.52	$8.52	$120.13	$108.79	10.4%
125	$9.50	$66.80	$40.20	$8.95	$125.44	$113.57	10.4%
150	$9.50	$80.15	$47.20	$10.74	$147.59	$133.50	10.6%
152 Sep. avg.	$9.50	$81.22	$47.76	$10.88	$149.36	$135.10	10.6%
175	$9.50	$93.51	$54.20	$12.52	$169.74	$153.43	10.6%
200	$9.50	$106.87	$61.20	$14.31	$191.89	$173.36	10.7%
250	$9.50	$133.59	$75.20	$17.89	$236.18	$213.22	10.8%
300	$9.50	$160.31	$89.20	$21.47	$280.48	$253.08	10.8%
350	$9.50	$187.03	$103.20	$25.05	$324.78	$292.94	10.9%
400	$9.50	$213.74	$117.20	$28.63	$369.07	$332.80	10.9%
450	$9.50	$240.46	$131.20	$32.21	$413.37	$372.66	10.9%
500	$9.50	$267.18	$145.20	$35.79	$457.67	$412.52	10.9%

Schedule RGG3-15

Customer Bill Impact - Winter Rates

Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Staff Proposed Rates - Total Bill	Current Rat Total Bill	Percent Increase
10		$9.50	$5.34	$5.40	$0.72	$20.96	$18.94	10.7%
20		$9.50	$10.69	$10.80	$1.43	$32.42	$29.87	8.5%
30		$9.50	$16.03	$16.20	$2.15	$43.88	$40.81	7.5%
40		$9.50	$21.37	$21.60	$2.86	$55.34	$51.74	6.9%
50		$9.50	$26.72	$26.50	$3.58	$66.30	$61.84	7.2%
60		$9.50	$32.06	$31.40	$4.29	$77.26	$71.93	7.4%
75		$9.50	$40.08	$38.75	$5.37	$93.69	$87.07	7.6%
100		$9.50	$53.44	$51.00	$7.16	$121.09	$112.30	7.8%
119	Annual avg.	$9.50	$63.59	$60.31	$8.52	$141.92	$131.48	7.9%
125		$9.50	$66.80	$63.25	$8.95	$148.49	$137.54	8.0%
150	Jan avg.	$9.50	$80.15	$75.50	$10.74	$175.89	$162.77	8.1%
167		$9.50	$89.24	$83.83	$11.95	$194.52	$179.93	8.1%
175		$9.50	$93.51	$87.75	$12.52	$203.29	$188.01	8.1%
200		$9.50	$106.87	$100.00	$14.31	$230.69	$213.24	8.2%
250		$9.50	$133.59	$124.50	$17.89	$285.48	$263.71	8.3%
300		$9.50	$160.31	$149.00	$21.47	$340.28	$314.18	8.3%
350		$9.50	$187.03	$173.50	$25.05	$395.08	$364.65	8.3%
400		$9.50	$213.74	$198.00	$28.63	$449.87	$415.12	8.4%
450		$9.50	$240.46	$222.50	$32.21	$504.67	$465.58	8.4%
500		$9.50	$267.18	$247.00	$35.79	$559.47	$516.05	8.4%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-16

Rate Schedule G-20, Master Metered Mobile Home Park Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	2,268		$50.00	$113,400
Commodity Charge All Therms		2,452,509	$0.31415	$770,456
Total - Excluding Cost of Gas				$883,856
Base Cost of Gas (per therm) (applies proposed base cost of gas for comparability)		2,452,509	$0.53436	$1,310,523
Total Revenue				$2,194,378

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	2,268		$60.00	$136,080	20.0%
Commodity Charge All Therms		2,452,509	$0.37600	$922,143	
Total - Excluding Cost of Gas				$1,058,223	19.7%
Base Cost of Gas (per therm)		2,452,509	$0.53436	$1,310,523	
Total Revenue				$2,368,746	7.9%

Schedule RGG3-16

Customer Bill Impact

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates Total Bill	Percent Increase
			Staff Proposed Rates				
200	$60.00	$106.87	$75.20	$14.31	$256.39	$234.02	9.6%
400 Aug. avg.	$60.00	$213.74	$150.40	$28.63	$452.77	$418.03	8.3%
600	$60.00	$320.62	$225.60	$42.94	$649.16	$602.05	7.8%
800	$60.00	$427.49	$300.80	$57.26	$845.54	$786.06	7.6%
1,000	$60.00	$534.36	$376.00	$71.57	$1,041.93	$970.08	7.4%
1,081 Annual avg.	$60.00	$577.64	$406.46	$77.37	$1,121.47	$1,044.61	7.4%
1,200	$60.00	$641.23	$451.20	$85.88	$1,238.32	$1,154.10	7.3%
1,400	$60.00	$748.10	$526.40	$100.20	$1,434.70	$1,338.11	7.2%
1,600	$60.00	$854.98	$601.60	$114.51	$1,631.09	$1,522.13	7.2%
1,800	$60.00	$961.85	$676.80	$128.83	$1,827.47	$1,706.14	7.1%
2,000	$60.00	$1,068.72	$752.00	$143.14	$2,023.86	$1,890.16	7.1%
2,500	$60.00	$1,335.90	$940.00	$178.93	$2,514.83	$2,350.20	7.0%
2,522 Jan. avg.	$60.00	$1,347.66	$948.27	$180.50	$2,536.43	$2,370.44	7.0%
3,000	$60.00	$1,603.08	$1,128.00	$214.71	$3,005.79	$2,810.24	7.0%
3,500	$60.00	$1,870.26	$1,316.00	$250.50	$3,496.76	$3,270.28	6.9%
4,000	$60.00	$2,137.44	$1,504.00	$286.28	$3,987.72	$3,730.32	6.9%
4,500	$60.00	$2,404.62	$1,692.00	$322.07	$4,478.69	$4,190.36	6.9%
5,000	$60.00	$2,671.80	$1,880.00	$357.85	$4,969.65	$4,650.40	6.9%
10,000	$60.00	$5,343.60	$3,760.00	$715.70	$9,879.30	$9,250.80	6.8%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-17

Rate Schedule G-25, General Gas Service, Small

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	393,517		$20.00	$7,870,340
Commodity Charge				
Sales Therms		47,676,684	$0.38024	$18,128,582
Transport Therms		183,935	$0.38024	$69,939
Total - Excluding Cost of Gas				$26,068,862
Base Cost of Gas (per therm)		47,676,684	$0.53436	$25,476,513
(applies proposed base cost of gas for comparability)				
Total Revenue				$51,545,375

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	393,517		$24.00	$9,444,408	20.0%
Commodity Charge					
Sales Therms		47,676,684	$0.44700	$21,311,478	
Transport Therms		183,935	$0.44700	$82,219	
Total - Excluding Cost of Gas				$30,838,105	18.3%
Base Cost of Gas (per therm)		47,676,684	$0.53436	$25,476,513	
Total Revenue				$56,314,618	9.3%

Schedule RGG3-18

Customer Bill Impact

Monthly Consumption (therms)	Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates Total Bill	Percent Increase
25	$24.00	$13.36	$11.18	$1.79	$50.32	$44.65	12.7%
50	$24.00	$26.72	$22.35	$3.58	$76.65	$69.31	10.6%
75	$24.00	$40.08	$33.53	$5.37	$102.97	$93.96	9.6%
100	$24.00	$53.44	$44.70	$7.16	$129.29	$118.62	9.0%
122 Annual avg.	$24.00	$65.19	$54.53	$8.73	$152.46	$140.31	8.7%
125	$24.00	$66.80	$55.88	$8.95	$155.62	$143.27	8.6%
150	$24.00	$80.15	$67.05	$10.74	$181.94	$167.93	8.3%
175	$24.00	$93.51	$78.23	$12.52	$208.26	$192.58	8.1%
200	$24.00	$106.87	$89.40	$14.31	$234.59	$217.23	8.0%
223 Jan. avg.	$24.00	$119.16	$99.68	$15.96	$258.80	$239.92	7.9%
250	$24.00	$133.59	$111.75	$17.89	$287.23	$266.54	7.8%
300	$24.00	$160.31	$134.10	$21.47	$339.88	$315.85	7.6%
400	$24.00	$213.74	$178.80	$28.63	$445.17	$414.47	7.4%
500	$24.00	$267.18	$223.50	$35.79	$550.47	$513.09	7.3%
600	$24.00	$320.62	$268.20	$42.94	$655.76	$611.70	7.2%
750	$24.00	$400.77	$335.25	$53.68	$813.70	$759.63	7.1%
1,000	$24.00	$534.36	$447.00	$71.57	$1,076.93	$1,006.17	7.0%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-19

Rate Schedule G-25, General Gas Service, Medium

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	83,248		$90.00	$7,492,320
Commodity Charge				
Sales Therms		137,503,584	$0.27211	$37,416,100
Transport Therms		2,781,916	$0.27211	$756,987
Total - Excluding Cost of Gas				$45,665,407
Base Cost of Gas (per therm)		137,503,584	$0.53436	$73,476,415
(applies proposed base cost of gas for comparability)				
Total Revenue				$119,141,823

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	83,248		$105.00	$8,741,040	16.7%
Commodity Charge					
Sales Therms		137,503,584	$0.30500	$41,938,593	
Transport Therms		2,781,916	$0.30500	$848,484	
Total - Excluding Cost of Gas				$51,528,118	12.8%
Base Cost of Gas (per therm)		137,503,584	$0.53436	$73,476,415	
Total Revenue				$125,004,533	4.9%

Schedule RGG3-20

Customer Bill Impact

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
			Staff Proposed Rates				
200	$105.00	$106.87	$61.00	$14.31	$287.19	$265.61	8.1%
400	$105.00	$213.74	$122.00	$28.63	$469.37	$441.22	6.4%
600	$105.00	$320.62	$183.00	$42.94	$651.56	$616.82	5.6%
800	$105.00	$427.49	$244.00	$57.26	$833.74	$792.43	5.2%
1,000	$105.00	$534.36	$305.00	$71.57	$1,015.93	$968.04	4.9%
1,250	$105.00	$667.95	$381.25	$89.46	$1,243.66	$1,187.55	4.7%
1,500	$105.00	$801.54	$457.50	$107.36	$1,471.40	$1,407.06	4.6%
1,690 Annual avg.	$105.00	$903.07	$515.45	$120.95	$1,644.47	$1,573.89	4.5%
2,000	$105.00	$1,068.72	$610.00	$143.14	$1,926.86	$1,846.08	4.4%
2,500	$105.00	$1,335.90	$762.50	$178.93	$2,382.33	$2,285.10	4.3%
2,682 Jan. avg.	$105.00	$1,433.15	$818.01	$191.95	$2,548.11	$2,444.90	4.2%
3,000	$105.00	$1,603.08	$915.00	$214.71	$2,837.79	$2,724.12	4.2%
4,000	$105.00	$2,137.44	$1,220.00	$286.28	$3,748.72	$3,602.16	4.1%
5,000	$105.00	$2,671.80	$1,525.00	$357.85	$4,659.65	$4,480.20	4.0%
7,500	$105.00	$4,007.70	$2,287.50	$536.78	$6,936.98	$6,675.30	3.9%
10,000	$105.00	$5,343.60	$3,050.00	$715.70	$9,214.30	$8,870.40	3.9%
15,000	$105.00	$8,015.40	$4,575.00	$1,073.55	$13,768.95	$13,260.60	3.8%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-21

Rate Schedule G-25, General Gas Service, Large

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	1,812		$500.00	$906,000
Billing Determinants		7,272,517	$0.072695	$6,344,107
Commodity Charge				
Sales Therms		47,519,293	$0.08548	$4,061,949
Transport Therms		26,148,523	$0.08548	$2,235,176
Total - Excluding Cost of Gas				$13,547,232
Base Cost of Gas (per therm)		47,519,293	$0.53436	$25,392,409
(applies proposed base cost of gas for comparability)				
Total Revenue				$38,939,642

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	1,812		$540.00	$978,480	8.0%
Billing Determinants		7,272,517	$0.077000	$6,719,806	
Commodity Charge					
Sales Therms		47,519,293	$0.10000	$4,751,929	
Transport Therms		26,148,523	$0.10000	$2,614,852	
Total - Excluding Cost of Gas				$15,065,067	11.2%
Base Cost of Gas (per therm)		47,519,293	$0.53436	$25,392,409	
Total Revenue				$40,457,477	3.9%

Schedule RGG3-22

Customer Bill Impact

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Staff Proposed Rates: Margin Rate	Billing Determinants	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
2,000	$540.00	$1,068.72	$200.00	$182.44	$143.14	$2,134.30	$2,055.06	3.9%
5,000	$540.00	$2,671.80	$500.00	$456.09	$357.85	$4,525.74	$4,387.64	3.1%
10,000	$540.00	$5,343.60	$1,000.00	$912.18	$715.70	$8,511.48	$8,275.28	2.9%
15,000	$540.00	$8,015.40	$1,500.00	$1,368.26	$1,073.55	$12,497.21	$12,162.92	2.7%
20,000	$540.00	$10,687.20	$2,000.00	$1,824.35	$1,431.40	$16,482.95	$16,050.56	2.7%
25,000	$540.00	$13,359.00	$2,500.00	$2,280.44	$1,789.25	$20,468.69	$19,938.19	2.7%
30,000	$540.00	$16,030.80	$3,000.00	$2,736.53	$2,147.10	$24,454.43	$23,825.83	2.6%
35,000	$540.00	$18,702.60	$3,500.00	$3,192.62	$2,504.95	$28,440.17	$27,713.47	2.6%
40,000	$540.00	$21,374.40	$4,000.00	$3,648.71	$2,862.80	$32,425.91	$31,601.11	2.6%
42,048 Annual avg.	$540.00	$22,468.77	$4,204.80	$3,835.52	$3,009.38	$34,058.46	$33,193.49	2.6%
45,000	$540.00	$24,046.20	$4,500.00	$4,104.79	$3,220.65	$36,411.64	$35,488.75	2.6%
50,000	$540.00	$26,718.00	$5,000.00	$4,560.88	$3,578.50	$40,397.38	$39,376.39	2.6%
51,574 Jan. avg.	$540.00	$27,559.08	$5,157.40	$4,704.46	$3,691.15	$41,652.09	$40,600.22	2.6%
60,000	$540.00	$32,061.60	$6,000.00	$5,473.06	$4,294.20	$48,368.86	$47,151.67	2.6%
75,000	$540.00	$40,077.00	$7,500.00	$6,841.32	$5,367.75	$60,326.07	$58,814.58	2.6%
100,000	$540.00	$53,436.00	$10,000.00	$9,121.77	$7,157.00	$80,254.77	$78,252.78	2.6%
150,000	$540.00	$80,154.00	$15,000.00	$13,682.65	$10,735.50	$120,112.15	$117,129.16	2.5%
200,000	$540.00	$106,872.00	$20,000.00	$18,243.53	$14,314.00	$159,969.53	$156,005.55	2.5%

Billing determinants for customer bill estimates is based upon the class average for the size of customer. Based upon varying usage characteristics, customers of the same size will have different billing determinants.
The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-23

Rate Schedule G-35, Gas Service to Armed Forces

Current Rates

	Bills	Therms	Current Rate	Revenue
Basic Service Charge	108		$350.00	$37,800
Commodity Charge				
Sales Therms		3,168,716	$0.18966	$600,979
Transport Therms		0	$0.18966	$0
Total - Excluding Cost of Gas				$638,779
Base Cost of Gas (per therm)		3,168,716	$0.53436	$1,693,235
(applies proposed base cost of gas for comparability)				
Total Revenue				$2,332,014

Proposed Rates

	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	108		$370.00	$39,960	5.7%
Commodity Charge					
Sales Therms		3,168,716	$0.21500	$681,274	
Transport Therms		0	$0.21500	$0	
Total - Excluding Cost of Gas				$721,234	12.9%
Base Cost of Gas (per therm)		3,168,716	$0.53436	$1,693,235	
Total Revenue				$2,414,469	3.5%

Schedule RGG3-24

Customer Bill Impact

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Proposed Rates Margin Rate	Proposed Rates Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1000	$370.00	$534.36	$215.00	$71.57	$1,190.93	$1,145.59	4.0%
2000	$370.00	$1,068.72	$430.00	$143.14	$2,011.86	$1,941.18	3.6%
3000	$370.00	$1,603.08	$645.00	$214.71	$2,832.79	$2,736.77	3.5%
4000	$370.00	$2,137.44	$860.00	$286.28	$3,653.72	$3,532.36	3.4%
5,000	$370.00	$2,671.80	$1,075.00	$357.85	$4,474.65	$4,327.95	3.4%
7,500	$370.00	$4,007.70	$1,612.50	$536.78	$6,526.98	$6,316.93	3.3%
10,000	$370.00	$5,343.60	$2,150.00	$715.70	$8,579.30	$8,305.90	3.3%
15,000	$370.00	$8,015.40	$3,225.00	$1,073.55	$12,683.95	$12,283.85	3.3%
20,000	$370.00	$10,687.20	$4,300.00	$1,431.40	$16,788.60	$16,261.80	3.2%
25,000	$370.00	$13,359.00	$5,375.00	$1,789.25	$20,893.25	$20,239.75	3.2%
30,000	$370.00	$16,030.80	$6,450.00	$2,147.10	$24,997.90	$24,217.70	3.2%
33,008 Annual avg.	$370.00	$17,638.15	$7,096.72	$2,362.38	$27,467.26	$26,610.83	3.2%
40,000	$370.00	$21,374.40	$8,600.00	$2,862.80	$33,207.20	$32,173.60	3.2%
50,000	$370.00	$26,718.00	$10,750.00	$3,578.50	$41,416.50	$40,129.50	3.2%
67,261 Jan. avg.	$370.00	$35,941.59	$14,461.12	$4,813.87	$55,586.57	$53,862.18	3.2%
75,000	$370.00	$40,077.00	$16,125.00	$5,367.75	$61,939.75	$60,019.25	3.2%
100,000	$370.00	$53,436.00	$21,500.00	$7,157.00	$82,463.00	$79,909.00	3.2%
150,000	$370.00	$80,154.00	$32,250.00	$10,735.50	$123,509.50	$119,688.50	3.2%
200,000	$370.00	$106,872.00	$43,000.00	$14,314.00	$164,556.00	$159,468.00	3.2%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-25

Rate Schedule G-40, Air Conditioning Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charges				
General Service - Small	317		$20.00	$6,340
General Service - Medium	24		$90.00	$2,160
General Service - Large	36		$500.00	$18,000
Essential Agricultural	12		$75.00	$900
Total Basic Service Charges				$27,400
Commodity Charge				
Sales Therms		1,207,635	$0.07613	$91,937
Transport Therms		628,909	$0.07613	$47,879
Total - Excluding Cost of Gas				$167,216
Base Cost of Gas (per therm)		1,207,635	$0.53436	$645,312
(applies proposed base cost of gas for comparability)				
Total Revenue				$812,528

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge					
General Service - Small	317		$24.00	$7,608	
General Service - Medium	24		$105.00	$2,520	
General Service - Large	36		$540.00	$19,440	
Essential Agricultural	12		$90.00	$1,080	
Total Basic Service Charges				$30,648	
Commodity Charge					
Sales Therms		1,207,635	$0.09500	$114,725	
Transport Therms		628,909	$0.09500	$59,746	
Total - Excluding Cost of Gas				$205,120	22.7%
Base Cost of Gas (per therm)		1,207,635	$0.53436	$645,312	
Total Revenue				$850,432	4.7%

Schedule RGG3-26

Customer Bill Impact - Small General Service

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Staff Proposed Rates Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
50	$24.00	$26.72	$4.75	$3.58	$59.05	$54.10	9.1%
100	$24.00	$53.44	$9.50	$7.16	$94.09	$88.21	6.7%
250	$24.00	$133.59	$23.75	$17.89	$199.23	$190.52	4.6%
500	$24.00	$267.18	$47.50	$35.79	$374.47	$361.03	3.7%
750	$24.00	$400.77	$71.25	$53.68	$549.70	$531.55	3.4%
1,000	$24.00	$534.36	$95.00	$71.57	$724.93	$702.06	3.3%
2,000	$24.00	$1,068.72	$190.00	$143.14	$1,425.86	$1,384.12	3.0%
3,000	$24.00	$1,603.08	$285.00	$214.71	$2,126.79	$2,066.18	2.9%
3,826 Annual avg.	$24.00	$2,044.46	$363.47	$273.83	$2,705.76	$2,629.56	2.9%
5,000	$24.00	$2,671.80	$475.00	$357.85	$3,528.65	$3,430.30	2.9%
7,500	$24.00	$4,007.70	$712.50	$536.78	$5,280.98	$5,135.45	2.8%
10,000	$24.00	$5,343.60	$950.00	$715.70	$7,033.30	$6,840.60	2.8%
15,000	$24.00	$8,015.40	$1,425.00	$1,073.55	$10,537.95	$10,250.90	2.8%
20,000	$24.00	$10,687.20	$1,900.00	$1,431.40	$14,042.60	$13,661.20	2.8%
30,000	$24.00	$16,030.80	$2,850.00	$2,147.10	$21,051.90	$20,481.80	2.8%
40,000	$24.00	$21,374.40	$3,800.00	$2,862.80	$28,061.20	$27,302.40	2.8%
50,000	$24.00	$26,718.00	$4,750.00	$3,578.50	$35,070.50	$34,123.00	2.8%

Schedule RGG3-27

Customer Bill Impact - Medium General Service

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Staff Proposed Rates: Margin Rate	Staff Proposed Rates: Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
50	$105.00	$26.72	$4.75	$3.58	$140.05	$124.10	12.8%
100	$105.00	$53.44	$9.50	$7.16	$175.09	$158.21	10.7%
250	$105.00	$133.59	$23.75	$17.89	$280.23	$260.52	7.6%
500	$105.00	$267.18	$47.50	$35.79	$455.47	$431.03	5.7%
750	$105.00	$400.77	$71.25	$53.68	$630.70	$601.55	4.8%
1,000	$105.00	$534.36	$95.00	$71.57	$805.93	$772.06	4.4%
2,000	$105.00	$1,068.72	$190.00	$143.14	$1,506.86	$1,454.12	3.6%
3,000	$105.00	$1,603.08	$285.00	$214.71	$2,207.79	$2,136.18	3.4%
3,826 Annual avg.	$105.00	$2,044.46	$363.47	$273.83	$2,786.76	$2,699.56	3.2%
5,000	$105.00	$2,671.80	$475.00	$357.85	$3,609.65	$3,500.30	3.1%
7,500	$105.00	$4,007.70	$712.50	$536.78	$5,361.98	$5,205.45	3.0%
10,000	$105.00	$5,343.60	$950.00	$715.70	$7,114.30	$6,910.60	2.9%
15,000	$105.00	$8,015.40	$1,425.00	$1,073.55	$10,618.95	$10,320.90	2.9%
20,000	$105.00	$10,687.20	$1,900.00	$1,431.40	$14,123.60	$13,731.20	2.9%
30,000	$105.00	$16,030.80	$2,850.00	$2,147.10	$21,132.90	$20,551.80	2.8%
40,000	$105.00	$21,374.40	$3,800.00	$2,862.80	$28,142.20	$27,372.40	2.8%
50,000	$105.00	$26,718.00	$4,750.00	$3,578.50	$35,151.50	$34,193.00	2.8%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-28

Rate Schedule G-45, Street Lighting Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
	348			
Commodity Charge				
Sales Therms		99,883	$0.47648	$47,592
Total - Excluding Cost of Gas				$47,592
Base Cost of Gas (per therm)		99,883	$0.53436	$53,373
(applies proposed base cost of gas for comparability)				
Total Revenue				$100,966

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
	348				
Commodity Charge					
Sales Therms		99,883	$0.54000	$53,937	
Total - Excluding Cost of Gas				$53,937	13.3%
Base Cost of Gas (per therm)		99,883	$0.53436	$53,373	
Total Revenue				$107,310	6.3%

Schedule RGG3-29

Customer Bill Impact

Monthly Consumption (therms)		Staff Proposed Rates: Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25		$13.36	$13.50	$1.79	$28.65	$27.06	5.9%
50		$26.72	$27.00	$3.58	$57.30	$54.12	5.9%
75		$40.08	$40.50	$5.37	$85.94	$81.18	5.9%
100		$53.44	$54.00	$7.16	$114.59	$108.24	5.9%
125		$66.80	$67.50	$8.95	$143.24	$135.30	5.9%
150		$80.15	$81.00	$10.74	$171.89	$162.36	5.9%
175		$93.51	$94.50	$12.52	$200.54	$189.42	5.9%
200		$106.87	$108.00	$14.31	$229.19	$216.48	5.9%
250		$133.59	$135.00	$17.89	$286.48	$270.60	5.9%
287	Annual avg.	$153.36	$154.98	$20.54	$328.88	$310.65	5.9%
300		$160.31	$162.00	$21.47	$343.78	$324.72	5.9%
350		$187.03	$189.00	$25.05	$401.08	$378.84	5.9%
400		$213.74	$216.00	$28.63	$458.37	$432.96	5.9%
500		$267.18	$270.00	$35.79	$572.97	$541.21	5.9%
750		$400.77	$405.00	$53.68	$859.45	$811.81	5.9%
1,000		$534.36	$540.00	$71.57	$1,145.93	$1,082.41	5.9%
1,500		$801.54	$810.00	$107.36	$1,718.90	$1,623.62	5.9%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-30

Rate Schedule G-55, Gas Service for Compression on Customer's Premises

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charges				
General Service - Small	264		$20.00	$5,280
General Service - Large	324		$170.00	$55,080
General Service - Residential	1,320		$8.00	$10,560
Total Basic Service Charges				$70,920
Commodity Charge				
Sales Therms - Small		182,313	$0.13305	$24,257
Sales Therms - Large		1,898,808	$0.13305	$252,636
Sales Therms - Residential		79,719	$0.13305	$10,607
Total - Excluding Cost of Gas				$358,420
Base Cost of Gas (per therm)		2,160,840	$0.53436	$1,154,666
(applies proposed base cost of gas for comparability)				
Total Revenue				$1,513,086

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charges					
General Service - Small	264		$24.00	$6,336	
General Service - Large	324		$185.00	$59,940	
General Service - Residential	1,320		$9.50	$12,540	
Total Basic Service Charges				$78,816	
Commodity Charge					
Sales Therms - Small		182,313	$0.16500	$30,082	
Sales Therms - Large		1,898,808	$0.16500	$313,303	
Sales Therms - Residential		79,719	$0.16500	$13,154	
Total - Excluding Cost of Gas				$435,355	21.5%
Base Cost of Gas (per therm)		2,160,840	$0.53436	$1,154,666	
(applies proposed base cost of gas for comparability)					
Total Revenue				$1,590,021	5.1%

Schedule RGG3-31

Customer Bill Impact - Small

Monthly Consumption (therms)	Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25	$24.00	$13.36	$4.13	$1.79	$43.27	$38.47	12.5%
50	$24.00	$26.72	$8.25	$3.58	$62.55	$56.95	9.8%
75	$24.00	$40.08	$12.38	$5.37	$81.82	$75.42	8.5%
100	$24.00	$53.44	$16.50	$7.16	$101.09	$93.90	7.7%
125	$24.00	$66.80	$20.63	$8.95	$120.37	$112.37	7.1%
150	$24.00	$80.15	$24.75	$10.74	$139.64	$130.85	6.7%
175	$24.00	$93.51	$28.88	$12.52	$158.91	$149.32	6.4%
200	$24.00	$106.87	$33.00	$14.31	$178.19	$167.80	6.2%
250	$24.00	$133.59	$41.25	$17.89	$216.73	$204.75	5.9%
300	$24.00	$160.31	$49.50	$21.47	$255.28	$241.69	5.6%
350	$24.00	$187.03	$57.75	$25.05	$293.83	$278.64	5.4%
400	$24.00	$213.74	$66.00	$28.63	$332.37	$315.59	5.3%
450	$24.00	$240.46	$74.25	$32.21	$370.92	$352.54	5.2%
500	$24.00	$267.18	$82.50	$35.79	$409.47	$389.49	5.1%
750	$24.00	$400.77	$123.75	$53.68	$602.20	$574.24	4.9%
1,000	$24.00	$534.36	$165.00	$71.57	$794.93	$758.98	4.7%
1,250	$24.00	$667.95	$206.25	$89.46	$987.66	$943.73	4.7%

Schedule RGG3-32

Customer Bill Impact - Large

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Staff Proposed Rates Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1000	$185.00	$534.36	$165.00	$71.57	$955.93	$908.98	5.2%
2000	$185.00	$1,068.72	$330.00	$143.14	$1,726.86	$1,647.96	4.8%
3000	$185.00	$1,603.08	$495.00	$214.71	$2,497.79	$2,386.94	4.6%
4000	$185.00	$2,137.44	$660.00	$286.28	$3,268.72	$3,125.92	4.6%
5,000	$185.00	$2,671.80	$825.00	$357.85	$4,039.65	$3,864.90	4.5%
6,000	$185.00	$3,206.16	$990.00	$429.42	$4,810.58	$4,603.88	4.5%
7,000	$185.00	$3,740.52	$1,155.00	$500.99	$5,581.51	$5,342.86	4.5%
8,000	$185.00	$4,274.88	$1,320.00	$572.56	$6,352.44	$6,081.84	4.4%
9,000	$185.00	$4,809.24	$1,485.00	$644.13	$7,123.37	$6,820.82	4.4%
10,000	$185.00	$5,343.60	$1,650.00	$715.70	$7,894.30	$7,559.80	4.4%
12,500	$185.00	$6,679.50	$2,062.50	$894.63	$9,821.63	$9,407.25	4.4%
15,000	$185.00	$8,015.40	$2,475.00	$1,073.55	$11,748.95	$11,254.70	4.4%
17,500	$185.00	$9,351.30	$2,887.50	$1,252.48	$13,676.28	$13,102.15	4.4%
20,000	$185.00	$10,687.20	$3,300.00	$1,431.40	$15,603.60	$14,949.60	4.4%
25,000	$185.00	$13,359.00	$4,125.00	$1,789.25	$19,458.25	$18,644.50	4.4%
35,000	$185.00	$18,702.60	$5,775.00	$2,504.95	$27,167.55	$26,034.30	4.4%
50,000	$185.00	$26,718.00	$8,250.00	$3,578.50	$38,731.50	$37,119.00	4.3%

Schedule RGG3-33

Customer Bill Impact - Residential

Monthly Consumption (therms)	Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
10	$9.50	$5.34	$1.65	$0.72	$17.21	$15.39	11.8%
15	$9.50	$8.02	$2.48	$1.07	$21.06	$19.08	10.4%
20	$9.50	$10.69	$3.30	$1.43	$24.92	$22.78	9.4%
25	$9.50	$13.36	$4.13	$1.79	$28.77	$26.47	8.7%
30	$9.50	$16.03	$4.95	$2.15	$32.63	$30.17	8.1%
35	$9.50	$18.70	$5.78	$2.50	$36.48	$33.86	7.7%
40	$9.50	$21.37	$6.60	$2.86	$40.34	$37.56	7.4%
45	$9.50	$24.05	$7.43	$3.22	$44.19	$41.25	7.1%
50	$9.50	$26.72	$8.25	$3.58	$48.05	$44.95	6.9%
60	$9.50	$32.06	$9.90	$4.29	$55.76	$52.34	6.5%
70	$9.50	$37.41	$11.55	$5.01	$63.47	$59.73	6.3%
80	$9.50	$42.75	$13.20	$5.73	$71.17	$67.12	6.0%
90	$9.50	$48.09	$14.85	$6.44	$78.88	$74.51	5.9%
100	$9.50	$53.44	$16.50	$7.16	$86.59	$81.90	5.7%
125	$9.50	$66.80	$20.63	$8.95	$105.87	$100.37	5.5%
150	$9.50	$80.15	$24.75	$10.74	$125.14	$118.85	5.3%
200	$9.50	$106.87	$33.00	$14.31	$163.69	$155.80	5.1%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

schedule RGG3-34

Rate Schedule G-60, Cogeneration Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charges				
General Service - Small	60		$20.00	$1,200
General Service - Medium	84		$90.00	$7,560
General Service - Large	108		$500.00	$54,000
Essential Agricultural	24		$75.00	$1,800
Total Basic Service Charges				$64,560
Commodity Charge				
Sales Therms		15,007,742	$0.08934	$1,340,792
Transport Therms		0	$0.08934	$0
Total - Excluding Cost of Gas				$1,405,352
Base Cost of Gas (per therm)		15,007,742	$0.53436	$8,019,537
(applies proposed base cost of gas for comparability)				
Total Revenue				$9,424,889

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge					
General Service - Small	60		$24.00	$1,440	
General Service - Medium	84		$105.00	$8,820	
General Service - Large	108		$540.00	$58,320	
Essential Agricultural	24		$90.00	$2,160	
Total Basic Service Charges				$70,740	
Commodity Charge					
Sales Therms		15,007,742	$0.11000	$1,650,852	
Transport Therms		0	$0.11000	$0	
Total - Excluding Cost of Gas				$1,721,592	22.5%
Base Cost of Gas (per therm)		15,007,742	$0.53436	$8,019,537	
Total Revenue				$9,741,129	3.4%

Schedule RGG3-35

Customer Bill Impact - Small

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Staff Proposed Rates Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25	$24.00	$13.36	$2.75	$1.79	$41.90	$37.38	12.1%
50	$24.00	$26.72	$5.50	$3.58	$59.80	$54.76	9.2%
75	$24.00	$40.08	$8.25	$5.37	$77.69	$72.15	7.7%
100	$24.00	$53.44	$11.00	$7.16	$95.59	$89.53	6.8%
125	$24.00	$66.80	$13.75	$8.95	$113.49	$106.91	6.2%
150	$24.00	$80.15	$16.50	$10.74	$131.39	$124.29	5.7%
175	$24.00	$93.51	$19.25	$12.52	$149.29	$141.67	5.4%
200	$24.00	$106.87	$22.00	$14.31	$167.19	$159.05	5.1%
250	$24.00	$133.59	$27.50	$17.89	$202.98	$193.82	4.7%
300	$24.00	$160.31	$33.00	$21.47	$238.78	$228.58	4.5%
350	$24.00	$187.03	$38.50	$25.05	$274.58	$263.34	4.3%
400	$24.00	$213.74	$44.00	$28.63	$310.37	$298.11	4.1%
450	$24.00	$240.46	$49.50	$32.21	$346.17	$332.87	4.0%
500	$24.00	$267.18	$55.00	$35.79	$381.97	$367.64	3.9%
750	$24.00	$400.77	$82.50	$53.68	$560.95	$541.45	3.6%
1,000	$24.00	$534.36	$110.00	$71.57	$739.93	$715.27	3.4%
1,250	$24.00	$667.95	$137.50	$89.46	$918.91	$889.09	3.4%

Schedule RGG3-36

Customer Bill Impact - Medium

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Staff Proposed Rates Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
500	$105.00	$267.18	$55.00	$35.79	$462.97	$437.64	5.8%
600	$105.00	$320.62	$66.00	$42.94	$534.56	$507.16	5.4%
700	$105.00	$374.05	$77.00	$50.10	$606.15	$576.69	5.1%
800	$105.00	$427.49	$88.00	$57.26	$677.74	$646.22	4.9%
900	$105.00	$480.92	$99.00	$64.41	$749.34	$715.74	4.7%
1,000	$105.00	$534.36	$110.00	$71.57	$820.93	$785.27	4.5%
1,250	$105.00	$667.95	$137.50	$89.46	$999.91	$959.09	4.3%
1,500	$105.00	$801.54	$165.00	$107.36	$1,178.90	$1,132.91	4.1%
2,000	$105.00	$1,068.72	$220.00	$143.14	$1,536.86	$1,480.54	3.8%
3,000	$105.00	$1,603.08	$330.00	$214.71	$2,252.79	$2,175.81	3.5%
4,000	$105.00	$2,137.44	$440.00	$286.28	$2,968.72	$2,871.08	3.4%
5,000	$105.00	$2,671.80	$550.00	$357.85	$3,684.65	$3,566.35	3.3%
7,500	$105.00	$4,007.70	$825.00	$536.78	$5,474.48	$5,304.53	3.2%
10,000	$105.00	$5,343.60	$1,100.00	$715.70	$7,264.30	$7,042.70	3.1%
12,500	$105.00	$6,679.50	$1,375.00	$894.63	$9,054.13	$8,780.88	3.1%
15,000	$105.00	$8,015.40	$1,650.00	$1,073.55	$10,843.95	$10,519.05	3.1%
20,000	$105.00	$10,687.20	$2,200.00	$1,431.40	$14,423.60	$13,995.40	3.1%

Schedule RGG3-37

Customer Bill Impact - Large

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Staff Proposed Rates Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
10,000	$540.00	$5,343.60	$1,100.00	$715.70	$7,699.30	$7,492.70	2.8%
12,500	$540.00	$6,679.50	$1,375.00	$894.63	$9,489.13	$9,230.88	2.8%
15,000	$540.00	$8,015.40	$1,650.00	$1,073.55	$11,278.95	$10,969.05	2.8%
17,500	$540.00	$9,351.30	$1,925.00	$1,252.48	$13,068.78	$12,707.23	2.8%
20,000	$540.00	$10,687.20	$2,200.00	$1,431.40	$14,858.60	$14,445.40	2.9%
25,000	$540.00	$13,359.00	$2,750.00	$1,789.25	$18,438.25	$17,921.75	2.9%
30,000	$540.00	$16,030.80	$3,300.00	$2,147.10	$22,017.90	$21,398.10	2.9%
35,000	$540.00	$18,702.60	$3,850.00	$2,504.95	$25,597.55	$24,874.45	2.9%
40,000	$540.00	$21,374.40	$4,400.00	$2,862.80	$29,177.20	$28,350.80	2.9%
45,000	$540.00	$24,046.20	$4,950.00	$3,220.65	$32,756.85	$31,827.15	2.9%
50,000	$540.00	$26,718.00	$5,500.00	$3,578.50	$36,336.50	$35,303.50	2.9%
75,000	$540.00	$40,077.00	$8,250.00	$5,367.75	$54,234.75	$52,685.25	2.9%
100,000	$540.00	$53,436.00	$11,000.00	$7,157.00	$72,133.00	$70,067.00	2.9%
150,000	$540.00	$80,154.00	$16,500.00	$10,735.50	$107,929.50	$104,830.50	3.0%
200,000	$540.00	$106,872.00	$22,000.00	$14,314.00	$143,726.00	$139,594.00	3.0%
300,000	$540.00	$160,308.00	$33,000.00	$21,471.00	$215,319.00	$209,121.00	3.0%
500,000	$540.00	$267,180.00	$55,000.00	$35,785.00	$358,505.00	$348,175.00	3.0%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-38

Rate Schedule G-75, Small Essential Agriculture User Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	1,347		$75.00	$101,025
Commodity Charge				
Sales Therms		7,988,994	$0.19468	$1,555,297
Transport Therms		4,590,241	$0.19468	$893,628
Total - Excluding Cost of Gas				$2,549,950
Base Cost of Gas (per therm)		7,988,994	$0.53436	$4,268,999
(applies proposed base cost of gas for comparability)				
Total Revenue				$6,818,949

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	1,347		$90.00	$121,230	20.0%
Commodity Charge					
Sales Therms		7,988,994	$0.22000	$1,757,579	
Transport Therms		4,590,241	$0.22000	$1,009,853	
Total - Excluding Cost of Gas				$2,888,662	13.3%
Base Cost of Gas (per therm)		7,988,994	$0.53436	$4,268,999	
Total Revenue				$7,157,661	5.0%

Schedule RGG3-39

Customer Bill Impact

Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Staff Proposed Rates Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25	$90.00	$13.36	$5.50	$1.79	$110.65	$95.02	16.5%
50	$90.00	$26.72	$11.00	$3.58	$131.30	$115.03	14.1%
100	$90.00	$53.44	$22.00	$7.16	$172.59	$155.06	11.3%
250	$90.00	$133.59	$55.00	$17.89	$296.48	$275.15	7.8%
500	$90.00	$267.18	$110.00	$35.79	$502.97	$475.31	5.8%
1,000	$90.00	$534.36	$220.00	$71.57	$915.93	$875.61	4.6%
2,500	$90.00	$1,335.90	$550.00	$178.93	$2,154.83	$2,076.53	3.8%
5,000	$90.00	$2,671.80	$1,100.00	$357.85	$4,219.65	$4,078.05	3.5%
7,500	$90.00	$4,007.70	$1,650.00	$536.78	$6,284.48	$6,079.58	3.4%
9,774 Annual avg.	$90.00	$5,222.83	$2,150.28	$699.53	$8,162.64	$7,900.16	3.3%
10,000	$90.00	$5,343.60	$2,200.00	$715.70	$8,349.30	$8,081.10	3.3%
10,192 Jan. avg.	$90.00	$5,446.20	$2,242.24	$729.44	$8,507.88	$8,234.82	3.3%
15,000	$90.00	$8,015.40	$3,300.00	$1,073.55	$12,478.95	$12,084.15	3.3%
25,000	$90.00	$13,359.00	$5,500.00	$1,789.25	$20,738.25	$20,090.25	3.2%
50,000	$90.00	$26,718.00	$11,000.00	$3,578.50	$41,386.50	$40,105.50	3.2%
75,000	$90.00	$40,077.00	$16,500.00	$5,367.75	$62,034.75	$60,120.75	3.2%
100,000	$90.00	$53,436.00	$22,000.00	$7,157.00	$82,683.00	$80,136.00	3.2%

The proposed base cost of gas of $0.53436 is used along with a monthly PGA rate of $0.07157 to reflect the actual total gas cost contained in Southwests rates in June 2005, excluding the temporary $0.02 per therm PGA surcharge.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-40

Rate Schedule G-80, Natural Gas Engine Gas Service

Current Rates

	Bills	Therms	Current Rate	Revenue
Basic Service Charge	3,623		$80.00	$289,840
Commodity Charge				
Sales Therms		21,271,370	$0.16189	$3,443,622
Total - Excluding Cost of Gas				$3,733,462
Base Cost of Gas (per therm)		21,271,370	$0.55840	$11,877,933
(applies proposed base cost of gas for comparability)				
Total Revenue				$15,611,395

Proposed Rates

	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	3,623		$95.00	$344,185	18.8%
Commodity Charge					
Sales Therms		21,271,370	$0.17600	$3,743,761	
Total - Excluding Cost of Gas				$4,087,946	9.5%
Base Cost of Gas (per therm)		21,271,370	$0.55840	$11,877,933	
Total Revenue				$15,965,879	2.3%

Schedule RGG3-41

Customer Bill Impact

Monthly Consumption (therms)	Basic Service Charge	Staff Proposed Rates Base Cost of Gas	Staff Proposed Rates Margin Rate	Total Bill	Current Rates - Total Bill	Percent Increase
50	$95.00	$27.92	$8.80	$131.72	$116.01	13.5%
100	$95.00	$55.84	$17.60	$168.44	$152.03	10.8%
200	$95.00	$111.68	$35.20	$241.88	$224.06	8.0%
500	$95.00	$279.20	$88.00	$462.20	$440.15	5.0%
1,000	$95.00	$558.40	$176.00	$829.40	$800.29	3.6%
1,500	$95.00	$837.60	$264.00	$1,196.60	$1,160.44	3.1%
2,000	$95.00	$1,116.80	$352.00	$1,563.80	$1,520.58	2.8%
2,936 Annual avg.	$95.00	$1,639.46	$516.74	$2,251.20	$2,194.77	2.6%
3,000	$95.00	$1,675.20	$528.00	$2,298.20	$2,240.87	2.6%
5,000	$95.00	$2,792.00	$880.00	$3,767.00	$3,681.45	2.3%
10,000	$95.00	$5,584.00	$1,760.00	$7,439.00	$7,282.90	2.1%
25,000	$95.00	$13,960.00	$4,400.00	$18,455.00	$18,087.25	2.0%
50,000	$95.00	$27,920.00	$8,800.00	$36,815.00	$36,094.50	2.0%
75,000	$95.00	$41,880.00	$13,200.00	$55,175.00	$54,101.75	2.0%
100,000	$95.00	$55,840.00	$17,600.00	$73,535.00	$72,109.00	2.0%
125,000	$95.00	$69,800.00	$22,000.00	$91,895.00	$90,116.25	2.0%
150,000	$95.00	$83,760.00	$26,400.00	$110,255.00	$108,123.50	2.0%

The cost of gas used for the G-80 rate schedule is the rate of $0.55840 per therm, the effective rate as of June 2005.

Customer bill impact calculations exclude taxes, regulatory assessments, and other adjustors and surcharges.

Schedule RGG3-42

Other Operating Revenues

Other Service Charges	Current Charge	Adjusted Test Year Revenue	Staff Proposed Charge	Revenue
Service Establishment Charge				
Schedule G-10, Normal Service	$24.00		see	
Schedule G-10, Expedited Service	$32.00		table	
Other Schedules, Normal Service	$30.00		below	
Other Schedules, Expedited Service	$40.00			
Subtotal		$6,950,610		$8,111,162
Customer Requested Meter Tests, per Test	$25.00	$1,705	$25.00	$1,705
Returned Item Charge, per item	$10.00	$135,450	$14.00	$189,630
Re-Read Charge, per read	$10.00	$547,658	$10.00	$547,658
Late Charge, Each Delinquent Bill	1.50% of the delinquent amount	$1,386,957	1.50%	$1,386,957
Field Collection Fee, each field collection	$20.00	$388,540	$20.00	$388,540
Rent from Gas Property		$767,198		$767,198
Other Revenue - Parts and Materials		$5,764		$5,764
Revenues		$10,183,882		$11,398,614

Staff Proposed Service Establishment Charges

Breakdown of Service Establishment Charges	Staff Proposed Charges	Percent of Customers	Estimated Hookups	Estimated Revenues
test year hookups	227,889			
Schedule G-10, Normal Service	$24.00	3.4%	7,726	$185,414
Schedule G-10, Expedited Service	$32.00	0.2%	407	$13,011
Other Residential Schedules, Normal Service	$34.00	87.1%	198,493	$6,748,776
Other Residential Schedules, Expedited Service	$48.00	4.6%	10,447	$501,457
Nonresidential Schedules, Normal Service	$60.00	4.5%	10,276	$616,534
Nonresidential Schedules, Expedited Service	$85.00	0.2%	541	$45,970
Total		100.0%	227,889	$8,111,162

assume 5 percent expedited, per Southwest

		percentage
G-10 test year bills	369,755	3.6%
Other resid. Bills	9,500,128	91.7%
Nonresid bills	491,801	4.7%
Total test year bills	10,361,684	

Sample Bill Calculations Under the Current Bill Structure and the Proposed Structure With a Base Cost of Gas of Zero

Sample Usage	80 therms

Hypothetical Bill Components	**Rate**
Basic Service Charge	$10.00 per month
Margin Rate	$0.30 per therm
Base Cost of Gas	$0.55 per therm
Monthly PGA Rate	$0.12 per therm

Rates as Shown Under Current Rate Structure

Basic Service Charge	$10.00 per month
Tariffed Rate	$0.85 per therm
Monthly PGA Rate	$0.12 per therm

Rates as Shown Under Proposed Structure With Base Cost of Gas of Zero

Basic Service Charge	$10.00 per month
Tariffed Rate	$0.30 per therm
Monthly PGA Rate	$0.67 per therm

Hypothetical Customer Bill Under Current Rate Structure

Basic Service Charge					$10.00
Tariffed Rate	80	therms	X	$0.85 per therm	$68.00
Monthly PGA Rate	80	therms	X	$0.12 per therm	$9.60
Total Bill					$87.60

Hypothetical Customer Bill Under Proposed Structure With Base Cost of Gas of Zero

Basic Service Charge					$10.00
Tariffed Rate	80	therms	X	$0.30 per therm	$24.00
Monthly PGA Rate	80	therms	X	$0.67 per therm	$53.60
Total Bill					$87.60

MILLER

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION – APPLICATION FOR AN INCREASE IN GAS IN GAS RATES.	))))	DOCKET NO. G-01551A-04-0876

DIRECT

TESTIMONY

OF

ROBERT E. MILLER

UTILITY CONSULTANT

PIPELINE SAFETY SECTION

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

July 26, 2005

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

A. My name is Robert E. Miller. I am a Utility Consultant with the Pipeline Safety Section ("Pipeline Safety") of the Utilities Division ("Staff") at the Arizona Corporation Commission ("Commission") and have been with the Commission since 1996. My business address is 2200 North Central Avenue, Suite 300, Phoenix, Arizona 85007.

Q. What are your responsibilities with Pipeline Safety?

A. My responsibilities include safety audits for intrastate pipeline operators in Arizona and – as an agent for the United States Department of Transportation, Office of Pipeline Safety ("OPS") – inspecting interstate pipelines in Arizona. I also investigate pipeline-related incidents that occur in Arizona. These investigations result in a report being composed by Pipeline Safety, which can identify the cause or causes of an incident and notes any probable noncompliances by an operator. My main focus is to ensure that pipeline operators are complying with applicable federal and state laws and regulations.

Q. What other background have you had in the pipeline safety field?

A. My resume is attached as Exhibit A to this testimony. But I have been involved in the gas industry for about twenty-five years. I have completed in excess of twenty courses sponsored by the U.S. Department of Transportation, Transmission Safety Institute. My experience in the gas industry includes construction supervisor, field operations manager and general manager.

Q. What is the purpose of your testimony here?

A. The purpose of my testimony is to give a general update on the status of Southwest Gas Corporation's compliance with applicable federal and state pipeline safety regulations.

Q. Before we discuss that, have you also been involved with other aspects of this rate case?

A. Yes. I have discussed the integrity management program ("IMP") with James Dorf and I have spoken with Robert Gray about the Gas Technology Institute ("GTI") program. Both Mr. Dorf and Mr. Gray discuss the IMP and GTI programs in their respective testimonies. If needed, I can provide more information on these programs.

Q. Please describe your recent responsibilities as they relate to Southwest Gas Corporation ("Southwest").

A. I am the primary Staff person responsible for conducting the annual compliance audit of Southwest Gas and have been responsible for the last three years. These audits are extensive, covering all aspects of operations. A major component of these audits involves field inspection of selected pipeline facilities, in addition to reviewing documentation and current procedures. After completing an audit, I will compose Pipeline Safety's audit compliance report, as I have done for the last few years. I have also been involved in investigating certain incidents involving Southwest pipeline facilities and aiding in the determination of whether any probable noncompliance items with federal and state regulations have occurred.

Q. Are you familiar with Southwest's pipeline recent safety record?

A. Yes.

Q. Please briefly describe the results of Pipeline Safety's most recent compliance audit inspections of Southwest.

A. It is Staff's opinion that Southwest Gas has been largely compliant with state and federal pipeline safety regulations, based on Staff's audit inspections. While Staff has found

noncompliance items with regulations on each audit, those noncompliance items have been addressed satisfactorily.

Q. Please explain further, Mr. Miller.

A. Certainly. When Staff performs a compliance audit, it not only inspects records and conducts a field inspection to ensure compliance, but also checks to make sure any noncompliance items noted from the last audit have been addressed. I have personally been conducting Southwest's audits for several years now and have found each year, it has taken steps to effectively address any noncompliance items noted from previous years. If an operator did not take steps to satisfactorily address any noncompliance, it is possible Pipeline Safety would recommend formal administrative action.

Q. Has Staff taken any formal administrative action against Southwest for noncompliance items noted in its compliance audits since the last rate order was approved for Southwest?

A. No. As stated earlier, Southwest has been attentive towards effectively addressing noncompliance items noted in Pipeline Safety's compliance audit reports. Because of that fact, there has not been a need to initiate formal administrative action.

Q. Has Staff taken any formal administrative action against Southwest for incidents since the last rate order?

A. The Commission issued its most recent rate order regarding Southwest in Decision No. 64172 on October 30, 2001. Since then, only two incidents have resulted in complaints by Staff against Southwest. Both involved probable noncompliance items stemming from actions taken by Southwest after natural gas leaks were discovered. One incident occurred at 16th Street and Palm Lane in Phoenix on June 26, 2002, and the other occurred near

22895 South 210th Street in Queen Creek on January 15, 2004. Both cases were resolved by agreement in Decision Nos. 66166 and 66966, respectively.

Q. Specifically referring to the Palm Street incident, did the settlement agreement in that case outline provisions to improve the safety of the public?

A. Yes. The settlement agreement approved by the Commission in Decision No. 66166 detailed several provisions to ensure that life and property are protected during an emergency situation involving natural gas. These provisions included stopping the flow of gas, emergency participation and valve operation. But perhaps the most important provision was for Staff and Southwest to meet quarterly about the status of any safety issues. These meetings started in 2003 and are still being held every three months.

Q. In Staff's opinion, have these meetings been productive?

A. Yes. These meetings have fostered a more congenial relationship between Staff and Southwest in recent years on Pipeline Safety issues. This, in turn, has lead to more cooperative efforts towards addressing noncompliance items found during annual audits and incident investigations. The public health and safety has improved as a result.

Q. Does that conclude your testimony at this time?

A. Yes, it does.

Robert E. Miller:

- Robert has been with the ACC Pipeline Safety Section since November 1996. Prior to his employment with the commission Robert owned and operated a general contracting business in his home state of Michigan. Having relocated to Arizona in 1980 Robert has worked exclusively in the gas industry. His duties from 1980 though 1996 encompassed all phases of pipeline construction and operations including Construction Supervisor, Field Operations Manager and General Manager.

- Robert brings to the Commission an extensive knowledge of plastic pipeline installation practices, and an understanding of gas pipeline regulatory issues from both a natural gas and Liquefied petroleum gas operator perspective. In addition Robert also served as a manufactures representative and trainer for a number of Polyethylene Pipeline and Fittings companies.

Training:

U. S. DEPARTMENT of TRANSPORTATION, TRANSPORTATION SAFETY INSTITUTE

Robert has successfully completed the following Transportation and Safety Institute courses with an average score of 92 and received DOT certification in the following subjects:

- Safety Evaluation of Pipeline Corrosion Control Systems I
- Gas Pressure Regulation and Overpressure Protection
- Safety Evaluation of Gas Pipeline Systems
- Pipeline Failure Investigation Techniques
- Safety Evaluation of Hazardous Liquid Pipeline Systems
- Joining of Pipeline Materials
- Safety Evaluation of Pipeline Corrosion Control Systems II
- Pipeline Safety Regulation Application and Compliance Procedures
- Liquefied Natural Gas Safety Technology and Inspection
- General Pipeline Safety Awareness (HAZWOPER)
- HAZWOPER Refresher 2002

- HAZWOPER Refresher 2004
- Welding Inspection
- Pipeline Reliability Assessment
- Fundamentals of Supervisory Control and Data Acquisitions (SCADA) Systems Technology and Operation
- Safety Evaluation of Hazardous Liquid Pipeline Integrity Management (IM) Programs
- Safety Evaluation of Breakout Tanks
- Operators Qualification CBT
- Safety Evaluation of Inline Inspection (ILI) Pigging Programs
  Integrity Management (IM) for Small Operators
- HAZWOPER Refresher 2005

ARIZONA CORPORATION COMMISSION

- New Employee Training (6 weeks)
- Master Meter Training Class
- Liquefied Petroleum Gas
- Welding Procedures and Visual Examination of Welds
- Incident Investigations

INDUSTRY TRAINING and CERTIFICATIONS

- Management of Managers Training Seminar – University of Michigan
- Amerigas Gas Check Safety Program
- Liquefied Petroleum Gas Association Equipment and Practices Course
- American Meter Measurement and Pressure Regulator Course
- Poly-Ark Pipe Fusion Instructor Certification
- CSR PolyPipe Fusion Instructor Certification
- Central Plastics Company Certifications:
  - Electrofusion Instructor/Trainer
  - Conventional Fusion Instructor/Trainer
  - Sidewall Fusion Instructor/Trainer
- Unrestricted Fusion Certifications for Plexico Pipe and Drisco Pipe
- Unrestricted Joining Certifications for Continental and Lycofit Fittings