ORIGINAL

SOUTHWEST GAS CORPORATION

May 8, 2008

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

Subject: Docket No. G-01551A-07-0504

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

Respectfully submitted,

Debra S. Gallo, Director
Government & State Regulatory Affairs

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

SOUTHWEST GAS CORPORATION®

Docket No. G-01551A-07-0504

2007
ARIZONA
GENERAL RATE CASE

Rebuttal Testimony

May 9, 2008

SOUTHWEST GAS CORPORATION

ARIZONA GENERAL RATE CASE

DOCKET NO. G-01551A-07-0504

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A

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

PREPARED REBUTTAL TESTIMONY
OF
ROGER C. MONTGOMERY

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
Roger C. Montgomery

Q. 1 Please state your name and business address.

A. 1 My name is Roger C. Montgomery. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same Roger C. Montgomery who sponsored direct testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

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

A. 3 The purpose of my testimony is to stress the importance to Southwest of coming out this proceeding with a rate design or regulatory mechanism that adequately addresses the financial implications of declining average residential usage and weather volatility.

Q. 4 Please elaborate.

A. 4 In my prepared direct testimony, I identified Southwest's inability to recover its fixed costs and earn the rate of return authorized by the Commission as one of the Company's primary problems and greatest challenges. I further identified three factors as the primary reasons for Southwest's inability to earn the Commission authorized rate of return. Two of the factors I identified were declining average usage by residential customers and Southwest's sensitivity to variations in weather. In Southwest's last general rate case, the Arizona Corporation Commission (Commission) stated that "We recognize that Southwest Gas is facing increased financial pressure due to declining usage on a per customer basis. . . ."[1] Notwithstanding this finding, Staff and RUCO failed to present proposals in their direct testimonies that adequately address the financial pressure caused by declining average residential usage and weather volatility.

Q. 5 What proposals did the Company present as part of its direct testimony to address declining usage and weather sensitivity?

A. 5 In its direct testimony, Southwest proposed a variety of new rate design and regulatory mechanisms that were designed to decouple revenues from sales volumes. These proposals included a revenue decoupling adjustment provision (RDAP) to address declining average usage, a weather normalization adjustment provision (WNAP) to address adverse effects of weather volatility for both customers and shareholders, and a volumetric rate design that includes a flat commodity rate, but which, for accounting purposes, has a declining block rate for non-gas charges and an inverted block rate for purchased gas

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[1] Decision 68487, p. 33, lns. 26-28.

cost. Southwest's volumetric rate design is based upon the rate design methodology currently authorized for Laclede Gas Company, a natural gas distribution company (LCD) serving over 630,000 customers in Missouri and one of the companies in the proxy group of eight LDCs selected by Southwest witness Frank Hanley.

Q. 6 Did Staff or RUCO support the Company's proposals in their direct testimony?

A. 6 No. Although proposing a higher basic service charge, both Staff and RUCO rejected the Company's RDAP, WNAP and volumetric rate design proposals. Southwest witnesses Ralph Miller and Brooks Congdon provide rebuttal testimony on Staff's and RUCO's rejection of these proposals.

Q. 7 Did any of the intervening parties support the Company's proposals in their direct testimony?

A. 7 Yes. The Southwest Energy Efficiency Project (SWEEP) and Arizona Investment Council (AIC) both sponsored testimony supporting at least one of the proposals presented by the Company.

Q. 8 If the Commission accepts Staff's and RUCO's recommendations to reject the Company's proposals, are there any other ways the Commission could mitigate the financial pressure due to declining average residential usage and weather volatility?

A. 8 Yes. One way would be for the Commission to use updated numbers for residential usage. Southwest's currently effective residential rates are based on average annual usage of 347 therms. Southwest's test year ended April 30, 2007 had weather normalized average annual residential customer usage of 332 therms. For the twelve months ended March 31, 2008, the Company has calculated that average annual residential usage has dropped from 332 therms to 319 therms. Southwest witness James Cattanach provides rebuttal testimony on the continuing decline in average residential usage that is being experienced by the Company. Southwest witness Brooks Congdon provides rebuttal testimony quantifying that the financial impact of the decline in residential average usage from 332 therms to 319 therms is approximately $6.3 million. The Commission could utilize this known and measurable change in average residential usage to calculate the revenue deficiency and to design residential rates in this proceeding.

Another way would be for the Commission to make an upward adjustment in the authorized rate of return on common equity capital that the Commission authorizes in this proceeding, as discussed in more detail in the rebuttal testimony of Southwest witness Theodore Wood. Either of these alternatives would allow the Commission to mitigate the financial impact declining residential use per customer has on the Company's ability to earn its Commission authorized rate of return.

Q. 9 Why is Southwest so resolute about finding a solution to the financial impact that declining residential usage and weather volatility has had on its ability to earn the Commission authorized rate of return?

A. 9 Absent affirmative corrective action by the Commission in this proceeding, the moment rates from this proceeding take effect, the Company will already have a revenue deficiency of approximately $6.3 million, assuming average residential usage does not decline further between March 2008 and the date that new rates in this proceeding become effective. Accordingly, Southwest implores the Commission to carefully weigh and consider the evidence in this proceeding and approve the RDAP, WNAP, or Southwest's volumetric rate design, or any combination of these proposals so that Southwest will be put on the path to improved financial stability, and have a reasonable opportunity to earn its Commission authorized rate of return.

Q. 10 Does this conclude your prepared rebuttal testimony?

A. 10 Yes, it does.

Tab

B

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

PREPARED REBUTTAL TESTIMONY
OF
RANDI L. ALDRIDGE

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Prepared Rebuttal Testimony
Of
RANDI L. ALDRIDGE

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
Of
Randi L. Aldridge

I. INTRODUCTION

Q. 1 Please state your name and business address.

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

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

A. 2 Yes, I did.

Q. 3 What is the purpose of your prefiled written rebuttal testimony?

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

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

A. 4 Yes. I prepared the exhibits identified as Rebuttal

Exhibit No.__(RLA-1) and Rebuttal Exhibit No.__(RLA-2).

Q. 5 Please summarize your rebuttal testimony.

A. 5 My rebuttal testimony will address Staff and/or RUCO's adjustments related to the following issues:

- Labor Annualization: RUCO's proposal to exclude the 2008 wage increase.
- Uncollectibles: RUCO's proposal to normalize uncollectibles expense based on a 3-year average.
- AGA Dues: Staff's proposal to exclude 40 percent of AGA dues from the cost of service.
- Employee Recognition: RUCO's proposal to exclude certain expenses from the cost of service.
- Miscellaneous Expenses: RUCO's proposal to exclude certain expenses from the cost of service.
- Intangible Plant: RUCO and Staff's adjustment to update intangible plant through December 31, 2007.
- A&G Error Correction: RUCO's acknowledgement of a $300,000 error to A&G.

II. LABOR ANNUALIZATION

Q. 6 Did the Company propose a post-test year wage increase in its Labor Annualization pro forma adjustment?

A. 6 Yes. The Company proposed to increase wages by three percent in 2008 for those employees who were employed by Southwest at the end of the test year.

Q. 7 Is this a similar adjustment to the 2005 wage increase adjustment that Southwest proposed and the Commission accepted in Southwest's 2004 general rate case?

A. 7 Yes. The Commission agreed that this adjustment "…should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no mismatch of revenues and expenses." (D.68487, p 13, Lns 1-4)

Q. 8 Does RUCO's concern that this adjustment results in a mismatch apply in this case?

A. 8 No. Similar to the 2005 wage increase adjustment, Southwest's proposed 2008 wage increase only applies to those employees employed by Southwest at the end of the test year so that the matching principle is not violated. This adjustment is also more reflective of costs that will be incurred by the Company when the rates set by the Commission from this proceeding will be effective.

Q. 9 What is the Commission's history of allowing post-test year adjustments for Southwest?

A. 9 The Commission has historically allowed certain post-test year adjustments in prior Southwest rate cases, as long as the matching principle is not violated. Examples of permissible post-test year adjustments include: wage increases for test year employees, completed construction not classified on non revenue-producing plant, and rate case expense. Staff witness Ralph C. Smith makes reference to post-test year adjustments and the care that the Commission must take regarding post-test year adjustments on page 6 of his direct testimony, wherein he states: "Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted." This observation is consistent with prior Commission orders that have allowed appropriate post-test year adjustments that do not violate the matching principle, like a post-test year wage increase for test year employees.

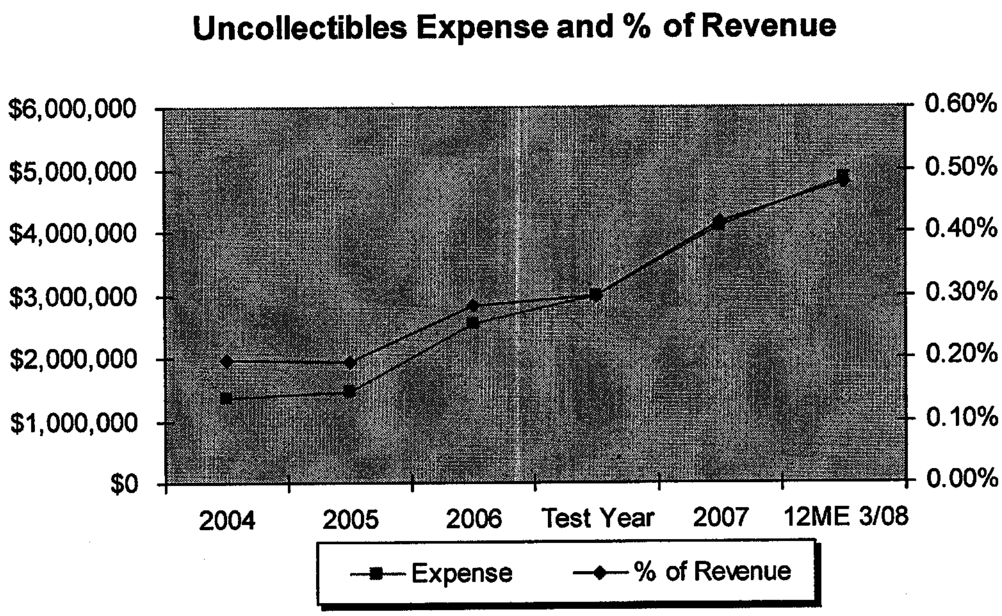
III. UNCOLLECTIBLES EXPENSE

Q. 10 RUCO proposed to normalize uncollectibles expense based on a three-year average, since uncollectibles expense tends to be volatile. Did Southwest consider normalizing uncollectibles expense, rather than using the test year amount recorded for uncollectibles expense?

A. 10 Yes.

Q. 11 Why did Southwest use the test year expense for uncollectibles, rather than normalizing using a historical average?

A. 11 Southwest analyzed historical uncollectibles expense, as well as the current and historical level of write-offs. Uncollectibles expense has increased steadily from 2004 to the present. At the time the rate case was filed, it was apparent that uncollectibles expense for 2007 would continue to trend upward. The following graph illustrates uncollectibles expense and uncollectibles as a percentage of total revenue over the time period 2004-2007 and the twelve months ended March 2008:



As illustrated in the graph, uncollectibles expense continues to trend upward. Based upon this historical trend and the continued impact that the slow economy and high energy costs are expected to have on ongoing uncollectibles expense, a historical average of test year uncollectibles expense would result in a clear under recovery of uncollectibles expense during the period of time that rates set by the Commission in this proceeding are effective. Southwest believes that test year uncollectibles expense more appropriately reflects expected ongoing uncollectibles expenses during the rate effective period. Staff applied similar logic with respect to several of its adjustments. Specifically, Staff recommends that the end of year balance for customer advances and customer deposits be used for ratemaking purposes because "the average balance is not representative of the conditions at the end of the test year, or on a going-forward basis." (Smith Direct, pp. 14 and 18.)

Q. 12 Should Staff's analysis of customer advances and customer deposits also be applied to uncollectibles expense?

A. 12 Yes. As with customer advances and customer deposits, the average historical ratio of uncollectibles expense to revenues is not representative of the conditions at the end of the test year, or on a going-forward basis. For this reason, Southwest proposes that the Commission apply Staff's proposal consistently, to customer deposits, customer advances, and uncollectibles expense.

IV. AGA DUES

Q. 13 What is Staff's proposal regarding AGA dues?

A. 13 Staff proposes to disallow 40 percent of AGA dues from cost recovery.

Q. 14 What is Staff's basis for this proposed disallowance?

A. 14 Staff relies heavily on outdated National Association of Regulatory Commissioners (NARUC) sponsored audits of AGA expenditures and the ratemaking treatment in selected states outside of Arizona for AGA dues.

Q. 15 Does NARUC continue to sponsor audits of AGA expenditures?

A. 15 No. For many years, NARUC had a Committee on Association Oversight that conducted an audit on AGA. However, NARUC discontinued the audit a few years ago as that body determined it was no longer necessary. The last NARUC-sponsored audit was dated March 2005, and the audit period ended December 31, 2002.

Q. 16 Staff witness Ralph C. Smith discusses a Florida Public Service Commission (FPSC) Staff memorandum at length, which provided justification for a 40 percent disallowance for a utility in Florida in 2003 and included a related attachment, and attached the audit reports from June 2001 and December 2000 (for years ended 1999 and 1998) to his testimony. Do you have any comments on Staff's reliance on these items?

A. 16 Yes. First, these attachments are outdated and reflect the activities of AGA nearly a decade ago. Second, as Southwest noted in response to Staff data request STF-10-7, AGA eliminated promotional expenditures in 2000. The latest report available to the FPSC at the time of its memo was 1999 data (which was the subject of the June 2001 audit report), which included promotional expenditures that AGA no longer incurs. Third, Staff provides no current information supporting the disallowance of a portion of any category other than advertising and lobbying. The outdated attachments relied upon by Staff that are included with Mr. Smith's testimony have no value or relevance in this proceeding.

Q. 17 Are you providing information regarding AGA in your rebuttal testimony?

A. 17 Yes. Southwest received additional information directly from AGA, including a description of AGA written in the form of testimony from the AGA's Chief Financial Officer, AGA's mission statement, and AGA's committee structure. This additional support for Southwest's request for AGA dues was provided as a supplemental response to Staff data request STF-12-1, and is attached as Rebuttal Exhibit No.__(RLA-1).

Q. 18 What was Southwest's pro forma adjustment to AGA dues, which removed the advertising and lobbying portion, based on?

A. 18 The pro forma adjustment proposed by Southwest was based on the AGA's 2007 budget, which was provided by the Company to Staff in response to Staff data request STF-6-52 (which is contrary to Staff's assertion that Southwest did not provide the percentages relating to AGA's functions [Smith direct, page 40]). I have also attached the AGA 2007 budget, which illustrates the percentages of AGA activities related to each function as Rebuttal Exhibit No.__(RLA-2).

Q. 19 How do you respond to Staff's assertion that Southwest failed to demonstrate that a 96.61 percent recovery of AGA dues is appropriate?

A. 19 My direct testimony provided an abundance of examples of how AGA's activities provide benefits to the Company and its customers (see Aldridge direct, pages 12 and 21-24). Furthermore, as noted by the AGA itself, AGA's efforts provide member benefits of $479 million of savings or avoided costs, in comparison with $18 million in total membership dues, which is information available on the AGA's website. Southwest has no reason to doubt the AGA's assertion. Staff made a broad assertion that the AGA activities would be subject to disallowance if they were conducted directly by the utility. However, Staff failed to specifically identify a single activity that Southwest has not already removed and would be disallowed if it conducted the activity directly. Despite Staff's broad assertions, Southwest provided an abundance of information regarding AGA functions and customer benefits. Accordingly, Southwest's pro forma adjustment removing 3.39 percent of AGA dues from cost recovery is appropriate.

V. EMPLOYEE RECOGNITION EXPENSE

Q. 20 RUCO proposes to remove $54,154 of employee recognition expenses from the cost of service. What does RUCO base its disallowance on?

A. 20 RUCO stated that it believes it is inappropriate to burden customers with expenses related to certain items.

Q. 21 Please describe the Company's employee recognition programs that comprise this expense item.

A. 21 There are four programs:

(1) Line Location Recognition Program: recognizes each

technician for every 2,500 consecutive Blue Stake requests completed without an error or mislocate.

(2) Meter Reading Recognition Program: recognizes employees who have performed their meter reading duties in an outstanding manner.

(3) Safety Awards: recognizes employees who drive a vehicle on a daily basis who complete a full calendar year without a preventable accident, and recognizes each employee in a department that completes a full calendar year without a lost time preventable injury.

(4) Trip Reduction Program: The Trip Reduction Program (TRP) ordinance is ***mandated*** for all employers in Maricopa County with 50 or more employees at a single work site (A.R.S. 49-581 et. seq.). The Company also agreed to be part of the Ozone Program and receive trip reduction credit for its participation.

Q. 22 What goals do these programs accomplish?

A. 22 The goal of the first three programs is to reduce the overall cost of service, along with improving safety and productivity. The Company recognizes that by providing modest awards to encourage employees to demonstrate a commitment to performing their job at the highest level can reduce overall costs. Customers are the primary beneficiaries of a reduced cost of service due to Southwest's efforts in preventing accidents and injuries, and reducing errors that cause additional work or compromise safety. Southwest participates in the TRP to comply with a county ordinance, and as a good corporate citizen to improve the environment in which the Company operates.

Q. 23 Do you agree with RUCO's assessment that the expenses related to these four programs should be disallowed?

A. 23 No. As explained above, these programs offer very modest rewards to employees whose performance is extraordinary, or participate in programs which improve air quality. Southwest's customers and the community at large benefit from employees who are motivated and rewarded for performing their job safely, efficiently, and with a higher than expected quality. In addition, the TRP is a program mandated by Maricopa County and the community benefits from Southwest's participation. It is unclear why RUCO would propose to disallow the expenses related to complying with a county ordinance. Furthermore, RUCO has not found these expenditures to be excessive or imprudent. Therefore, these programs should be allowed in rates.

VI. MISCELLANEOUS EXPENSES

Q. 24 RUCO proposes to disallow a number of expenses which it terms "inappropriate or unnecessary". What is your response to this adjustment?

A. 24 Southwest disagrees with RUCO as to whether the expenses are appropriate for cost recovery.

Q. 25 Can you provide additional testimony supporting the appropriateness of these costs?

A. 25 Yes.

(1) Gift Certificates: The gift certificates that RUCO identified in this adjustment were for the Meter Reading Recognition Program, Trip Reduction Program, and Safety Awards Program. RUCO already removed the total costs incurred for these programs in its Employee Recognition Expense adjustment, which I discussed and rebutted earlier. Therefore, removing $18,230 of costs again in the Miscellaneous Expenses adjustment is a proposal to disallow these costs twice, which is clearly inappropriate.

(2) Office Refreshments: It is not unreasonable for a company to provide convenient onsite access to coffee, tea, and water in order to improve the productivity and morale of employees. Productive employees help Southwest keep its customer-to-employee ratio low, which benefits customers through a lower cost of service.

(3) Meals offered during meetings: Southwest often requires that certain employees be present for meetings outside of normal business hours. Alternatively, some meetings or work situations may offer a break that is insufficient in length for employees to obtain a meal off-site. When appropriate, the Company offers meals to employees

who attend such meetings or are included in certain work situations. The meals that Southwest did not remove from the cost of service were offered to keep employees present during non-working hours at the Company's convenience to improve productivity. The majority of these employees are exempt (not eligible for overtime), and covering a meal for them occasionally is far cheaper than hiring additional employees to compensate for the inability to hold meetings only during business hours with no meals offered. Also, the Company offers continuing professional education (CPE) luncheons twice a month to its accountants who have licenses or professional certifications and need CPE credits, which is less expensive than sending employees to off-site seminars or conferences to obtain the required CPE credits.

(4) Off-site meetings: rather than own and maintain the facilities needed for certain kinds of meetings, it is more economical to hold them offsite. Many hotels and other locations maintain the kinds of facilities that are suitable for Southwest's occasional needs.

Q. 26 Did Southwest agree to remove additional items that RUCO identified during its audit?

A. 26 Yes. In response to request RUCO-5-1, Southwest agreed to withdraw its request to recover $13,904 in operating expenses.

Q. 27 Did RUCO raise a reasonable doubt as to whether the remaining costs are appropriate for cost recovery?

A. 27 No. There are several additional items that RUCO proposes to remove. Examples include: safety kits, photography and photo processing used for communications or recordkeeping, a payment to a builder to refund an overpayment, offsite meetings (in addition to those RUCO identified specifically), and a leadership conference. Other than the $13,904 that Southwest identified above, the remaining items are prudent and necessary business expenses that are properly included in rates.

VII. MISCELLANEOUS INTANGIBLE PLANT

Q. 28 Please explain Southwest's pro forma adjustment to miscellaneous intangible plant.

A. 28 Since the majority of these items are software projects with a three year amortization period, Southwest made a post-test year adjustment to remove all items with an amortization expiring December 31, 2007 or earlier, and to add the items estimated to close to plant during that same time period. The purpose of this adjustment was to better match the Company's request related to intangible plant to those projects that will be amortized during the time rates from this proceeding are effective.

Q. 29 Did Southwest provide updates to its estimates during the discovery process?

A. 29 Yes. In response to Staff data requests STF-6-49 and

STF-11-4, Southwest provided the actual projects that closed to plant after the test year and through December 31, 2007.

Q. 30. How did RUCO address the update of intangible plant?

A. 30 RUCO fully updated intangible plant as of December 31, 2007. RUCO's adjustment reflects an appropriate match and comports with the spirit of Southwest's pro forma adjustment, which removed all projects that expired by December 31, 2007 and added all projects closed by December 31, 2007.

Q. 31 Why do you disagree with Staff's adjustment?

A. 31 Since Staff did not include all intangible plant projects closed prior to December 31, 2007 in its adjustment, it results in a mismatch of ratemaking elements.

Q. 32 Does the Company agree with RUCO's adjustment?

A. 32 Yes. For the reasons stated above, the Company agrees with RUCO and the Commission should adopt RUCO's adjustment to intangible plant.

VIII. A&G ERROR CORRECTION

Q. 33 In RUCO's Operating Adjustment No. 2, RUCO made a conforming adjustment of $283,664. Can you provide some additional background regarding this adjustment to A&G expenses?

A. 33 Yes. There was a $300,000 credit that was erroneously booked to Account 923, Outside Services, during the test year. This credit should have been charged to Injuries and Damages, Account 925. The reason there was such a large deficiency impact is that the test year amount for Account 923 was understated by $300,000. Whereas, the injuries and damages component of Account 925 was based on a 10-year average and was 4-factored. As such, this correction had a much smaller impact on Account 925. Southwest wants to clarify that this adjustment results in a $300,000 increase to Account 923 and a $16,336 decrease to Account 925.

Q. 34 Does this conclude your prepared rebuttal testimony?

A. 34 Yes, it does.

TESTIMONY OF KEVIN M. HARDARDT
OF THE AMERICAN GAS ASSOCIATION
ON THE BENEFITS OF AGA MEMBERSHIP
FOR THE ARIZONA CORPORATION COMMISSION

Q. Would you please state your name and address?

A. My name is Kevin M. Hardardt, 400 North Capitol Street, N.W., Washington, D.C.

Q. By whom are you employed and in what position?

A. I am the Chief Financial & Administrative Officer for the American Gas Association (AGA).

Q. What is the purpose of your testimony today?

A. I am here to explain and illustrate how membership in AGA provides a direct and substantial benefit to a member company's customers -- specifically, how, through a variety of policies and programs, AGA aids member companies in improving the quality and reducing the cost of gas service. Membership in AGA helps the member company, provide the best service to the customer at a lower cost.

Q. What will be the structure of your testimony today?

A. First, I will briefly discuss the purposes and organization of AGA. Then I will highlight some of the benefits accruing to a member company's customers as a result of its membership in AGA. Specifically, I will discuss a few activities in each of AGA's major functional areas and illustrate how a member company's customers benefit -- either directly or indirectly -- from each. I also will show how, if a member company were to seek to obtain, by its sole efforts, even a few of the benefits AGA provides, the cost might quickly exceed the total dues payment of a member company to AGA. As discussed below, the projects AGA performs and the availability of various materials are significant. In addition, I have included three Schedules that will be described below.

Q. Would you begin then by briefly describing the purposes and organization of AGA?

A. Yes. AGA is a national trade association comprising 200 distribution companies serving 64 million customers. As such, it exists to fulfill the needs of the local natural gas distribution companies and thereby improve the industry's ability to better serve its customers. Schedule 1 provides an elaboration of AGA's mission. Schedule 2 shows AGA's current committee organization. Schedule 3 shows AGA's expense breakdown by functional areas for 2008.

Q. Would you briefly describe the information shown on Schedule 2?

A. Yes. The Chairman, First and Second Vice-Chairmen and the Immediate Past-Chairman are top officials of member companies, and, together with our President, are the senior officers of AGA. The Board of Directors, who are top executives of member companies, establishes AGA's policies and actively controls the programs, projects, activities and budget of the Association. Reporting to the Board of Directors are various committees. Each committee is composed of employees of member companies of various sizes and from various parts of the country, and each committee has a "charter" that focuses its efforts on a specific functional area of a gas company's operations. Member company employees serve on the approximately 50 committees and their subcommittees and task forces. In addition, through AGA's functional area contact lists, other employees also regularly receive materials and information of special interest to their functional areas. It is through the work and with the guidance of these committees that many of AGA's activities are undertaken.

Q. How does a member company and its customers benefit from participation in AGA?

A. AGA serves a member company and its customers in two general ways: the first is by helping them improve their local programs, practices, and procedures in all areas of their operation. In this regard, AGA provides hundreds of forums and other vehicles through which a member company's employees can exchange information with their peers in other companies in order to better serve its customers. These face-to-face exchanges include committee meetings, workshops, seminars, and other forums. In addition, AGA provides program "clearinghouse" services in a number of areas including customer relations, educational services, and training and development. Through such clearinghouses, AGA maintains information on successful programs conducted by member companies and makes this information available to other companies upon request.

The second way AGA serves a member company and its customers is by doing things collectively or at the national level that the utility could not do or could not do cost-effectively on its own. Just one example of the hundreds of projects is the Gas Engineers Operating Practices manuals that have been made available to member companies. These practice manuals convey the latest engineering information in such areas as distribution, utilization, transmission, measurement and supply. It has been estimated that each of the twelve volumes of these practice manuals would cost a utility between $275,000 to $300,000 per manual to produce on its own.

All of these activities are directed at the same goal --to improve the efficiency and effectiveness of member companies in all areas of operation without having them incur unnecessary "learning curve" costs. If AGA did not exist, solid business practice would call for creation of such an organization.

Q. Would you please describe the type of activities conducted in some of the functional areas, emphasizing how these activities benefit -- either directly or indirectly -- a member company's customers?

A. Yes. The following are some relatively recent examples of AGA's operating and engineering activities -- activities that include literally hundreds of projects to improve the safety, efficiency and productivity of member companies' engineering and operating functions. For example:

(1) The safety record of natural gas utilities is outstanding and it keeps getting better. To help improve the safety of the natural gas delivery system, on December 5-6, 2007, AGA hosted a Safety Leadership Summit for its members to come together and discuss the state of the natural gas industry in four critical areas of safety:

1. Employee Safety
2. Utility Contractor Safety
3. Pipeline Safety
4. Public Safety

Officers, executives and managers from AGA member companies listened to outstanding presentations from industry leaders and various guest speakers, including Secretary of US Department of Labor, Elaine L. Chao and Admiral Frank L. "Skip" Bowman (USN Retired), President of Nuclear Energy Institute. The Summit participants exchanged ideas and experiences through roundtable discussions on all aspects of safety.

(2) AGA publishes the Gas Piping Technology Committee (GPTC) Guide. The Guide is prepared by safety experts from gas distribution and transmission companies, federal and state regulatory agencies, manufacturers and industry consultants.

(3) The Operating Section helped initiate a campaign to increase awareness among contractors and excavators about the damage that can be done to buried pipeline mains as a result of their activities. AGA is a supporting sponsor of this National Program known as the "Common Ground Alliance." Two out of three reportable incidents on these mains are a result of third party excavators. Most incidents occurred because the utility was not notified that work was about to be done or given the opportunity to mark the line. As a result of this effort, we have raised the public awareness of the importance of damage prevention programs and provided a forum for states to better address this issue. We continue to work to improve communication with excavators and reduce these incidents which are costly in terms of injuries and repair expenses and are avoidable.

(4) AGA has taken the lead in developing easy-to-use personal computer software to deal with a variety of operating/engineering issues faced by gas companies. The cost of these programs to members is minimal in relation to the hours of effort they save. So far, programs have been developed in the following areas: (1) Gas Measurement - performs orifice flow and super compressibility calculations; (2) Gas Properties – using the most recent versions of AGA Report No. 10, Speed of Sound in Natural Gas and AGA Report No. 8, Compressibility Factors of Natural Gas, this software calculates natural gas speed of sound, critical flow coefficient and other thermodynamic properties.

(5) AGA updates "Report No. 3, Orifice Metering of Natural Gas." This Report is standard reference in gas contracts. Because of the higher unit cost of gas at the city gate and wellhead, improved measurement accuracy will be of a great economic importance to gas consumers.

(6) AGA's Plastic Materials Committee evaluates the use of plastic materials and new fabrication techniques for gas piping systems. This Committee publishes the AGA Plastic Pipe Manual for Gas Services, which includes the latest information on plastic materials, piping components, and design as well as installation procedures covered under today's codes and standards for natural gas distribution piping systems. Through the use of this information, member companies can more quickly, confidently and safely move to increase the use of more cost-effective plastic materials.

(7) The AGA Best Practices Program for Gas Distribution is an effort to identify procedures of superior performing gas industry companies and innovative work practices that can be used to improve participants' operations. It focuses on improving the safety and efficiency of gas distribution system construction, maintenance, operation and inspection. This committee makes available information regarding a number of operational improvements in areas such as street repairs, safer trenchless technology and automated dispatching. Our members have documented millions of dollars in savings from participation in this program. These savings translate to lower costs for the customer.

(8) We develop a large number of manuals and textbooks that are essential in day-to-day operation of gas utilities. An excellent example is the Gas Engineering and Operating

Practices Services. This 11 book services has become the authoritative work on gas utility engineering.

(9) AGA's Operating Section Continues to provide support to its members who seek industry information on a variety of operations and engineering issues. The SOS Program is a resource for AGA members who have the need to query others on a particular subject. The SOS program is a simple and effective way for members to better understand how others are addressing a particular issue/challenge.

Recent SOS requests include member-initiated surveys on the following topics:

- Oversight and quality checks on contractors that perform locating services
- Security metrics
- Excavation and backfill practices around transmission lines
- 3rd party damage claims
- Gas odorization practices
- Budget practices used for forecasting operations & maintenance workload
- Elevated delivery pressure
- Right of Way acquisition

These are just a few of the many operating and engineering-related projects that benefit a member company and its customers. While in most areas the benefits to consumers in terms of efficiency and lower costs can not easily be quantified in specific dollar amounts, taken together they represent very significant cost benefits to the consumers.

Q. Would you please highlight AGA's financial and administrative activities and how they benefit a member company's customers?

A. Yes. The following are some relatively recent examples of AGA's financial and administrative activities.

(1) AGA sponsors topical workshops on cutting-edge issues facing our member companies. This past year we sponsored a seminar on Accounting for Derivatives, which focused on accounting for the new rules and their applications as they specifically effect the utility industry.

(2) The Accounting Principles Committee works extensively with the Financial Accounting Standards Board and the Securities and Exchange Commission to ensure that new accounting standards or information requests are sound and not unnecessarily burdensome. Over the past two years, numerous responses have been filed with these organizations on their proposals, and have been instrumental in the positions adopted.

(3) Through AGA's Risk Management Committee, member companies are provided with confidential insurance surveys that are beneficial in negotiating insurance coverages, premiums and deductibles. Membership also provides utilities the opportunity to meet with committees representing insurance companies to resolve mutual problems. In addition, AGA was instrumental in forming a utility mutual insurance company that provides competition to the commercial insurance markets, resulting in broader coverage and more competitive premiums. Most member companies' insurance coverage is with this mutual insurance company. Premium savings to companies range up to 20 percent over insurance from other

sources.

(4) In the customer activities area, AGA's Data Source is the utility industry's premier tool for benchmarking customer service programs. Subjects covered include call centers, energy assistance programs, billing and meter reading. A powerful online search engine and analytical tools enable member to retrieve data efficiently, thereby increasing employee productivity.

(5) Through AGA's Rate Committee, and its rate seminars, member company representatives are able to learn of successful programs undertaken by other gas utilities, for example, in the areas of innovative rate design. This information, in turn, can translate into reduced gas costs and load retention, both of which help reduce consumers' gas costs.

(6) Our Rate Committee has developed and maintains an excellent rate fundamentals training course and textbook that is used by many member companies and regulatory agencies in their training programs; the Accounting Services Committee has developed a training program on public utility accounting.

(7) AGA has many programs that assist companies in labor negotiations, collective bargaining agreements and employee benefits. AGA publishes regular collective bargaining reports, which assist member companies in reducing their labor costs. AGA also provides corporate and employee salary and benefit information which is helpful in identifying trends and implementing adjustments. This helps to control

costs.

These are just a few examples. In addition, we develop a range of financial and administrative manuals and reference documents. These are widely used in almost every gas utility. Although the cost to a member company for this information is small, if a member company were to develop this information on its own, the cost could be in the tens of thousands of dollars.

Q. What is the function of the General Counsel's Office?

A. The Office of General Counsel provides legal counsel to AGA. A significant responsibility of AGA's legal staff is to assist member company attorneys in more effectively performing their duties, thereby reducing their companies' cost of service. For example, AGA offers litigation alerts, forums and workshops. Antitrust Compliance Programs, assistance to members in potentially precedent-setting litigation, and analyses and legal summaries. The AGA Legal Committee sponsors Legal Forum, the preeminent legal program for attorneys at gas utilities. Continuing legal education credit is available for attorneys that participate in AGA's legal programs.

Q. Would you please highlight AGA's Policy and Planning activities and explain how they benefit a member company's customers?

A. Yes. AGA's Planning and Planning activities provide an important and timely information service to a member company. For example:

(1) A vast array of data about all aspects of the natural gas industry is collected and compiled in ready-reference form. Among these publications are **GAS FACTS**, and Heating/Cooling Degree-Day Statistics.

(2) AGA also undertakes a wide range of analyses on environmental, financial, gas supply, gas demand, consumer cost, capital requirements, resource efficiency and other issues facing the gas industry. These analyses are of great value in assisting a member company and other decision-makers in resolving the country's current energy problems and in establishing public policies that will be in the nation's best interest.

Q. Would you please describe AGA's Public Affairs program and discuss the benefits to a member company's customers of these activities?

A. AGA has in place a program to monitor federal legislative activities and to discuss with members of Congress and their staff the regulated gas industry's views on these activities. While the subject matter AGA monitors is broad, all of AGA's legislative positions have either a direct or indirect benefit to gas utility customers.

AGA also has been among the leaders in advocating for increased funding of the Low Income Home Energy Assistance Program by the federal government -- a program that is essential in reducing the financial burden of those on low and fixed incomes as they provide themselves with needed basic energy services. And, with the increasing help of many other consumer-oriented organizations, AGA continues to work to ensure the maintenance of adequate funding for the Program. Indeed, AGA's efforts have been a contributing factor in restoring the amounts that were proposed to be cut from the program the last several years.

Another important issue on which AGA has lobbied is the budget authorizations and allocations for the Department of Energy's research and development programs. DOE's R&D budget has been drastically reduced in recent years. We believe, however, that gas-related programs have suffered unjustifiably large cutbacks compared with projects for other forms of energy -- especially in light of the present and future importance of gas to the nation and the substantial benefits these programs could provide U.S. gas consumers.

These are a few examples. The point is that AGA's government relations efforts play a key role in protecting the interests of a member company and its customers from proposed legislation that inadvertently or otherwise could have serious impacts on gas supply and cost of gas service.

Q. Is the work of the AGA government relations program primarily devoted to lobbying?

A. No. AGA's involvement in federal government lobbying is a small part of the program. For example, AGA frequently comments on regulations proposed by a great number of executive branch agencies such as EPA, departments such as DOE, and independent agencies such as the FERC and DOT to communicate the interests of the gas industry and its customers, much as companies do individually before the FERC in rulemaking proceedings.

Reviewing and commenting on the economic and other impacts of the many regulations affecting the gas industry is an important aspect of AGA's governmental relations' work. Such efforts reduce the operating costs of member companies and thus are of direct benefit to consumers who must ultimately pay the costs of compliance with these regulations.

Q. Are government relations' activities or oversight by groups or associations, such as AGA, needed by and beneficial to natural gas distribution companies?

A. Yes, with government at the federal level continuing to be involved in matters such as safety, clean air and water, funding of energy research, and conservation of energy, there continues to be a need for the regulated gas companies to be aware of proposed actions and their potential economic and other impacts in a timely manner and for the industry to have its collective views made known to the federal decisionmakers. The only way the governmental process can arrive at balanced results is for all interested groups to express their views. AGA is the most efficient way through which the views of its member companies on gas industry matters collectively can be communicated, complementing individual companies' own communications. It is important to note, however, that communication between AGA and federal agencies is not just one way. Federal agencies look to AGA when there is a need to get a special notice to gas utilities quickly. On many occasions, we have provided this service to the Consumer Products Safety Commission (CPSC), the Environmental Protection Agency, and the National Transportation Safety Board. For example, CPSC asked AGA to help them get information to gas utility customers about the proper venting of vented gas heaters. AGA developed an extensive information package on this issue and distributed this package to each of our member companies, urging them to incorporate information from it in their customer communications programs.

Q. Would you summarize your testimony about the benefits to a member company's customers of membership in AGA?

A. The benefits of almost all of AGA's activities either directly or indirectly are realized by the customers of AGA's members. I have briefly highlighted a few of AGA's activities and attempted to show how a member company's consumers benefit from them. AGA's website www.aga.org contains additional information about AGA and its programs to benefit members and their customers.

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04/22/2008 3:16 PM*

AGA Vision and Mission Statement

VISION STATEMENT

AGA's vision is to be the most effective and influential energy trade association in the United States while providing clear value to its membership.

MISSION STATEMENT

The American Gas Association represents companies delivering natural gas to customers to help meet their energy needs. AGA members are committed to delivering natural gas safely, reliably and cost-effectively in an environmentally responsible way. AGA advocates the interests of its members and their customers, and provides information and services promoting efficient demand and supply growth and operational excellence in the safe, reliable and efficient delivery of natural gas.

To further this mission, AGA:

1. Encourages, facilitates, and assists members in sharing information designed to achieve operational excellence by improving their safety, security, reliability, efficiency, and environmental and other performance metrics;

2. Assists members in managing and responding to customer energy needs, regulatory trends, natural gas markets, capital markets and emerging technologies;

3. Collects, analyzes and disseminates data on a timely basis to policy makers and the public about energy utilities and the natural gas industry;

4. Focuses on the advocacy of natural gas issues that are priorities for the membership and that are achievable in a cost-effective way;

5. Serves as a voice on behalf of the energy utility industry and promotes natural gas demand growth by emphasizing before a variety of audiences the energy efficiency, environmental and other benefits of natural gas and promotes natural gas supply growth by advocating public policies favorable to increased supplies and lower prices to customers; and

6. Delivers measurable value to AGA members.

Approved September 19, 2006

Rebuttal Exhibit No.__(RLA-1)
Sheet 16 of 16

Attachment C
STF-12-1 Supplemental

AGA Committee Structure

(Shaded Committees are Board-level)

- **AGA Board of Directors/ Executive Committee**
  Chairman, *David M. McClanahan*
  1st Vice Chairman, *Thomas E. Skains*
  2nd Vice Chairman, *Robert C. Skaggs, Jr.*
- **Nominating Committee**
  Chairman, *Thomas E. Skains*

- **Board Audit Committee**
  Chairman, *Glenn R. Jennings*
- **Board Finance Committee**
  Chairman,
  James H. DeGraffenreidt, Jr.
- **Compensation Committee**
  Chairman, *David M. McClanahan*
- **Strategic Planning Committee**
  Chairman, *Thomas E. Skains*

- **Government Relations Policy Committee**
  Chairman, *Kevin Burke*
- **Safety Committee**
  Chairman,
  Kenneth W. DeFontes, Jr.
- **Security, Integrity & Reliability Committee**
  Chairman, *John K. Allred*
- **Membership Services Committee**
  Chairman, *John Russell*

- **Legislative Committee**
  Chairman, *Junior Aston*
- **FERC Regulatory Committee**
  Chairman, *Bridget E. Shahan*
- **State Regulatory Committee**
  Chairman, *Charles J. Harder*
- **Public Relations Committee**
  Chairman, *Chad K. Jones*
- ***Operations Safety Regulatory Action Committee**
  Chairman, *Paul M. Preketes*
- ***Environmental Regulatory Action Committee**
  Chairman, *Daniel E. Smith, III*

- **Small Member Council**
  Chairman, *John B. Williamson, III*
- **Legal Committee**
  Chairman, *Paul R. Shlanta*
- **Leadership Council**
  Chairman,
  Robert C. Skaggs, Jr.
- **Climate Change Task Force, Chairman**
  [illegible]

Operating Section Managing Committee
Chairman, *Susan L. Fleck*

- Building Energy Codes & Stds.
- Corrosion Control
- Distribution Construction & Maintenance
- Distribution & Transmission Engineering
- Distribution Measurement
- Environmental Matters
- Executive Committee
- Gas Control
- Natural Gas Security
- Plastic Materials
- Safety & Occupational Health
- Supplemental Gas
- Transmission Measurement
- Underground Storage
- Utility & Customer Field Services

Marketing Communications Committee
Chairman, *Donna N. Peeples*

Finance Committee
Chairman, *David H. Anderson*

- Accounting Advisory Council
- Accounting Principles
- Accounting Services
- Compensation & Benefits
- Customer Service
- Human Resources Policy
- Internal Audit
- Labor Relations
- Rate
- Risk Management
- Taxation
- Technology Advisory Council

Operations & Engineering Services Associates Section Managing Committee
Chairman, *Scott A. Kranstuber*

*Regulatory Action committees also report to the Operating Section Managing Committee

January 2008

AMERICAN GAS ASSOCIATION
2007 BUDGET

STF-6-52

	\$ 2007 ALLOCATION	% 2007 ALLOCATION
Advertising	$345,000	1.39%
Corporate Affairs	$2,099,000	8.44%
General & Administrative	$4,665,000	18.77%
General Counsel	$1,016,000	4.09%
Industry Finance & Administrative Programs	$1,283,000	5.16%
Operations & Engineering Management	$5,993,000	24.11%
Policy, Planning & Regulatory Affairs	$3,669,000	14.76%
Public Affairs	$5,790,000	23.29%
Total Budget	$24,860,000	100.00%

Note:
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 2% of member dues in 2007.

Tab

C

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

PREPARED REBUTTAL TESTIMONY
OF
ROBERT A. MASHAS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Prepared Rebuttal Testimony
Of
ROBERT A. MASHAS

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
ROBERT A. MASHAS

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Robert A. Mashas. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

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

A. 2 Yes, I did.

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

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

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

A. 4 Yes. I prepared the exhibits identified as Rebuttal

Exhibit No.__(RAM-1) through Rebuttal Exhibit No.__(RAM-5).

Q. 5 Please summarize your rebuttal testimony?

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

- Injuries and Damages: Staff's calculation of the 10-year average of self-insured retentions.
- Yuma Manors: Staff's proposal to disallow all gas plant required to replace 50-year old pipe.
- Deferred Taxes: RUCO's proposal to remove deferred taxes related to Supplemental Executive Retirement Plan (SERP) and Management Incentive Plan (MIP).
- Lead-Lag Study: RUCO's proposal regarding interest expense lag and revenue tax lag.
- Line Extension Analysis: Staff's recommendation to update certain inputs in the Company's Incremental Contribution Model.

II. INJURIES AND DAMAGES

Q. 6 Please summarize Staff's adjustment to the Company's proposed injuries and damages expense?

A. 6 Staff's adjustment focuses on the calculation of the ten-year average self-insured retentions. First, Staff calculates a ten-year average level of direct Arizona self-insurance using the ten years of direct Arizona recorded self-insurance amounts. Second, Staff calculates a ten-year average level of System Allocable self-insurance by using the ten years of recorded System

Allocable self-insured expense. However, Staff excludes a $10 million dollar expense recorded in 2006 related to an incident that occurred in Arizona in 2005.

Q. 7 Is Staff's methodology flawed?

A. 7 Yes. Staff calculates its 10-year average (Staff Schedule C-12, Sheet 2 of 2, Column (C) lines 1 through 16) by using the recorded net accruals charged directly to Arizona. Although on the surface that appears appropriate, in reality it is not. The period shown on that schedule is from January 1998 through November 2007. From January 1998 through July 2004, the Company's insurance policies, in effect during that time period, provided that Southwest was self-insured for up to the first $1 million of expense related to a single claim. As such, Southwest's accounting records would only reflect a maximum of $1 million for the cost of self insurance. Beginning August 1, 2004 through July 31, 2005, the insurance policies in effect provided that Southwest was self-insured for not only the first $1 million per claim, but also self-insured for aggregate claims up to $10 million. In other words, the $10 million can come from more than one incident. Beginning August 1, 2005, and continuing through the present, Southwest acquired an additional policy that covers any aggregate claim amounts from $5 to $10 million.

During the periods August 1, 2004 though July 31, 2005, and August 1, 2005 through the present, Southwest's accounting records reflect the cost of self-insurance that may result due to either the $10 million or $5 million aggregate self-insurance. Since August 1, 2004, only one claim has exceeded the $1 million per incident self-insured amount, and that was the May 2005 incident that occurred in Arizona, but was recorded as a System Allocable expense. This is the claim that Staff has removed from its ten-year average of System Allocable expense.

Accordingly, Staff's ten-year calculation does not properly reflect the cost of self insurance that is reflective of what the Company will experience during the rate effective period because it only reflects the average of the recorded $1 million per claim self-insurance and not Southwest's $5 million aggregate level of self-insurance.

Q. 8 Is the Company's proposed ratemaking for the self-insured aggregate consistent with its proposal that Staff and RUCO accepted and the Commission adopted in the Company's last general rate case that resulted in Decision No. 68487.

A. 8 Yes. My direct testimony in that proceeding detailed the Company's proposed change in ratemaking related to the $1 million self-insurance per incident and the introduction of the self-insurance up to $10 million aggregate. In that proceeding, the Commission ultimately approved the parties' agreed upon methodology of using a ten-year average of self-insurance including the average of the restated claims above $1.0 million but less than the $10.0 million aggregate to properly calculate the level of injuries and damages expense that the Company anticipates incurring during the rate effective period.

Q. 9 Please describe how the ten-year average was calculated in the Company's last general rate case.

A. 9 The Company treated all self-insured amounts as system allocable. Therefore, the total of the up to $1 million incident amount recorded on the Company's books and the $1 million up to $10 million aggregate not recorded on the Company's books were used in the calculation of the ten year average. Once the ten year average was calculated, Arizona's allocation was determined using the Four Factor allocation methodology. In order to derive a reasonable estimate that reflected the up to $10 million aggregate level, the Company used its previous ten years of claims history for all rate jurisdictions. These amounts were not reflected on the Company's books because these amounts would have been indemnified by insurance carriers based upon the insurance policies in place during applicable the time period (1994-2004). To the extent claims exceeded the $10 million aggregate level, those amounts were not used in the calculation. This exercise is necessary to calculate a ten-year average that is reflective of a level of expense that will be incurred by the Company during the rate effective period.

Q. 10 Are there any changes to the Company's level of self insurance since its last general rate case?

A. 10 The only change is that the aggregate is limited to $5 million instead of $10 million as a result of the Company acquiring an additional layer of insurance that covers the $5 million to $10 million portion of aggregate claims.

Q. 11 Has RUCO proposed a deviation from the methodology that was accepted in the Company's last general rate case?

A. 11 No. RUCO proposes no adjustment to the Company's calculation of Arizona's portion of the self-insured $1 million per incident or the $5 million aggregate.

Q. 12 What adjustment to Staff's proposal is needed to reflect the 10-year average of Arizona direct amounts subject to the up to $5 million aggregate?

A. 12 Staff's proposed level of self insurance would need to be increased by $1,596,611. During the previous 10 years (1997-2007), there were a number of incidents experienced where the amount of claims paid exceeded $1 million but were less than $5 million. The ten-year average of these Arizona direct amounts was $1,596,611. Staff Schedule C-12, Sheet 2, Line 12, Column (e) should be increased from the $820,000 to $2,410,000 and should be brought forward to Sheet 1, Line 2, Column (d). Staff Schedule C-12, Sheet 1, Line 2, Column (e) should be $2,968,765 and Line 18, Column (e) should be a positive $728,283. Using the average of the Arizona direct amounts rather than the

Four Factor of all Southwest amounts (proposed by Southwest) results is a number that is higher by $728,283. Southwest Rebuttal Exhibit No.__(RAM-1) provides Staff's Schedule C-12, Sheets 1 and 2, adjusted to reflect the Arizona direct $1,596,611 ten-year average aggregate self-insurance for amounts paid between $1 million to $5 million.

Q. 13 Do you have exhibits that support this calculation of the $1,596,611?

A. 13 Yes. Rebuttal Exhibit No.__(RAM-2) consists of two sheets, both of which were included in the workpapers to this application and provided to both Staff and RUCO. The first sheet summarizes the ten-year historical claims paid by each rate jurisdiction. This workpaper supports the summarized amounts shown on the Company's filing Schedule C-2, Adjustment. 10, sheet 1. Rebuttal Exhibit No.__(RAM-2) Sheet 2, shows the dollars paid by year, and rate jurisdiction, grouped into three categories. The first category includes claim dollars related to incidents resulting in payments less than $1 million. The second category includes claim dollars related to incidents resulting in payments of at least $1 million. Both of these categories would have been recorded on the Company's books and charged directly to the respective rate jurisdiction throughout the ten year period (1997-2007). The third category shown on sheet 2 lines 25 through 36, relates to claim amounts that resulted from incidents where the payment exceeded $1 million per claim, but to the extent that payments related to a claim exceeded $5 million, that additional amount is not included on the schedule. With the exception of the amount on line 33, these amounts were not recorded on the Company's books and therefore, not included in Staff's calculation. Staff also removes the claim shown on line 33, therefore none of the amounts in this third category are reflected in Staff's calculation.

Q. 14 In regards to the calculation of the appropriate level of self-insurance, should the Commission deviate from the methodology it adopted in Decision No. 68487?

A. 14 No. The methodology agreed to by the Company, Staff and RUCO and adopted by the Commission in the Company's last general rate case is reasonable and appropriate. Nothing has changed except for the lowering of the self-insured aggregate exposure.

III. YUMA MANORS

Q. 15 Please summarize the Staff proposal concerning Yuma Manors.

A. 15 Staff believes that the Commission should disallow 100 percent of Southwest's costs incurred in replacing the pipe to serve the Manors subdivision in Yuma because "the circumstances that necessitated the immediate replacement of this system were the direct result of incorrect actions taken by Southwest personnel resulting in the failure of this system."

Q. 16 Please describe the scope of your rebuttal testimony with regard to this issue.

A. 16 My rebuttal testimony, on this issue, is limited to a review of the ratemaking standards and precedents that the Commission has established in past Southwest rate proceedings to determine the appropriate level of pipe replacement costs in rate base.

Q. 17 Please describe the standard that the Commission has used in previous Southwest rate case proceedings.

A. 17 The Commission has previously used a betterment/remedial approach to guide it in determining the appropriate portion of pipe replacement cost to be included in rate base. Betterment is the life extending value that results from installing new pipe, while the remedial portion is the maintenance value associated with pipe replacement. The Commission has consistently ruled that the betterment portion benefits the customer and 100 percent of this cost should be included in rate base. Conversely, the Commission has historically ruled that the remedial portion of pipe replacement does not directly benefit customers and this cost should not be included in rate base.

Beginning in Commission Decision No. 57075 and in every subsequent Commission rate case decision for Southwest, the remedial portion of pipe replacement was shared equally between customers and shareholders, if the original installation of the pipe was by a gas company other than Southwest. This was the case regarding Arizona Public Service (APS) installed ABS pipe. This was also the Commission ruling in regards to Tucson Gas and Electric (TG&E), now Tucson Electric Power (TEP), installed Aldyl A, ABS and 1960s vintage steel pipe. In the one instance where pipe replacement was the result of Southwest installed Aldyl HD pipe, the remedial portion of pipe replacement was the sole responsibility of Southwest's shareholders.

Q. 18 Did each of the five pipe replacement programs share anything in common?

A. 18 Yes. All five pipe replacement programs resulted in the premature replacement of pipe resulting from either defective material and/or installation. For example, the APS ABS pipe replacement took place from 1985 to 1990 and replaced pipe that was originally installed from 1960 through 1970, or on average, after only 23 years of service. The reason for the replacement was related to defective material. In Decision No. 57075, page 35, the Commission found that 43 percent of the replacement expenditure was betterment and the responsibility of the customer. The Commission later, on page 41, ruled that the remedial portion, after certain adjustments, would be shared equally between shareholders and customers.

Another example was TG&E installed Aldyl A pipe that was installed from 1967 though 1979 and replaced from 1986 through 1993, after an average useful life of approximately 22 years. The Commission determined in Decision No. 57745, page 12, that 28.1 percent of the replacement was betterment and also ruled that the remedial portion be shared equally between shareholders and customers.

Q. 19 Please comment on the Commission's previous ruling regarding 1960s steel installed by TG&E.

A. 19 In 1971, the federal government ordered all gas utilities to cathodically protect their steel pipe systems by 1976. The steel portion of the gas distribution system that Southwest acquired in 1979 from TG&E was not fully cathodically protected. In 1989, the Company began a program to have the entire steel pipe system cathodically protected by 1998. The portions of the steel system that could not be protected were replaced.

In Decision No. 58693, the Commission adopted and approved a settlement between all parties to that proceeding. The settlement addressed the appropriate level of steel pipe replacement that would be included in rate base. For steel originally installed in the 1960s and replaced from July 1993 through June 1994, 81 percent would be included in rate base and the remaining 19 percent would be written-off. The average year of original install of 1960s steel pipe was 1964. Therefore, pipe that had an average useful life of approximately 30 years was afforded 81 percent rate base treatment. The settlement also provided that for replacement expenditures taking place in future years, an additional one percent of rate base inclusion would be granted. As a result, in the case of 1960s steel pipe, all replacement expenditures would be included in rate base by 2012. Therefore, the settlement also provided 100 percent rate base treatment for all Pre-1960's steel pipe replacement, similar to Yuma Manors pipe.

Q. 20 Did the Commission amend the 1993 Settlement agreement in the Company's last general rate case?

A. 20 Yes. In its Decision No. 68487, the Commission granted the Company's request to adopt a "40-Year rule". The Company requested that the Commission modify the write-off percentages contained in the 1993 Settlement to acknowledge that once pipe has served customers for 40 years, any subsequent replacement expenditures would be afforded 100 percent rate base treatment. As a result of its decision, 100 percent of the cost to replace 1960s steel pipe made after 2004 would be included in rate base.

Q. 21 Is Staff's proposal consistent with any of the above Commission rulings on pipe replacement?

A. 21 No. In Decision No. 58693, the Commission adopted a settlement, which provided 100 percent recovery of replacement cost for steel pipe that was first installed prior to 1960. The 100 percent recovery was for pre-1960 steel pipe that was replaced in the 1990s. In this proceeding Staff is recommending 100 percent disallowance of pre-1960 steel pipe that was replaced in 2007 more than ten years later. Staff's proposal is totally inconsistent with previous Commission precedent acknowledging the betterment value of pipe replacement, as I am not aware of a single instance where the Commission disallowed 100 percent of any Southwest pipe replacement cost.

Q. 22 Are there any pipe costs incurred in replacing the 50-year old steel pipe system at the Yuma Manors subdivision that Southwest would be willing to exclude from rate base in this and future proceedings?

A. 22 Yes. Southwest is willing to make an adjustment to exclude the additional cost incurred by the Company due to the urgency required to replace the Yuma Manors steel pipe system in a relatively short period of time. The Company incurred costs that were above the level that would be experienced had the replacement took place over a more routine time period. The Company considers the cost related to overtime, shift premiums, and other related costs to be over and above those that it would have experienced had the replacement been done in a more routine manner. The Company has identified this amount to be $320,779 (Mains $123,397 and Services $197,382). As such, the Company believes if any adjustment should be made to the Yuma Manors pipe replacement it should be limited to these additional costs. The balance of the cost represents a reasonable level required to replace

50-year old pipe that betters the system and will serve customers for 40 or more years, and as such, should be allowed in rate base.

IV. DEFERRED TAXES - MIP AND SERP

Q. 23 Please explain RUCO's adjustment to deferred taxes relative to the Management Incentive Plan (MIP) and the Supplemental Executive Retirement Plan (SERP).

A. 23 RUCO attempts to remove a portion of deferred taxes related to the MIP and SERP. Deferred taxes resulting from MIP and SERP are debits properly recorded in Account 283, Accumulated Deferred Income Taxes-Other. RUCO refers to the Company's response to Staff Data Request No. 11-11, which indicates that the deferred taxes in question are recorded in Account 283. RUCO's adjustment results in a decrease in rate base of $880,989 by increasing deferred taxes from a credit of $142,464,212 to a credit of $143,513,286 as shown on RUCO Schedule RLM-2 Page 1, line 8.

Q. 24 Is RUCO's adjustment appropriate?

A. 24 No. Southwest's Schedule B-6, Sheet 3 of 3, lines 1 and 2, show deferred taxes recorded in Accounts 282, Accumulated Deferred Income Taxes-Other Property, and Account 190, Accumulated Deferred Income Taxes, netting to the amount of $142,632,297. Account 283, Accumulated Deferred Income Taxes is not used as a component of rate base. Therefore, RUCO's adjustment removes from rate base deferred taxes that were not included by the Company in rate base. Furthermore, the MIP and SERP are System Allocable amounts and would first need to be allocated to Paiute and the balances then allocated to the Company's state ratemaking jurisdictions using the Four Factor allocation methodology. RUCO's adjustment is not appropriate and should not be adopted by the Commission for ratemaking.

V. LEAD-LAG STUDY - INTEREST EXPENSE LAG

Q. 25 Please comment on RUCO's proposed changes to the Company's interest expense lag in its lead-lag study.

A. 25 RUCO proposes to include preferred securities and interest on customer deposits in the calculation of the interest expense lag. The Company agrees with RUCO on the inclusion of preferred securities, but disagrees with interest on customer deposits. Interest on preferred securities is afforded similar ratemaking treatment as other interest expense, and is included in the cost of capital. Although the weighted cost of preferred securities is included in the $48,035,008 shown on Southwest Schedule B-5, Sheet 2 of 5, line 6, column (b), the lag impact of preferred securities is not included in the computation of the 84.65 lag days shown on line 6, column (c). The interest lag on preferred securities should be considered in the interest expense lag. The interest expense lag including the impact of preferred securities is only 79.5 days.

Interest on customer deposits is not afforded similar ratemaking treatment as other debt and preferred securities. Customer deposits are not a component of the cost of capital and more importantly, the 13-month average balance is used as a rate base deduction. A customer already receives the cash flow value of the average balance in rate base, and to include the lag in the interest expense calculation would be giving customers the cash flow value twice. The interest on customer deposits should not be included in the interest lag calculation if the 13-month average balance is used as a rate base deduction.

VI. LEAD-LAG STUDY - REVENUE TAX LAG

Q. 26 Please comment on RUCO's proposal to include a revenue tax lag in its proposed lead-lag study.

A. 26 RUCO Schedule RLM-6, Page 2 of 5, line 9, includes a component for revenue based taxes. Column A shows $97,747,450 under the caption "Company Expenses as Filed". Column D shows a lag of 51.75 days. The Company did not include revenue taxes in its cash working capital allowance as shown on Schedule B-5, Sheet 2 of 4. The Company has not included revenue taxes in its lead-lag studies in previous rate cases. Although the adjusted $100,949,060 revenue tax shown on Schedule RLM-6, Page 2 of 5, line 9, column C is Southwest's total revenue taxes, the 51.75 day lag is not a Southwest calculated number. A review of the current TEP rate case shows 51.75 days is TEP's revenue tax lag, and it appears this number may have been included in Southwest's case in error.

Q. 27 Should the Commission include revenue taxes in the lead-lag study, and, if so, what is the appropriate lag?

A. 27 Approximately 90 percent of the revenue taxes are paid monthly and the lag on these taxes closely approximate the revenue lag and, as such, would not impact the lead-lag study results. The remaining taxes (mill and franchise) would impact the lead-lag study. A review of the most recent APS rate case shows a revenue tax lag of 42.5 days. APS provides service to customers residing in more than one county throughout Arizona much like Southwest's service territory. Southwest has calculated its revenue tax lag to be 45.24 days, which not surprisingly is closer to APS' lag days, however Southwest's lag calculation does fall between the APS and TEP lag days. Should the Commission decide to include revenue taxes in the lead-lag study, the 45.24 day lag is more appropriate.

Q. 28 Please describe Rebuttal Exhibit No.__(RAM-3).

A. 28 Rebuttal Exhibit No.__(RAM-3) sheet 1, calculates the interest expense lag including the impact of the preferred securities lag, while sheet 2 calculates the Southwest revenue tax lag.

VII. LINE EXTENSION POLICY

Q. 29 Did Staff provide an opinion on the Company's Tariff Rule No. 6, which addresses the Company's line extension policies and procedures?

A. 29 Yes. Staff opines that conceptually it is a reasonable methodology, assuming <u>current cost figures and revenue estimates</u> (emphasis added) are used. However, Staff indicates that it has not examined the application of the methodology.

Q. 30 Is this the first time that the Company's application of Tariff Rule No. 6 and the Incremental Contribution Study (ICS) methodology has been addressed in Southwest rate proceedings?

A. 30 No. This is the third consecutive Arizona rate case proceeding where the Company's application of the ICS has been addressed. The ICS uses the Incremental Contribution Model (ICM) as the tool that ensures new customer additions are cost-justified and do not place a burden on existing customers.

Q. 31 Please summarize the rate case history of the ICM?

A. 31 In Docket No. G-01551A-00-0309, resulting in Decision No. 64172, one intervener took issue with the Company's application of Tariff Rule No. 6. Decision No. 64172, at page 32, line 6, states: "Based on the evidence before us, we do not believe that the allowance, or the methodology for its calculation should be changed. We believe, however, that in its next rate case, the Company should specifically address the issue of how it determines the allowance for the hookup of new residential customers."

In compliance with the Commission's order, in its next filed general rate case (G-01551A-04-0879) Southwest included direct testimony detailing its line extension policies and procedures. Specifically, the Company detailed how average therm use by type of appliance, investment and operating expenses are determined and how the projected results are compared to the authorized rate of return to determine if the customer is required to provide a non-refundable contribution in aid of construction (CIAC). Neither Staff nor RUCO took exception to the Company's ICS practice, or ICM application.

Q. 32 When was the last time the Company reviewed, changed, or modified the revenue and cost components contained in the ICM?

A. 32 Although it has been nearly ten years since the Company has filed with the Commission to modify the Rule 6 portion of its tariff, one should not conclude that the Company has not updated the ICM. Since the last tariff change the Company has modified the model on numerous occasions. The most recent updates were implemented March 2008.

Q. 33 What are the important ICM drivers that require periodic review and updating?

A. 33 There are five primary drivers that need periodic updating to keep the ICM current. They are as follows: 1) gas appliance estimated therm use; 2) standard lengths and cost per foot estimates for service stubs and extensions; 3) incremental expense; 4) pressure reinforcement standard amounts; and 5) Commission authorized amounts.

Q. 34 How often are these drivers updated?

A. 34 Items one through four are updated annually and item five is updated immediately following a Commission rate case decision.

Q. 35 Please describe how the Company calculates the estimated levels of therm use for the appliances, and how they are used in the ICM.

A. 35 The ICM calculates margin per new customer by multiplying the authorized margin rate per customer times the estimated therm use for the following appliances: 1) space heat; 2) water heat; 3) cooking; 4) clothes drying; and 5) natural gas logs. All other gas appliances are not considered in determining residential customer margin. The Company's Demand Planning department annually conducts an analysis of new "vintage year" customer additions and determines the estimated use for the five appliances. The analysis is performed annually on a district basis. The most recent study analyzed the normalized use (12-months ended August 2007) for customers added for vintage years 2003 through 2005. Resulting changes were implemented in March 2008.

Q. 36 Please describe how the Company calculates the average length of service stubs and service extensions and average cost per foot for each, and how they are used in the ICM.

A. 36 Due to the high volume of relatively small lengths of service pipe that run from the main in the street to a customer's premise, the Company records the cost of service in blanket work orders. On an annual basis, the dollars charged to blankets and associated footage are compiled to determine the average length and cost per foot of the service stub (pipe from the main in the street to the stub near the curb or sidewalk) and the service extension (pipe from the stub to the meter). The statistics are compiled by each district office. The results are entered into the ICM and used to analyze all new residential customer additions. Staff Exhibit No. PST-2 shows the six years (2002 - 2007) of cost statistics that are embedded in the ICM in regards to the cost of service stubs and extensions. During this six year period, Southwest extended service to 235,000 new Arizona customers, or approximately 24 percent of all Arizona customers served as of December 2007. As previously mentioned, the most recent change to this component of the ICM was March 2008.

Q. 37 Please describe how the Company calculates the average incremental expense, and how it is used in the ICM.

A. 37 The ICM contains a component for the incremental expense that is expected as a result of adding a new customer. Expenses such as meter reading, billing, uncollectibles, customer assistance and blue stake line location expense are used in the ICM. The standard amount used in the ICM is determined using average per customer amounts experienced during the most recent twelve months. In March 2008, the model was updated to reflect the average expense during the twelve months ended December 2007.

Q. 38 Please describe how the Company calculates pressure reinforcement, and how it is used in the ICM.

A. 38 During the last two years, the ICM was modified to include a component for pressure reinforcement capital expenditures that result from load growth over an extended period of time. This is an indirect cost of customer growth. The cost estimates for pressure reinforcements are reviewed annually on a district basis. Historical and projected costs are used in the estimate. As previously mentioned, the most recent change was implemented in March 2008.

Q. 39 What are the Commission authorized amounts used in the ICM.

A. 39 The ICM uses the cost of capital, state and federal income tax rates, property tax assessment ratio, and assessment rate that was used by the Commission to set rates in the Company's most recent rate case. The current basic service charges and margin rates for all rate schedules are also used in the model.

Q. 40 Please describe how the Company calculates the cost of mains, and how it is used in the ICM.

A. 40 The cost of mains is determined through engineering estimates and captured through the work authorization process included in the Company's Work Management System (WMS). The cost of mains includes all pipe, diameter, sizes. WMS provides a tool to estimate the cost of mains and a review of the estimate to actual cost once the project is completed.

Q. 41 Is the ICM updated by the Company to reflect the most recent cost data available.

A. 41 Yes. The five primary drivers used in the ICM are updated annually by the Company or following a Commission decision in a general rate case filing.

Q. 42 Do these periodic changes require a tariff filing with the Commission?

A. 42 No.

Q. 43 Has the Company formalized the change process regarding the ICM?

A. 43 Yes. The Company has formalized the policies and procedures for the ICM. Exhibit No.__(RAM-4) contains the "Project Charter to Formalize Policies and Procedures for the ICM". Also, Exhibit No.__(RAM-5) is a copy of Standard Practice 920.0 Incremental Contribution Method (ICM) Model (Arizona)(SP 920.0). The purpose of SP 920.0 is to describe the use, change in management controls, processes and procedures related to the ICM. SP 920.0 goes on to describe the Company's policy, scope and the responsibilities of the twelve departments that are involved in the use, change in management controls, processes and procedures regarding the ICM.

Q. 44 Was Southwest's senior management kept apprised of the final results of the project?

A. 44 Yes.

Q. 45 Since the Company filed its general rate case in Docket No. G-01551A-00-0309, where the ICM was first addressed by the Commission, has the Company strived to improve the mechanics and keep key drivers current?

A. 45 Yes. Since the filing of Docket No. G-1551A-00-0309, the Company has frequently reviewed how the ICM is used and the key drivers have been frequently updated.

Q. 46 Does the above testimony, in this proceeding, adequately respond to Staff's proposal for the Company in its next rate case proceeding?

A. 46 Yes. Staff's testimony beginning at the top of page 8, recommends that the Company, in its next rate proceeding, file an explanation of how it has been implementing Tariff Rule No. 6 provisions and to explain whether and to what extent it has made changes in the methodology and its application over the 10 years the current tariff provisions have been in place. The Company believes this testimony should satisfy Staff's concerns. As for the recommendation to file sample calculations, the Company is willing to get together with Staff to explain how the model works with real examples of actual projects. The Company believes that the recommendation to present this information in the next rate case is not necessary and should not be ordered by the Commission.

Q. 47 Does this conclude your rebuttal testimony?

A. 47 Yes, it does.

Southwest Gas Corporation
Injuries and Damages, Account 925

Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule C-12
Page 1 of 2

Line No.	Description		Company Test Year As Recorded (A)	Company Requested As Filed (B)	Company Requested As Corrected (C)	Staff Proposed (D)	Staff Adjustment (E) Col.D - Col.B
	Arizona Direct						
1	Legal and Other Costs		$ 467,269	$ 467,269	$ 467,269	$ 467,269	$ -
2	Reserve for Self Insurance		$ (558,765)	$ (558,765)	$ (858,765)	$ 2,410,000 c	$ 2,968,765
3	Self-Insured Workmen's Comp		$ 497,524	$ 497,524	$ 497,524	$ 497,524	$ -
4	Total Arizona Direct		$ 406,028	$ 406,028	$ 106,028	$ 3,374,793	$ 2,968,765
	Common Before Allocation to Arizona						
5	Legal and Other Costs		$ 179,014	$ 179,014	$ 179,014	$ 179,014	$ -
6	Reserve for Self Insurance		$ 200,000	$ 4,130,256	$ 5,030,024	$ 200,000 c	$ (3,930,256)
7	Self-Insured Workmen's Comp		$ 23,243	$ 23,243	$ 23,243	$ 23,243	$ -
8	Insurance		$ 9,292,136	$ 9,738,915	$ 9,738,915	$ 9,738,915	$ -
9	Subtotal before Paiute Allocation		$ 9,694,393	$ 14,071,428	$ 14,971,196	$ 10,141,172	$ (3,930,256)
10	Paiute Allocation	3.96%	$ (395,033) a	$ (380,379) a	$ (592,859)	$ (401,590)	$ (21,211)
11	Subtotal after Paiute Allocation		$ 9,299,360	$ 13,691,049	$ 14,378,337	$ 9,739,582	$ (3,951,467)
	Arizona Allocation of Common						
12	Legal and Other Costs	56.70%	$ 101,501	$ 101,501	$ 101,501	$ 101,501	$ -
13	Reserve for Self Insurance	56.70%	$ 113,400	$ 2,341,855	$ 2,852,024	$ 113,400	$ (2,228,455)
14	Self-Insured Workmen's Comp	56.70%	$ 13,179	$ 13,179	$ 13,179	$ 13,179	$ -
15	Insurance	56.70%	$ 5,268,641	$ 5,521,965	$ 5,521,965	$ 5,521,965	$ -
16	Paiute Allocation	56.70%	$ (223,984)	$ (215,675)	$ (336,151)	$ (227,702)	$ (12,027)
17	Total Common Allocated to Arizona		$ 5,272,737	$ 7,762,825	$ 8,152,518	$ 5,522,343	$ (2,240,482)
18	Total Arizona Direct and Allocated		$ 5,678,765	$ 8,168,853	$ 8,258,546	$ 8,897,136	$ 728,283
19	Company's proposed adjustments to Account 925 in its filing			$ 2,490,088 Col.B - Col.A	$ 2,579,781 Col.C - Col.A	$ 728,283	
	Components of Company's proposed adjustments to Account 925, I&J Expense:						
20	SWG Adjustment 7, Out of Period Expenses			$ 253,324	$ 253,324	$ 253,324	
21	SWG Adjustment 10, Self Insured Retention Normalization			$ 2,228,455 b	$ 2,318,148 b	$ 2,956,738	
22	SWG Adjustment 12, A&G Expenses, Annualized Paiute Allocation			$ 8,309	$ 8,309	$ 8,309	
23	Total Company-proposed adjustments to Account 925 expense			$ 2,490,088	$ 2,579,781	$ 3,218,371	
24	Percentage increase over test year recorded amount			44%	45%	57%	
25	Staff proposed adjustment to SWG as-filed pro forma expense for Account 925					$ 728,283 L.23, Col.D - Col.B	$ 728,283

Notes and Source

A SWG response to Staff data request STF-9-14
B Derived from SWG filing, Schedule C-2, Company Adjustment Nos. 7, 10 and 12 and response to STF-9-14
C SWG response to Staff data request STF-9-14
D See page 2 of this schedule for Staff analysis of ten years of recorded expense for
a Paiute allocation used by SWG in its filing does not calculate exactly to 3.96%
b SWG Adjustment 10, Self Insured Retention Normalization

Line	Component	SWG Recorded	SWG Filed	SWG Corrected	Staff Adjusted	Staff Adjustment
26	Arizona Direct	$ (558,765)	$ (558,765)	$ (858,765)	$ 2,410,000	$ 2,968,765
27	Common Allocated to Arizona	$ 113,400	$ 2,341,855	$ 2,852,024	$ 113,400	$ (2,228,455)
28	Subtotals	$ (445,365)	$ 1,783,090	$ 1,993,259	$ 2,523,400	$ 740,310
29	Net SWG Proposed Adjustment, before change in Paiute allocation		$ 2,228,455 L.27, Col.B - Col.A To Line 21	$ 2,438,624 L.27, Col.C - Col.A	$ 2,968,765	
30	Paiute allocation	$ (223,984) Line 16		Line 16 Less line 22 $ (344,460)	$ (236,011)	$ (12,027)
31	Change in Paiute allocation from test year recorded			$ (120,476)	$ (12,027)	
32	Company's proposed corrected adjustment, net of change in Paiute allocation			$ 2,318,148 To Line 21		$ 728,283 c
33	Staff adjustment to Southwest recorded, net of change in Paiute allocation				$ 2,956,738 To Line 21	

c See page 2 of this schedule for details of Staff recommended normalized amount for self-insured expense.

Southwest Gas Corporation
Injuries and Damages, Account 925
Reserve for Self-Insurance Expense Normalization
Test Year Ended April 30, 2007

Line No.	Description	Year	Total Expense Recorded Arizona (A)	Total Expense Recorded Common (B)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Arizona (C)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Common (D)	Staff Proposed Arizona (E)	Staff Proposed Common (F)
	Reserve for Self-Insurance Expense							
1		1998	$ 751,083	$ 500,000	$ 751,083	$ 500,000		
2		1999	$ 500,000	$ (200,000)	$ 500,000	$ (200,000)		
3		2000	$ 1,080,545	$ -	$ 1,080,545	$ -		
4		2001	$ 426,955	$ 100,000	$ 426,955	$ 100,000		
5		2002	$ 350,000	$ 200,000	$ 350,000	$ 200,000		
6		2003	$ 1,941,509	$ (300,000)	$ 1,941,509	$ (300,000)		
7		2004	$ 2,154,000	$ 275,000	$ 2,154,000	$ 275,000		
8		2005	$ 1,360,224	$ 10,367,500 a	$ 1,360,224			
9		2006	$ (975,540)	$ 200,000	$ (975,540)	$ 200,000		
10		2007 YTD November	$ 588,629	$ (25,500)	$ 588,629	$ (25,500)		
11	Total		$ 8,177,405	$ 11,117,000	$ 8,177,405	$ 749,500		
12	**Ten Year Average Plus $1,596,611**		$ 817,741	$ 1,111,700	**$ 2,414,352**	$ 74,950	**$ 2,410,000** b	$ 200,000 c
13	Pauite allocation	0.0396		$ (44,023)		$ (2,968)		$ (7,920)
14	Common before AZ allocation			$ 1,067,677		$ 71,982		$ 192,080
15	AZ allocation	56.7%		$ 605,373		$ 40,814		$ 108,909
16	AZ allocated and direct		$ 817,741	$ 605,373	$ 2,414,352	$ 40,814	$ 2,410,000	$ 108,909
	Adjustment to Southwest Proposed as Filed							
17	Page 1, Col.B, Lines 2 and 13, respectively		$ (558,765)	$ 2,341,855	$ (558,765)	$ 2,341,855	$ (558,765)	$ 2,341,855
18	Adjustment to SWG Proposed As Filed, Based on Ten-Year Average	L.16 - L.17	$ 1,376,506	$ (1,736,482)	$ 2,973,117	$ (2,301,041)	**$ 2,968,765**	$ (2,232,946)
19	Net adjustment to Arizona expense		$ (359,977)		$ 672,076		**$ 735,819**	
			L.18, Col.A&B		L.18, Col.C&D		L.18, Col.E&F	
	Adjustment to Southwest Proposed as Corrected							
20	Page 1, Col.C, Lines 2 and 13, respectively		$ (858,765)	$ 2,852,024	$ (858,765)	$ 2,852,024	$ (858,765)	$ 2,852,024
21	Adjustment to SWG Proposed As Filed, Based on Ten-Year Average	L.16 - L.20	$ 1,676,506	$ (2,246,651)	$ 3,273,117	$ (2,811,210)	**$ 3,268,765**	$ (2,743,115)
22	Net adjustment to Arizona expense		$ (570,146)		$ 461,907		**$ 525,650**	
			L.21, Col.A&B		L.21, Col.C&D		L.21, Col.E&F	

Notes and Source

Ten-Year Average is from the Company's' workpapers for Schedule C-2, Adjustment No. 10, Sheets 72 to 75 and response to data requests STF-6-60 and STF-9-14.

a The 2005 common expense is abnormally high because of the impact of a May 2005 leaking gas line fire. The eventual settlement of that incident exceeded the Company's self-retention in effect at the time of the occurrence, per the response to data requests, such as STF-10-11(B) and (F)

b Ten-Year Average, rounded upward to nearest $10,000

c 2006 accrual used as reasonably representative; note this amount exceeds the 10-year average, excluding the impact of the abnormal and extreme payout relating to the May 2005 leaking gas line fire.

Rebuttal Exhibit No.__(RAM-1)
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF SELF-INSURANCE (10 YEAR AVERAGE)
ADJUSTMENT NO. 10

Line No.	Claims Paid (a)	FERC (b)	So. Ca. (c)	No. Ca. (d)	So. Nv. (e)	No. Nv. (f)	Arizona (g)	System Allocable (h)	Total (i)	Line No.
1	< $1MM Per Claim	$ 0	$ 177,500	$ 24,375	$ 1,350,143	$ 195,000	$ 5,809,865	$ 141,255	$ 7,698,138	1
2	At $1MM Per Claim	0	0	0	1,000,000	2,000,000	5,000,000	0	8,000,000	2
3	At $5MM Aggregate	0	0	0	0	997,774	15,966,105	0	16,963,879	3
4		$ 0	$ 177,500	$ 24,375	$ 2,350,143	$ 3,192,774	$ 26,775,970	$ 141,255	$ 32,662,017	4
	Total Company Experience									
5	10 Year Average	$ 0	$ 17,750	$ 2,438	$ 235,014	$ 319,277	$ 2,677,597	$ 14,126	$ 3,266,202	5
6	Less: Paiute & SGTC at 3.96%								(129,342)	6
7	Net System Allocable								$ 3,136,860	7
8	Four Factor %		7.9%	2.3%	27.3%	5.7%	56.7%			8
9	Allocation of Self-Insurance	$ 129,342	$ 249,067	$ 72,775	$ 856,049	$ 180,056	$ 1,778,600	$	$ 3,136,546	9
10						Arizona Allocation Percent			56.70%	10
11						Arizona Allocation			$ 1,778,422	11
12						Less: Test Year as Recorded			(449,856)	12
13						Arizona Revised Adjustment			$ 2,228,278	13

SOUTHWEST GAS CORPORATION
ARIZONA
TEN YEAR HISTORY OF LIABILITY CLAIMS
FOR AMOUNTS LESS THAN ONE MILLION AND FIVE MILLION AGGREGATE PER YEAR

Line No.	Year (a)	Palute (b)	So. Ca. (c)	No. Ca. (d)	So. Nv. (e)	No. Nv. (f)	Arizona (g)	Sys Alloc. (h)	Total (i)	Line No.
					Less Than $1,000,000 Self-Insurance Per Claim					
1	1997						450,384		450,384	1
2	1998						1,494,253	123,755	1,618,008	2
3	1999			6,250	256,333		37,545		300,128	3
4	2000			18,125	208,216	195,000			421,341	4
5	2001		100,000		415,093		609,455		1,124,548	5
6	2002						400,000		400,000	6
7	2003		50,000		31,000		95,491		176,491	7
8	2004				92,500		560,500		653,000	8
9	2005		27,500		342,000		179,500	17,500	566,500	9
10	2006						1,853,678		1,853,678	10
11	2007				5,001		129,059		134,060	11
12		$ 0	$ 177,500	$ 24,375	$ 1,350,143	$ 195,000	$ 5,809,865	$ 141,255	$ 7,698,138	12
					$1,000,000 Self-Insurance Per Claim					
13	1997						1,000,000		1,000,000	13
14	1998					1,000,000	2,000,000		3,000,000	14
15	1999								0	15
16	2000					1,000,000			1,000,000	16
17	2001								0	17
18	2002								0	18
19	2003						1,000,000		1,000,000	19
20	2004						0		0	20
21	2005				1,000,000		1,000,000		2,000,000	21
22	2006								0	22
23	2007								0	23
24		$ 0	$ 0	$ 0	$ 1,000,000	$ 2,000,000	$ 5,000,000	$ 0	$ 8,000,000	24
					$5 Million Agregate above $1,000,000 Self-Insurance Per Claim					
25	1997						2,726,235		2,726,235	25
26	1998					6,272	1,739,870		1,746,142	26
27	1999								0	27
28	2000					991,502			991,502	28
29	2001								0	29
30	2002								0	30
31	2003						5,000,000		5,000,000	31
32	2004						1,500,000		1,500,000	32
33	2005						5,000,000		5,000,000	33
34	2006								0	34
35	2007								0	35
36		$ 0	$ 0	$ 0	$ 0	$ 997,774	$ 15,966,105	$ 0	$ 16,963,879	36
37	Total	$ 0	$ 177,500	$ 24,375	$ 2,350,143	$ 3,192,774	$ 26,775,970	$ 141,255	$ 32,662,017	

[1] Amounts for 1997 (May-December) and 2007 (January-April) are a partial year; 1998 through 2006 are based on calendar year amounts.

Rebuttal Exhibit No.__(RAM-3)
Sheet 1 of 2

SOUTHWEST GAS CORPORATION
COMPUTATION OF INTEREST LAG DAYS
FOR THE 2007 ARIZONA RATE CASE

Line No.	Description (a)	Principal Amount Outstanding (b)	Unamortized Debt Expense and Discount (c)	Net Proceeds (b)	Effective Interest Rate (c)	Interest Expense (d)	Lag Days (e)	Dollar Days (f)	Line No.
	Debentures								
1	8.0% Debenture, Due 2026	75,000,000	6,089,371	68,910,629	8.89%	6,126,155	91.25	559,011,638	1
2	8.375% Note, Due 2011	200,000,000	1,807,388	198,192,612	8.61%	17,064,384	91.25	1,557,125,031	2
3	7.625% Note, Due 2012	200,000,000	1,380,294	198,619,706	7.79%	15,472,475	91.25	1,411,863,356	3
4	Total Debentures	$ 475,000,000	$ 9,277,052	$ 465,722,948	8.30%	$ 38,663,014		3,528,000,025	4
	Medium Term Notes								
5	7.59% MTN, Due 2017	25,000,000	147,215	$ 24,852,785	7.68%	$ 1,908,694	91.25	174,168,319	5
6	7.78% MTN, Due 2022	25,000,000	175,679	24,824,321	7.86%	1,951,192	91.25	178,046,239	6
7	7.92% MTN, Due 2027	25,000,000	204,455	24,795,545	8.00%	1,983,644	91.25	181,007,479	7
8	6.89% MTN, Due 2007	17,500,000	7,731	17,492,269	7.00%	1,224,459	91.25	111,731,869	8
9	6.76% MTN, Due 2027	7,500,000	3,458	7,496,542	6.88%	515,762	91.25	47,063,289	9
10	6.27% MTN, Due 2008	25,000,000	42,553	24,957,447	6.40%	1,597,277	91.25	145,751,493	10
11	Total Medium Term Notes	$ 125,000,000	$ 581,090	$ 124,418,910	7.38%	$ 9,181,027		837,768,689	11
12	Total Fixed Rate Debt [1]	$ 600,000,000	$ 9,858,142	$ 590,141,858	8.11%	$ 47,844,041		4,365,768,714	12
	Variable Rate Debt								
13	Term Facility [2]			$ 30,441,057	6.83%	$ 2,079,124	3.67	7,619,990	13
14	CP Facility [3]			22,728,142	5.96%	1,354,597	-24.05	(32,578,064)	14
15	Total Variable Rate Debt			$ 53,169,199	6.46%	$ 3,433,721		(24,958,074)	15
						$ 51,277,762		4,340,810,640	
	Perferred equity					7,722,141	45.25	349,426,880	
	customer deposits			31,921,898	0.06		182.5	-	
						58,999,903	79.50	4,690,237,521	

AzRateCase07-InterestLag.xls

Lead Lag Analysis

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504

ESTIMATED LAG DAYS FOR REVENUE BASED TAXES

Line No.	Revenue Based Taxes (1)	Paid Monthly	Paid Quarterly	Paid Annually	Total	Line No.
1	Franchise Fees	$ 6,448,399	$ 10,717,071	$ 0	$ 17,165,470	1
2	Privilege/Sales Taxes	82,412,358	0	354	82,412,712	2
3	Business Occupational Taxes	0	85,768	0	85,768	3
4	Mill Assessments (ACC/RUCO)	0	0	1,757,145	1,757,145	4
5	Totals	$ 88,860,757	$ 10,802,839	$ 1,757,499	$ 101,421,095	5
6	Ratio to Total	87.62%	10.65%	1.73%	100.00%	6
7	Lag Days	39.53	66.43	203.93		7
8	Weighted Lag Days	34.63	7.08	3.53	45.24	8
9	Dollar Days				$ 4,588,290,338	9

MEMORANDUM

To: **Distribution**

From: Eric DeBonis, Ed Janov

Date: August 7, 2007

Subject: Project Charter to Formalize Policies and Procedures for the ICM

Please be advised that effective August 1, 2007, Mike Harrington is the Project Manager of the Project to Formalize Policies and Procedures for the Incremental Contribution Method (ICM) Model. During this assignment, Mike will work closely with Tom Rader, Director/Special Projects, to facilitate the documentation and development of procedures to update and maintain the Arizona ICM.

We will serve as joint Project Sponsors and have authorized Mike and Tom to coordinate and manage the overall process. The immediate goals are to reconstitute the ICM model, document the code, and develop the change management process. Secondary goals are to determine the best long-term platform for the application, establish internal controls and auditing protocols; and develop a verification process to ensure model accuracy.

The primary project stakeholders will consist of an Oversight Committee and a Project Team. A kick-off meeting will be scheduled shortly with the stakeholders. Attached is the project Organization Chart.

Please join us in welcoming Mike to this assignment. Please give him all of your support in leading the group to a successful project completion.

Distribution:

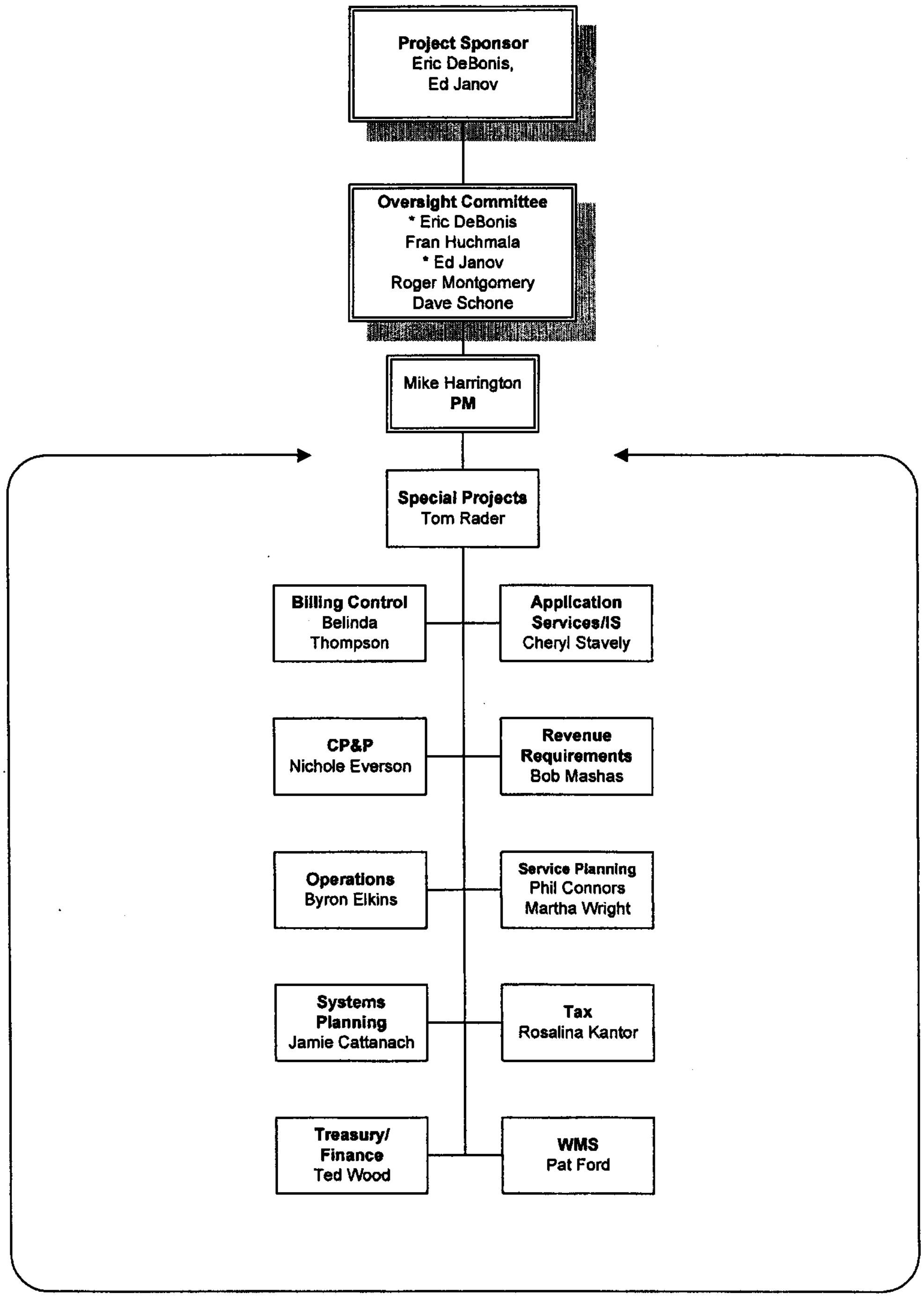
Jamie	Cattanach
Phil	Connors
Byron	Elkins
Nichole	Everson
Pat	Ford
Mike	Harrington
Fran	Huchmala
Rosalina	Kanter
Bob	Mashas
Roger	Montgomery
Tom	Rader
Dave	Schone
Cheryl	Stavely
Belinda	Thompson
Ted	Wood
Martha	Wright

c. Gary Clark
Eric DeBonis
John Hester
Roxann DelVecchio
Ed Janov
Richard Jordan
Jim Kane
Ken Kenny
Bill Moody
Lisa Moses
Chris Palacios
Jeff Shaw
Lisa Wamble
Bob Weaver

Attachment

Project Organization Chart

Project To Formalize Policies and Procedures For The ICM



Project Team

*** Joint Project Sponsors**

Project to Formalize Policies and Procedures for the ICM Model

PROJECT DEFINITION DOCUMENT

Last Updated: August 28, 2007

Approved By:	Signature	Date
Eric DeBonis Project Sponsor		
Ed Janov Project Sponsor		

Project to Formalize Policies and Procedures for the ICM Model
Project Definition Document

Table of Contents

Project Background and Objectives

Southwest Gas Corporation (Southwest) utilizes an Incremental Contribution Method (ICM) model to conduct economic feasibility analyses for potential natural gas projects in Arizona. The ICM model is used to determine the appropriate level of refundable advance and non-refundable contribution to ensure an adequate rate of return during and after the build-out phase of the potential project.

This model has been updated periodically to conform to Arizona regulatory requirements (Tariff Rule No. 6.B.4) and to reflect current costs, margins and volumes. The primary platform for the ICM model is an Excel spreadsheet, designed with the appropriate instructions, security, fields (cells) and formulas. The Revenue Requirements department has held primary responsibility for ensuring the accuracy and functionality of the model.

The primary user of the ICM model is Division Service Planning. After obtaining estimated costs for proposed new projects from Division Engineering, these costs are entered into the model by Division Service Planners. Other developer provided information such as number of residential units, number of appliances, and build-out projections are entered into the model by Division Service Planners.

To ensure the ICM model remains accurate and reflective of current rates, policies and demand data, a Project Team was formed to develop procedures to verify, document, and update the model. The Project Team and stakeholders will re-build the model, fully document all of the calculations and assumptions in the model, and establish the change management and auditing procedures to maintain the integrity of the model. The team will also identify the best form and/or application database environment for the model to reside in the long term.

The specific objectives of this project are to:

- Re-build and verify the accuracy of the ICM model.
- Document the calculations, logic and assumptions in the ICM model.
- Develop procedures for maintaining and updating the ICM model.
- Develop control procedures and an audit trail for model changes.
- Develop procedures for handling change requests.
- Develop procedures for distributing the model and managing revisions.
- Develop training materials and a Users Manual for the ICM model.
- Determine the best platform and database for the model.
- Evaluate specific training needs for users.
- Document the procedures and application environment.
- Close the project in a timely manner.

Project Success Criteria

This Project to Formalize Policies and Procedures for the ICM model will be measured by the following success criteria (Note: See Responsibility Assignment Matrix beginning on page 6, and Exhibit 1 at the end of this document for a description of the groups and team members):

- The Oversight Committee and Project Team will take an active role in the project to ensure project quality.
- The Project Team will have a working understanding of the components of the ICM and its purpose.
- The ICM Model Owner will be responsible for coordinating development of policies and procedures.
- The Project Manager and ICM Model Owner will report progress and escalate matters to the Oversight Committee and Project Sponsors.
- The Project Team will re-build and document the calculations, logic, and assumptions in the ICM model.
- The Project Team will complete procedures for maintaining and updating the ICM model.
- The Project Team will create internal controls and change management procedures for the ICM model.
- The Project Team will create training materials and a Users Manual for the ICM model.
- The Project Team will recommend the best platform for the database application for the model to reside in the long term.

Project Scope

The project scope is limited to the following tasks:

- Develop a focused Project Team review of the ICM model (including sub-committees) and reconstitute the model.
- Develop a set of standard procedures for the use of the ICM model.
- Develop a set of procedures for handling changes to the ICM model.
- Determine the best application and database environment for the ICM model.
- Establish a method of approving changes to the ICM model.
- Establish a means of periodically testing and verifying the ICM model.
- Establish audit trails for tracking changes and version controls of the ICM model.
- Research and evaluate potential integration with other systems.
- Develop a communication process for educating users of the ICM model.

The project scope will **not** include:

- Evaluation and modification of the ICM methodology.
- Review and development of any other analysis tool using different criteria than the ICM model.
- Evaluation and purchase of available software packages for modeling.
- Development of a similar model for the California and Nevada jurisdictions.
- Development of Arizona Division business processes for Service Planning.

Business Impact

The ICM model is used primarily by Arizona Division Service Planning to conduct economic feasibility analyses for potential natural gas projects in Arizona. The Excel spreadsheet model was originally developed and maintained by the Revenue Requirements department.

Data input for the model is provided by various departments, including Systems Planning, Revenue Requirements, and Division Service Planning. The data provided by corporate departments includes average gas loads, estimated costs and margin.

The ICM model does not directly interface with the Work Management System (WMS); however, the current ICM model is accessible through WMS as an Excel worksheet. Therefore, modifications to the ICM during the course of this project will need to consider impacts, if any, to WMS.

In addition, the project will introduce tighter controls in the change control process for the model. All impacted departments will require notification when changes to the ICM model are made and approved. Version control will be available in the new process for historical versions of the model.

Deliverables

The deliverables of this project are:

Phase I

- A comprehensive review, documentation of code and reconstitution of the ICM model.
- An improved change management process.
- A comprehensive set of procedures for the use, maintenance and revision process for the ICM model.
- A Business Process Flow document for handling revisions, document retention and communications regarding the ICM model and ownership processes.
- A Responsibility Support Matrix identifying all support roles and responsibilities.

Phase II

- A recommendation for the best application and/or database platform for housing the ICM model.
- Implementation of the recommended application and/or database following management approval.
- Improved internal controls and auditing protocols for the ICM model.
- An improved verification process to ensure the ICM model integrity.

Project Approach

Existing Southwest project management methodology will be used to formally document the project process and results.

The project documentation will also include periodic progress reports and documented results of working sessions.

A detailed work plan will be prepared and will be maintained.

The project reporting structure will be as follows:

- Project Sponsors - Eric DeBonis and Ed Janov
- Oversight Committee
- Project Manager
- ICM Model Owner
- Project Team
- Project Sub-committees (as needed)

(See Exhibit 1 for the full Project Organization Chart)

Responsibility Assignment Matrix

Resource	Title(s)	Roles and Responsibilities
Project Sponsors		
Eric DeBonis	General Manager/CAD Operations	– Responsible for authorizing the project and providing high level direction. Provide high level go, no go decisions.
Ed Janov	Senior VP/Finance	
Oversight Committee		Applies to all:
Eric DeBonis	General Manager/CAD Operations	– Responsible for providing the overall business and corporate area direction to the project.
Fran Huchmala	Dir./Cntrl Ops and Planning	– Advise the Project Manager and discuss status of the project with the manager on a regular basis.
Ed Janov	Senior VP/Finance	
Roger Montgomery	VP/Pricing	– Resolution of escalated issues and go, no go decisions at an overall company level.
Dave Schone	Dir./Bus Ops and Tech Support	– Ensure adequate departmental resources for project tasks.
Lisa Wamble	Director/Accounting	– Ensure all regulatory and governmental issues are adhered to.
Project Manager		
Mike Harrington	Project Manager/IS	– Responsible for coordinating and managing the project through completion. – Provide status reports to appropriate project members and conduct meetings as necessary. – Work with and coordinate activities with the ICM Model Owner.

Resource	Title(s)	Roles and Responsibilities
ICM Model Owner		
Tom Rader	Director/Special Projects	– Responsible for coordinating the development of the ICM model procedures. – Responsible for ensuring an annual update process. – Responsible for coordinating the development of user guides and instructions where applicable. – Responsible for coordinating the scheduling of regular audits. – Responsible for developing and maintaining version controls for the ICM model.
Project Team		
Roxanne DelVecchio	Manager/Accounting Billing Control	– Responsible for supporting the current Excel spreadsheet model and providing accounting controls and information related to Billing Control. – Responsible for inputting and validating data to the current Excel ICM model as provided by Revenue Planning and Demand Planning. – Responsible for version control and document retention.
Cheryl Stavely	Mgr/Application Services	– Responsible for providing input for the database and application environment. – Responsible for assisting with documentation of the ICM Excel spreadsheet model. – Responsible for evaluation and documentation to support analysis for different application platforms. – Responsible for supporting a new application and database if the Excel ICM model is transitioned to another environment.
Nichole Everson	Admin/Accounting (CPP)	– Responsible for providing policy and procedures documentation expertise.

Resource	Title(s)	Roles and Responsibilities
Project Team (cont)		
Bob Mashas	Dir./Revenue Requirements	– Responsible for providing input and information for the ICM model. – Responsible for making physical changes to current ICM model and coordinating with Treasury Services and the Model Owner.
Byron Elkins	Mgr./Ops Planning and Development	– Responsible for representing Arizona Divisions and ensuring regulatory adherence.
Phil Connors	Dir./Service Planning CAD	– Responsible for coordinating the development and implementation of procedures to periodically update the ICM model input, such as loads and costs to ICM model for CAD.
Martha Wright	Mgr./Service Planning SA	– Responsible for coordinating the development and implementation of procedures to periodically update the ICM model input, such as loads and costs to ICM model for SAZ
Jamie Cattanach	Mgr./Demand Planning	– Responsible for providing load information and planning for ICM model input.
Rosalina Kantor	Specialist/Corp Tax	– Responsible for Tax input and other ICM accounting and tax information impacting the ICM.
Ted Wood	Sr. Mgr./Treasury Services	– Responsible for providing financial analysis input and rate of return information.
Pat Ford	Sr. Mgr./ B.O.A.T.S./WMS	– Responsible for assisting with physical changes to the current ICM model and coordinating changes with Revenue Planning and the ICM Model Owner. – Responsible for providing information for the ICM model. – Responsible for how WMS will utilize the ICM model in new platforms and environments.

Dependencies

Each identified department may have dependencies with other departments. In addition to scheduled team meetings, each department representative will be required to schedule time as needed with dependent departments in order to assist with analyses and tasks.

Examples of dependencies:

- The ICM Excel worksheet is attached to WMS. The ICM Model Owner and other departments need to be aware that updates to the ICM model may impact WMS.
- Systems Planning and Regulatory Affairs will need to coordinate changes to the ICM model with the ICM Model Owner.
- Treasury Services may need to be involved with changes to the model and will need to coordinate activities with the ICM Model Owner as well as other departments as necessary.
- The Corporate Policy and Procedures department (CP&P) will be instrumental in developing written procedures and will need to interface with the various departments impacted.
- Division Service Planning will be directly impacted by the ICM model and will need assurance that the model is accurate and up to date.

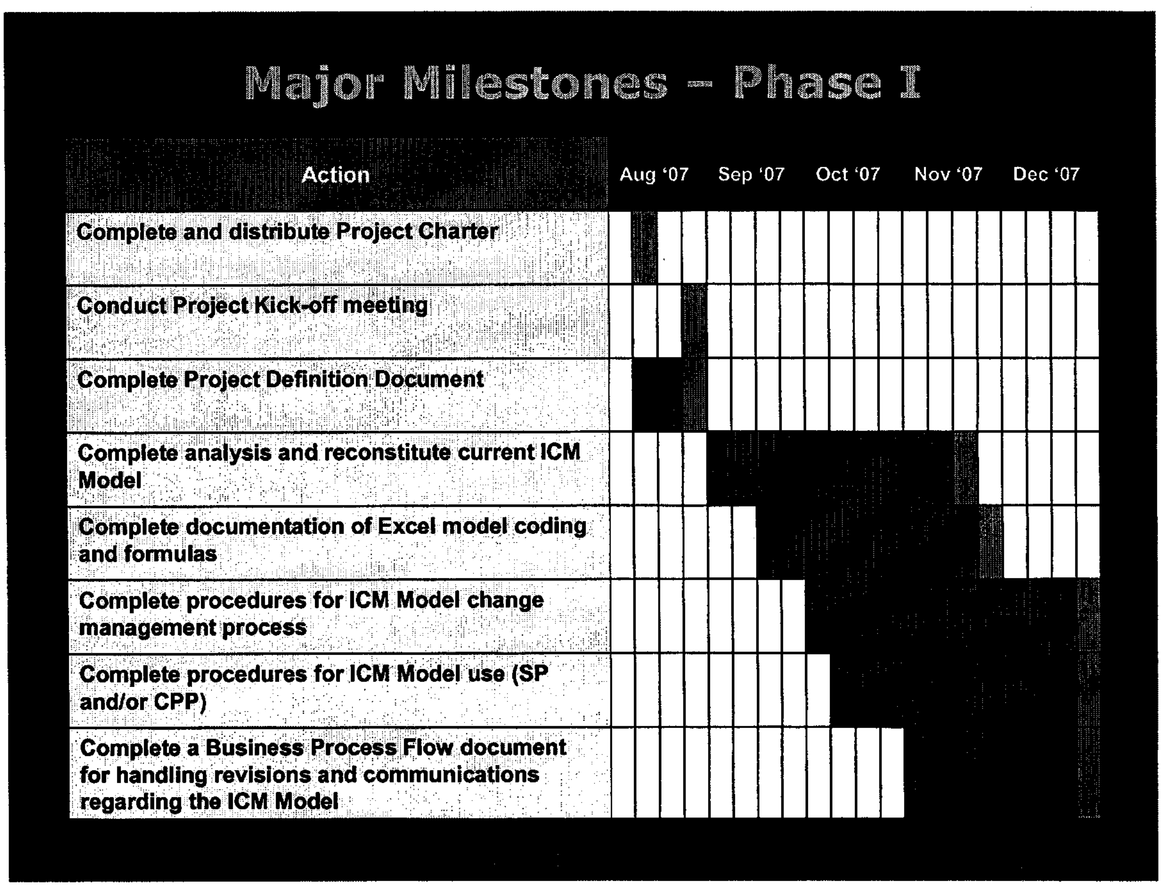
Schedule

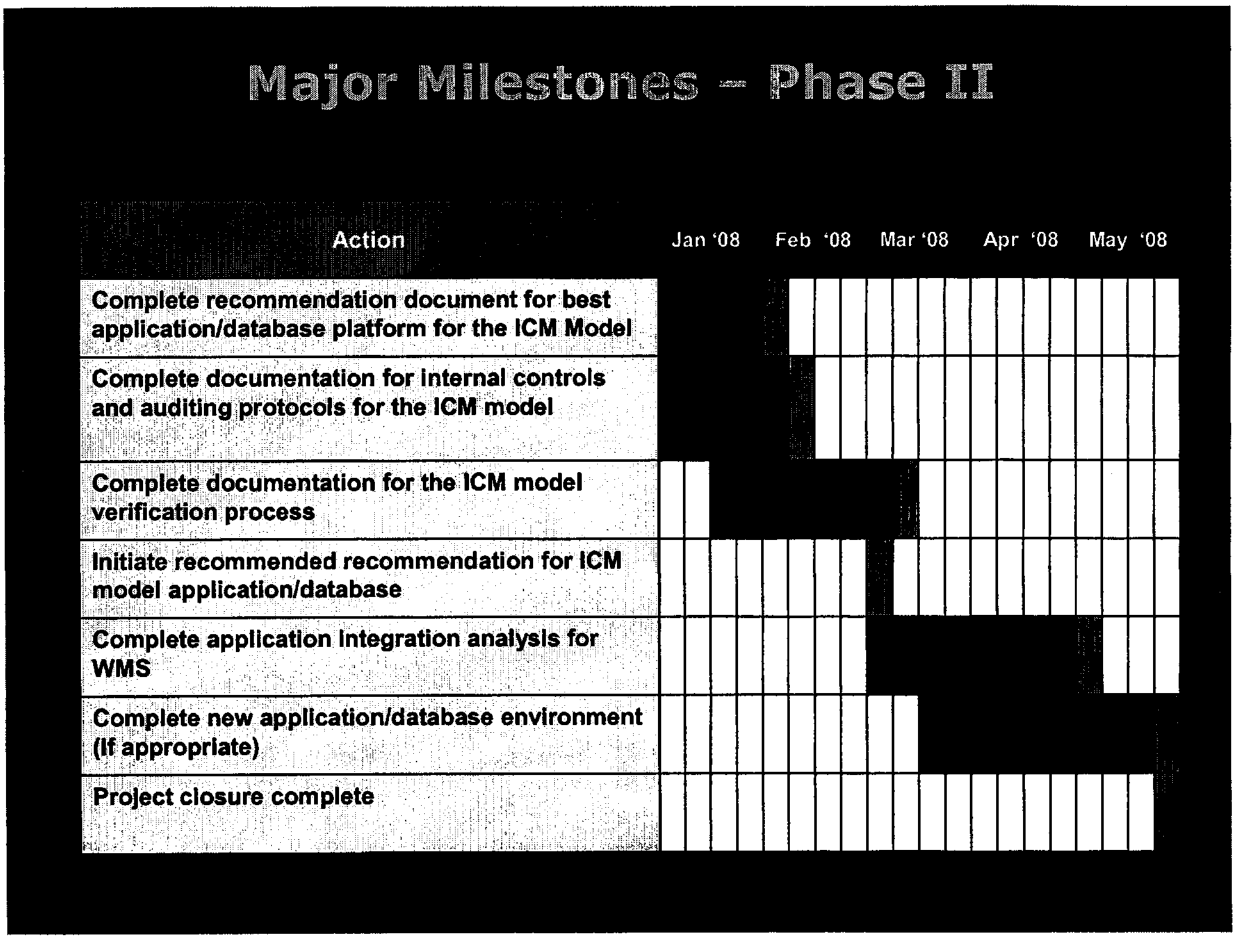
The request to formalize policies and procedures utilizing a project methodology was initiated in May 2007 and a formal Project Charter was issued in August 2007. The project will consist of two phases with Phase I scheduled for completion by the end of 2007. Senior management has requested the completion of formal procedures by December 2007. The selection and development of a new Application database and environment is dependent on further research and will fall into Phase II of the project. Integration with other applications may also be considered during a later phase of the project. Every effort will be made to complete all tasks prior to the end of each phase.

Milestones

The following graphs represent high level milestone estimates based on information available at August 2007. Dates may be modified based on additional information received during the course of the project.

Areas marked in blue represent an estimated duration of the task. Areas marked in green represent an approximate milestone completion date. Some tasks will run concurrently with other tasks as necessary.





Risks

Risks identified in this document are high level and may require more extensive analyses and plans for contingency/mitigation. The known project risks, at this time are:

Risk: *Dependent tasks impacting each other and the projected timeline.*

Mitigation(s):

- *Identify all dependent tasks in the project plan schedule and prioritize accordingly.*

Risk: Time restrictions on Project Team members or sub-committees may cause restrictions that delay completion of identified tasks.

Mitigation(s):

- *Obtain department head commitments for personnel prior to and during the project kick-off meeting.*

- *Ensure a copy of the Project Definition Document is routed to all project stakeholders.*
- *Obtain senior management support for the project.*

Risk: *The Excel spreadsheet (i.e. ICM model) is not accurately calculating customer Contributions/Advance requirements due to incorrect formulas, logic errors, or data inputs and/or assumptions.*

Mitigation(s):

- *As one of the initial tasks of the project, the Project Team will analyze in detail the ICM model and identify each cell and formula to ensure accuracy prior to documenting.*

Risk: *Requirements for the new platform and/or database are more complex than originally thought and will impact the project timeline (Phase II issue)*

Mitigation(s):

- *Schedule a series of requirements meetings with the appropriate Project Team personnel and sub-committees to determine extent of potential changes required for a new application/database platform.*
- *Ensure that representatives from I/S represent not only applications, but also Technical Services and database administrators.*

Contingencies:

- *Maintain the current Excel spreadsheet as a production tool until a full assessment can be made for changing to a different platform.*

Risk: *Requirements for integration with other applications may be more complex than originally thought and will impact the project timeline (Phase II issue).*

Mitigation(s):

- *Include application services representatives for WMS, CSS and other applications if appropriate to determine requirements for integration.*
- *Delay integration until a future phase.*

Contingencies:

- *Maintain current copy of ICM model until full requirements are developed.*

Risk: *Requests from management to add or modify a significant piece of the spreadsheet may require lengthy evaluation and coding.*

Mitigation(s)

- *Significant changes to the ICM model will be considered outside the scope of this project. Normal change management processes will be used to develop changes and will be approved by the Director/Special Projects.*

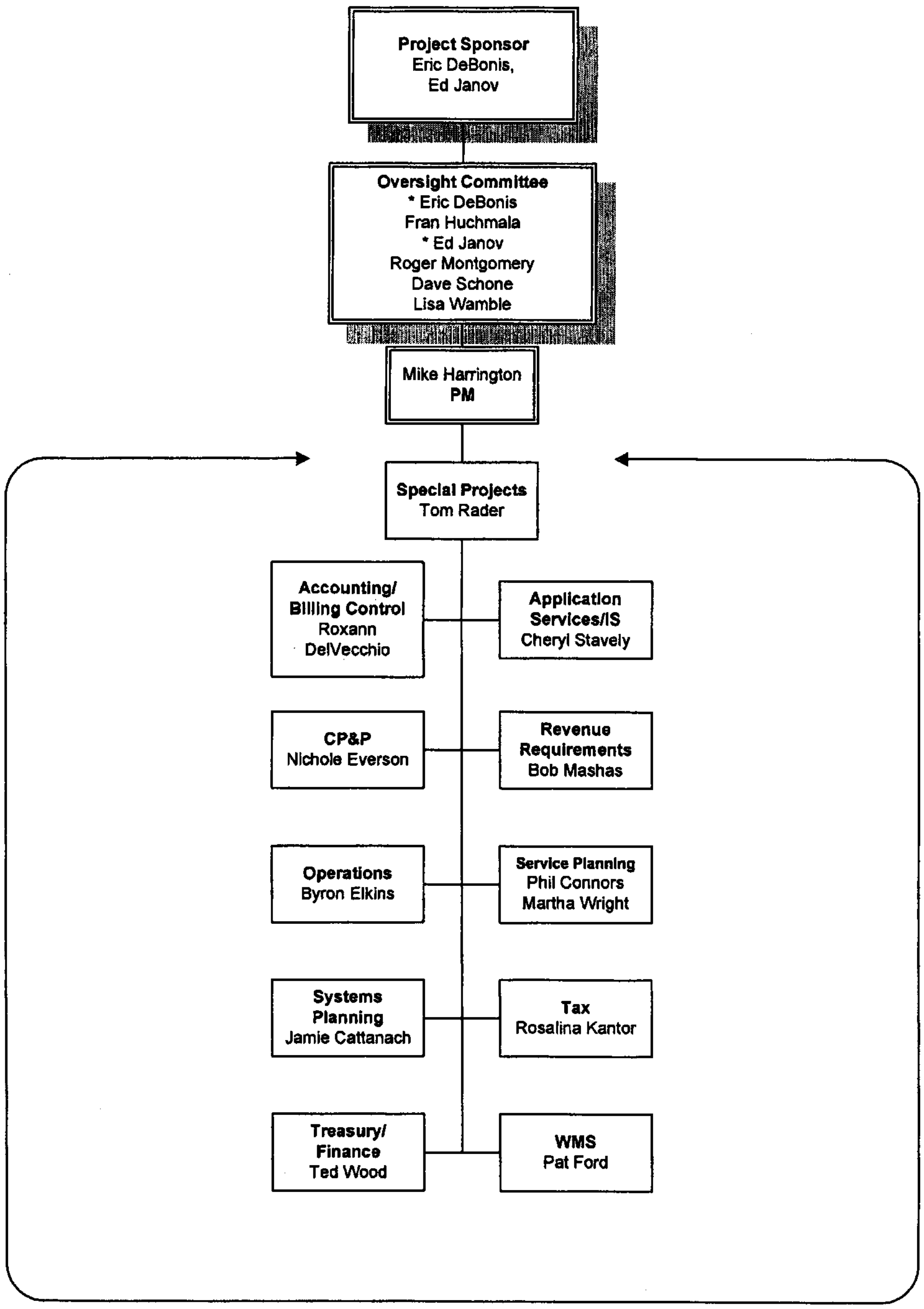
Assumptions

This project is based on certain assumptions:

- The current Excel version of the ICM model has been reviewed by a prior team and is functional for production use.
- Formulas, logic, and input data are accurate in the current production ICM model.
- Ownership of the ICM model will be formally transitioned to the ICM Model Owner.
- All Project Team members (or designates) will be available to assist with the project tasks and will attend the working meetings.
- The ICM model is currently in use as a WMS attachment and is updated as changes are made to the model.

Exhibit 1

Project to Formalize Policies and Procedures for the ICM



Project Team

*** Joint Project Sponsors**

Rebuttal Exhibit No.__(RAM-5)
Sheet 1 of 28

SOUTHWEST GAS CORPORATION

SP 920.0 Incremental Contribution Method (ICM) Model (Arizona)

Effective Date: 01/01/2008

SP Owner: Corporate Development

TABLE OF CONTENTS

Procedure E--Service Line Average Length and Cost Changes (Arizona - Standard Amounts)

Procedure F--Model Modifications

Reference

ICM Change Process Flow Charts

Purpose

To describe the use, change management controls, processes and procedures related to the Incremental Contribution Method (ICM) model.

Policy

1. To conform to Arizona regulatory requirements, Southwest Gas Corporation (the Company) utilizes an ICM model (the model) to conduct economic feasibility analyses for potential natural gas projects in Arizona. The model is used to determine the appropriate level of refundable advance and non-refundable contribution to ensure an adequate rate of return during and after the build-out phase of a potential project.

2. The model is updated as needed to conform to Arizona regulatory requirements (Arizona Gas Tariff Rule No. 6.B.4) and to reflect current costs, margins, and volumes.

3. The processes and procedures in this Standard Practice (SP) will be followed to ensure the model is utilized appropriately, remains accurate and includes current rates, policies, and demand data.

4. The current model is maintained on the InfoNet (Online Manuals) and is accessed and used by all departments.

5. The model consists of fourteen spreadsheets, all of which are password protected. Billing Control is responsible for protecting and maintaining security on the Standard Amounts worksheet and the ACC Authorized Rates worksheet within the model. Revenue Requirements is responsible for protecting and maintaining security on the other twelve worksheets within the model.

6. Departments will receive notification when approved changes are placed into production.

Scope

This SP applies to all Company employees that utilize and maintain the model.

Responsibility

1. Corporate Development

a. Ensure annual consumption changes (through Demand Planning), annual service line average length and cost changes (through Revenue Requirements), and authorized rate changes (through Revenue Requirements) are initiated and completed in a timely manner.

b. Act as initial contact point for problems identified in the model that may result in modifications to the model.

c. Provide final approval for all model updates and modifications including:

- Consumption changes
- Service line average length and cost changes
- Rate changes
- Model modifications

d. Rename tested and verified model to a production version using the appropriate naming convention.

e. Forward approved production version of model to Billing Control for placement into production environments [InfoNet and Work Management System (WMS)].

2. Billing Control

a. Create and maintain password protection for the Standard Amounts worksheet and Arizona Corporation Commission (ACC) Authorized Rates worksheet in the model.

b. Input data into the Standard Amounts worksheet and ACC Authorized Rates worksheet (as provided by Revenue Requirements and Demand Planning).

c. Review and update documentation comments on the Standard Amounts worksheet and ACC Authorized Rates worksheet.

d. Name and route test version of data changes to the department originally providing the data for verification and approval prior to placing into production.

e. Open a change request through the Help Desk to attach the new model version in the WMS (for Operations Systems Support) and InfoNet (for Customer Assistance Support and Training).

NOTE: The change request will consist of two activities – one to attach the new model version to WMS (for Operations Systems Support) and one to place the new model version on the InfoNet (for Customer Assistance Support and Training).

f. Monitor Action Request System (ARS) for change request closure prior to placing new version model into production environments.

g. Confirm new version is attached to WMS and placed on the InfoNet.

h. Maintain an accurate notification list.

i. Notify departments (key management and user departments and Corporate stakeholders) of production version model release.

3. <u>Revenue Requirements</u>

a. Create and maintain password protection for model worksheets other than the Standard Amounts worksheet and ACC Authorized Rates worksheet.

b. Provide input data for the Standard Amounts worksheet and ACC Authorized Rates worksheet including:

- Average margin rate per therm

- Service line historical information for average length and cost
- Key parameter information

c. Work with Treasury Services and Demand Planning to determine data inputs for the model.

d. Forward data input information to Corporate Development for approval prior to entry into the Standard Amounts worksheet and ACC Authorized Rates worksheet.

e. Maintain documentation for data inputs provided to Corporate Development.

f. Consult with Treasury Services for model modifications.

g. Maintain document support for comments and descriptions within the model, except for the Standard Amounts worksheet and ACC Authorized Rates worksheet (Billing Control responsibility).

h. Maintain verified version in electronic files within department.

i. Enter current version release notes in the Release Notes worksheet.

j. Work with Division Service Planning for review of annual service line information.

4. Demand Planning

a. Develop analyses and input data for the Standard Amounts worksheet (including District consumption averages).

b. Work with Revenue Requirements to determine data inputs for model.

c. Forward data input information to Corporate Development for approval prior to entry into the Standard Amounts worksheet.

d. Maintain documentation for data inputs provided to Corporate Development.

e. Consult with Revenue Requirements and Treasury Services for model

Rebuttal Exhibit No.__(RAM-5)
Sheet 6 of 28

modifications.

f. Maintain documentation support for comments and descriptions within the model, except for the Standard Amounts worksheet and ACC Authorized Rates worksheet (Billing Control responsibility).

g. Maintain verified test version in electronic files within department.

5. Treasury Services

a. Provide consultation for model design and formulas.

b. Maintain formulas used in the model and assist with testing of the model if changes are made.

c . Provide input data to Revenue Requirements for the ACC Authorized Rates worksheet.

d. Provide input for comments and documentation within the model to Revenue Requirements as needed.

6. Corporate Tax

a. Provide consultation for tax related information within the model.

b. Provide Revenue Requirements with document support for tax related comments and descriptions within the model.

7. Service Planning (Arizona Divisions)

a. Use the model to justify residential and non-residential construction projects.

b. Provide suggestions for model changes to Division Service Planning Management.

c. Assure completed analysis is attached to WMS job.

d. Use model from InfoNet to justify or consider projects outside of WMS.

8. IGE (Arizona Divisions)

a. Use the model to justify non-residential new construction projects.

b. Provide suggestions for model changes to Division Service Planning Management.

c. Assure completed analysis is attached to WMS job.

d. Use model from InfoNet to justify or consider projects outside of WMS.

9. Key Account Management (KAM)

a. When appropriate, use the model to justify non-residential new construction projects.

b. Provide suggestions for model changes to Corporate Development, Revenue Requirements, and/or Division Service Planning Management.

c. Assure completed analysis is attached to WMS job.

d. Use model from InfoNet to justify or consider projects outside of WMS.

e. Notify department employees each time the model is updated.

f. Provide model training for department personnel.

10. Service Planning Management (Arizona Divisions)

a. Use the model to justify residential and non-residential new construction projects.

b. Provide suggestions for model changes to Corporate Development.

c. Work with Revenue Requirements to review annual service line information.

d. Assure completed analysis is attached to WMS job.

e. Notify department employees each time the model is updated.

f. Provide model training for department personnel.

11. Operations Systems Support (OSS)

a. Receive and process ARS activity ticket for attaching the model to WMS.

12. Customer Assistance Support and Training (CAST)

a. Receive and process ARS activity ticket for updating and maintaining the model on the InfoNet.

PROCEDURE A--Usage - Service Planning

A-1. Service Planning (Arizona Divisions)

a. Access the current model on the InfoNet.

b. Provide project information to Engineering (to process through WMS and engineering design), and receive cost estimates and designs From Engineering (includes main, stub, and service extensions, etc.).

c. Input data in the Cost and Resi Sales Input worksheet, Gen Serv Sales Input worksheet, and Build-out worksheet in the model.

d. Review the rate of return calculated from the advance amount.

e. Determine the amount of refundable advance and/or contribution (if necessary) to ensure the appropriate rate of return.

f. Forward project to Service Planning Management for review and approval.

A-2. Service Planning Management (Arizona Divisions)

a. Review and approve project – completing appropriate tasks in WMS.

PROCEDURE B--Usage - Key Account Management

B-1. IGE (Arizona Divisions)

a. Access the current model on the InfoNet.

b. Input data in the Cost and Resi Sales Input worksheet, Gen Serv Sales Input worksheet, and Build-out worksheet in the model.

c. Assemble project package (includes print out of cost model, copy of customer contract, and other related documentation).

d. Save associated project model in accordance with department practices.

e. Send project package to Key Account Management (KAM) for review and approval.

B-2. <u>Key Account Management (KAM)</u>

a. Review and approve project package from IGE.

b. Ensure associated project contracts are reviewed and approved by Legal Affairs and the VP/Gas Resources.

PROCEDURE C--Annual Consumption Changes

NOTE: Annual consumption analyses should begin each August with model inputs due to Corporate Development by January the following year. These changes should be coordinated along with annual service line length and cost information due each February.

C-1. <u>Corporate Development</u>

a. Each August, confirm that Demand Planning and Revenue Requirements have initiated analysis of annual residential consumption data to determine annual estimates for each appliance (at District level), and are maintaining related information and records in accordance with department practices. Confirm January, or earlier due date.

b. Coordinate annual consumption changes with Revenue Requirements to determine if changes are required to the average rates section of model.

C-2. Demand Planning

a. Conduct analysis of residential end use/consumption, determine annual estimates for each appliance (at District level), and file results in accordance with department practices.

b. Provide residential consumption estimates to Revenue Requirements and conduct review, as required.

C-3. Revenue Requirements

a. Review residential consumption estimates and determine if a change to the average margin rate section of the model is required.

b. Forward decision with justification and inputs to Corporate Development no later than January, or earlier due date.

C-4. Corporate Development

a. Review justification with Demand Planning and Revenue Requirements.

b. **If no change to the model is required**, provide notification to Billing Control.

> *NOTE: This completes the annual consumption change process.*

c. **If a change to the model is required**, route the approved residential consumption inputs to Billing Control.

C-5. Billing Control

a. Access the current model on the InfoNet, and create a test version using appropriate naming convention.

b. Input annual consumption changes and average margin rate per therm changes into the Standard Amounts worksheet in the model, verify the accuracy, update documentation comments, and protect the worksheet.

Rebuttal Exhibit No.__(RAM-5)
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c. Forward the updated, protected model test version to Demand Planning for verification.

C-6. Demand Planning

a. Verify and test Billing Control inputs for annual consumption changes.

b. Route to Revenue Requirements for verification of the average margin rate section of the Standard Amounts worksheet.

C-7. Revenue Requirements

a. Verify and test Billing Control inputs for the average margin rate section of the Standard Amounts worksheet.

b. Unprotect the current Release Notes worksheet.

c. Enter current version comments into the Release Notes worksheet and protect worksheet.

d. Route to Corporate Development for final approval.

C-8. Corporate Development

a. Review and approve the updated, protected model test version and notify Demand Planning of approval.

b. Ensure that all worksheets in the model are adequately protected.

c. Rename tested and verified version of model to production version using appropriate naming convention.

d. Forward approved production version of model to Billing Control for placement into production environments.

C-9. Billing Control

a. Call the Help Desk to open a change request to move the model into production.

NOTE 1: The parent change request will consist of two activities

– one to attach the new version to WMS (for Operations Systems Support) and one to place the new version on the InfoNet (for Customer Assistance Support and Training).

NOTE 2: The new version will be the current model, and the replaced version will be added to the historical versions for control purposes.

C-10. <u>Operations Systems Support (OSS)</u>

a. Receive ARS activity ticket to place new version of model in WMS attachments area.

b. Schedule new version to be attached to WMS.

NOTE: Change should be coordinated with InfoNet change for same production release date.

c. Close activity in ARS and notify Billing Control.

d. Add new version to notification e-mail.

C-11. <u>Customer Assistance Support and Training (CAST)</u>

a. Receive ARS activity ticket to place new version of model on InfoNet (Online Manuals).

b. Schedule new version to be placed on InfoNet.

NOTE: If change is a result of an approved rate change, the new version should be expedited.

c. Add new version to page and move old version into previous version section.

NOTE: Change should be coordinated with WMS change for same production release date.

d. Close activity in ARS and notify Billing Control.

C-12. <u>Billing Control</u>

a. Maintain an accurate notification list.

b. Notify departments (key management and user departments and Corporate stakeholders) of production version model release.

c. Close the parent change request.

C-13. Service Planning Management (Arizona Divisions) and Key Account Management (KAM)

a. Notify department employees each time the model is updated.

PROCEDURE D--Rate Changes

D-1. Corporate Development

a. Ensure Revenue Requirements is providing timely updates for authorized rate changes, and maintaining related information and records in accordance with department practices.

D-2. Revenue Requirements

a. Conduct analysis of customer rates and tariffs, and file results in accordance with department practices.

b. Provide related rate and tariff proposed changes to Corporate Development for review and approval.

D-3. Corporate Development

a. Review and approve proposed rate change information.

b. Route the approved rate change information to Billing Control.

D-4. Billing Control

a. Access the current model on the InfoNet, and create a test version using appropriate naming convention.

b. Input rate changes into the Standard Amounts worksheet in the model, verify the accuracy, update documentation comments, and protect the worksheet.

c. Input rate changes into the ACC Authorized Rates worksheet in the model, verify the accuracy, update documentation comments, and protect the worksheet.

d. Forward the updated, protected model test version to Revenue Requirements for verification.

D-5. Revenue Requirements

a. Verify and test Billing Control inputs for rate changes.

b. Unprotect the current Release Notes worksheet.

c. Enter current version comments into the Release Notes worksheet and protect worksheet.

d. Route to Corporate Development for final approval.

D-6. Corporate Development

a. Review and approve the updated, protected model test version and notify Revenue Requirements of approval.

b. Ensure that all worksheets in the model are adequately protected.

c. Rename tested and verified version of model to production version using appropriate naming convention.

d. Forward approved production version of model to Billing Control for placement into production environments.

D-7. Billing Control

a. Call the Help Desk to open a change request to move the model into production.

NOTE 1: The parent change request will consist of two activities – one to attach the new version to WMS (for Operations

Systems Support) and one to place the new version on the InfoNet (for Customer Assistance Support and Training).

NOTE 2: The new version will be the current model, and the replaced version will be added to the historical versions for control purposes.

D-8. Operations Systems Support (OSS)

a. Receive ARS activity ticket to place new version of model in WMS attachments area.

b. Schedule new version to be attached to WMS.

NOTE: Change should be coordinated with InfoNet change for same production release date.

c. Close activity in ARS and notify Billing Control.

d. Add new version to notification e-mail.

D-9. Customer Assistance Support and Training (CAST)

a. Receive ARS activity ticket to place new version of model on InfoNet (Online Manuals).

b. Schedule new version to be placed on InfoNet.

NOTE: If change is a result of an approved rate change, the new version should be expedited.

c. Add new version to page and move old version into previous version section.

NOTE: Change should be coordinated with WMS change for same production release date.

d. Close activity in ARS and notify Billing Control.

D-10. Billing Control

a. Maintain an accurate notification list.

b. Notify departments (key management and user departments and Corporate stakeholders) of production version model release.

c. Close the parent change request.

D-11. Service Planning Management (Arizona Divisions) and Key Account Management (KAM)

a. Notify department employees each time the model is updated.

PROCEDURE E--Service Line Average Length and Cost Changes (Arizona - Standard Amounts)

NOTE: Revenue Requirements will work with Division Service Planning to review service line average length and cost information prior to review by Corporate Development. Changes to service line information should be coordinated along with annual consumption changes to the model. The year-end information to conduct the annual service line analysis is not available to Revenue Requirements until mid-January.

E-1. Corporate Development

a. Each December, confirm that Revenue Requirements has initiated analysis of service line average length and cost and is maintaining related information and records in accordance with department practices. Confirm February, or earlier due date.

E-2. Revenue Requirements

a. Conduct analysis of service line average length and cost and document and maintain results in accordance with department practices.

b. Work with Division Service Planning Management to review the annual service line information.

c. Provide proposed service line average length and cost to Corporate Development each February for review and approval.

E-3. Service Planning Management (Arizona Divisions)

a. Work with Revenue Requirements to review the annual service line information.

E-4. Corporate Development

a. Review justification with Revenue Requirements.

b. **If no change to the model is required**, provide notification to Billing Control.

NOTE: This completes the annual service line average length and cost change process.

c. **If a change to the model is required**, route the approved service line average length and cost inputs to Billing Control.

E-5. Billing Control

a. Access the current model on the InfoNet, and create a test version using appropriate naming convention.

b. Input applicable data into the Standard Amounts worksheet, verify the accuracy, update documentation comments, and protect the worksheet.

c. Forward the updated, protected model test version to Revenue Requirements for verification.

E-6. Revenue Requirements

a. Verify and test Billing Control inputs for service line average length and cost changes.

b. Unprotect the current Release Notes worksheet.

c. Enter current version comments into the Release Notes worksheet and protect worksheet.

d. Route to Corporate Development for final approval.

E-7. Corporate Development

a. Review and approve the updated, protected model test version and notify Revenue Requirements of approval.

b. Ensure that all worksheets in the model are adequately protected.

c. Rename tested and verified version of model to production version using appropriate naming convention.

d. Forward approved production version of model to Billing Control for placement into production environments.

E-8. Billing Control

a. Call the Help Desk to open a change request to move the model into production.

NOTE 1: The parent change request will consist of two activities – one to attach the new version to WMS (for Operations Systems Support) and one to place the new version on the InfoNet (for Customer Assistance Support and Training).

NOTE 2: The new version will be the current model, and the replaced version will be added to the historical versions for control purposes.

E-9. Operations Systems Support (OSS)

a. Receive ARS activity ticket to place new version of model in WMS attachments area.

b. Schedule new version to be attached to WMS.

NOTE: Change should be coordinated with InfoNet change for same production release date.

c. Close activity in ARS and notify Billing Control.

d. Add new version to notification e-mail.

E-10. Customer Assistance Support and Training (CAST)

a. Receive ARS activity ticket to place new version of model on InfoNet (Online Manuals).

b. Schedule new version to be placed on InfoNet.

c. Add new version to page and move old version into previous version section.

NOTE: Change should be coordinated with WMS change for same production release date.

d. Close activity in ARS and notify Billing Control.

E-11. Billing Control

a. Maintain an accurate notification list.

b. Notify departments (key management and user departments and Corporate stakeholders) of production version model release.

c. Close the parent change request.

E-12. Service Planning Management (Arizona Divisions) and Key Account Management (KAM)

a. Notify department employees each time the model is updated.

PROCEDURE F--Model Modifications

NOTE: Modifications to the model that result in changes, additions, and/or deletions to the Standard Amounts worksheet or the ACC Authorized Rates worksheet and data therein will be subject to the appropriate processes set forth in Procedures C, D, and E.

F-1. Key Account Management (KAM), Revenue Requirements, Service Planning Management, Corporate Tax, or Treasury Services

a. Determine that a modification is necessary.

b. Provide data and information regarding modification request to Revenue Requirements.

F-2. Revenue Requirements

a. Consult with Treasury Services to review and conduct analysis of modification, determine impact to the model, and determine if a change to the model is required.

b. Route proposed model changes, including justification, to Corporate Development for review and final approval.

F-3. Corporate Development

a. Review the proposed model changes and notify Revenue Requirements of decision.

b. Determine the timing of the proposed modifications.

F-4. Revenue Requirements

a. If changes are required for the Standard Amounts worksheet or the ACC Authorized Rates worksheet within the model, request unprotected version from Billing Control.

b. If no changes are required for the Standard Amounts worksheet or the ACC Authorized Rates worksheet, access the current model on the InfoNet, create a test version using appropriate naming convention, and proceed to Procedure F-6.

F-5. Billing Control

a. If contacted by Revenue Requirements for an unprotected version of the Standard Amounts worksheet or the ACC Authorized Rates worksheet, access the current model on the InfoNet, and create a test version (unprotected) using appropriate naming convention.

b. Forward the unprotected version to Revenue Requirements.

F-6. Revenue Requirements

a. Modify the test version model.

b. Verify and test the updated model. Document and maintain results in accordance with department practices.

c. Enter current version release notes in the Release Notes worksheet and protect worksheet.

d. Route the model test version to Billing Control if changes were made to the Standard Amounts worksheet or the ACC Authorized Rates worksheet.

e. If changes were not made to the Standard Amounts worksheet or the ACC Authorized Rates worksheet, protect the model and route to Corporate Development for final approval.

F-7. Billing Control

a. If changes were made to Standard Amounts worksheet or the ACC Authorized Rates worksheet, verify changes, update documentation comments, and re-protect the worksheets. Rename the model using appropriate naming convention.

b. Route protected model to Corporate Development for final approval.

F-8. Corporate Development

a. Review the updated, protected model test version and notify Revenue Requirements and Treasury Services of approval.

b. Ensure that all worksheets in the model are adequately protected.

c. Rename tested and verified version of model to production version using appropriate naming convention.

d. Forward approved production version of model to Billing Control for placement into production environments.

F-9. Billing Control

a. Call the Help Desk to open a change request to move the model into production.

NOTE 1: The parent change request will consist of two activities – one to attach the new version to WMS (for Operations Systems Support) and one to place the new version on the InfoNet (for Customer Assistance Support and Training).

NOTE 2: The new version will be the current model, and the replaced version will be added to the historical versions for control purposes.

F-10. Operations Systems Support (OSS)

a. Receive ARS activity ticket to place new version of model in WMS attachments area.

b. Schedule new version to be attached in WMS.

NOTE: Change should be coordinated with InfoNet change for same production release date.

c. Close activity in ARS and notify Billing Control.

d. Add new version to notification e-mail.

F-11. Customer Assistance Support and Training (CAST)

a. Receive ARS activity ticket to place new version of model on InfoNet (Online Manuals).

b. Schedule new version to be placed on InfoNet.

c. Add new version to page and move old version into previous version section.

NOTE: Change should be coordinated with WMS change for same production release date.

d. Close activity in ARS and notify Billing Control.

F-12. <u>Billing Control</u>

a. Maintain an accurate notification list.

b. Notify departments (key management and user departments and Corporate stakeholders) of production version model release.

c. Close the parent change request.

F-13. <u>Service Planning Management (Arizona Divisions) and Key Account Management (KAM)</u>

a. Notify department employees each time the model is updated.

F-14. <u>Key Account Management (KAM), Revenue Requirements, Service Planning Management, Corporate Tax, or Treasury Services</u>

a. If a problem or issue is identified with the new version, notify Revenue Requirements directly. (Changes will be made as required, repeating the above change process.)

<u>Reference</u>

<u>Other</u>

Action Request System (ARS)

Arizona Gas Tariff

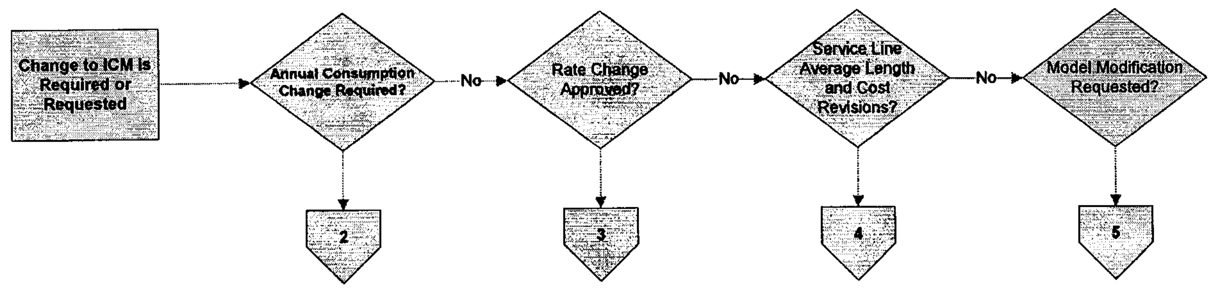
Incremental Contribution Method (ICM) Model

<u>Online Manuals</u>

Work Management System (WMS)

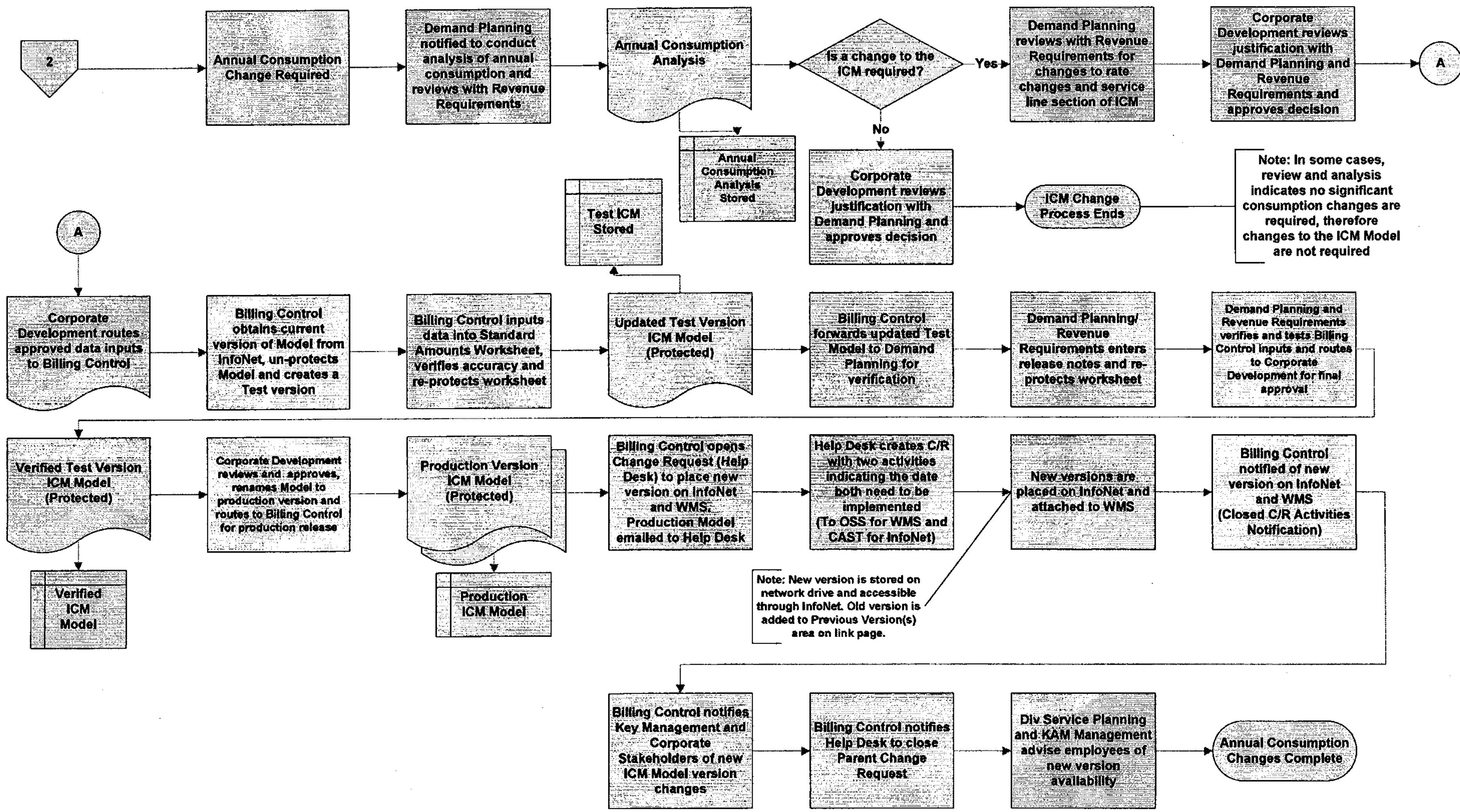
* * *

High Level ICM Change Process



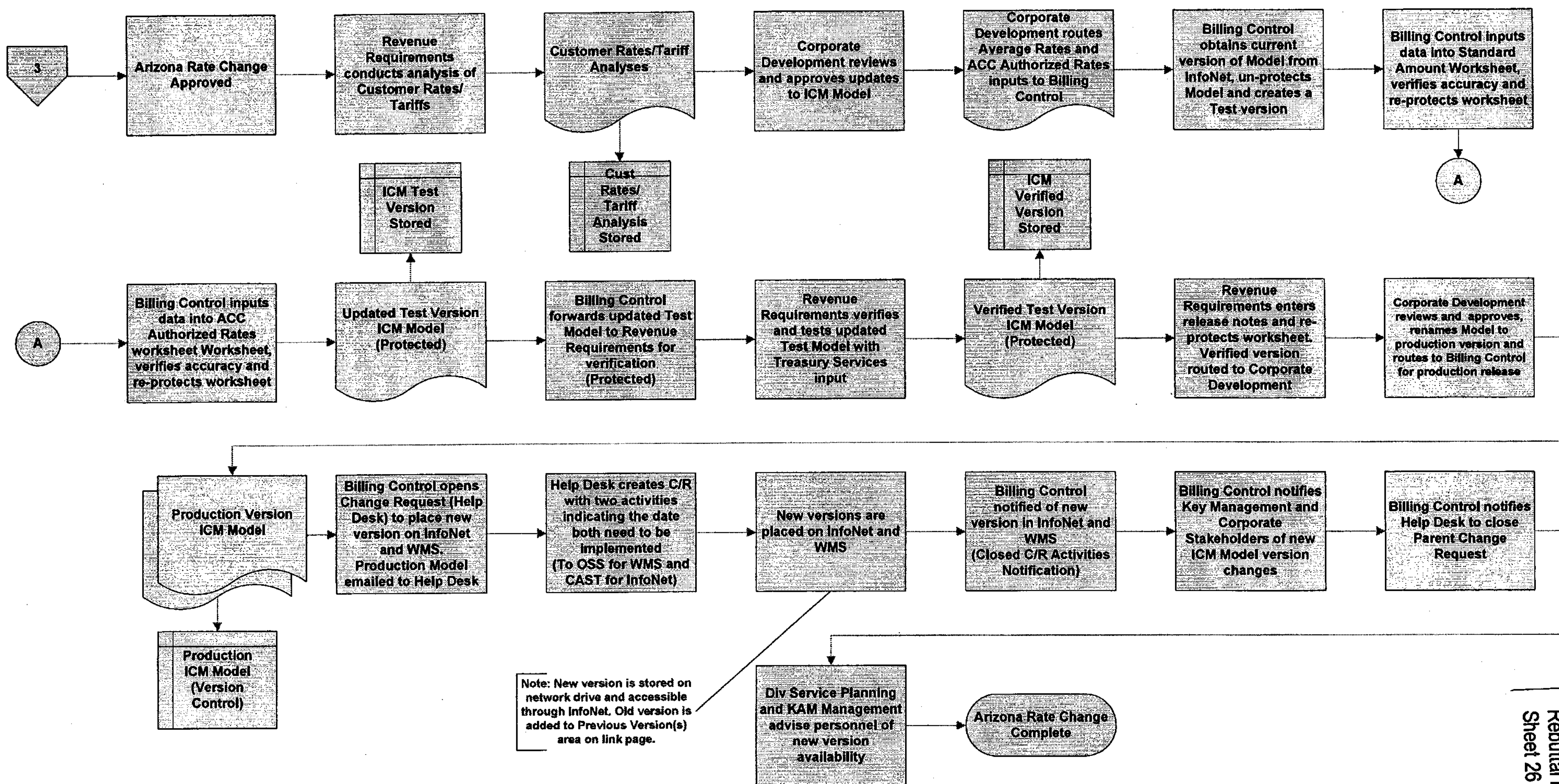
Rev: 1/16/2008

ICM Model – Annual Residential Consumption Updates



Rev: 1/16/2008

ICM Model – Rate Change Updates
ACC Authorized Rates and Standard Amounts Tabs



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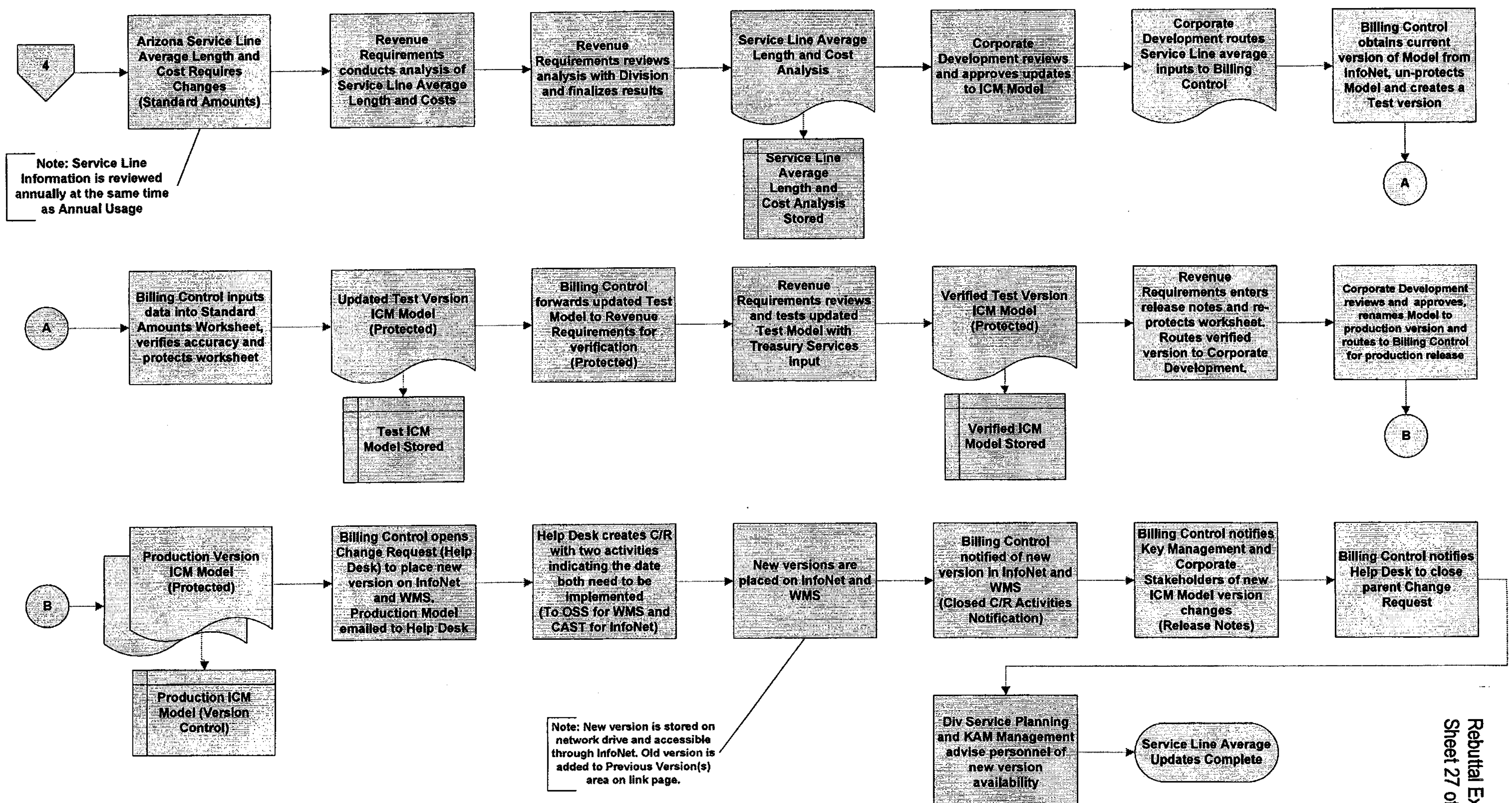
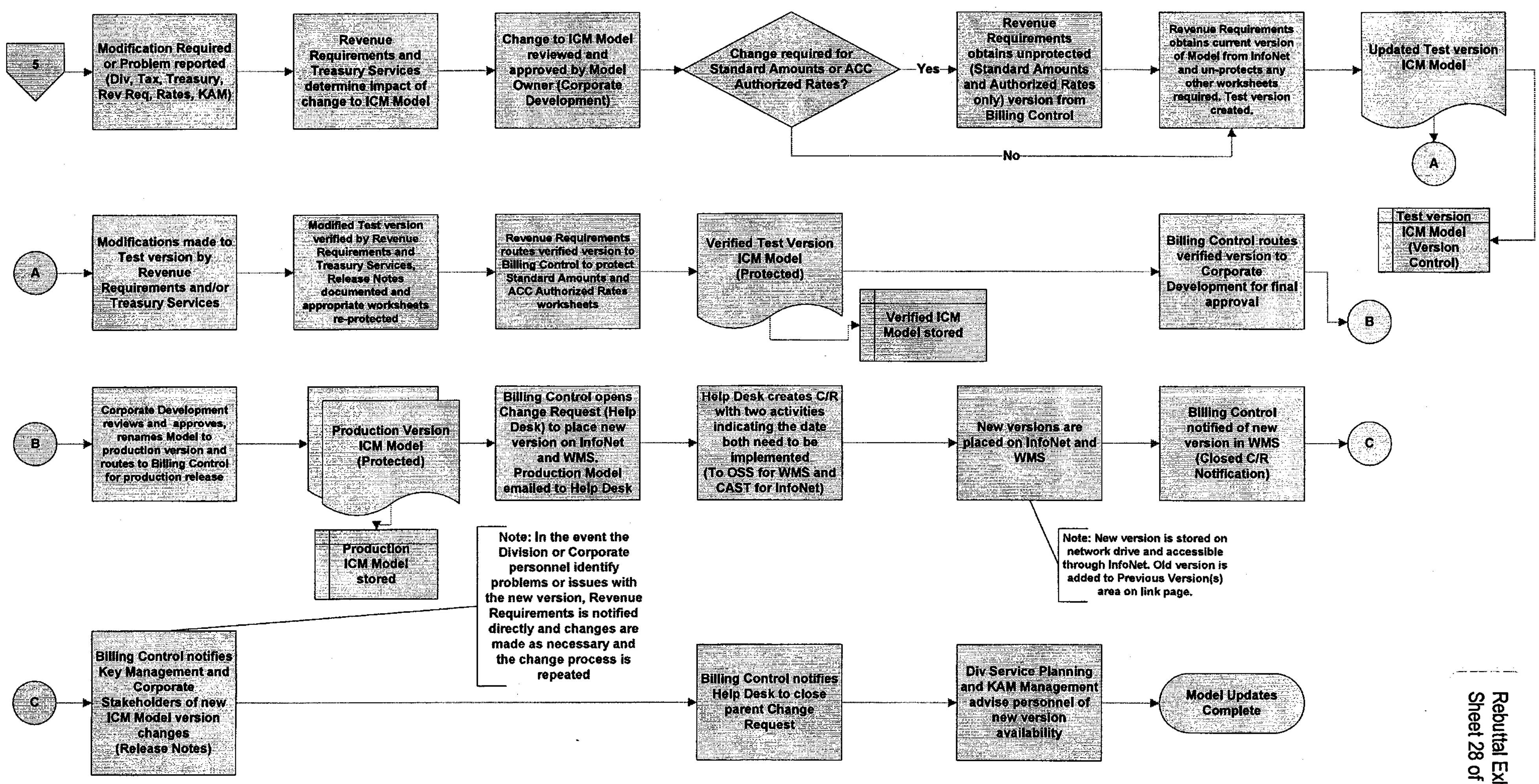
Rev: 1/16/2008

ICM Model – Annual Service Line Average Length and Cost Updates



Rev: 1/16/2008

ICM Model Modifications Change Process



Rebuttal Exhibit No.__(RAM-5)
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Tab

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

PREPARED REBUTTAL TESTIMONY
OF
JEROME T. SCHMITZ

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
Prepared Rebuttal Testimony
Of
JEROME T. SCHMITZ

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
Jerome T. Schmitz

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Jerome T. Schmitz. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 Please briefly describe your background and experience?

A. 2 My background and experience is attached as Appendix A.

Q. 3 Did you sponsor direct testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 3 No.

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

A. 4 The purpose of my prepared rebuttal testimony is to respond to specific aspects of the direct testimony presented by Arizona Corporation Commission Utilities Division Staff (Staff) witness Mr. Corky Hanson regarding "…the concerns Pipeline Safety has relating to the costs and reasons for replacing the gas distribution system in the Manors subdivision ("Manors") in Yuma."[1] My

[1] Hanson Direct, p. 1, lns. 21-23

testimony and that of Company witness Robert Mashas will also address Mr. Hanson's recommendations related to Staff's proposal to disallow all gas plant required to replace approximately 50-year old pipe in the Manors subdivision in Yuma, Arizona (Yuma Manors).

Q. 5 Did you prepare exhibits to support your rebuttal testimony?

A. 5 Yes. I prepared the exhibits identified as Rebuttal Exhibit No.__(JTS-1) through Rebuttal Exhibit No.__(JTS-3).

II. STEEL DISTRIBUTION PIPE

Q. 6 How would you characterize Mr. Hanson's statement that "[p]ipe corrosion is one of the leading causes of pipeline failures?

A. 6 Mr. Hanson's statement is vague and misleading. Furthermore, it is not representative of recent national incident data for gas distribution systems, or Southwest's leakage data for its distribution system in Arizona. It also is not representative of the risk associated with corrosion on distribution systems in general.

Q 7 When were the federal pipeline safety regulations amended to include corrosion protection requirements?

A. 7 The federal pipeline safety regulations, adopted by the US Department of Transportation (USDOT), Title 49 Code of Federal Regulations, Part 192 (49 CFR 192) were amended in June 1971 to include Subpart I, which contains the corrosion protection requirements. The requirement to protect steel gas distribution piping installed prior to August 1, 1971 with cathodic protection did not go into effect until August 1976.

Q. 8 What does Southwest's leak data show regarding corrosion compared to other leak causes in Arizona?

A. 8 In Arizona, corrosion accounts for only 14.2% of the total leaks by cause for the period 2003-2007 (Exhibit No___(JTS-1). Leaks caused by excavation damages are nearly three times greater. These statistics are consistent with national numbers.

Q. 9 Has Southwest had any USDOT reportable incidents caused by corrosion in Arizona during the last 5 years (2003-2007)?

A. 9 No.

Q. 10 What information do you rely upon in support of your answer?

A. 10 First, Southwest's own leakage data for its distribution system in Arizona. As noted above, corrosion is not a leading cause of pipeline leaks, as excavation related damages dwarf corrosion damage by nearly three times. Second, the US Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) commissioned Allegro Energy Consulting (Allegro) to analyze reporting information and produce a report to examine this very issue, among many others. Allegro's report, "Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards, April 2005" provides guidance to PHMSA as to how many pipeline safety issues can be addressed from a risk-based perspective in PHMSA's anticipated Distribution Integrity Management Program. Allegro's report, which was based on data collected nationally, indicated in particular the following:

> "*…only 3% of gas distribution incidents reported to USDOT were caused by* Corrosion, *all of it external corrosion. This is a marked departure from the situation with other types of pipeline systems such as gas transmission and oil pipelines, where corrosion is one of the leading causes of reportable incidents. It is interesting that the reason for this difference does not seem to lie in the use of polyethylene mains and services that do not corrode. Even in steel assets, corrosion accounts for less than 4% of the reportable incidents for gas distribution systems. One factor is that corrosion leaks, while plentiful, can usually be repaired without the kind of consequences that make it a reportable incident. Another consideration is that the pipe wall thickness on these small diameter lines is relatively greater than it is*

for larger diameter transmission lines, providing an extra margin of safety before a corrosion pit fails. (If the small diameter lines had the same ratio of wall thickness to diameter as the larger diameter lines, they would be too thin to maintain structural integrity for regular use.)" [Emphasis added.]

III. YUMA MANOR DISTRIBUTION PIPE

Q. 11 Please provide a brief summary of the history of the gas distribution pipe in the Yuma Manors subdivision.

A. 11 The system operates at or below 27 psig. Most of the steel mains and services were installed between 1954 and 1958 by Arizona Public Service Company (APS). The system had no cathodic protection following installation until September 1982 at which time a ground-bed and rectifier was installed, which provided cathodic protection to the system. Southwest acquired this system when it purchased the APS gas properties in 1984. In April 1991, Southwest replaced the old rectifier with a new rectifier at the same site using the existing ground-bed.

In February 2004, Southwest's Technical Service personnel determined that the ground-bed was no longer effective and a work plan to replace the ground-bed was initiated. The rectifier was returned to operation again in January 2006.

Q. 12 Why did Southwest elect to install a ground bed and re-energize the rectifier in February 2004?

A. 12 As a prudent and safe operator, Southwest strives to comply with all state and federal pipeline safety regulations. At the time, the installation of an anode ground bed was the most cost-effective way to maintain the safety of the system and comply with those regulations.

Q. 13 What was Southwest's intent with the installation of the ground bed?

A. 13 It was Southwest's intent to maintain a safe and reliable system in compliance with pipeline safety regulations.

Q. 14 Was it Southwest's intent to extend the service life of the Manors system for 20 years?

A. 14 Not directly. As previously stated, it was Southwest's intent to maintain a safe and reliable system in compliance with pipeline safety regulations. Any extension of service life to pipe of this vintage is a possible consequence of actions done to remain compliant with the pipeline safety regulations. The long-term effect on the service life of the pipe due to the replacement of the ground bed is uncertain. As such, Southwest continues to assess its distribution systems to annually determine the need for replacement, regardless of when cathodic protection facilities have been installed.

Q. 15 Staff contends that had Southwest connected the rectifier correctly the Yuma Manors distribution systems had significant remaining life that could have been extended, do you agree?

A. 15 No. Mr. Hanson is making too many assumptions to arrive at his conclusion. A pipeline does not operate in a constant environment, like a laboratory setting, at standard temperatures and conditions, so it is difficult, if not impossible, to predict any remaining life for a pipeline after it has served its average useful service life, as was the case with the Yuma Manors system. In my opinion, given the age of the pipe, the type of coating, the lack of cathodic protection for approximately the first 25 years of its existence, this system would have been a candidate for replacement any time in the near future. Mr. Hanson has provided no studies or other evidence to support his conclusion that the pipe "had significant remaining life" or "could have last for many more years."

Q. 16 What process does Southwest use to determine the need for main and service replacements?

A. 16 Main and service replacements are generally determined through the distribution integrity management policies and procedures, which Staff has reviewed on an annual basis. This is a risk-based process, which includes criteria such as: type and age of pipe; operating pressure; pipe coating; leakage; class location of pipe (proximity to buildings); pipe condition; pipe cover; potential for external damage; soil conditions; cathodic protection system effectiveness; type of customer(s) served; etc. This does not preclude replacement of mains and services for conditions found that are an immediate public safety concern.

Q. 17 Why did Southwest initiate the replacement in the Yuma Manors?

A. 17 In early 2007, Southwest observed an unusual increase in leakage. At the time, the cause of this increase was not known to Southwest[2] As a prudent operator, Southwest made the decision to replace the steel pipe in concert with Southwest's policies and procedures to address what Southwest felt was an immediate public safety concern. Southwest evaluated which steel needed replacement, and which could remain in service. An action plan was instituted during the replacement process to make sure that public safety was maintained. (See Exhibit No.__ (JTS-2)). Construction resources were immediately mobilized to expedite the replacement project. The replacement work started on January 22, 2007 and was completed on April 14, 2007.

Many compelling factors, including age of the system piping (1950s vintage), pipe coating type (tar), prior

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[2] It was later learned by Southwest that an employee had incorrectly installed the rectifier, which likely contributed to the increase in leakage.

maintenance history, which included periods without cathodic protection, leakage and general public safety concerns, were considered in the decision to replace the pipe.

Q. 18 Was all the steel pipe serving Yuma Manors replaced by Southwest?

A. 18 No. Some 4-inch steel pipe serving the Yuma Manors was checked at tie-in locations during replacement work and left in service, as the condition of this pipe and its coating were found to be good.

Q. 19 Do you consider the decision to replace the gas distribution piping in the Yuma Manors to be prudent?

A. 19 Yes.

Q. 20 Does Mr. Hanson also believe that the decision to replace the gas distribution piping in the Yuma Manors was prudent?

A. 20 Yes. In his response to Southwest Data Request 2.4, Mr. Hanson indicates that the decision to replace the piping in the Yuma Manors was prudent. However, Mr. Hanson qualified his response by further noting that "but only after SWG reversed polarity on the rectifier creating the need to replace the system." At the time of the replacement, both Mr. Hanson and Mr. Bohnenkamp visited the site and agreed that the actions that were being taken by the Company were appropriate.

Q. 21 Was the Yuma Manors part of what Mr. Hanson refers to as

"…the Company's failure to conduct CP monitoring in 2006"?

A. 21 No. The Yuma Manors system was monitored in 2006 Rebuttal Exhibit No.__(JTS-3).

Q. 22 Do you have any other comments regarding Mr. Hanson's recommendation?

A. 22 Yes. First, when a new ground bed was installed and the rectifier was reenergized in January 2006, it was not known what condition the pipe was in at that time. Given the information Southwest had available to it at that time, it determined that replacement of the pipe was not necessary. It very well could have been on the verge of failure at that time, no one knows. Mr. Hanson disregards this fact and other facts that are known when he speculates as to how much longer this pipe may have lasted before it needed replacement. For example, most of this pipe was over 50-years old, approximately 25 years of which did not include cathodic protection.

Second, contrary to Mr. Hanson's testimony and responses to data requests, Company replacement of the approximately 50-year old pipe results in an improvement to the Yuma Manors distribution system, which has an associated extension of useful life to the system or betterment value. As previously noted, it is speculative to ascertain the remaining life of the pipe that was replaced. However, given the facts that are known, this pipe very well could have been a candidate for replacement any time in the near future. To the contrary, I can say with a reasonable degree of certainty that the replacement pipe should last 40 or more years. Had this been ten or fifteen year old steel pipe that had been cathodically protected I could better appreciate Mr. Hanson's recommendation. Even then, as Company witness Mashas states in his rebuttal testimony, regardless of the cause for the need to replace the pipe, the Commission has historically always given the utility a betterment (or life extending) value associated with the replacement pipe. Accordingly, given the facts that are known by the parties surrounding this particular pipe, there is simply no support for a disallowance of the entire cost of the distribution pipe.

Q. 23 Are you aware of any previous Commission orders relating to the treatment of vintage pipe as it is removed from service?

A. 23 I am aware of several Commission determinations related to this issue, which Company witness Robert Mashas will address in further detail.

Q. 24 What concerns do you have regarding the potential effect such a disallowance, such as the one proposed by Mr. Hanson, may have on decisions relating to utility investment decisions?

A. 24 I am concerned that such a disallowance may result in less than optimum decisions when maintenance versus replacement decisions are being made. This is especially true on a long-term asset that has served or exceeded its expected service life, and is eligible for retirement. Such a disallowance sends the wrong policy message and seems to encourage operators to consider pursuing minimum investments, perhaps by spending only maintenance funds, instead of making larger long-term investments that will provide long-term benefits to customers and the utility's system.

Q. 25 Does this conclude your testimony?

A. 25 Yes, it does.

SUMMARY OF QUALIFICATIONS
Jerome T. Schmitz, P.E.

Jerome T. Schmitz is the director/Engineering Staff for Southwest Gas Corporation (Southwest). He directs and coordinates support to five operating divisions for pipeline safety code compliance; distribution integrity management; material specifications and approval; environmental compliance; proper energy measurement; pipeline cathodic protection; project design; and the training and qualification of technical services personnel.

Schmitz joined Southwest in 1989 as an engineer in Phoenix. He was subsequently promoted to distribution engineer in 1991; distribution engineer/Compliance and Operations Audit Staff in Engineering Staff later that year; supervisor/Engineering in the Central Arizona Division in 1993; manager/Operational Quality Assurance for Engineering Staff in 1998; and director/Gas Operations Support in 2003. He holds a bachelor of science degree in Genetics from the University of California, Davis, and a bachelor of science degree in Mechanical Engineering from Arizona State University. He is a registered Professional Engineer in the State of Arizona with a proficiency in Mechanical Engineering, and is certified as a Quality Auditor with the American Society for Quality. He also served on the Distribution Integrity Government Industry Team (DIGIT) that oversaw the production of the American Gas Foundation report, *Safety Performance and Integrity of the Natural Gas Distribution Infrastructure*. In addition, he served on the Risk Control Practices Group of the Distribution Integrity Management Quality Action Team sponsored by the Pipeline and Hazardous Materials Safety Administration (PHMSA). These groups were designed to collect and analyze available information and to reach findings and conclusions to inform future work by the PHMSA relative to implementing integrity management principles for gas distribution pipelines.

Schmitz currently serves as a member of the ASME B31Q Qualification of Pipeline Personnel Technical Committee. He also serves on the AGA Distribution and Transmission Engineering Committee as well as the Operations Safety Regulatory Action Committee.

JEROME T. SCHMITZ

7612 Grassy Bank Street
Las Vegas, NV 89139

Home (702) 492-1412
Work (702) 364-3263

Work Experience

2004- Director/Engineering Staff, Southwest Gas Corporation, Las Vegas, Nevada
Direct the Company's design and standards, pipeline safety compliance, distribution integrity management program, environmental programs, measurement, regulation, instrumentation and corrosion control technical skills training, material specifications, and technical services and engineering-related policy and procedures manuals. Prepare budgets, hire and train personnel and coordinate department activities to meet corporate strategic goals.

2003-2004 Director/Gas Operations Support Staff, Southwest Gas Corporation, Las Vegas, Nevada
Directed the Company's technical skills training, Operator Qualification training and testing, tool and equipment evaluations, operations-related procedures manuals, Incident Management System and operation of a state-of-the-art emergency response training facility.

1998-2003 Manager/Operational Quality Assurance, Southwest Gas Corporation, Tempe, Arizona
Managed a department that develops and conducts operational quality assurance reviews and customer supplier quality audits. The department provides an independent and objective assessment of the level of quality associated with the Company's gas operations and guides corporate quality improvement activities.

1993-98 Engineering Supervisor, Southwest Gas Corporation, Phoenix, Arizona
Supervised the activities of various engineering groups including New Business, Franchise, Code Compliance, Planning, Special Projects, System Improvement and Pipe Replacement.

1991-93 Distribution Engineer/Code Compliance, Southwest Gas Corporation, Las Vegas, Nevada
Monitored external pipeline safety audits and conducted internal audits of natural gas transmission, storage and distribution facilities to evaluate the level of compliance with federal and state regulations and Company standards. Provided interpretations of regulatory codes and code-related standards for gas operations personnel.

1989-91 Engineer, Southwest Gas Corporation, Phoenix, Arizona
Completed a year-long training program in all aspects of natural gas operations including customer service, construction, engineering, system planning, measurement, regulation and corrosion control. Supervised an engineering group for one year designing new installations, system improvements and other projects.

1983-85 Site Coordinator (Administrator), Central Texas College, Fort Greely, Alaska
Represented Central Texas College and oversaw all educational contract obligations including two-year degree programs, military specialty courses and the operation of a library, testing center and learning resource center at a remote military post. Hired, trained and supervised all site personnel; counseled students; and prepared all administrative and financial reports for the operation of the satellite campus.

Education

Arizona State University, Tempe, Arizona
Bachelor of Science in Engineering, Mechanical Engineering, 1988, summa cum laude

University of California, Davis
Bachelor of Science, Genetics, 1981

Servite High School, Anaheim, California
Valedictorian, 1977

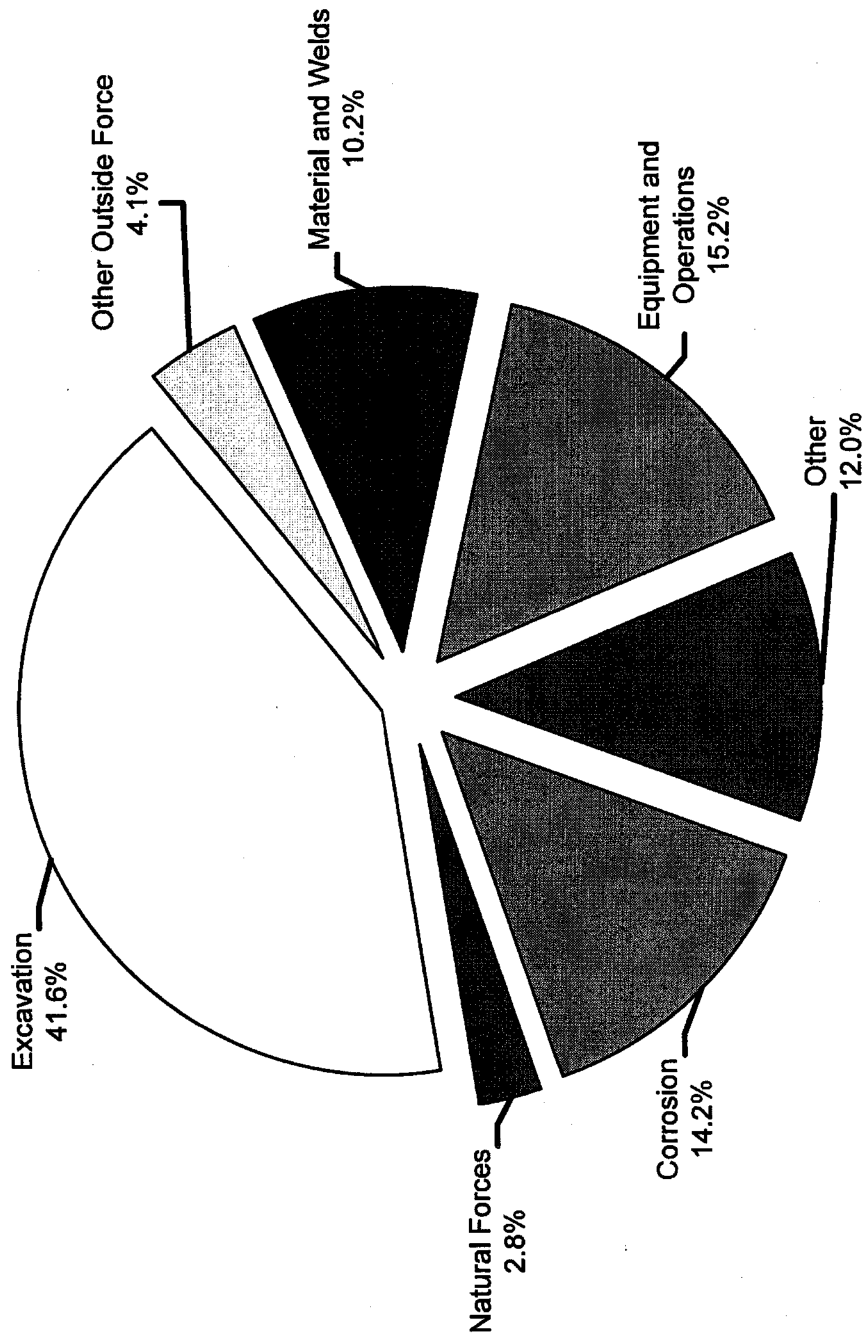
Registered Professional Engineer, Mechanical Engineering, Arizona, Certificate Number 28206

Awards, Organizations and Interests

National Society of Professional Engineers, Southern Nevada Chapter Member, Central Arizona Chapter President (2000-2001); American Gas Association, Distribution and Transmission Engineering Committee Member and Operations Safety Regulatory Action Committee Member; American Society of Mechanical Engineers, Member and ASME B31Q Qualification of Pipeline Personnel Technical Committee Member; American Society for Quality, Senior Member and Certified Quality Auditor; National Engineers Week Future City Competition, Phoenix Region Co-coordinator (1998-2003); 2002 Chairman's Award, National Engineers Week (Phoenix, Arizona); Distribution Infrastructure Government Industry Team (DIGIT) Member; Distribution Integrity Quality Action Team Member; and President of Board of Directors for Academy for Learning.

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

Arizona Gas Leak Data
2003-2007 By Cause



Source: Southwest's 2003-2007 Annual DOT reports

SOUTHWEST GAS CORPORATION

February 23, 2007

Mr. Robert Miller
Supervisor of Pipeline Safety
Office of Pipeline Safety
Arizona Corporation Commission
2200 N. Central Ave. Suite 300
Phoenix, AZ 85004

Delivered 2/23/07 RRC

Re: Leaks and Evacuations, Yuma Manors, Arizona
Informal Data Request – Amendment to Item REM 1.5

Dear Mr. Miller:

Southwest Gas Corporation (Southwest) respectfully submits the attached Amendment to Attachment # ACC - REM 1.5 in the Southwest Response to the Arizona Corporation Commission Staff's Data Request on the leaks and evacuations in Yuma, Arizona that occurred during January and February, 2007. The amended portion is contained in the Manors System Improvement Project (MSIMP) ACTION PLAN attachment, Page 1 of 2, section subtitled "Leak Survey". I have bolded and highlighted the amended portion of the attached Plan for your convenience. All other data in the response remains the unchanged.

Please let me know if you have any questions. I can be reached at 602-525-4787.

Sincerely,

Robert Clarillos
Administrator/Compliance/Arizona
Engineering Staff

Attachment

c: Galen Denio

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS
SOUTHWEST GAS CORPORATION
YUMA DISTRICT LEAKAGE

ATTACHMENT # ACC-REM 1.5
AMENDMENT TO ACTION PLAN

Manors System Improvement Project (MSIMP)
ACTION PLAN

Purpose

The Manors System Improvement Project is being performed as a result of corrosion leakage identified on 1950's vintage steel main and service within the Manors Subdivision in Yuma, Arizona. This Action Plan places into motion the rapid and systematic replacement of steel main and service pipe to eliminate the potential of future corrosion leakage within the corrosion control area (s) currently served by rectifier system Y-18.

Location

The system boundaries are: west: Arizona Avenue; east: Engler Avenue; north: Morrison avenue; and south: 26th Place. The area is primarily comprised of single family homes, a trailer park, and a few adjacent apartment complexes and small businesses.

Scope of Project

Replacement or abandonment of 36,690 feet of main and 545 services as follows:

Main

	Abandon	32,650 feet of 4", 2", and 1¼" steel
	Install	35,340 feet of 4" and 2" PE 8100
		1,350 feet of 2" steel
Service		
	Abandon	406 - ¾" steel
		139 - ½" plastic
	Install	545 - ½" PE 8100

Schedule

It is the intent of this plan to provide adequate manpower and material to accomplish design and replacement of the existing steel facilities described above on or prior to the target date of April 30th, 2007.

Implementation

To accomplish the aggressive replacement schedule, the design and installation of the project will be completed in approximately 9 phases of similar size. By dividing the project into phases replacement work can commence on the early phases while later phases are being designed. The entire design process is anticipated to take approximately 4½ weeks to complete, with approximately 2 phases of design completed each week.

Design – Phased design process will be completed by Yuma District engineering technician.

Construction - To accomplish work in rapid order, a temporary parallel construction work group will be staffed to provide supervision, inspection, construction crews, and, clerical support to process necessary Blue Stake requests, permits, traffic control and documentation.

Leak Survey – A baseline leak survey of the steel main and service within the affected area was completed on 02/05/2007. A subsequent survey will be performed within two weeks and the results reviewed. **The leak survey will continue to be performed daily until all of the remaining steel main and services in the Manors subdivision has been surveyed (at this**

Manors System Improvement Project (MSIMP)
ACTION PLAN

time, the survey cycle for the remaining steel takes approximately 8 days). The leak survey cycle will then continue to repeat itself upon any remaining steel until all steel in the subdivision affected by the rectifier and ground bed in question has been replaced. At that point, this specialized leak survey will end.

Southwest Gas Corporation
Pipe To Soil Inspection Form

CP Area Yuma **System Number** 1-4090230032 **QS/Grid/Tile** 4090230032 ;97-W269	**Date First Protected** 1/30/1990	**District** 48 **Area** Yuma **Group** TS	
Read Cycle January **Type of Protection (G / I)** I **Main Footage** 32140 **Current Requirement of the System:** 0		**Rectifier(s)** Y-19	

est #	Component Type Meter Number	Location Location Description Measurement		QS/Grid/Tile GPS: Lat — Long		Pipe To Soil (VOLTS)	Test Date
	Test Point - .85 V	2407 S DONNA AVE	808	4090230032 0— 0	S97-W269	-.36	5-3-2005
)	Test Point - .85 V	2028 E 26 ST		4090230032 0— 0	S97-W269	-.32	
	Test Point - .85 V	2520 S BARBARA AVE	808	4090230032 0— 0	S97-W269	-.43	
	Test Point - .85 V	920 E LA MESA ST	708	4090230032 0— 0	S97-W269	-.31	
	Test Point - .85 V	1351 E MORRISON ST	709	4090230032 0— 0	S97-W269	-.27	
	Test Point - .85 V	1362 E 25 PL		4090230032 0— 0	S97-W269	-.27	
	Test Point - .85 V	2402 S MARY AVE		4090230032 0— 0	S97-W269	-.32	
	Test Point - .85 V	2572 S MARY AVE		4090230032 0— 0	S97-W269	-.32	
	Test Point - .85 V	2001 E 25 ST		4090230032 0— 0	S97-W269	-.36	
	Test Point - .85 V	2049 E 24 PL		4090230032 0— 0	S97-W269	-.32	
	Test Point - .85 V	1335 E 25 PL (TW)		4090230032 0— 0	S97-W269	-.30	
	Test Point - .85 V	2036 E LA MESA ST		4090230032 0— 0	S97-W269	-.30	5-3-2005

Southwest Gas Corporation
Pipe To Soil Inspection Form

CP Area Yuma **System Number** 1-4090230032 **QS/Grid/Tile** 4090230032 ;97-W269	**Date First Protected** 1/30/1990	**District** 48 **Area** Yuma **Group** TS

Read Cycle January **Type of Protection (G / I)** I **Main Footage** 32140 **Current Requirement of the System:** 0		**Rectifier(s)** Y-18

est #	Component Type Meter Number	Location Location Description Measurement	QS/Grid/Tile GPS: Lat — Long		Pipe To Soil (VOLTS)	Test Date
1	Test Point - .85 V	2400 E JAMES AVE	4090230032 0— 0	S97-W269	-.34	5-3-2005
2	Test Point - .85 V	2500 S BARBARA AVE	4090230032 0— 0	S97-W269	-.33	
3	Test Point - .85 V	1355 E 24 PL	4090230032 0— 0	S97-W269	-.31	
4	Test Point - .85 V	1360 E 26 ST	4090230032 0— 0	S97-W269	-.27	
5	Test Point - .85 V	2049 E 26 ST	4090230032 0— 0	S97-W269	-.27	
5	Test Point - .85 V	2022 E 24 PL	4090230032 0— 0	S97-W269	-.30	
7	Test Point - .85 V	2541 S DONNA AVE	4090230032 0— 0	S97-W269	-.32	
8	Test Point - .85 V	1353 E LA MESA ST	4090230032 0— 0	S97-W269	-.31	
1	Test Point - .85 V	929 E 24 PL 808	4090230032 0— 0	S97-W269	-.31	
2	Test Point - .85 V	2480 SIERRA VISTA 808	4090230032 0— 0	S97-W269	-.28	
3	Test Point - .85 V	2550 S MARION	4090230032 0— 0	S97-W269	-.26	
4	Test Point - .85 V	2598 S MARION	4090230032 0— 0	S97-W269	-.28	5-3-2005

Southwest Gas Corporation
Pipe To Soil Inspection Form

CP Area	Yuma	Date First Protected 1/30/1990	District 48
System Number	1-4090230032		Area Yuma
QS/Grid/Tile	4090230032 S97-W269		Group TS

Read Cycle: January
Type of Protection (G / I): I
Main Footage: 32140
Current Requirement of the System: 0

Rectifier(s)
Y-18

Test #	Component Type Meter Number	Location Location Description Measurement	QS/Grid/Tile	GPS: Lat — Long	Pipe To Soil (VOLTS)	Test Date
	Test Point - .85 V	2411 S CAROL AVE	4090230032	S97-W269 0 — 0	-.33	5-3-2005
	Test Point - .85 V	927 E 26 ST	4090230032	S97-W269 0 — 0	-.31	
	Test Point - .85 V	2274 E 25 ST	4090230032	S97-W269 0 — 0	-.23	
	Test Point - .85 V	2269 E 25 ST	4090230032	S97-W269 0 — 0	-.27	
	Test Point - .85 V	2199 E 25 PL	4090230032	S97-W269 0 — 0	-.28	
	Test Point - .85 V	909 E 25 ST	4090230032	S97-W269 0 — 0	-.36	
	Test Point - .85 V	917 E LA MESA ST	4090230032	S97-W269 0 — 0	-.35	
	Test Point - .85 V	940 E 26 PL	4090230032	S97-W269 0 — 0	-.36	5-3-2005

Inspection Verification
Inspected By: Alex Garcia — ALEX GARCIA CORROSION SPECIALIST
Inspection Date: 5-3-2005

Supervisor Verification
Supervisor: [signature] DARREN N. RUTLEDGE Supervisor/T.S.-Engr.
Review Date: 6/17/05

System Information

	Yes	No
Down System	X	
LMR Created		
LMR Number		
WR Created		
WR Number		
Man Hours	4.0	

Remarks

Southwest Gas Corporation - Work Management
WR Work Activity Report

Report Run on May 7, 2008 09:12:23 AM

Rebuttal Exhibit No.__(JTS-3)
Sheet 4 of 8

Work Request Information

Service Address | | | 48DCP0000833 | | |
WR Number 212686
City, State, and Zip Yuma,AZ
Related WR
Location/Cross Street
WO #
WR Name CATHODIC PROTECTION PIPE TO SOIL SYSTEM
Nature of Request
WR Type ISPCP-INSPECTION CP
AC Code DANNLPPESOILSRV - CATHODIC PROT PIPETOSOIL SYS
Operating District 48-YUMA
Construction Complete Date 02/28/2006
Crew Headquarter 6975T-YUMA TECH SERVICES
Reporting Complete Date 01/29/2007
WR Owner YBARRA, SAMUEL EDWARD **Premise ID** **Atlas** 4090230032 **Tile** x-300y618

Compatible Unit Cost Summary

As-Built Level

P/S #1 **Tax Code** INVALID CODE **Acct #** 88701699 **Contractor**

Facility Action **Facility Type** **Facility ID** 48DCP0000833

Crew ID	Accept Date	CU Code	CU Description	ACT CD	CAT CD	CO/ CN	Install Qty	Retire Qty	Material Rate	Labor Cost	Amount
4502	02/28/06	GLABOR	LABOR - MAINS (SWG ONLY)	I	ISP	CO	5	0		$13.57	$67.85

Total amount for this Point/Span $67.85

Total amount in As-Built Level $67.85

WR Attributes

Mandatory Attributes are Bolded

MATL INVESTIGATION NO PROJECT PROGRAM NO ________

Compliance Work Results
Procedure Details

Approved Y **Procedure Code** DPSSYSTEM **Facility** DPSSYSTEM - 48DCP0000833
Atlas **Survey Area**
Tile **X Coordinate** **Gps Latitude**
Altitude Zone **Y Coordinate** **Gps Longitude**

Component Type & ID RECTIFIER 119493

Step Instruction	Result	Executed On	By	Comments
RECTIFIER READ TAKEN	YES	02/28/2006	GARCIA, ALEXANDER F	
DC VOLTAGE READ	7.8	02/28/2006	GARCIA, ALEXANDER F	
DC CURRENT READ	5.5	02/28/2006	GARCIA, ALEXANDER F	
P/S POTENTIAL	-2.13	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118291

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.52	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118292

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.72	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Compliance Work Results
Procedure Details

Approved Y **Procedure Code** DPSSYSTEM **Facility** DPSSYSTEM - 48DCP0000833
Atlas **Survey Area**
Tile **X Coordinate** **Gps Latitude**
Altitude Zone **Y Coordinate** **Gps Longitude**

Component Type & ID 850TESTPT 118293

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.22	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118294

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.19	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118295

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.32	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118296

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.34	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118297

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.41	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118298

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.39	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118299

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.37	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118300

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.49	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Compliance Work Results
Procedure Details

Approved Y **Procedure Code** DPSSYSTEM **Facility** DPSSYSTEM - 48DCP0000833
Atlas **Survey Area**
Tile **X Coordinate** **Gps Latitude**
Altitude Zone **Y Coordinate** **Gps Longitude**

Component Type & ID 850TESTPT 118301

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.37	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118302

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.70	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118303

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.21	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118304

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.25	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118305

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.62	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118306

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.41	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118307

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.58	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118308

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.29	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Compliance Work Results
Procedure Details

Approved Y **Procedure Code** DPSSYSTEM **Facility** DPSSYSTEM - 48DCP0000833
Atlas **Survey Area**
Tile **X Coordinate** **Gps Latitude**
Altitude Zone **Y Coordinate** **Gps Longitude**

Component Type & ID 850TESTPT 118309

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.32	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118310

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.22	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118311

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	NO	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118312

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-.97	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118313

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-.96	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118314

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-.95	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118315

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.05	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118316

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	NO	02/28/2006	GARCIA, ALEXANDER F	TEST POINT NO LONGER NEEDED.

Component Type & ID 850TESTPT 118317

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.01	02/28/2006	GARCIA, ALEXANDER F	

Southwest Gas Corporation - Work Management
WR Work Activity Report

Report Run on May 7, 2008 09:12:23 AM

Compliance Work Results
Procedure Details

Approved Y **Procedure Code** DPSSYSTEM **Facility** DPSSYSTEM - 48DCP0000833

Atlas **Survey Area**

Tile **X Coordinate** **Gps Latitude**

Altitude Zone **Y Coordinate** **Gps Longitude**

Component Type & ID 850TESTPT 118317

Step Instruction	Result	Executed On	By	Comments
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118318

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-.99	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118319

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.00	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118320

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.21	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118321

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.18	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118322

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	NO	02/28/2006	GARCIA, ALEXANDER F	TEST POINT NO LONGER NEEDED.

Component Details

Component ID 118311 **Component Type** 850TESTPT **Action** Uninstall

Atlas **Tile** **Address** Yuma AZ

Manufacturer **Serial Number** **Lot Number** **Gps Longitude**

X Coordinate **Y Coordinate** **Gps Latitud**

Characteristic **Original Value** **New Value**

Component ID 118316 **Component Type** 850TESTPT **Action** Uninstall

Atlas **Tile** **Address** Yuma AZ

Manufacturer **Serial Number** **Lot Number** **Gps Longitude**

X Coordinate **Y Coordinate** **Gps Latitud**

Characteristic **Original Value** **New Value**

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

PREPARED REBUTTAL TESTIMONY
OF
LAURA LOPEZ HOBBS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
LAURA LOPEZ HOBBS

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

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
Laura Lopez Hobbs

I. INTRODUCTION

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

A. 1 My name is Laura Lopez Hobbs. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002. I am employed by Southwest Gas Corporation (Southwest or the Company) as Vice President of Human Resources.

Q. 2 Did you sponsor direct testimony on behalf of Southwest in this proceeding?

A. 2 Yes.

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

A. 3 The purpose of my prepared rebuttal testimony is to respond to the direct testimony presented by Mr. Ralph Smith, witness for the Arizona Corporation Commission (ACC) Utilities Division Staff (Staff), and Mr. Rodney Moore, witness for the Residential Utility Consumer Office (RUCO), regarding their recommendations and comments concerning the Company's Management Incentive Program (MIP), other stock-based compensation, and its Supplemental Executive Retirement Plan (SERP) expenses.

II. SOUTHWEST'S POSITION ON INCENTIVE PAYMENTS

Q. 4 Why does Southwest believe it should be allowed cost recovery of incentive payments?

A. 4 As discussed in my prefiled direct testimony, Southwest's incentive payments are calculated and paid to qualified employees based on reliability, safety, cost-efficiency and customer satisfaction targets directly related to the provision of natural gas service. In order to ensure customers receive the most reliable and cost-effective gas service, Southwest must attract, retain and motivate a skilled and highly competent work force capable of meeting and even exceeding customer expectations. My analysis of compensation in the utility industry proxy groups demonstrates that annual variable pay, in addition to base pay, is standard in the industry. Base salary plus annual variable pay is defined as total compensation for the Company's qualified employees. Southwest's total executive compensation is much less than the market average and is reasonable, as shown in Exhibit No.__(LLH-1) of my prepared direct testimony. The fact that Southwest's executive compensation per customer is much lower than that of the other major western energy utilities, including Pinnacle West and Unisource, was given no weight by Staff and RUCO. As such, it is appropriate for customers to bear these costs as they do other reasonable costs of service.

III. STAFF'S AND RUCO'S RECOMMENDATIONS REGARDING THE COMPANY'S MIP EXPENSES

Q. 5 Do Staff and RUCO make any recommendations regarding the

Company's MIP?

A. 5 Yes. In their direct testimony, both Staff witness, Mr. Smith, and RUCO witness, Mr. Moore, recommend a 50/50 sharing as "a reasonable balancing of the interests between ratepayers and shareholders." See Smith Direct, page 26 and Moore Direct, page 29.

Q. 6 Do you agree with Staff's and RUCO's adjustments related to the MIP?

A. 6 No, I do not. The sharing concept relating to the Company's MIP expense is premised upon a false assumption that the program is an additional cost to customers. To the contrary, I believe the information the Company provided demonstrates that the MIP expense results in savings to customers. The program provides a valuable management tool to promote additional cost savings, to promote financial health, to motivate individual employees, to encourage groups of employees to work together to impact specific goals, and to aid in the retention of the higher-performing individuals. Each of these benefits is ultimately passed on to customers. The goals or targets of the current MIP are also heavily weighted toward providing benefits to customers. Identifying which of the goals is a greater benefit to whom in deciding cost recovery is irrelevant. Penalizing the Company for utilizing an employee program that reduces costs to customers, promotes increased safety, provides increased customer services, reduces other costs and increases the financial soundness of the Company is unreasonable and bad policy. Furthermore, Staff and RUCO's "sharing" recommendation essentially encourages the Company to eliminate management incentive compensation as a component of total compensation, which would negate any benefits that are currently being received by customers as a result of the at-risk structure of the incentive compensation.

IV. SOUTHWEST'S STOCK-BASED INCENTIVE EXPENSES

Q. 7 Does Staff make any recommendations regarding Southwest stock-based incentive expenses?

A. 7 Yes. Staff witness Mr. Smith at page 36 of his direct testimony recommends the removal of the Company's stock option compensation expense allocated for Arizona cost recovery.

Q. 8 Do you agree with Staff witness Mr. Smith's contention at page 34 of his direct testimony that a stock-based incentive program provides an incentive for an employee to perform "in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate"?

A. 8 No. Southwest takes issue with Mr. Smith's insinuation that Southwest management would perform in a manner that could negatively affect the Company's provision of safe, reliable utility service. As discussed earlier in my prepared rebuttal testimony, Southwest's MIP uses five measures to determine the short-term and long-term payouts to qualified employees. The customer satisfaction and customer-to-employee ratios both serve as counter balances for return on equity measures. Management clearly has no incentive to cut corners on customer safety expenditures or reduce staff, such that customer satisfaction suffers.

V. STAFF'S AND RUCO'S RECOMMENDATIONS REGARDING THE COMPANY'S SERP EXPENSES

Q. 9 Do Staff and RUCO make any recommendations concerning the Company's SERP expenses in this proceeding?

A. 9 Both Staff and RUCO are recommending the disallowance of 100 percent of the Company's SERP expenses.

Q. 10 Do you agree with Mr. Moore's statement at page 30 of his direct testimony that providing the SERP to officers of the Company is an unnecessary cost of providing natural gas service?

A. 10 No, I believe that such a program is a necessary cost of providing service because it is part of the Company's overall executive compensation, which neither RUCO nor Staff has deemed unreasonable. As Staff witness Mr. Smith recognizes, companies provide SERP benefits to attract and retain qualified employees. RUCO witness, Mr. Moore asserts that because executives are "fairly compensated for their work" and are "provided with a wide array of benefits including medical plan, dental plan, life insurance, long term disability, paid absence time and a retirement plan" that no other cost of benefits should be borne by the customer.[1]

Q. 11 Is the payout under the Company's SERP guaranteed to qualified employees?

A. 11 No. The SERP is an unqualified plan and, as such, payments are not guaranteed (i.e., participants are general creditors of the corporation). Benefits from the qualified retirement plan for a vested, 30 year employee typically equal 50 percent of the employee's final salary. The SERP only makes up the difference between the benefits from the qualified plan. Benefits from the SERP, when added to the benefits received under the basic retirement plan, will equal 60 percent of annual compensation for senior executives, and 50 percent of annual compensation for all others.

Q. 12 Are SERP benefits standard in the natural gas industry?

A. 12 Yes. Contrary to both Staff's and RUCO's testimony, each of the proxy groups used in my analysis of total executive compensation provides such a plan. Furthermore, contrary to both Staff witness Mr. Smith's and RUCO witness Mr. Moore's assertion that SERP is not a necessary cost of providing natural gas service, Mr. Moore could not identify a single gas or electric utility that offers a qualified defined benefit pension plan, but that does not provide officers with a supplemental

[1] Moore Direct at page 30.

executive retirement plan.[2] (See RUCO response to Southwest Data Request 2.5, Rebuttal Exhibit No.__(LLH-1)) Mr. Moore also could not identify a single gas or electric utility that does not provide officers with a supplemental executive retirement plan, regardless of whether the company offers a qualified defined benefit pension plan.[3] (See RUCO response to Southwest Data Request 2.6, Rebuttal Exhibit No.__(LLH-2)) Mr. Smith's and Mr. Moore's assertion that SERP is not a necessary cost of doing business as a utility is inconsistent with the reality that such plans are a standard imprint of natural gas utility executive compensation.

Q. 13 Please summarize your prepared rebuttal testimony.

A. 13 Southwest has proven that the Company's total executive compensation expenses are prudently managed and reasonable. Neither Staff nor RUCO have offered testimony that the Company's total executive compensation is unreasonable. As such, it is appropriate for the Company to be permitted to recover these costs as they do other reasonable costs of service. MIP, stock-based compensation, and SERP are key components of Southwest's prudently managed total executive compensation expense and are vital to the Company's attraction and retention

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[2] Mr. Smith simply made no attempt to conduct such an investigation. See Staff response to Southwest Data Request 2.40.

[3] Mr. Smith simply made no attempt to conduct such an investigation. See Staff response to Southwest Data Request 2.41.

of highly-skilled employees, which ultimately benefits customers.

Q. 14 Does this conclude your prepared rebuttal testimony?

A. 14 Yes, it does.

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

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

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

Response: Rodney L. Moore

I am not aware of any.

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

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

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

Response: Rodney L. Moore

I am not aware of any.

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IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY

OF

THEODORE K. WOOD

ON BEHALF OF

SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
THEODORE K. WOOD

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
THEODORE K. WOOD

I. INTRODUCTION

Q. 1 Please state your name and business address.

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

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

A. 2 Yes.

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

A. 3 The purpose of my rebuttal testimony is to respond to specific aspects of the direct testimony presented by David C. Parcell, witness for the Arizona Corporation Commission Utilities Division Staff (Staff) and William A. Rigsby, witness for the Residential Utility Consumer Office (RUCO), regarding their recommendations and comments concerning the ratemaking capital structure, Southwest's investment risk relative to other natural gas utilities, and the overall allowed rate of return. Company witness, Frank J. Hanley, will address the cost of common equity capital methodology and the resulting allowed return on common equity recommended by Mr.

Parcell and Mr. Rigsby. In addition, Mr. Hanley addresses Mr. Parcell's testimony on the fair value rate base rate of return.

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

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

Q. 5 Please summarize your rebuttal testimony.

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

- I will comment on both Staff's and RUCO's recommended ratemaking capital structures. RUCO has accepted the Company's requested target capital structure, which contains 45 percent common equity, 4 percent preferred equity and 51 percent long-term debt. Staff has proposed to use the Company's actual test period capital structure, which contains 42.9 percent common equity, 4.4 percent preferred equity and 52.7 percent long-term debt. Therefore, I will rebut certain aspects of Staff's justifications for its recommended capital structure and discuss why the Company's requested target capital structure, with a slightly higher equity component, is warranted;
- I will comment on both RUCO's and Staff's failure to adequately consider Southwest's higher investment risk relative to the other natural gas utilities

used to estimate the cost of common equity capital in this proceeding; and

- I will comment on both Staff's and RUCO's overall recommended rate of return.

II. RECOMMENDED CAPITAL STRUCTURE

A. RUCO's Recommended Capital Structure

Q. 6 What is RUCO's recommendation concerning the appropriate capital structure for ratemaking in this proceeding?

A. 6 RUCO's recommendation is to adopt the Company's requested target capital structure of 45 percent common equity, 4 percent preferred equity, and 51 percent long-term debt. On page 49 of his direct testimony RUCO witness, Mr. Rigsby, states that the Company's requested capital structure is reasonable given his proxy group's average capital structure of 45.9 percent long-term debt, 0.2 percent preferred equity, and 53.9 percent common equity.

B. Staff's Recommended Capital Structure

Q. 7 What is Staff's recommendation concerning the appropriate capital structure for ratemaking in this proceeding?

A. 7 Mr. Parcell is recommending the use of the Company's actual capital structure at the end of the test period, which is comprised of 42.9 percent common equity, 4.4 percent preferred equity and 52.7 percent long-term debt. Both the Company and RUCO recommend the use of a common equity ratio of 45 percent, which is the common equity ratio anticipated to be achieved near or shortly after rates from this proceeding become effective.

Q. 8 Has the Commission previously authorized the use of a target capital structure for ratemaking purposes?

A. 8 Yes. In the recent UNS Gas general rate case, Docket No. G-042041-06-0463, UNS Gas requested a target capital structure for ratemaking purposes. The UNS Gas actual test period (December 31, 2005) and the requested target capital structures were as follows:

UNS Gas
Docket No.G-0404A-06-0463

Component	Actual Ratio	Target Ratio
Long-Term Debt	55.33%	50.00%
Common Equity	44.67%	50.00%
Total	100.00%	100.00%

In Decision No. 70011 (November 27, 2007), the Commission accepted the target capital structure requested by UNS Gas. The rationale for the approval is found on page 38 of the Order, which states:

> "We believe the Company's efforts to improve its equity ratio over the past several years, through retained earnings and additional equity investment by its parent, should be recognized and encouraged. As indicated by UNS witness Grant, the Company's equity ratio has improved steadily since 2003, and UNS anticipates achieving a 50 percent equity ratio by the end of 2008."

The Commission authorized the UNS Gas requested target capital structure, which contained a common equity component that was 5.33 percentage points greater than the actual test period common equity ratio.

Q. 9 Are Southwest's circumstances similar to UNS Gas, which would support the Commission's approval of the Company's requested target capital structure?

A. 9 Yes. Similar to UNS Gas, Southwest has also achieved significant improvement in its common equity ratio. The improvement in Southwest's common equity ratio was described on pages 6-8 of my direct testimony. In addition, similar to UNS Gas, Southwest reasonably expects to achieve the requested target capital structure near or shortly after the time new rates become effective. In comparison, Southwest's requested target common equity ratio of 45 percent is lower than the target 50 percent approved for UNS Gas. In addition, the target common equity ratio is only 2.1 percentage points higher than the test period actual common equity ratio of 42.9 percent, where UNS Gas received approval of a target common equity ratio that was 5.33 percentage points higher than the actual test period common equity ratio.

Q. 10 Is the requested 45 percent common equity ratio the Company's long-term common equity ratio target?

A. 10 No. As stated in my direct testimony on page 19, it is the Company's long-run goal to achieve an "A" credit rating. The common equity ratio required to achieve and sustain this goal will not solely be a function of the Company's common equity ratio, but will also be a function of the Company's financial, business, and regulatory risk. As a result, the Company's long-term goal will require a common equity ratio similar to the proxy group companies, which on average have a common equity ratio greater than 45 percent. The target capital structure requested in this proceeding is only one step and one part of the Company's strategy to achieve an "A" credit rating[1]. Staff's recommended capital structure fails to recognize the Company's ongoing improvement, will impede the Company's effort in obtaining its long-term goal, and most importantly, is not representative of the capital structure expected to be in place on a going-forward basis.

III. SOUTHWEST'S HIGHER RELATIVE INVESTMENT RISK

Q. 11 Did you present evidence of Southwest's higher relative investment risk in your direct testimony?

A. 11 Yes. I presented evidence in my direct testimony on pages 20-24, regarding Southwest's relative investment risk in order to gauge the Company's investment risk relative to the proxy group companies used to estimate the cost of common equity. The following relative risk measures were used: (1) credit rating; (2) return on common equity; (3) interest coverage ratios; (4) S&P Business Position; (5) Value Line Safety Rank; and (6) the common stock book-to-market ratio. Based on a comparison of these relative measures of investment risk

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1 See Southwest Gas Corporation Recapitalization Plan, filed April 20, 2007, attached as Exhibit No.___(TKW-1) to Theodore K. Wood's direct testimony.

for Southwest and the average for the proxy group, each of these measures indicate a higher level of investment risk for Southwest.

Company witness Frank Hanley estimated the cost of common equity for a proxy group of eight natural gas utilities to be 11.0 percent, which he adjusted upward by 25 basis points to account for Southwest's higher investment risk. The basis for the adjustment was the difference in the credit rating of Southwest versus the average of the proxy group companies. This adjustment is conservative because it does not fully take into account Southwest's higher investment risk, as a majority of the proxy group companies have revenue stabilizing rate designs, and Mr. Hanley's recommendation assumed that Southwest's rate design proposals would be approved by the Commission in this proceeding.

Q. 12 Have other regulatory commissions utilized such a risk adjustment to determine a fair and reasonable allowed return on common equity?

A. 12 Yes. In the recent California annual cost of capital proceeding, the California Public Utilities Commission (CPUC) utilized such an adjustment for investment risk. In Decision No. 07-12-049, the CPUC adjusted San Diego Gas & Electric's (SDG&E) allowed return on common equity to account for the difference in SDG&E's credit rating versus the proxy groups used to estimate the cost of common equity. The decision stated[2]:

> "The first adjustment results from a disparity of credit ratings among the utilities included in the proxy groups of SDG&E, FEA, and DRA. Approximately 60% of those utilities have a lower medium grade credit rating of BBB in comparison to SDG&E's upper medium grade credit rating of A.[3] Ten percent of the utilities in the proxy group have an investment grade credit rating of BBB-, only one notch above the lowest investment grade credit rating. With BBB utilities being more risky than SDG&E, the financial models results are skewed toward a riskier side. Therefore, it is necessary to counter-balance the skewed financial models results that include more risky utilities. We adopt a 30 basis point downward adjustment to the base ROE range being adopted for SDG&E."

The same logic applies in Southwest's current proceeding, as it is necessary to counter-balance the skewed results of the financial models that include less risky utilities in the proxy group (average A/A3 bond rating) relative to Southwest (BBB-/Baa3 bond rating) by providing an upward adjustment to the base return on common equity range for the Company. The magnitude of the Company's requested relative investment risk adjustment of 25 basis points is somewhat lower, but comparable to the adjustment of 30 basis points found to be appropriate by the CPUC, based on the difference in credit ratings.

A. RUCO's Investment Risk Assessment

Q. 13 Did RUCO's recommended cost of common equity capital account for Southwest's higher relative investment risk

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2 CPUC Decision No. 07-12-049, December 20, 2007, pages 41-42.
3 Footnote omitted

compared to the proxy group?

A. 13 No. In estimating the cost of common equity capital, Mr. Rigsby used the same proxy group of eight natural gas distribution companies as did Company witness Frank Hanley. From his common equity analyses, Mr. Rigsby concluded that the required return on common equity is in the range of 9.20 percent to 10.83 percent, with a midpoint of 10.02 percent. Mr. Rigsby used the point estimate of 9.88 percent, which is lower than the mid-point of his range and provided no adjustment for Southwest's additional investment risk relative to the proxy group.

Q. 14 Did RUCO acknowledge that Southwest has higher relative financial risk compared to the proxy group?

A. 14 Yes. RUCO witness Mr. Rigsby, on page 49, lines 13-21, of his direct testimony, acknowledges Southwest's higher financial risk, stating:

> "…SWG's actual capital structure is heavier in debt and preferred equity than the natural gas utilities included in my sample (Schedule WAR-9). Thus, the cost of equity derived in my DCF analysis is applicable to companies that are not as leveraged and, theoretically speaking not as risky than a utility with a level of debt similar to SWG's. In the case of a publicly traded company, such as those included in my proxy group, a company with SWG's level of debt would be perceived as having a higher level of financial risk and therefore would also have a higher expected return on common equity."

Q. 15 Did RUCO make any risk adjustment to the cost of common equity capital given Southwest's higher level of financial risk?

A. 15 No. Mr. Rigsby stated that his support to use the Company's requested target capital structure adequately compensated for the additional financial risk.

Q. 16 Do you agree with Mr. Rigsby's conclusion that given the use of the Company's requested capital structure, no financial risk adjustment is required?

A. 16 No. The target capital structure is what the Company reasonably expects the actual capital structure to be near or shortly after the time when new rates will become effective. Even after achieving the target capital structure, Southwest will still have a higher level of financial risk relative to the proxy group of natural gas utilities used by both the Company and RUCO to estimate the cost of common equity capital.

Q. 17 Is there a quantitative method that can be used to quantify the remaining difference in financial risk for Southwest's requested capital structure?

A. 17 Yes. One method that can be used is what has been referred to as the "Hamada" adjustment method. Using this method, it is possible to estimate the difference in the cost of common equity capital for Southwest employing the leverage of the requested target capital structure compared to the actual leverage employed by the proxy group companies.

Q. 18 Has RUCO used the "Hamada" adjustment method in past proceedings?

A. 18 Yes. In the general rate case for Arizona Public Service Company, Docket No. E-01345A-05-0816, RUCO witness Stephen G. Hill used this method to quantify the difference in financial risk[4].

Q. 19 Please explain the methodology behind the "Hamada" adjustment to measure the difference in financial risk.

A. 19 Beta, the measure of a firm's sensitivity to systematic risk used in the CAPM, is a function of both business and financial risk. The relationship between beta and leverage (financial risk) is defined in the following formula[5]:

$$B_L = [1+(1-t) \times D/E] \times B_U$$

where:

B_L = levered beta

t = income tax rate

D/E = the market value debt to equity ratio

B_U = unlevered beta

As can be seen from the formula, increases in the market value of leverage increase beta. In order to remove the effects of leverage and calculate the risk of an unlevered firm, i.e., the beta of an all equity financed firm, compute the "unlevered" beta by simply rearranging the previous equation and solve for Bu. This formula is:

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4 Direct Testimony of Stephen G. Hill, Docket No. E-01345A-05-0816, pages 43-46.

5 See Roger A. Morin, *New Regulatory Finance*, (Arlington, Virginia: Public Utilities Reports, Inc., 2006), pp. 221-225, for a discussion of the relationship between beta and financial risk.

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$$B_U = B_L / [1+(1-t) \times D/E]$$

Q. 20 Please explain how the levered and unlevered beta formulas can be used to estimate the cost of common equity capital impact of Southwest's higher leverage relative to the proxy group companies.

A. 20 The calculation is performed using the following steps:

1) calculate the unlevered beta for each company in the proxy group;
2) calculate the average unlevered beta of the proxy group;
3) use the average unlevered beta of the proxy group to calculate the relevered beta for Southwest based on Southwest's market value leverage resulting from its proposed target capital structure;
4) compute the difference in Southwest's relevered beta from the proxy groups average levered beta; and
5) estimate the impact to the cost of common equity capital for the difference in leverage by multiplying the change in the levered betas by the equity risk premium.

Q. 21 What are the results of this analysis?

A. 21 Rebuttal Exhibit No.__(TKW-1) displays the leverage adjustment analysis. The average unlevered beta for the proxy group of eight natural gas companies was calculated to be 0.63. Employing the average proxy group unlevered beta to calculate a relevered beta for Southwest resulted in the following:

$$B_L = [1+(1-t) \times D/E] \times B_U$$

$$B_L = [1+(1-.365) \times .844] \times 0.63$$

$$B_L = 0.97$$

Subtracting the proxy group average levered beta of 0.86 from Southwest's relevered beta of 0.97 results in a difference of 0.11. The estimated change in the cost of common equity capital is found by multiplying the difference by the equity risk premium used in the CAPM. Based on the average equity risk premia used by Staff, Southwest, and RUCO, the range of impacts is 63 to 107 basis points. Based on this methodology and using the Company's requested capital structure, Southwest still has significant financial risk which RUCO did not take into consideration in its analyses. Moreover, the analysis shows the Company's 25 basis point upward adjustment to be both conservative and reasonable.

B. Staff's Investment Risk Assessment

Q. 22 Did Staff agree with Southwest's relative investment risk adjustment proposed by Southwest?

A. 22 No. Mr. Parcell used the same proxy group of eight natural gas distribution companies as did Company witness

Frank Hanley and he also used a second proxy group that included four additional natural gas utilities listed in the Value Line Investment Survey, including Southwest. From his common equity analyses, Mr. Parcell concluded that the required return on common equity is in the range of 9.30 percent to 10.5 percent, with a midpoint of 9.9 percent. Mr. Parcell used the midpoint estimate of 9.9 percent and added 10 basis points to account for Southwest's lower common equity ratio and lower credit ratings relative to the proxy groups to arrive at his recommended 10 percent return on common equity for Southwest.

Q. 23 What was Staff's rationale for rejecting the investment risk adjustment proposed by the Company?

A. 23 Mr. Parcell, on pages 40-41 of his direct testimony, states that such an adjustment is not warranted because Southwest's bond rating still contains the lingering effects of historically lower common equity ratios and because Southwest owned PriMerit Bank during the time period 1987-1995. In addition, he states that the Company's current common equity ratio is similar to other gas distribution utilities.

Q. 24 Do you agree with this justification?

A. 24 No. First, credit ratings are not based on historical common equity ratios, but are a function of a rating agency's assessment of a variety of factors about the utility's current conditions and projected financial performance. Second, any reference to PriMerit Bank, which was sold nearly 13 year ago, is not germane to the Company's current credit ratings. Third, while Southwest has significantly improved its common equity ratio, the Company's common equity ratio is still below that of the proxy groups used to estimate the cost of common equity capital in this proceeding.

Q. 25 On what basis did Staff compare Southwest's common equity ratio to the common equity ratio of the proxy groups?

A. 25 Mr. Parcell, on page 17 of his direct testimony, makes comparisons using common equity ratios based on both a permanent and total capital structure basis. The difference between permanent and total capital structure is that the latter includes short-term debt.

Q. 26 What type of capital structure is used by the Commission for ratemaking purposes?

A. 26 For ratemaking purposes, the Commission's longstanding practice has been to utilize capital structures based upon permanent capital, which excludes short-term debt, as permanent capital is the capital used to finance the long-term rate base investment of a utility. The rationale for this practice is that utilities generally use short-term debt to finance working capital requirements, including deferred energy balances, and to finance construction work in progress. Short-term debt that is used to finance a utility's working capital requirements and deferred energy receivable balances should not be included in setting an allowed rate of return, as this would lead to an incorrect estimate of the true cost of financing a utility's long-term rate base assets. Support for using the permanent capital structure for ratemaking purposes can be found in Decision No. 57075 (August 1990), lines 5-9, page 67, where the Commission discussed the appropriate capital structure for Southwest:

> "It properly excludes short-term debt from the capital structure in accordance with prior decisions. See e.g., <u>APS</u>, Decision Nos. 53761 (date), 55228 (October 9,1986) 55931 (April 1, 1988); and <u>Mountain States Telephone and Telegraph Company</u>, Decision No. 53849 (December 22, 1983)."

Southwest has consistently excluded short-term debt in our general rate case filing before the ACC and the Commission has accepted that practice.

Q. 27 If comparisons of common equity ratios are based on total capital structure, how should the comparison be done?

A. 27 When making comparisons based on a total capital structure, it is best to use a twelve-month average ratio rather than an end-of-period ratio. The reason for using an average ratio is due to the seasonal nature of the natural gas distribution business, where operating cash flows and income are higher during the heating season and lower during the remainder of the year. Correspondingly, short-term debt balances generally are reduced during the heating season and then build-up outside of the heating season to accommodate working capital requirements. Using a twelve-month average total capital structure avoids the distortions in leverage caused by short-term debt used for seasonal working capital requirements.

Rebuttal Exhibit No.___(TKW-2) displays the common equity ratio computed on both the permanent and total average capital structures for the two proxy groups used by Mr. Parcell for the time period 2003-2007. On a permanent capital or ratemaking basis, the 2007 average common equity ratio of the proxy group of 12 natural gas distribution companies and the proxy group of 8 natural gas distribution companies is 55.6 percent and 55.9 percent, respectively. On a total capital structure basis, the 2007 average common equity ratio of the proxy group of 12 natural gas distribution companies and the proxy group of 8 natural gas distribution companies is 49.8 percent and 49.6 percent, respectively. Southwest's actual and requested target common equity ratios are lower then the proxy groups used to estimate the cost of common equity capital.

IV. THE OVERALL RATE OF RETURN RECOMMENDATIONS OF STAFF, RUCO, AND SOUTHWEST

Q. 28 Please summarize the cost of capital recommendations of Staff, RUCO, and Southwest.

A. 28 A summary of the recommended overall rates of returns (ROR), returns on common equity (ROE), and capital structures, are displayed in the following table:

Witness	ROR	ROE	Ratemaking Capital Structure: Common Equity	Preferred Equity	Total Debt
Parcell(Staff)	8.86%	10.00%	43.44%	4.48%	52.08%
Rigsby(RUCO)	8.83%	9.88%	45.00%	4.00%	51.00%
Hanley/Wood(SWG)	9.45%	11.25%	45.00%	4.00%	51.00%

The rates of return in the table above are on an original cost rate base (OCRB) basis. The resulting fair value rate base (FVRB) rate of return will depend on the appropriate methodology accepted by the Commission for the rate of return to be applied the FVRB increment above the OCRB. Company witness Frank Hanley addresses the FVRB rate of return methodology in his rebuttal testimony.

Q. 29 What are the key issues concerning Staff's and RUCO's cost of capital recommendations?

A. 29 The key issues of concern regarding the recommendations by Staff and RUCO are: (1) how the recommended return on common equity and the resulting overall rates of return will impact the Company's ability to maintain or improve its existing credit ratings; and (2) the Company's ability to continue to attract capital on a reasonable basis.

Q. 30 How do credit rating agencies evaluate the authorized rate of return when determining a utility's creditworthiness?

A. 30 The impact of utility ratemaking is a key factor used by credit rating agencies in evaluating the creditworthiness of a utility. This issue was addressed in an article by S&P and was attached to my direct testimony as Exhibit No.___(TKW-4). I have restated a portion of the S&P article from my direct testimony explaining what key ratemaking issues S&P analyzes[6]:

> "The analysis of the rate case fundamentally explores a two-fold question: are the new rates based on a rate of return consistent with the company's rating, and is the utility being afforded a legitimate opportunity to actually earn that rate of return?
>
> On the former question, the analyst looks to equity returns being authorized for other utilities of the same credit quality, as well as the capital structure employed to arrive at the overall rate of return being used to set rates."

S&P evaluates the authorized rate of return based on comparisons to the common equity returns authorized for other utilities and the capital structure utilized to set rates. S&P also analyzes whether the utility is afforded a reasonable opportunity to earn its authorized rate of return. In doing so, S&P reviews the utility's approved rate design, which is a critical issue in this proceeding.

Q. 31 Why is it important to consider rating agencies views concerning the authorized rate of return?

A. 31 The credit rating impact is an important consideration since the Company's current bond ratings are at or near

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6 Todd A. Shipman, "*Energy Risk - Fresh Look at US Utility Regulation*", PowerMarkers.com, February 2, 2004.

the lowest investment grade level for S&P, Moody's and Fitch ("BBB-" by S&P, "Baa3" by Moody's, and "BBB" by Fitch). Given the capital intensive nature of the natural gas distribution business, it is important that Southwest has sufficient access to capital and credit capacity at reasonable costs. Changes in the Company's credit rating are ultimately borne by customers through its cost of capital.

Improvement in the Company's credit rating would be beneficial in reducing the Company's cost of debt and preferred securities. In addition, it would help Southwest remain at investment grade during unfavorable business conditions. Also, it would increase the amount of credit supplied to Southwest by its suppliers. Conversely, falling below an investment grade credit rating would be disastrous, significantly increasing the Company's cost of capital, which would lead to higher rates for customers.

A. Comparison to Authorized Returns on Common Equity

Q. 32 Please comment on the reasonableness of the rates of returns on common equity recommended by Staff and RUCO compared to those authorized for other utilities.

A. 32 Company witness Frank Hanley, has provided a schedule, Exhibit No.____(FJH-30) that reveals, for the twelve months ended March 31, 2008, the average authorized return on common equity was 10.33 percent, based on an average authorized common equity ratio of 52.42 percent for sixteen litigated cases of natural gas distribution companies. The following table comparatively displays the recommended returns on common equity and the common equity component of the capital structure for all of the cost of capital witnesses to the average authorized returns on common equity:

Description	ROE	Equity Ratio
Average Authorized[1]	10.33%	52.42%
Parcell(Staff)	10.00%	43.40%
Rigsby(RUCO)	9.88%	45.00%
Hanley/Wood(Southwest)	11.25%	45.00%

[1] See F. Hanley Exhibit No.___(FJH-30)

In evaluating the reasonableness of both Staff and RUCO's proposed return on common equity to the average authorized returns, the higher average authorized common equity ratio relative to Southwest's lower target ratio must be taken into consideration. This is due to the relationship between the cost of common equity capital and financial leverage, where increased leverage (lower common equity ratio) results in a higher cost of common equity capital.

Mr. Rigsby's recommendation of a return on common equity of 9.88 percent is 45 basis points less than the average authorized rate of return on common equity of 10.33 percent, and his recommended common equity ratio of 45.00 percent is 7.42 percentage points less than the average authorized common equity ratio of 52.42 percent. Based on this comparison, it is evident his recommendation is significantly below the authorized returns granted to other gas distribution companies.

Mr. Parcell's recommendation of a return on common equity of 10.0 percent is 33 basis points less than the average authorized return on common equity of 10.33 percent, and his recommended common equity ratio of 43.4 percent is 9.02 percentage points less than the average common equity ratio of 52.42 percent. Based on a comparison to the average return on common equity and common equity ratio authorized for other gas utilities, Mr. Parcell's recommended rate of return would put Southwest at a competitive disadvantage.

In his rebuttal testimony, Company witness Mr. Hanley addresses the specific deficiencies in Mr. Rigsby's and Mr. Parcell's cost of capital methodologies that result in their less than adequate recommended rates of return on common equity.

B. Reasonable Opportunity to Earn Authorized ROE

Q. 33 Please comment on Staff's and RUCO's rate design proposals in terms of Southwest's ability to earn it authorized rate of return and the resulting impact to its credit rating.

A. 33 Both Staff and RUCO are recommending the Commission reject the Company's proposed rate design and tariff mechanisms, including the Revenue Decoupling Adjustment Provision ("RDAP"), the Weather Normalization Adjustment Provision ("WNAP") and the Volumetric Rate Design, which are designed to address declining average customer usage and the Company's sensitivity to weather. Absent a significant improvement in rate design to address the phenomenon of declining average customer usage, Southwest will remain exposed to an asymmetric downside risk, as, on average, Southwest will not earn its authorized return on common equity. Southwest's ability to earn the Commission-authorized rate of return and return on common equity are critical determinants of credit protection, as they provide the ability to generate equity capital internally, attract capital externally on a reasonable basis in the capital markets, and withstand adverse market or business conditions.

Clearly, the absence of any significant improvement in rate design will have negative credit rating implications for Southwest. Given the relatively long regulatory lag in Arizona, the possibility of any future improvement in rate design is, at a minimum, two years out from the decision in this case. In its last credit opinion for Southwest, Moody's stated that[7]:

> "Due to the regulatory lag and gaps in the company's rate design in Arizona and Nevada, this has placed Southwest among the lowest rated investment grade gas utility companies."

In addition, Moody's cited the factors that could cause the Company's credit rating to be downgraded[8]:

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7 Moody's Investor Services, Credit Opinion: Southwest Gas Corporation, June 21, 2007.

8 *Id.*

> "Continuing high leverage, continuing earnings volatility on account of weather variations, eroding margins from declining customer consumption related to gas conservation and continuing lags in recovery of capital investment costs or increase in operating expenses that erode the company's profitability could all be causes for a possible downgrade."

S&P, which currently has a "positive" credit rating outlook for Southwest, stated that the outlook could return to "stable"[9]:

> "if financial performance deteriorates from current levels as a result of unfavorable regulatory actions, an increase in leverage, or material reductions in customer usage (either due to weather or efficiency) without adequate regulatory protections."

Also, S&P stated[10]:

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

Recognizing that Southwest is already on the edge of having a non-investment grade (junk bond) credit rating, an authorized rate design that does not adequately address the Company's problems with either declining customer usage or sensitivity to weather, will

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

10 *Id.*

substantially reduce the Company's chances of improving or even maintaining its current credit rating.

Q. 34 Please illustrate how declining residential consumption per customer impacts Southwest's ability to earn its authorized rate of return on common equity.

A. 34 In his rebuttal testimony, Company witness James Cattanach has calculated that the weather-normalized residential consumption per customer is 319 therms for the twelve-months ended March 31, 2008. This is a decrease of 13 therms from the test period amount of 332 therms per residential customer. Based on this information, Company witness Brooks Congdon has estimated that the annual reduction in revenues at present rates is approximately $6.3 million.

The estimated impact of the $6.3 million revenue reduction on Southwest's ability to earn its proposed return on common equity can be quantified. All else constant, using Southwest's proposed rate base and overall rate of return, the $6.3 million reduction in revenue would result in a return on common equity of 10.48 percent. This is 77 basis points below Southwest's proposed return on common equity of 11.25 percent.

Rebuttal Exhibit No.__(TKW-3) displays the calculation of the impact to Southwest's proposed return on common equity. The calculation clearly illustrates the deleterious impact and the asymmetric nature that declining average usage has on the Company's opportunity to earn its authorized rate of return. If Southwest's rate design and tariff mechanism proposals are rejected, then the Commission should consider increasing the return on common equity to compensate for the lost margin due to declining consumption per residential customer.

C. Capital Attraction Basis

Q. 35 On the basis of capital attraction, what benchmarks are useful to check the reasonableness of Staff's and RUCO's recommendations?

A. 35 Southwest must compete with other utilities and alternative investment opportunities in fully competitive global capital markets to attract capital. For Southwest to successfully attract capital, it must demonstrate an ability to achieve a competitive risk-adjusted return on that capital.

To examine the reasonableness of the RUCO and Staff recommendations on a capital attraction basis, the recommendations can be judged against the historical and prospective returns on the average book value common equity of other natural gas distribution utilities. Rebuttal Exhibit No.___(TKW-4) provides the historical returns for the time period 2003-2007, and the projected returns for the periods 2008, 2009, and 2011-2013[11]. The analysis for the proxy groups[12] of natural gas

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11 Information was derived from the Value Line Investment Survey, March 14, 2008.

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

distribution companies can be summarized as follows:

Proxy Group	Historical 2003-2007 ROE	Historical 2003-2007 Common Equity	Projected 2008-2013 ROE	Projected 2008-2013 Common Equity
Proxy Group 1	12.1%	53.9%	11.9%	57.5%
Proxy Group 2	13.2%	52.4%	12.4%	57.8%

Southwest's common stock currently trades at a discount to other natural gas utilities, as pointed out in a recent Merrill Lynch investment report, where it stated[13]:

> "..SWX trades at a 10% discount to its peers (13.8x)[14]. In our view, this discount is warranted given high EPS volatility, rate structures that prevent SWX from earning allowed returns in growing jurisdictions, and uncertainty surrounding regulators' willingness to instate decoupling measures."

Recognizing that the investment risk associated with Southwest is higher than the average investment risk of the proxy group companies, approving an authorized return on common equity significantly below the level expected for other natural gas utilities would place Southwest at a competitive disadvantage in terms of attracting capital.

Proxy Group 2 - the additional proxy group of twelve natural gas distribution companies used by Staff.

13 Merrill Lynch Investment Report, Southwest Gas, February 21, 2008, page 1.

14 The 13.8x is the common stock price to earnings per share ratio.

V. SUMMARY

Q. 36 Please summarize your response to the overall rates of return proposed by RUCO and Staff.

A. 36 The Company must earn an adequate overall rate of return that fairly compensates investors for Southwest's higher level of business, financial, and regulatory risk. The Company will continue to need frequent access to the capital markets. For the Company to attract additional capital at reasonable rates, and have the ability to maintain and improve its credit rating (which benefits its customers), it must have a realistic opportunity to earn a rate of return that adequately compensates its investors for the degree of risk they assume.

The overall rates of return proposed by Staff and RUCO based on their recommended returns on common equity are inadequate based on the following:

(1) Neither RUCO nor Staff gave adequate consideration to Southwest's relative higher investment risk relative to the proxy groups of natural gas distribution companies used to estimate the cost of common equity capital in this proceeding.

(2) Both RUCO and Staff's proposed rates of return on common equity are below the authorized rates of return on common equity for other natural gas utilities. The average authorized return on common equity for the twelve months ended March 31, 2008 is 10.33 percent with an average authorized common equity ratio of 52.42 percent.

In comparison, Southwest's requested common equity ratio of 45 percent is significantly below the average authorized, and therefore, has higher relative financial risk.

(3) Both RUCO and Staff's proposed returns on common equity are significantly below the recently achieved and projected rates of return on common equity for other natural gas utilities. Value Line Investment Survey reports the proxy group companies, on average, have achieved returns on average common equity of 12.1-13.2 percent (2003-2007) and are projected to earn 11.9-12.4 percent (2008-2013).

In addition to the Commission's determined appropriate rate of return for Southwest, the Company needs to have a reasonable opportunity to actually earn its Commission-authorized rate of return. Investors do not make investment decisions based on authorized rates of return, but on actual and expected realized rates of return. The Company's requested overall rate of return assumes that the Commission will approve the Company's rate design proposals. If the rate design proposals are rejected, as both Staff and RUCO are advocating, then the Commission-authorized rate of return should be adjusted upward to account for the higher variability in the Company's returns due to weather and the asymmetric downside risk associated with Southwest's declining average usage per customer.

Q. 37 Does this conclude your prepared rebuttal testimony?
A. 37 Yes, it does.

Form No. 155.0 (03/2001) Word

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

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

			2007 Average					
Line No.	Company	Beta[1]	Common Equity[2]	Market/Book Ratio[3]	Market Value Debt / Equity Ratio[4]	Tax Rate[1]	Unlevered Beta[5]	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	AGL Resources	0.85	46.0%	1.82	64.5%	37.6%	0.61	1
2	Atmos Energy Corp.	0.85	46.5%	1.31	87.8%	35.8%	0.54	2
3	Laclede Gas	0.90	43.3%	1.62	81.0%	33.4%	0.58	3
4	NICOR Inc.	1.00	58.4%	2.16	32.9%	30.0%	0.81	4
5	Northwest Natural Gas Co.	0.80	50.4%	2.05	47.9%	37.2%	0.62	5
6	Piedmont Natural Gas Co.	0.85	47.8%	2.04	53.5%	33.0%	0.63	6
7	South Jersey Industries	0.80	50.0%	2.25	44.4%	40.7%	0.63	7
8	WGL Holdings	0.85	54.7%	1.61	51.3%	39.1%	0.65	8
9	Average	0.86	49.6%	1.86	57.9%	35.9%	0.63	9
	Southwest Target Capital Structure							
10	Southwest Relevered Beta[6]	0.97	45.0%	1.45	84.4%	36.5%	0.63	10
11	Proxy Group Average Levered Beta	0.86						11
12	Difference In Beta	0.11						12
	Change in Cost of Equity[7]							
13	Equity Risk Premium = 5.69%[8]	0.63%						13
14	Equity Risk Premium = 5.90%[9]	0.65%						14
15	Equity Risk Premium = 9.70%[10]	1.07%						15

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

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

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504
PROXY GROUP OF 8 NATURAL GAS DISTRIBUTION COMPANIES

COMMON EQUITY RATIOS BASED ON AVERAGE PERMANENT CAPITAL STRUCTURE[1]

Line No.	Company	2007	2006	2005	2004	2003	5-Year Average	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	AGL Resources Inc.	51.55%	50.58%	48.05%	48.77%	47.59%	49.31%	1
2	Atmos Energy Corp.	49.24%	45.18%	42.43%	48.34%	48.66%	46.77%	2
3	Laclede Group	54.90%	52.37%	52.05%	49.86%	50.62%	51.96%	3
4	Nicor Inc.	66.65%	63.81%	61.51%	60.03%	63.97%	63.19%	4
5	Northwest Natural Gas	54.05%	54.74%	52.55%	52.91%	51.23%	53.09%	5
6	Piedmont Natural Gas	52.34%	53.92%	59.08%	57.35%	57.93%	56.12%	6
7	South Jersey Industries	56.89%	54.97%	53.89%	51.52%	47.46%	52.94%	7
8	WGL Holdings, Inc.	61.29%	60.67%	61.51%	58.69%	56.21%	59.68%	8
9	**Proxy Group Average**	**55.86%**	**54.53%**	**53.88%**	**53.43%**	**52.96%**	**54.13%**	9

COMMON EQUITY RATIOS BASED ON AVERAGE TOTAL CAPITAL STRUCTURE [1]

	Company	2007	2006	2005	2004	2003	5-Year Average	
10	AGL Resources Inc.	45.96%	44.04%	44.23%	45.15%	42.26%	44.33%	11
11	Atmos Energy Corp.	46.47%	41.38%	40.74%	48.06%	46.08%	44.55%	12
12	Laclede Group	43.30%	40.98%	43.28%	42.48%	38.55%	41.72%	13
13	Nicor Inc.	58.43%	55.97%	53.09%	48.39%	45.62%	52.30%	14
14	Northwest Natural Gas	50.42%	49.93%	50.35%	50.01%	48.15%	49.77%	15
15	Piedmont Natural Gas	47.78%	48.24%	53.10%	54.46%	49.94%	50.70%	16
16	South Jersey Industries	50.00%	45.56%	48.41%	46.76%	39.51%	46.05%	17
17	WGL Holdings, Inc.	54.69%	53.20%	54.85%	52.99%	51.24%	53.39%	18
18	**Proxy Group Average**	**49.63%**	**47.41%**	**48.51%**	**48.54%**	**45.17%**	**47.85%**	19

[1] Source - Bloomberg

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504
PROXY GROUP OF 12 NATURAL GAS DISTRIBUTION COMPANIES

COMMON EQUITY RATIOS BASED ON AVERAGE PERMANENT CAPITAL STRUCTURE [1]

Line No.	Company (a)	2007 (b)	2006 (c)	2005 (d)	2004 (e)	2003 (f)	5-Year Average (g)	Line No.
1	AGL Resources Inc.	51.55%	50.58%	48.05%	48.77%	47.59%	49.31%	1
2	Atmos Energy Corp.	49.24%	45.18%	42.43%	48.34%	48.66%	46.77%	2
3	Energen Corp.	69.92%	62.71%	54.71%	57.96%	56.14%	60.29%	3
4	Laclede Group	54.90%	52.37%	52.05%	49.86%	50.62%	51.96%	4
5	Nicor Inc.	66.65%	63.81%	61.51%	60.03%	63.97%	63.19%	5
6	New Jersey Resources Corp.	65.13%	64.97%	60.79%	60.48%	62.42%	62.76%	6
7	Northwest Natural Gas	54.05%	54.74%	52.55%	52.91%	51.23%	53.09%	7
8	Piedmont Natural Gas	52.34%	53.92%	59.08%	57.35%	57.93%	56.12%	8
9	South Jersey Industries	56.89%	54.97%	53.89%	51.52%	47.46%	52.94%	9
10	Southwest Gas Corporation	41.92%	38.46%	37.00%	35.22%	34.32%	37.38%	10
11	UGI Corp.	43.21%	41.94%	45.15%	40.66%	38.21%	41.83%	11
12	WGL Holdings, Inc.	61.29%	60.67%	61.51%	58.69%	56.21%	59.68%	12
13	**Proxy Group Average**	**55.59%**	**53.69%**	**52.39%**	**51.82%**	**51.23%**	**52.94%**	13

COMMON EQUITY RATIOS BASED ON AVERAGE TOTAL CAPITAL STRUCTURE [1]

	Company	2007	2006	2005	2004	2003	5-Year Average	
14	AGL Resources Inc.	45.96%	44.04%	44.23%	45.15%	42.26%	44.33%	14
15	Atmos Energy Corp.	46.47%	41.38%	40.74%	48.06%	46.08%	44.55%	15
16	Energen Corp.	66.21%	59.84%	52.93%	53.96%	53.64%	57.32%	16
17	Laclede Group	43.30%	40.98%	43.28%	42.48%	38.55%	41.72%	17
18	Nicor Inc.	58.43%	55.97%	53.09%	48.39%	45.62%	52.30%	18
19	New Jersey Resources Corp.	52.79%	53.44%	48.58%	49.11%	49.86%	50.76%	19
20	Northwest Natural Gas	50.42%	49.93%	50.35%	50.01%	48.15%	49.77%	20
21	Piedmont Natural Gas	47.78%	48.24%	53.10%	54.46%	49.94%	50.70%	21
22	South Jersey Industries	50.00%	45.56%	48.41%	46.76%	39.51%	46.05%	22
23	Southwest Gas Corporation	41.28%	37.50%	35.73%	33.94%	33.93%	36.48%	23
24	UGI Corp.	40.68%	38.98%	39.65%	37.64%	34.38%	38.27%	24
25	WGL Holdings, Inc.	54.69%	53.20%	54.85%	52.99%	51.24%	53.39%	25
26	**Proxy Group Average**	**49.83%**	**47.42%**	**47.08%**	**46.91%**	**44.43%**	**47.14%**	26

[1] Source - Bloomberg

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504
ESTIMATED IMPACT ON COMPANY'S ABILITY TO EARN THE AUTHORIZED RATE OF RETURN DUE TO DECLINING RESIDENTIAL CONSUMPTION PER CUSTOMER

Line No.	Description (a)	Capital Ratio (b)	Capital Cost (c)	Weighted Cost of Capital (d)	Grossed-Up Weighted Cost of Capital (e)	Rate Base (f)	Cost of Capital Revenue Requirement (g)	Line No.
	Southwest Proposed							
1	Long-Term Debt	51.00%	7.96%	4.06%	4.06%	$ 1,094,790,046	$ 44,444,097	1
2	Preferred Equity	4.00%	8.20%	0.33%	0.33%	1,094,790,046	3,612,807	2
3	Common Equity	45.00%	11.25%	5.06%	8.40%	1,094,790,046	91,925,825	3
4	Total	100.00%		9.45%	12.79%		$ 139,982,729	4
	Impact of Revenue Reduction							
5	Long-Term Debt	51.00%	7.96%	4.06%	4.06%	$ 1,094,790,046	$ 44,444,097	5
6	Preferred Equity	4.00%	8.20%	0.33%	0.33%	1,094,790,046	3,612,807	6
7	Common Equity	45.00%	10.48%	4.72%	7.82%	1,094,790,046	85,633,118	7
8	Total	100.00%		9.11%	12.21%		$ 133,690,022	8
9	Change		-0.77%				$ (6,292,707)	9

Gross-up Factor = 1.6586

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504
PROXY GROUP OF 8 VALUE LINE GAS DISTRIBUTION COMPANIES[1]
RETURN ON AVERAGE BOOK COMMON EQUITY[2]

Line No.	Company	Actual Return on Common Equity						Projected Return on Common Equity				Line No.
		2003	2004	2005	2006	2007	5-Year Average	2008	2009	2011-2013	Average	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	AGL Resources	15.31%	13.94%	13.28%	13.60%	12.82%	13.79%	12.70%	12.78%	14.50%	13.80%	1
2	Atmos Energy Corp.	11.25%	9.10%	9.06%	9.99%	9.20%	9.72%	8.94%	9.28%	9.50%	9.34%	2
3	Laclede Gas	11.85%	11.16%	11.09%	13.11%	11.96%	11.83%	11.62%	11.24%	11.00%	11.17%	3
4	NICOR, Inc.	12.53%	13.01%	12.84%	15.19%	13.76%	13.47%	10.92%	12.29%	13.50%	12.74%	4
5	Northwest Natural Gas Co.	9.17%	9.26%	10.07%	10.87%	12.41%	10.35%	11.42%	11.76%	11.00%	11.24%	5
6	Piedmont Natural Gas	12.15%	12.38%	11.64%	10.96%	11.75%	11.78%	12.27%	12.25%	12.50%	12.41%	6
7	South Jersey Inds.	13.09%	13.35%	13.20%	17.20%	13.33%	14.03%	13.40%	13.73%	14.50%	14.12%	7
8	WGL Holdings Inc.	14.36%	11.93%	12.14%	10.75%	11.02%	12.04%	11.22%	10.89%	10.50%	10.72%	8
9	**Proxy Group Average**	**12.46%**	**11.77%**	**11.67%**	**12.71%**	**12.03%**	**12.13%**	**11.56%**	**11.78%**	**12.13%**	**11.94%**	9

COMMON EQUITY RATIO[1]

	Company	Actual Common Equity Ratio						Projected Common Equity Ratio				
		2003	2004	2005	2006	2007	5-Year Average	2008	2009	2011-2013	Average	
10	AGL Resources	49.70%	46.00%	48.10%	49.80%	49.80%	48.68%	50.00%	50.00%	50.00%	50.00%	10
11	Atmos Energy Corp.	49.80%	56.80%	42.30%	43.00%	48.00%	47.98%	49.00%	48.00%	49.00%	48.80%	11
12	Laclede Gas	49.40%	48.30%	51.80%	50.40%	54.60%	50.90%	55.00%	55.00%	53.00%	53.80%	12
13	NICOR, Inc.	60.30%	60.10%	62.50%	63.70%	70.00%	63.32%	73.00%	76.00%	79.00%	77.20%	13
14	Northwest Natural Gas Co.	50.30%	54.00%	53.00%	53.70%	53.70%	52.94%	53.50%	53.50%	53.00%	53.20%	14
15	Piedmont Natural Gas	57.80%	56.40%	58.60%	51.70%	51.60%	55.22%	51.90%	52.20%	53.30%	52.80%	15
16	South Jersey Inds.	49.00%	51.00%	55.10%	55.30%	57.30%	53.54%	58.50%	59.50%	59.00%	59.00%	16
17	WGL Holdings Inc.	54.30%	57.20%	58.60%	61.50%	60.30%	58.38%	62.50%	63.50%	66.50%	65.10%	17
18	**Proxy Group Average**	**52.58%**	**53.73%**	**53.75%**	**53.64%**	**55.66%**	**53.87%**	**56.68%**	**57.21%**	**57.85%**	**57.49%**	18

[1] Source: Value Line Investment Survey, March 14, 2008.
[2] Average $ROE_t = (EPS_t) / ((BVPS_t + BVPS_{t-1}) / 2)$
where:
ROE = Return on Common Equity
EPS = Earnings Per Share
BVPS = Book Value Per Share

SOUTHWEST GAS CORPORATION
PROXY GROUP OF 12 VALUE LINE GAS DISTRIBUTION COMPANIES[1]
RETURN ON AVERAGE BOOK COMMON EQUITY[2]

		Actual Return on Common Equity						Projected Return on Common Equity				
Line No.	Company (a)	2003 (b)	2004 (c)	2005 (d)	2006 (e)	2007 (f)	5-Year Average (g)	2008 (h)	2009 (i)	2011-2013 (j)	Average (k)	Line No.
1	AGL Resources	15.31%	13.94%	13.28%	13.60%	12.82%	13.79%	12.70%	12.78%	14.50%	13.80%	1
2	Atmos Energy Corp.	11.25%	9.10%	9.06%	9.99%	9.20%	9.72%	8.94%	9.28%	9.50%	9.34%	2
3	Energen Corp.	17.18%	16.97%	20.32%	22.21%	24.52%	20.24%	22.37%	22.68%	16.50%	18.91%	3
4	Laclede Gas	11.85%	11.16%	11.09%	13.11%	11.96%	11.83%	11.62%	11.24%	11.00%	11.17%	4
5	New Jersey Resources Corp.	16.76%	15.81%	16.20%	14.61%	10.16%	14.71%	13.44%	13.01%	10.50%	11.59%	5
6	NICOR, Inc.	12.53%	13.01%	12.84%	15.19%	13.76%	13.47%	10.92%	12.29%	13.50%	12.74%	6
7	Northwest Natural Gas Co.	9.17%	9.26%	10.07%	10.87%	12.41%	10.35%	11.42%	11.76%	11.00%	11.24%	7
8	Piedmont Natural Gas	12.15%	12.38%	11.64%	10.96%	11.75%	11.78%	12.27%	12.25%	12.50%	12.41%	8
9	South Jersey Inds.	13.09%	13.35%	13.20%	17.20%	13.33%	14.03%	13.40%	13.73%	14.50%	14.12%	9
10	Southwest Gas Corporation	6.22%	8.83%	6.53%	9.73%	8.78%	8.02%	8.88%	9.43%	10.00%	9.66%	10
11	UGI Corp.	21.93%	16.48%	19.48%	16.14%	15.68%	17.94%	15.33%	15.25%	12.50%	13.62%	11
12	WGL Holdings Inc.	14.36%	11.93%	12.14%	10.75%	11.02%	12.04%	11.22%	10.89%	10.50%	10.72%	12
13	**Proxy Group Average**	**13.48%**	**12.68%**	**12.99%**	**13.70%**	**12.95%**	**13.16%**	**12.71%**	**12.88%**	**12.21%**	**12.44%**	13

COMMON EQUITY RATIO[1]

		Actual Common Equity Ratio						Projected Common Equity Ratio				
	Company	2003	2004	2005	2006	2007	5-Year Average	2008	2009	2011-2013	Average	
14	AGL Resources	49.70%	46.00%	48.10%	49.80%	49.80%	48.68%	50.00%	50.00%	50.00%	50.00%	14
15	Atmos Energy Corp.	49.80%	56.80%	42.30%	43.00%	48.00%	47.98%	49.00%	48.00%	49.00%	48.80%	15
16	Energen Corp.	55.80%	56.70%	56.60%	67.40%	71.00%	61.50%	70.00%	70.00%	67.00%	68.20%	16
17	Laclede Gas	49.40%	48.30%	51.80%	50.40%	54.60%	50.90%	55.00%	55.00%	53.00%	53.80%	17
18	New Jersey Resources Corp.	61.90%	59.70%	58.00%	65.20%	62.70%	61.50%	66.00%	68.00%	73.00%	70.60%	18
19	NICOR, Inc.	60.30%	60.10%	62.50%	63.70%	70.00%	63.32%	73.00%	76.00%	79.00%	77.20%	19
20	Northwest Natural Gas Co.	50.30%	54.00%	53.00%	53.70%	53.70%	52.94%	53.50%	53.50%	53.00%	53.20%	20
21	Piedmont Natural Gas	57.80%	56.40%	58.60%	51.70%	51.60%	55.22%	51.90%	52.20%	53.30%	52.80%	21
22	South Jersey Inds.	49.00%	51.00%	55.10%	55.30%	57.30%	53.54%	58.50%	59.50%	59.00%	59.00%	22
23	Southwest Gas Corporation	34.00%	35.80%	36.20%	39.40%	41.90%	37.46%	43.00%	43.50%	48.00%	46.10%	23
24	UGI Corp.	33.00%	35.00%	41.70%	35.90%	39.30%	36.98%	42.00%	45.00%	52.00%	48.60%	24
25	WGL Holdings Inc.	54.30%	57.20%	58.60%	61.50%	60.30%	58.38%	62.50%	63.50%	66.50%	65.10%	25
26	**Proxy Group Average**	**50.44%**	**51.42%**	**51.88%**	**53.08%**	**55.02%**	**52.37%**	**56.20%**	**57.02%**	**58.57%**	**57.78%**	26

[1] Source: Value Line Investment Survey, March 14, 2008.
[2] Average $ROE_t = (EPS_t) / ((BVPS_t + BVPS_{t-1}) / 2)$
where:
ROE = Return on Common Equity
EPS = Earnings Per Share
BVPS = Book Value Per Share

Tab

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BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

CONCERNING

COMMON EQUITY COST RATE

RE: SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

May 9, 2008

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REBUTTAL TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

BEFORE THE

ARIZONA CORPORATION COMMISSION

EXHIBITS
(FJH-15) THROUGH (FJH-30)

TO ACCOMPANY THE

REBUTTAL TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

CONCERNING

COMMON EQUITY COST RATE

RE: SOUTHWEST GAS CORPORATION

DOCKET NO. G-01151A-07-0504

<u>Southwest Gas Corporation</u>
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<u>of Frank J. Hanley</u>

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
FRANK J. HANLEY

I. PURPOSE

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

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

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

A.2 Yes, I am.

Q.3 What is the purpose of this testimony?

A.3 The purpose of this testimony is to rebut certain aspects of the direct testimonies of Arizona Corporation Commission (ACC) Staff Witness David C. Parcell and Residential Utility Consumer Office (RUCO) Witness William A. Rigsby concerning their recommended common equity capital cost rates for Southwest Gas Corporation (Southwest or the Company). I also respond to certain aspects of the critique of both Messrs. Parcell and Rigsby of my direct testimony. In addition, I present an updated cost of common equity capital analysis from which I conclude that my original recommended common equity capital cost rate of 11.25% is still appropriate. Finally, I rebut Mr. Parcell's recommended rates of return related to Southwest's fair value rate base.

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

A.4 Yes. They have been denoted as Exhibits__(FJH-15) through (FJH-30).

II. SUMMARY

Q.5 Please briefly summarize your rebuttal testimony.

A.5 My testimony describes the errors contained in the testimonies of Witnesses Parcell and Rigsby, which result in a significant understatement of the cost rate of common equity capital to Southwest. Moreover, their contentions that a reduction in common equity capital cost rate is in order should the Company's requested tariff tools be approved are totally incorrect.

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

- I will explain why Mr. Parcell's contention that if the Company's rate design proposals are approved it would require a significant downward adjustment to the Company's common equity capital cost rate is incorrect and that he is also incorrect when he concludes that "it does not appear that the Company acknowledges this risk transfer in terms of its requested rate of return."[1]
- I will show that Mr. Parcell's significant reliance upon the Discounted Cash Flow (DCF) cost rates is inappropriate because of the tendency of the method to understate common equity capital cost rate when market values exceed their book values.
- I will show that Mr. Parcell's recommended common equity capital cost rate is too low, as his Capital Asset Pricing Model (CAPM) and comparable earnings cost rates are grossly understated.

[1] Parcell Direct Testimony, p. 15, l. 9-10.

- I will show the inadequacy of Witness Parcell's CAPM calculations and demonstrate why it is incorrect to place any reliance upon geometric mean data in arriving at the market equity risk premium in a cost of capital determination.
- I will explain why Mr. Parcell's use of total return on long-term government bonds is incorrect and results in a significant understatement of market equity risk premium. Moreover, I will explain why his failure to utilize the Empirical CAPM (ECAPM) exacerbates his understatement of a proper common equity capital cost rate.
- I will explain why his comparable earnings conclusion is incorrect because of his presumption that if a stock sells at a substantial premium over its book value, it is earning more than its cost of capital.

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

- In addition to the problems associated with significant reliance upon the DCF method which I address with respect to Mr. Parcell, I explain the problems associated with Mr. Rigsby's exclusive reliance upon the sustainable growth method in reaching his DCF conclusion.
- I will explain why Mr. Rigsby's CAPM cost rates are grossly understated; why his sole reliance upon geometric mean data as well as his reliance upon 91-day U.S. Treasury Bill rate as the risk-free rate are incorrect. Moreover, I will explain why his failure to utilize the ECAPM exacerbates his understatement of a proper common equity capital cost rate.
- I explain and demonstrate why Mr. Rigsby's comments at page 59 of his testimony regarding risk mitigation related to the Company's revenue decoupling proposal,

including his statement that such a mechanism would "essentially provide SWG with a guaranteed return on the Company's invested capital",[2] are totally incorrect.

In addition to the foregoing, I respond to the critique made of my direct testimony by Messrs. Parcell and Rigsby and show that their criticisms are invalid. I also provide an updated cost of common equity capital analysis, which demonstrates that the requested 11.25% is still valid, if not conservative. Finally, I address Mr. Parcell's testimony with regard to fair value rate base cost of capital contained at pages 41-49 of his direct testimony. I explain why his conclusions are incorrect and further why his alternate proposed weighted average cost of capital (WACC) is significantly understated.

III. ACC STAFF WITNESS PARCELL

Q.6 Notwithstanding your disagreement with Mr. Parcell's range of common equity capital cost rate, is his allowance of 0.1% (the difference between his recommended 10.0% and midpoint of his range of 9.9%) adequate to recognize Southwest's lower common equity ratio and significantly lower debt ratings?

A.6 No. It is grossly inadequate. I have prepared Exhibit__(FJH-15), which consists of three sheets. Sheet 1 shows Standard & Poor's (S&P) bond ratings, business risk, and financial risk profiles for the companies in each of Mr. Parcell's two proxy groups. I have also shown Southwest separately for purposes of comparison. It is shown on Sheet 1 that the average Moody's bond rating for each of the two proxy groups is A3 versus Southwest's Baa3, while the difference is even more extreme based upon the S&P bond ratings, which is an average of A for each of the two proxy groups, while Southwest's is BBB-. It is also shown that the average business risk profile for each proxy group is "Excellent", while Southwest is lower at "Strong". Similarly, the

2 Rigsby Direct Testimony, p. 59, l. 12-17.

financial risk profile for each proxy group is classified "Intermediate", while that for Southwest is "Aggressive". In short, Southwest is viewed as considerably more risky. On Sheet 3, I have shown that the risk differential between bonds rated A3 and Baa3 by Moody's has increased substantially in the 11 months between April 2007 and March 2008. As shown, it has increased from 0.31% to 0.61%, a virtual doubling. This indicates that the market places greater value on quality and views bottom of investment grade (Southwest's bond rating) even more risky than it did almost one year ago.

Q.7 In discussing the Company's request to implement two new rate design proposals, Mr. Parcell, at page 15 of his testimony states that "if approved, (they) are risk-reducing ... (T)he net effect of these proposals is to transfer a significant portion of the Company's risks from its shareholders to its ratepayers. Yet, it does not appear that the Company acknowledges this risk in terms of its requested rate of return." Please comment.

A.7 There is no question that the requested rate design proposals would help to reduce risk by stabilizing revenues and earnings. However, Mr. Parcell is completely incorrect when he suggests that the Company somehow does not recognize this in its requested rate of return. I have prepared Exhibit__(FJH-16), which consists of two sheets. Sheet 1 graphically depicts what had been previously discussed in my direct testimony, namely that in Southwest's Arizona jurisdiction, it has neither any type of rate decoupling mechanism, nor performance-based rates, or weather normalization adjustment protection. In contrast, the chart on Sheet 1 shows that 75% of the proxy group upon which all three witnesses rely, consisting of 8 LDCs, have some type of rate decoupling mechanisms in place, 50% have some type of performance-based rates in place, and 87.5% have some type of weather normalization adjustment mechanism in place. Consequently, any cost rate for common equity capital derived from such proxy group already overwhelmingly reflects investors' recognition of risk reduction attributable thereto. In addition, since Southwest's bond rating is at the bottom of investment grade, one full rating difference vis-à-vis the proxy groups (Baa3 vs. A3), even if the requested mechanisms were approved, it is extremely unlikely that there would be a significant improvement in the bond rating immediately. By that I mean the rating may go up a notch or two initially to Baa2 or perhaps even Baa1, but still would not in the immediate future be equal to the proxy group average of Moody's A3 or S&P's A. Consequently, it is likely that Southwest's cost of common equity capital would remain somewhat above any cost rate derived from the proxy LDCs, although the cost rate differential would lessen. Mr. Parcell's observations are simply incorrect.

Q.8 Previously, you suggested that Mr. Parcell's "recognition" of the Company's lower equity ratio and lower bond rating of 0.1% (from a midpoint of 9.9% of his range to his recommended 10.0%) is grossly inadequate. Even though you do not agree with his recommendation in absolute terms, do you have any evidence that recognition of only 10 basis points is wholly inadequate?

A.8 Yes. Of course, I have demonstrated <u>supra</u> that the risk rate differential has increased dramatically for Southwest in the last 11 months because of the perceived increasing risk with lower quality rated investments such as investment in bonds of a company with a rating at the bottom of investment grade. That differential currently is 0.61% or 61 basis points as discussed <u>supra</u> and shown in Exhibit__(FJH-15), Sheet 3. Mr. Parcell claims to have taken into account Southwest's lower equity ratio and lower debt ratings versus the proxy groups.[3] However, those factors and many others are reflected in the bond rating process as discussed in my direct testimony at page 13, line 10 through page 14, line 3 and shown in Exhibit__(FJH-2), Sheets 3 through 9). In addition, Southwest witness Wood has quantified the minimal financial risk difference at 0.63% or 63 basis points in Rebuttal Exhibit__(TKW-1).

In view of the foregoing, it is clear that Mr. Parcell's recognition of only 10 basis points is grossly inadequate.

Q.9 Please comment upon the applicability of the range of Mr. Parcell's DCF cost rates of 9.3% to 10.4% with a midpoint of 9.9% as discussed at page 25 of his testimony.

A.9 A common equity capital cost rate of 9.9%, based upon what is known as the "simplified" DCF model, which all three witnesses utilize in this case, will mathematically mis-specify investors' required return rate when the market value of common stock differs significantly from its book value. It is a basic assumption of the model. As utility rate of return experts all know, and as I discussed in my direct testimony, market values and book values are seldom at unity. A market-based DCF model will result in a total annual dollar return on book common equity capital equal to the total annual dollar return expected by investors only when market and book values are equal, a rare and unlikely situation.

Utility stocks continue to trade at market-to-book ratios well above unity. As shown on Exhibit__(FJH-17), Sheet 2, the market-to-book ratios of the proxy groups of gas distribution companies utilized by all three cost of capital witnesses, including Mr. Parcell's two groups (one of which is the same as mine), are selling at substantial premiums over book values.

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3 Parcell Direct Testimony, p. 34, l. 2-4.

As discussed in my direct testimony, at page 25, lines 9-12:

> ...a <u>market-based</u> DCF cost rate applied to the book value per share will either overstate investors' required common equity cost rate when market value is less than book value or understate investors' required common equity cost rate when market value is above book value.

I have demonstrated the inadequacy of Mr. Parcell's DCF cost rate (as well as Mr. Rigsby's), on Sheet 1 of Exhibit__(FJH-17), which demonstrates that there is no realistic opportunity to earn the market-based rates of return on book value. In this example, the average market price of Mr. Parcell's two proxy groups of $36.395 is 187.78% in excess of the average book value of $19.375 and the investor expects a total return rate of 9.90%, the midpoint of Mr. Parcell's DCF cost rate range. The 9.90% market-based cost rate implies an annual return of $3.603 consisting of $1.401 in dividends and $2.202 in growth (market-price appreciation). When the 9.90% return rate is applied to the book value of $19.375, which is just 53.24% of market value, an opportunity for a total annual return is just $1.918 on book value. With annual dividends of $1.401, there is an opportunity to earn only $0.517 in market-price appreciation, which is a mere 1.42% on market price in contrast to the 6.05% growth in market price expected on average by investors for both groups. There is no possible way to achieve the expected growth of $2.202 (6.05%) related to an average market price of $36.395 absent a huge cut in annual cash dividends, an unreasonable expectation since such an action by a board of directors is usually indicative of an extremely adverse financial condition. Of course, if the converse situation exists (market prices substantially below their book values), a market-based DCF cost rate applied to the book value of common equity capital would overstate the cost rate.

On the right hand side of Sheet 1, I have shown similar computations related to the proxy group of eight LDCs relied upon by Mr. Rigsby (and myself) and in part by Mr. Parcell. As shown, the expected rate of growth implicit in Mr. Rigsby's DCF cost rate of 9.73% is 5.18%, but when it is applied to the average book value of $19.668, it returns an opportunity for growth in market value of only 1.11%.

Q.10 Please comment on Mr. Parcell's statement at page 26 lines 7-11 of his direct testimony that "...the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings."

A.10 Mr. Parcell is incorrect. Beta is a measure of systematic risk, which reflects on average only 32% of company-specific risk as reflected by the average R-squared statistic (or coefficient of determination resulting from the regression analyses from which the Value Line betas relied upon by Mr. Parcell were derived) for both proxy groups relied upon by Mr. Parcell as shown on Exhibit__(FJH-20), which will be discussed infra. This means that only 32% of total risk is explained by beta. In contrast, the "simple" risk premium method, which I use in addition to CAPM/ECAPM, DCF, and comparable earnings, relies upon the use of a company-specific expected bond yield. As shown on Exhibit__(FJH-2), Sheets 3 through 9, S&P explains how and why the utility bond rating process takes into account all of the diversifiable basic components of business and financial risk. Moreover, I also utilize beta to allocate a total market equity risk premium, which is a portion of the total market equity risk premium. Consequently, my approach to the risk premium analysis reflects all company-specific risk (i.e., in the company-specific bond yield which reflects all diversifiable business and financial risk, plus that non-diversifiable portion which is reflected in beta) and the remainder of all risk is reflected through the use of beta in determining the applicable equity risk premium. In view of the foregoing, Mr. Parcell's comments about the CAPM versus the "simple" risk premium method are incorrect.

Q.11 Please comment upon Mr. Parcell's estimation of the market return component of his CAPM analysis.

A.11 Mr. Parcell used the actual achieved rates of earnings on book common equity capital of the S&P 500 Composite for the period 1978-2006 as shown on Exhibit__(DCP-7). As discussed previously, both the cost of capital and ratemaking are prospective in nature. And, the underlying theory of the CAPM requires the use of a *market return*. Therefore, the use of historically achieved earnings on book common equity capital is inconsistent with both the prospective nature of the cost of capital and ratemaking as well as with the very theory of the CAPM. In his alternative CAPM analysis, Mr. Parcell calculates the historic risk premium using Ibbotson Associates' average total return on large company stocks from 1926-2005, which are appropriately market returns – not returns on book common equity capital. Thus, Mr. Parcell's two CAPM analyses are a mismatch because he has mixed returns on book common equity capital with market returns.

Q.12 Another element considered by Mr. Parcell in arriving at his estimation of market equity risk premium is that he relied upon the total return on long-term government bonds from the Morningstar, Inc. 2008 Yearbook relating to the

period 1926 through 2007. Is Mr. Parcell's use in the CAPM of the total return on long-term government bonds appropriate?

A.12 No. In fact, it is incorrect. I have prepared Exhibit__(FJH-18) which consists of five sheets. Sheets 1 through 4 contain a discussion by Morningstar related to calculation of the equity risk premium for use in the CAPM. Sheet 5 is a copy of Table 2-1 from the same publication which represents a summary of total returns, income returns, and capital appreciation of the basic asset classes for the period 1926 through 2007. There are several things to be noted from the Morningstar publication. First, they indicate that the 30-year Treasury Bond yield is "theoretically more correct due to the long-term nature of business valuation."

Moreover, as shown at the top of page 28 of Mr. Parcell's direct testimony, he relied upon a yield on long-term government bonds of 5.8% which represents total return and not the income return of 5.2% for the same period of time. Morningstar, Inc. states under the caption "Income Return" at the bottom of Sheet 2 and top of Sheet 3 of Exhibit__(FJH-18):

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. *The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.*[2] (footnote omitted) (italics added)

Thus, his use of the total return on long-term government bonds results in a substantial understatement of CAPM cost rate.

Q.13 Please comment on Mr. Parcell's direct testimony at lines 22-25 on page 27 wherein he notes that he has considered both the arithmetic and geometric mean returns for the S&P 500 group as well as for long-term government bonds tabulated by Morningstar, Inc.

A.13 As discussed in my direct testimony at page 37, line 14 through page 38, line 9, it is the arithmetic mean return that is appropriate for cost of capital purposes precisely because it captures the effect of changing economic conditions on risk premia over time. Because historical total returns and equity risk premia spreads differ in size and direction over time, the arithmetic mean provides insight into the variance and standard deviation of returns. The prospect for variance, i.e., standard deviation, captured in the arithmetic mean, provides the valuable insight needed by investors and rate of return analysts alike to estimate the expected risk of stocks. Absent such insight, investors cannot meaningfully evaluate prospective risk.

As stated previously, the financial literature is quite clear on this point, namely that risk is measured by the variability of expected returns, i.e., the probability distribution of returns. Morningstar, Inc. explains in detail, in original pages 77 through 83 of <u>Stocks, Bonds, Bills and Inflation: Valuation Edition 2007 Yearbook</u>, shown at Sheets 2 through 8 (Exhibit__(FJH-11)) why the arithmetic mean calculated over a very long period of time is <u>the</u> correct mean to use when estimating the cost of capital.

Weston and Brigham[4] provide the standard financial textbook definition of the riskiness of an asset when they state:

> The riskiness of an asset is defined in terms of the likely variability of future returns from the asset. (emphasis added)

As previously discussed, investors gain insight into relative riskiness by analyzing expected future variability. This is accomplished by the use of the arithmetic mean of a distribution of returns / premia because it takes into account all of the returns / premia, thereby providing meaningful insight into the variance and standard deviation of those returns / premia. In contrast, the geometric mean is a constant return, which provides no insight into variability.

Q.14 Can it be demonstrated that the arithmetic mean takes into account all of the returns and therefore, that the arithmetic mean is appropriate to use when estimating the opportunity cost of capital?

A.14 Yes. I have prepared Exhibit__(FJH-19) which consists of two sheets, which graphically demonstrates this premise. Sheet 1 charts the returns on large company stocks for each and every year, 1926 through 2007 from Morningstar, Inc.'s Stocks, Bonds, Bills, and Inflation – Valuation Edition 2008 Yearbook. It is clear from looking at the variation of these returns that stock market returns, and hence, equity risk premia, vary significantly from year to year.

Shown on Sheet 2 is the distribution of each and every one of those annual returns for the entire period from 1926 through 2007. There is a clear bell-shaped pattern to the probability distribution of returns. The arithmetic mean of this distribution of returns takes into account all of the returns in the distribution and thus the potential variance and standard deviation likely to be experienced in the

4 J. Fred Weston and Eugene F. Brigham, Essentials of Managerial Finance, 3rd Ed., The Dryden

future when estimating the rate of return based upon such historical returns. In contrast, the bold years: 1926 and 2007, shown on Sheet 2 are the only years considered when the geometric mean is calculated. That is only two of the eighty-two returns are taken into account, namely the initial and terminal years, which, in this case, are 1926 and 2007. Based upon only those two years, a <u>constant rate</u> of return is calculated by the geometric average. That constant return, when represented graphically, would be a flat line over the entire 1926 to 2007 time period which is obviously far different from reality, based upon the probability distribution of returns shown on Sheet 2 and shown chronologically on Sheet 1.

In view of the foregoing, it should be clear that the arithmetic mean long-term historical risk premium takes into account the standard deviation of returns, which is critical to risk analysis. Therefore, Mr. Parcell's inclusion of geometric mean returns is inappropriate for estimating the cost of capital and thus for ratemaking purposes.

Q.15 Mr. Hanley, have you recalculated CAPM cost rates utilizing Mr. Parcell's two proxy groups and a proper long-term arithmetic average market premium?

A.15 Yes, I have. That information is shown on Exhibit__(FJH-20). In Exhibit__(FJH-20), I have utilized Mr. Parcell's risk-free rate of 4.49% and his March 2008 Value Line betas. I utilized the market premium of 7.10%, which is the arithmetic mean average calculated utilizing the long-term average income return on U.S. government securities of 5.2% and the long-term average total return on large stocks of 12.30%. As shown, the average CAPM cost rate for the group of 12 gas distribution companies is 10.71%, while the average for the proxy group of 8 gas distribution companies is 10.62%. The median of both groups is 10.53%.

Press, 1974, p. 272.

It is clear from the foregoing that Mr. Parcell's CAPM cost rates are grossly understated.

Q.16 Do you have any further comment upon Mr. Parcell's CAPM analysis?

A.16 Yes. In addition to his incorrect use of returns on book common equity capital in developing the market return component of the CAPM, his inclusion of geometric market returns, and his use of total returns on long-term government bonds, Mr. Parcell failed to consider that although numerous tests of the CAPM have confirmed its validity, it has been determined that the empirical Security Market Line (SML) described by the traditional CAPM is not as steeply sloped as the predicted SML. (See my direct testimony at page 42, line 18 through page 43, line 29). Hence, the traditional CAPM understates the cost rate for common equity capital for companies with betas less than 1.0 and overstates the cost rate for companies with betas greater than 1.0. Mr. Parcell erred by not employing the ECAPM.

Q.17 In Exhibit__(FJH-20), you have corrected Mr. Parcell's CAPM calculations. In view of his failure to include the ECAPM, have you also calculated what proper ECAPM cost rates would be, using the inputs described in connection with Exhibit__(FJH-20)?

A.17 Yes, I have. That information is set forth in Exhibit__(FJH-21), which consists of five sheets. Sheet 1 contains a summary of the results of the calculations, while Sheets 2 through 5 represent the excerpted portion from Roger Morin's book <u>New Regulatory Finance</u> related to discussion of the ECAPM, which provide further support for its validity and necessity of use. As shown on Sheet 1, the mean ECAPM cost rates are 10.93% relative to the proxy group of twelve gas distribution companies and 10.86% for the proxy group of eight gas distribution companies. The median of both groups is 10.79%. These data further confirm the gross understatement of Mr. Parcell's CAPM mean cost rates of 9.7% and medians of 9.5% as set forth in Exhibit__(DCP-8).

Q.18 Do you have any comments regarding Mr. Parcell's application of the CEM?

A.18 Yes. At page 32 of his direct testimony, Mr. Parcell discusses his recommended range of 10.0% to 10.5%. As support for his conclusion he cites recent returns of 10.0% to 11.0% and market-to-book ratios that substantially exceed 100%. He concludes that "...the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of 10 percent to 11 percent reflect earnings that exceed the cost of equity for those regulated companies." (page 32, lines 1-4). By these statements, it is clear that Mr. Parcell believes that a direct relationship exists between market-to-book ratios and the rates of earnings on book common equity capital . Such a relationship is supported by neither the academic literature nor a historical analysis of the experience of non-price regulated companies.

Q.19 What does the academic literature say about the relationship between allowed regulatory rates of return on common equity capital and utility market-to-book ratios?

A.19 It is very clear from the academic literature that there is no such relationship. The following excerpts are also set forth on page 24 of my direct testimony. Phillips[5] states the following:

> Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently

[5] Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, 1993, Public Utilities Reports, Inc., Arlington, VA, p. 395.

> high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.

In addition, Bonbright[6] states:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate Orders will have on the market prices of the stocks of the companies they regulate. In the second place, *whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market.* Moreover, even if a commission did possess the power of control, any attempt to exercise it . . . would result in harmful, uneconomic shifts in public utility rate levels. (italics added)

Q.20 Have you performed an analysis to determine whether or not there exists a direct relationship between the market-to-book ratios of non-price regulated companies and their earned rates of return on book common equity capital?

A.20 Yes. There is no relationship. The results of my analysis are presented on Exhibit__(FJH-22). I analyzed the market-to-book ratios and earned rates of return on book common equity capital for the S&P Industrial Index and its successor, the S&P 500 Composite Index, which does not include public utilities, over a long period of time. On Exhibit__(FJH-22), I have shown the market-to-book ratios, rates of return on book common equity capital (earnings/book ratios), annual inflation rates, and the earnings/book ratios net of inflation (real rate of earnings) annually for the years 1947 through 2006. In <u>each and every year</u>, the market-to-book ratios equaled or exceeded 1.00 times. In 1949, the only year in which the market-to-book ratio was 1.00 (or 100%), the real rate of earnings on book equity, adjusted for <u>deflation</u>, was 18.1% (16.3% + 1.8%). In contrast, in 1961, when the S&P Industrial Index experienced a market-to-book ratio of 2.01 times, the real rate of earnings on book equity for the Index was only 9.1% (9.8% - 0.7%). In 2006, the preliminary market-to-book ratio for the Index was 2.75 times, while the average real rate of earnings on book equity was 14.4% (16.9% - 2.5%).

6 James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, <u>Principles of Public Utility Rates</u>, 1988, Public Utilities Reports, Inc., Arlington, VA, p. 334.

This analysis clearly demonstrates that competitive, non-price regulated companies have never sold below book value, on average, and have sold at book value in only one year since 1947. The data show that there is no relationship between earnings/book ratios and market-to-book ratios.

Because this lack of a relationship between earnings/book ratios and market-to-book ratios covers a 60-year period, 1947 through 2006, it cannot be validly argued that going forward a direct relationship would exist between earnings/book ratios and market-to-book ratios. The analysis shown on Exhibit__(FJH-22), coupled with the supportive academic literature, demonstrate the following:

1. While regulation is a substitute for marketplace competition, it can only influence, but not directly control market prices, and, hence, market-to-book ratios; and

2. The rates of return investors expect to achieve on market value have no meaningful, direct relationship to rates of earnings on book equity.

A. <u>Response to ACC Staff Witness Parcell's Comments on Company Testimony</u>

Q.21 On page 36, lines 19-21 of his direct testimony, Mr. Parcell states "To make a modification of the DCF cost rates, as Mr. Hanley proposes, amounts to an attempt to "reprice" stock values in order to develop a DCF cost rate more in line with what he thinks the results should be." Please comment.

A.21 I made no modification of DCF cost rates and did not "reprice" stock values. I utilized informed expert judgment upon reviewing all of the indicated DCF cost rates vis-à-vis the cost rate results from application of all of the other cost of common equity capital models which I employ as well as my utilization of a reasonableness check on my recommended common equity capital cost rate. The basis for the exercise of my informed expert judgment was set forth clearly in my direct testimony at page 31, line 15 through page 32, line 12. Moreover, in

Decision No. 69663 of the Commission re: Arizona Public Service Company, dated June 28, 2007, the Commission recognized the infirmity of the DCF results when it stated:

> …(W)e note that the DCF results from all witnesses tend to the lower end of the range. However, we compare those results with the results from the other methods, and believe that the DCF results alone would result not in an appropriate cost of equity in this case for APS. We are cognizant of APS's current bond rating as well as the Company's continued growth and the capital costs associated with that growth. (Decision at p. 49)

The results of the other cost of common equity models and properly calculated CAPM cost rates for Messrs. Parcell and Rigsby ranging from 10.61% to 10.93% (Exhibit__(FJH-20, 21 and 25) confirm that their recommended common equity capital cost rates are understated considerably. Moreover, Southwest's Moody's bond rating of Baa3 is actually one notch lower than APS' Baa2, while the S&P ratings of each are the same, namely BBB-. Also, Southwest has had one of the highest growth rates of any LDC in the nation. As discussed supra, the cost of capital has not declined for bottom of investment grade utilities and the risk differential vis-à-vis higher rated utilities has increased.

Q.22 At page 37, lines 1 through 13 of his testimony, Mr. Parcell draws on his memory from the 1970's and early 1980's. He states that he can recall no instances in which any AUS witness testified that the DCF result overstated the cost of equity. Please respond to his recollection.

A.22 In the 1970's and early 1980's, there was no clear trend by regulatory agencies to place great reliance upon the DCF methodology. It was only in later years that many commissions turned toward either exclusive use of the DCF methodology or to place significant weight on it in arriving at an allowed common equity capital cost rate in a general rate case proceeding. However, if Mr. Parcell was familiar with cases during that era in which I testified, he would find that my recommended common equity capital cost rates were much lower than the 15%, 16% or 17% DCF common equity capital cost rates, which were indicated based upon market conditions at those points in time. Because it was not necessary to emphasize that DCF cost rates were overstated 25 or 30 years ago does not mean that consideration was not given to their overstatement when market/book ratios of many utilities were below 100%. I did so back then, as I have consistently done, relying upon multiple methodologies including the CAPM and risk premium methods.

Q.23 At page 37 of his testimony, Mr. Parcell criticizes your use of the long-term holding period returns published by Morningstar, Inc. in your application of the risk premium methodology. Please comment.

A.23 Mr. Parcell's criticism of the use of long-term average holding period returns for the period 1926-2006 is invalid for several reasons. First, Mr. Parcell himself utilizes such long-term returns in his application of the CAPM as discussed supra. Secondly, Morningstar, Inc. in its Valuation Edition 2007 Yearbook, and cited in my direct testimony at page 36, line 6 through page 37, line 20, as discussed supra, and again in the Valuation Edition 2007 Yearbook excerpts shown in Exhibit__(FJH-11), Sheets 5 through 8 provides a complete explanation of why the use of the long-term holding period returns is correct when estimating the cost of capital.

The use of the long-term arithmetic mean, by both myself and Mr. Parcell in part, is consistent with the long-term investment horizon of utilities' common stocks. The typical application of the DCF model used in regulation presumes an infinite, i.e., long-term, investment horizon and a constant growth rate. The presumption of a constant growth rate in the DCF model is no different than the presumption of a constant equity risk premium based upon long-term historical holding period returns as discussed in my direct testimony, page 40, line 11 through page 41, line 14. As Morin[7] states:

> It is not necessary that g be constant year after year to make the model valid. *The growth rate may vary randomly around some average expected value. Random variations around trend are perfectly acceptable, as long as the mean expected growth is constant.* The growth rate must be 'expectationally constant' to use formal statistical jargon. (italics added)

The foregoing confirms that the RPM is similar to the DCF model. The use of a very long-term historic mean equity risk premium does not mean that in actuality it is constant year after year in order for the model to be valid. The equity risk premium may vary randomly around some average expected value. As to Mr. Parcell's suggestion that it is somehow incorrect to rely upon the use of long-term average market equity risk premium such as 1926-2006, he contradicts himself by its use in the CAPM as discussed <u>supra</u>. Moreover, Morningstar, Inc. explains very clearly why the use of a long-term historical average is appropriate as discussed at page 36, line 6 through page 37, line 20 of my direct testimony and in detail at Sheets 5 through 8 of Exhibit__(FJH-11). Mr. Parcell's criticism is without merit.

Q.24 Mr. Parcell criticizes your use of the empirical CAPM. Please comment.

A.24 Mr. Parcell states at lines 6-8 on page 39 of his direct testimony that "[w]hat the empirical CAPM actually does is inflate the CAPM cost for the selected company or industry on one-fourth of its equity and assumes that one-fourth of the company has the risk of the overall market." This statement reflects a misunderstanding of the empirical CAPM. Sheets 2 through 5 of Exhibit__(FJH-21) contain that portion of Roger Morin's text, which fully explain the academic/empirical support for the ECAPM.

Q.25 Mr. Parcell, in discussing the ECAPM, at page 39 of his testimony states that you provided no rationale or reasons to believe that investors would ignore published betas and instead rely on "hypothetical betas" that are neither published nor readily available. How do you respond?

A.25 Mr. Parcell's comments make it clear that he does not understand the ECAPM. Roger Morin explains clearly (Exhibit__(FJH-21), Sheet 5 of 5) that the ECAPM is not a beta adjustment. Rather, it is a return adjustment. Some of what Morin states, which is contained in its entirety on Sheet 5 of 5 of Exhibit__(FJH-21) is as follows:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. ...This argument is erroneous. Fundamentally, the ECAPM is not an adjustment increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk/return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprise two separate features of asset pricing.

It seems clear to me that Mr. Parcell is confusing the Security Market Line (SML) with beta. I have prepared Exhibit__(FJH-23) which consists of six sheets, which are excerpts from the book, Financial Management – Theory & Practice, Fourth Edition by Eugene F. Brigham and Louis C. Gapenski. As the authors

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[7] See page 41 of Mr. Hanley's Direct Testimony.

explain in Footnote 12 on original page 203, which is shown at Sheet 5 of 6 of Exhibit__(FJH-23), "students sometimes confuse beta with the slope of the SML (Security Market Line)." The authors go on to state that beta does represent the slope of the line, but not the SML. It is, after all, the SML where the intercept is the risk-free rate. The ECAPM represents an adjustment to that return axis recognizing the reality of a flatter SML slope than that predicted by the CAPM. Consequently, it is a return adjustment as explained by Morin and not a beta adjustment. Therefore, Mr. Parcell's contention that I have used a "hypothetical" beta is incorrect.

Q.26 Mr. Parcell criticizes your application of the CEM by stating at lines 5-7 on page 40 of his direct testimony that "The equivalence of beta values (i.e., the basis for his selection of comparison companies) does not indicate that the expected earnings and cost of common equity for these non-utilities and utilities are the same." Please comment.

A.26 Mr. Parcell's comments relative to the equivalence of beta are incorrect. The basis of my CEM is identical to that presented in an article co-authored by Pauline M. Ahern and myself published in the summer of 1994 in the American Gas Association's Financial Quarterly Review entitled "Comparable Earnings: New Life for an Old Precept", attached as Exhibit__(FJH-24), which consists of six sheets. The article presents a selection process of unregulated, domestic companies based upon unadjusted betas, which is entirely logical and consistent with well-documented financial concepts supported by the academic literature, namely, that beta is the product of market prices which, based upon the EMH, reflect all elements of risk. The betas derived from those market prices reflect non-diversifiable market systematic risk, while the residual standard deviations, or standard errors of the regression analyses from which the betas were derived, reflect the remaining company-specific (or non-systematic) risks. Thus, the selected comparable domestic non-price regulated companies in my analysis are indeed comparable to my proxy group of LDCs on a total risk basis, i.e., the sum of non-diversifiable systematic risk and diversifiable, unsystematic or company-specific, risk. Mr. Parcell cites the Hope Natural Gas case at page 6 of his testimony which states in part:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

The basis of selection of my comparable companies is the regression statistics of market prices, which reflect all elements of risk. So, my non-price regulated proxy companies are indeed comparable in total risk to the proxy LDCs. Mr. Parcell's criticisms are unfounded and should be disregarded.

IV. RUCO WITNESS WILLIAM A. RIGSBY

Q.27 At pages 9 through 16 of his testimony, Mr. Rigsby discusses and adopts the exclusive use of the sustainable growth method reflected in the equation g = br + sv for use in the DCF model. Please comment.

A.27 Myron Gordon, who first introduced the DCF model adapted for utility ratemaking, came to recognize long after his book "The Cost of Capital to a Public Utility" was published in 1974, that the growth component of his original "Gordon Model," which relied upon the sustainable growth method had a serious limitation. Dr. Gordon, in a presentation on March 27, 1990 (some 16 years after the publication of his 1974 book), before the Institute for Quantitative Research in Finance, in Palm Beach, Florida, entitled, "The Pricing of Common Stocks", stated that analysts' growth rate projections were superior to the sustainable growth method when he stated:

> The most serious limitation of the Gordon Model is the assumption that the dividend expectation can be represented with just two parameters, D and br ... We have seen that earnings and growth estimates by security analysts were found by Malkiel and Cragg to be superior to data obtained from financial statements for the explanation of variation in price among common stocks. That is, better estimates are obtained for the coefficient of the various explanatory variables. ...*estimates by security analysts available from sources such as IBES are far superior to the data available to Malkiel and Cragg. Secondly, the estimates by security analysts must be superior to the estimates derived solely from financial statements.* (italics added for emphasis)

Q.28 It is clear that the "father" of the DCF model for use in utility rate proceedings, Dr. Myron Gordon, said analysts' forecasts are superior to the sustainable growth method, but what are the problems with using the sustainable growth method itself?

A.28 It is circular in nature because it relies upon an expected return on equity (ROE). In turn, it utilizes that ROE to establish an allowed ROE, which is lower than the expected ROE. Roger Morin, in his 2006 book, <u>New Regulatory Finance</u>, sums up the problems with the g = br + sv method for estimating growth in the DCF model as follows:

- It may be more difficult to estimate what b, r, s, and v investors have in mind than it is to estimate what g they envision.
- There is a potential element of circularity in estimating g by a forecast of b and ROE for the utility being regulated, since ROE is determined in large part by regulation.
- The sustainable growth method is not as significantly correlated to measures of value, such as stock price and price/earnings ratios as other historical measures or analysts' growth forecasts. (pp. 306-307)

Q.29 Do you have any additional comments regarding the sustainable growth, i.e., g = br + sv, calculations made by Mr. Rigsby?

A.29 Yes. Mr. Rigsby states on page 16, lines 17 through 22 that "The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratios of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M / B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's [sic] expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0." Underlying this statement by Mr. Rigsby is the presumption of a direct relationship between market-to-book ratios and returns on book common equity capital which, as discussed in my direct testimony at pages 23-28, is erroneous and can lead to fatal conclusions of judgment. Moreover, as noted on page 24 of my direct testimony, Charles F. , Phillips[8] states:

> Many question the assumption that market price should equal book value, believing that '*the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.*' (italics added)

In addition, Bonbright[9] states:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, *whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market. In short, market prices are beyond the control, though not beyond the influence of rate regulation.* (italics added)

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8 Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, 1993, Public Utility Reports, Inc., Arlington, VA, p. 395.

9 James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, 1998, Public Utilities Reports, Inc., Arlington, VA, p. 334.

Hence, there is no valid empirically supported reason to use diluted market-to-book ratios because of the erroneous assumption that such ratios will move toward one, i.e., 1.00, or 100%. Doing so results in the understatement of the growth component in the DCF and the DCF cost rate itself.

Q.30 Is Mr. Rigsby correct in his use of the yield on 3-month U.S. Treasury Bills as the risk-free rate in his CAPM analysis?

A.30 No. Mr. Rigsby relies upon information contained in the Morningstar, Inc.'s SBBI 2007 Yearbook for estimating his equity risk premium for use in the CAPM. However, he has ignored Morningstar's recommendation that the yield on long-term Treasury Bonds is the proper risk-free rate to utilize in the CAPM. Sheet 4 of Exhibit___(FJH-25) is a copy of page 59 of Stocks, Bonds, Bills and Inflation – Valuation Edition – 2008 Yearbook. Note that Morningstar states:

> The horizon of the chosen Treasury security should match the horizon of whatever is being valued. *When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond.* (italics added for emphasis)

The DCF model which Mr. Rigsby utilizes, implicitly contains an infinite investment horizon. Southwest is a going concern. Moreover, Harrington[10], with regard to the use of short-term Treasury Bill rates in the CAPM states:

> Anyone using the CAPM must choose the R_F proxy with great care. The most widely used proxies, *30-or 90-day Treasury Bill rates, are empirically inadequate and theoretically suspect.* (italics added)

Thus, in view of the foregoing, it is clear that only the use of a long-term Treasury Bond yield is appropriate for use as the risk-free rate in the application of the CAPM.

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10 Diana R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc., 1983, p. 108.

Q.31 On page 27 of his testimony, lines 8-10, Mr. Rigsby states that he "used both a geometric and an arithmetic mean of the historical returns . . . as the proxy for the market rate of return." Is the use of the geometric mean for estimating the cost of capital correct?

A.31 No. I have previously discussed the error of using the geometric mean to estimate the cost of capital in my rebuttal to ACC Staff Witness Parcell, supra. Investors are constantly buying and selling stocks. Potential investors require insight into the degree of risk they will experience before they can determine whether to purchase common stock of a firm and the price they are willing to pay. Such insight is critical because the degree of the risk mandates the rate of return required in accordance with the basic financial precept of risk and return, i.e., greater risk means a greater rate of return is required and vice versa. Morningstar, Inc. explains why only the use of the arithmetic mean is appropriate when estimating the cost of capital (see Exhibit__(FJH-11), Sheets 2 through 4 and Exhibit__(FJH-19) discussed supra re Mr. Parcell's use of the geometric mean.

The financial literature is quite clear that business risk is measured by the variability of expected pretax returns, i.e., the probability distribution of returns[11].

Weston & Brigham[12] define the riskiness of an asset thusly:

> The riskiness of an asset is defined in terms of the *likely variability of future returns from the asset.* (italics added)

Finally, Jeremy J. Siegel[13] defines risk as follows:

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11 Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition, The Dryden Press, 1989, p. 639.

12 J. Fred Weston and Eugene F. Brigham, Essentials of Managerial Finance, 3rd Edition, The Dryden Press, 1974, page 272.

13 Jeremy J. Siegel, Stocks for the Long Run – A guide to Selecting Markets for Long-Term Growth, Irwin, 1994, p. 40.

> A common measure of risk is the *standard deviation* of yearly returns. (italics in original, underlining added for emphasis)

And, in a note at the bottom of Table 1-1 on page 11 of Stocks for the Long-Run, Siegel notes that: "Risk = standard deviation of *arithmetic returns*." (italics added for emphasis).

Thus, it is clear that use of the geometric mean is incorrect to use when estimating the cost of capital.

Q.32 Aside from the fact that Mr. Rigsby used a 91-day Treasury Bill rate as the risk-free rate, which you have already discussed, is there anything else about the rate that he used that is inconsistent, and therefore incorrect?

A.32 Yes. I have explained, supra, why the use of 91-day Treasury Bill rate as the risk-free rate is incorrect. However, Mr. Rigsby's use of a recent six-week average rate exacerbates the error. By that I mean he has used the long-term returns on large stocks for the period 1926 through 2006, but did not use a compatible rate. In other words, even though the use of a 91-day Treasury Bill rate is incorrect, the fact that he did not utilize an average rate for 91-day Treasury Bills over the same period, i.e., 1926 through 2006, exacerbates the problem even further.

Q.33 Have you recalculated Mr. Rigsby's CAPM results appropriately relying on forecasted yields on long-term U.S. Treasury Bonds as the risk-free rate, the income return on long-term U.S. Treasury Bonds in calculating the equity risk premium, and the long-term arithmetic mean average equity risk premium?

A.33 Yes. On Exhibit ___(FJH-25), I have shown that the traditional CAPM result is 10.61% while the ECAPM result is 10.85%. As can be seen on Sheet 1, Mr. Rigsby's average understatement is 0.71%, or 71 basis points.

A. Response to RUCO Witness Rigsby's Comments on Southwest Gas Corporation's Cost of Equity Capital

Q.34 At the top of page 55 of his testimony, Mr. Rigsby criticizes your elimination of returns below 9.60% and suggests that you refuse to consider the fact that the market has priced returns of LDCs at a lower level than what regulators have adopted. Please comment.

A.34 Mr. Rigsby's comment is incorrect for several reasons. First, he either is not aware or ignores the fact that the results of my DCF, CAPM, and CEM methods are substantially higher than 9.60%, thereby confirming through the use of multiple models that anything below 9.60% is frankly unrealistic, not required by investors, and should be disregarded. Moreover, the use of multiple models is discussed and encouraged in the academic/financial literature. According to the Efficient Market Hypothesis (EMH), upon which the DCF model is predicated, investors are aware of the fact that there are multiple models, that their use is encouraged, and that many commissions, including this Commission, consider other such models. Mr. Rigsby's criticism is without merit.

Secondly, the 9.60% floor is actually predicated upon the lowest return during that period awarded by regulators, as can be seen by reference to Exhibit__(FJH-14). Also shown on that exhibit, is that the average of litigated cases awards was 10.48% relative to a common equity ratio of 45.92%.

Q.35 At page 55, lines 16-18, Mr. Rigsby states that the ECAPM uses unadjusted betas that are lower than the adjusted Value Line betas. Also, at page 57, lines 8-11, he states that the ECAPM overstates the expected return because of the use of an adjusted beta in a model that contains an upward adjustment for the risk-free rate of return. Please comment.

A.35 Mr. Rigsby, in some sense acknowledges the distinction between an upward adjustment for the risk-free rate of return and beta. However, the use of an adjusted beta in a CAPM (or ECAPM) is to adjust for regression bias, i.e., the tendency of betas which are higher than 1.00 to move downward and conversely, for betas which are lower than 1.00 to move upward. The ECAPM represents an adjustment for the tendency of the CAPM (using adjusted betas) to still mis-specify the cost rate which is on a different axis from beta. As discussed <u>supra</u> in connection with Mr. Parcell's testimony, Morin has made clear (refer to Sheet 5 of Exhibit__(FJH-21)) that the argument of double-counting by using adjusted beta is erroneous. He states:

> This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if ECAPM is used, the return for low-beta securities is understated if the betas are understated.

In addition, it is clear that because the adjustment for an increased risk-free rate results from the ECAPM because the SML is flatter than predicted by the CAPM, has nothing to do with beta. As discussed <u>supra</u> in connection with Mr. Parcell's testimony, Brigham and Gapenski (see Exhibit__(FJH-23)) make it clear that beta is a line, but it is not the SML. The ECAPM is a return adjustment and not a beta adjustment. Mr. Rigsby's comments are incorrect and should be disregarded.

Q.36 At page 59, lines 6-18 of his testimony, Mr. Rigsby contends that implementation of the Company's requested decoupling adjustment provision (RDAP) would "essentially provide SWG with a guaranteed return on the

Company's invested capital, does in itself merit a lower cost of common equity capital that reflects the elimination of the risk of not being able to earn an authorized rate of return." Is he correct?

A.36 No. This is a matter of common sense. The requested RDAP will help to stabilize revenues, but it does not guarantee a level of return or revenues. Also, see the Direct Testimony of Southwest Witness Ralph E. Miller at page 3, line 21 through page 4, line 3. While a RDAP, or its equivalent, would stabilize revenues and hence earnings, it would certainly not "essentially provide a guaranteed return" as contended by Mr. Rigsby.

Q.37 If Mr. Rigsby's contention were correct, namely that the implementation of a decoupling mechanism would essentially guarantee a return, what implication would that have with regard to the volatility of market price relative to a market index?

A.37 If Mr. Rigsby's contention were correct, where such clauses were in effect, the companies should have betas of essentially zero, since they would have virtually no non-diversifiable risk. However, such is not the case. For example, California has had in place revenue decoupling mechanisms such as the Electric Revenue Adjustment Mechanism (ERAM) for nearly three decades. Yet, the betas of California energy companies are not, and have not been, even remotely close to zero. Even prior to the re-structuring of the electric industry in California, betas were still fairly high. For example, in 1996, the Value Line beta for Pacific Gas & Electric Company (PG&E) was 0.75. Yet, an ERAM had been in place for many years. Mr. Rigsby's contention is without merit and should be disregarded.

Q.38 Have you looked at a California utility company for insight into the validity of Mr. Rigsby's contention regarding the impact of a decoupling mechanism, or its equivalent?

A.38 I have prepared Exhibit__(FJH-26), which consists of three sheets. They are excerpts from a presentation made by Roland Risser, Director – Customer Energy Efficiency, Pacific Gas & Electric Company on August 2, 2006. It can be determined from Sheet 2 that decoupling of revenues and sales for non-fuel costs began in California in 1978 for its natural gas operations and in 1982 for its electric operations. It can also be determined by reference to Sheet 3 of Exhibit__(FJH-26) that nearly all of PG&E revenues are now decoupled; namely, only about 6% of electric revenues are at risk and only about 4.2% of natural gas revenues are at risk.

Q.39 Would the implementation of a revenue per customer decoupling mechanism result in the reduction of a level of risk to the extent that the common equity capital return rate would essentially be guaranteed?

A.39 No. Such a proposition is preposterous for several reasons. First, revenues would be stabilized, but not guaranteed, e.g., the loss of customers or the shifting of customers between rate classes. Second, expenses have a significant impact on earnings and their potential for variability, consistent with the definition of business risk. Third, while there is some reduction in risk attributable to a compression of volatility of revenues and EBIT, it is far from eliminated. Thus, there is still the need to earn an ROE commensurate with the real risk perceived by investors and reflected in the cost of capital, including bond ratings/yields. I have prepared Exhibit__(FJH-27) which consists of eight sheets. It is a copy of the June 19, 2007 research report from Standard & Poor's RatingsDirect relative to PG&E.

As can be seen, its credit rating was BBB+, and still is, despite the fact that it has had an ERAM (equivalent to a RDAP) in effect since 1982 and a similar decoupling mechanism in effect for gas revenues since 1978. As noted on Sheet 2 of Exhibit__(FJH-27), the current authorized ROE for most California Public Utilities Commission (CPUC) jurisdictional operations is 11.35%, despite the fact that all electric and gas companies have had revenue decoupling mechanisms in effect for nearly three decades.

Q.40 Has PG&E, which has both electric and gas revenue decoupling mechanisms in effect, recently received a rate increase?

A.40 Yes. As shown on Exhibit__(FJH-28), Sheet 2 of 4, a rate increase was authorized March 15, 2007, which included a return of 11.35% relative to a common equity ratio of 52%. Moreover, as shown on Sheet 4 of Exhibit ____ (FJH-28), as noted by Regulatory Research Associates in its March 19, 2008 Regulatory Focus re California Regulatory Review, on December 20, 2007, the California PUC issued ROE determinations for 2008 adopting 11.35% for PG&E as well as 11.5% for Southern California Edison and 11.1% for San Diego Gas & Electric.

I believe the foregoing data confirms that there is no merit to Mr. Rigsby's contention regarding the implementation of a decoupling mechanism on the cost of common equity capital.

V. UPDATED COMMON EQUITY CAPITAL COST RATE

Q.41 Have you prepared an update of your common equity capital cost rate to reflect more current capital market conditions?

A.41 Yes, I have. In my update, Exhibit__(FJH-29), which consists of 32 sheets, I utilized the most recent information available. In addition, I utilized the same cost of common equity capital models and applied them in the same manner as discussed in detail in my direct testimony. My updated common equity capital cost rate remains the same at 11.25%. A brief summary of my updated common equity capital cost rates and updated cost of common equity capital of 11.25% is shown on Sheet 2 of 32.

I believe that by keeping my updated common equity capital cost rate at 11.25% is conservative in view of a considerable increase in the risk premium and CAPM/ECAPM cost rates since the time my direct testimony was prepared. This is attributable in part to the fact that there has been no decline in long-term debt cost rate for Southwest despite a substantial decline in the yields on long-term U.S. Treasury securities; a modest decline in the long-term debt yields of higher rated utility bonds, which translates to an increase in the risk differential for Southwest as investors have become more wary of investing in lower quality long-term debt such as Southwest's bottom of investment grade rated bonds. Also, there has been an increase in Southwest's beta. As shown on Sheet 2 of 32 of Exhibit__(FJH-29), a cost rate of 11.00% based on the proxy group of eight LDCs translates to a cost rate of 11.61% when the increased risk differential (Southwest's Baa3 bond rating vs. A3 bond rating of the proxy group) of 0.61% is taken into account. Thus, keeping my updated recommended common equity capital cost rate at 11.25% is reasonable and conservative.

VI. REASONABLENESS CHECK

Q.42 Have you performed an updated reasonableness check in order to further ascertain whether your updated common equity capital cost rate of 11.25% is reasonable?

A.42 Yes, I have. I have prepared Exhibit__(FJH-30) which consists of 7 sheets. On Sheet 1, I show a summary of regulatory awards made to gas distribution companies and the gas operations of combination electric and gas companies for the 12 months ended March 31, 2008. As shown, the average authorized rate of return on common equity capital in litigated rate cases was 10.33% relative to a 52.42% common equity ratio. The average equity risk premium awarded over the yield on Moody's A rated public utility bonds was 4.25%. As discussed supra, in view of the increasing financial turmoil in our economy in the past year, there has been a decided trend by investors to higher quality long-term debt resulting in greater cost rate differentials to companies with lower quality debt such as Southwest's bottom of investment grade ratings of Baa3 by Moody's and BBB- by S&P. For this reason, utility bonds such as those of Southwest's, which are rated at the bottom of investment grade (one more notch down would put them into junk bond status) has increased substantially. Thus, in view of a prospective bond yield of 7.01% (6.26% + 0.75%) on debt rated Baa3, and an average equity risk premium of 4.25 percentage points consistent with that of the recent past, i.e., twelve months ended March 31, 2008, it is seen on Exhibit__(FJH-32) that an 11.26% common equity capital cost rate is indicated to be applicable to Southwest. During the past year, the yield has declined somewhat on higher rated public utility bonds, but has remained essentially the same for Southwest, indicating a substantial increase in the relative cost attributable to Southwest's bottom of investment grade rating.

Q.43 I notice that you have excluded from your average of awards made for return on cost of common equity capital in litigated rate cases the award to National Fuel

Gas Distribution Corp. of 9.10% by the New York Public Service Commission. Why did you exclude the results from that rate case?

A.43 At Sheets 2 through 7 of Exhibit__(FJH-30), I presented information from Regulatory Research Associates relative to that rate proceeding. As can be gleaned from RRA's evaluation at the bottom of Sheet 3, they indicate that it is "negative from an investor viewpoint." They go on to state:

> The PSC authorized a return on equity (ROE) that is well below the average returns authorized energy utilities nationwide during the past 12 months. We note that the authorized ROE is equal to that authorized for Consolidated Edison subsidiary Orange & Rockland Utilities' (ORU) electric operations in October 2007 following an earnings investigation. At that time, we indicated that to our knowledge, the 9.1% ROE was the lowest equity return authorized an energy utility nationwide in at least the last 30 years.

In view of Southwest's bottom of investment grade rating and RRA's evaluation of the National Fuel Gas Distribution order, it is inappropriate to include those results in an attempt to verify the reasonableness of my recommendation.

In view of the foregoing, I believe that my updated recommendation, which is unchanged from my original recommendation of an 11.25% common equity capital cost rate is both reasonable and conservative.

VII. FAIR VALUE RATE BASE COST OF CAPITAL

Q.44 Mr. Hanley, have you reviewed the section of ACC Staff Witness Parcell's direct testimony entitled, "Fair Value Rate Base Cost of Capital"?

A.44 Yes, I have.

Q.45 Do you believe that the Company's overall cost of capital of 9.45% should or must be applied to the fair value rate base?

A.45 No, I do not.

Q.46 Is it your understanding that the Commission has the discretion to determine the appropriate methodology for establishing the rate of return to be applied to a fair value rate base?

A.46 Yes.

Q.47 Is there a link between the concepts of rate base and the cost of capital as suggested by Mr. Parcell?

A.47 Yes, I believe there are. However, I differ considerably with Mr. Parcell who contends that the fair value rate base (FVRB) increment should be considered as cost-free capital.

Q.48 Why do you disagree with Mr. Parcell's contention that the FVRB increment should be considered as cost-free capital?

A.48 The concept of a fair value rate base is analogous to ownership in a private residence. When market values rise, the differential between cost and fair value (less any mortgage debt, etc.) benefits the owner through an increase in the owner's equity. Conversely, in a market such as being experienced currently and in the recent past, when market values have been declining, the equity of the owner diminishes to his or her detriment.

Q.49 You do agree, however, do you not that if the normally determined market-based common equity capital cost rate were applied to the FVRB increment that it would represent a windfall to shareholders?

A.49 Yes, I do. I recognize that it has long been established in regulatory ratemaking that application of a weighted average cost of capital (WACC or the overall cost of capital) to an original cost rate base (OCRB) provides for a fair and reasonable opportunity to earn a return. However, Mr. Parcell's cost-free capital approach to the

FVRB increment totally obviates any purpose of the FVRB increment. In fact, his methodology would provide an opportunity for net operating income, which is actually less than that which would be obtained through application of Staff's recommended WACC of 8.86% to its proposed OCRB. This is easily demonstrated as follows:

Net Operating Income Under ACC Staff Proposed OCRB Rate Base

OCRB Rate Base	$1,070,195,857
Staff Proposed WACC	x .0886
Net Operating Income	$94,819,353

Net Operating Income Based Upon ACC Staff's Proposed FVRB Where the Increment Above OCRB is Considered as Zero Cost Capital

ACC Staff Proposed FVRB	$1,393,340,942
Proposed WACC Applicable	x .0680
Net Operating Income	$94,747,660

As can be readily determined by comparison of the above, Mr. Parcell's proposed treatment of the increment of the FVRB as cost-free capital actually results in $71,693 less net operating income than by applying the WACC of 8.86% to Staff's proposed OCRB. Clearly, this methodology is not only illogical but even worse than the methodology that has already been rejected by the Arizona Appeals Court decision in Chaparral City Water Company (Appeals No. CA-CC 05-002).

Q.50 **Mr. Parcell has recommended an alternative method whereby he applies a 1.25% return rate to the FVRB increment and arrives at a WACC relative to the Staff proposed fair value rate base of 7.09%. Do you agree with his alternative method?**

A.50 No. I generally agree with the basic notion of applying some type of net of inflation risk-free rate to the FVRB increment, but disagree with his application of 1.25%. Mr.

Parcell's conclusion of allowing only one-half of what he believes is the net of inflation risk-free rate is totally arbitrary and should be rejected.

Q.51 Why do you believe that some type of net of inflation risk-free rate is applicable?

A.51 First, let me say that I think it would be completely inappropriate to subtract inflation from the WACC because any benefit or detriment of FVRB increment should only relate to the common shareholders. The application of a net of inflation risk-free rate will provide for minimal benefit of FVRB increment rather than to apply the common equity capital cost rate which would provide an opportunity for an unreasonable windfall to the common shareholders. I believe an appropriate net of inflation risk-free rate to be applied to the FVRB increment is 2.05%, which is the rate that I recommend.

Q.52 What is the basis of the 2.05% cost rate, which you recommend applicable to the FVRB increment which constitutes 23.18% of the Staff proposed FVRB?

A.52 Mr. Parcell and I have both relied upon the yield on long-term Treasury Bonds. We each use 4.5%. This is reasonable since the cost of capital is a long-term calculation. Mr. Parcell subtracted 2.0% for inflation to get a 2.5% risk-free rate, but then arbitrarily only applied one-half of it, or 1.25%. I rely upon the average of expected inflation represented by the Consumer Price Index (CPI) for the six calendar quarters ending with the third quarter of 2009 of 2.45% from Blue Chip Financial Forecasts dated April 1, 2008 as shown on Sheet 22 of Exhibit__(FJH-29). I believe that using the average expected inflation rate makes sense in view of rising consumer prices and the expectational concept of the cost of capital. Thus, the net of inflation risk-free rate, which is applicable to the FVRB increment is 2.05% (4.50% - 2.45% expected inflation).

Q.53 Does that conclude your rebuttal testimony?

A.53 Yes, it does.

Southwest Gas Corporation
Comparison of Bond Ratings, Business and Financial Profiles
for ACC Staff Witness Parcell's Two Proxy Groups of Value Line Gas Distribution Companies

	Moody's Bond Rating March 2008		Standard & Poor's Bond Rating March 2008		Standard & Poor's			
	Bond Rating	Numerical Weighting (1)	Bond Rating	Numerical Weighting (1)	Business Risk Profile (2)	Numerical Weighting (1)	Financial Risk Profile (2)	Numerical Weighting (1)
ACC Staff Witness Parcell's Value Line Gas Distribution Companies								
AGL Resources Inc. (3)	A3	7.0	A-	7.0	Excellent	1.0	Intermediate	2.0
Atmos Energy Corp. (4)	Baa3	10.0	BBB	9.0	Excellent	1.0	Aggressive	3.0
Energen Corporation (5)	A1	5.0	BBB+	8.0	Excellent	1.0	Intermediate	2.0
The Laclede Group, Inc. (6)	A3	7.0	A	6.0	Excellent	1.0	Intermediate	2.0
New Jersey Resources Corp.(7)	Aa3	4.0	A+	5.0	Excellent	1.0	Intermediate	2.0
NICOR Inc. (8)	A1	5.0	AA	3.0	Excellent	1.0	Intermediate	2.0
Northwest Natural Gas Company	A2	6.0	AA-	4.0	Excellent	1.0	Intermediate	2.0
Piedmont Natural Gas Company, Inc.	A3	7.0	A	6.0	Excellent	1.0	Intermediate	2.0
South Jersey Industries, Inc. (9)	Baa1	8.0	A	6.0	Excellent	1.0	Aggressive	3.0
Southwest Gas Corporation	Baa3	10.0	BBB-	10.0	Strong	2.0	Aggressive	3.0
UGI Corporation (10)	A3	7.0	NR	–	NA	–	NA	–
WGL Holdings, Inc. (11)	A2	6.0	AA-	4.0	Excellent	1.0	Intermediate	2.0
Average	A3	6.8	A	6.2	Excellent	1.1	Intermediate	2.3
ACC Staff Witness Parcell's Proxy Group of Eight Value Line Gas Distribution Companies (12)								
AGL Resources Inc. (3)	A3	7.0	A-	7.0	Excellent	1.0	Intermediate	2.0
Atmos Energy Corp. (4)	Baa3	10.0	BBB	9.0	Excellent	1.0	Aggressive	3.0
The Laclede Group, Inc. (6)	A3	7.0	A	6.0	Excellent	1.0	Intermediate	2.0
NICOR Inc. (8)	A1	5.0	AA	3.0	Excellent	1.0	Intermediate	2.0
Northwest Natural Gas Company	A2	6.0	AA-	4.0	Excellent	1.0	Intermediate	2.0
Piedmont Natural Gas Company, Inc.	A3	7.0	A	6.0	Excellent	1.0	Intermediate	2.0
South Jersey Industries, Inc. (9)	Baa1	8.0	A	6.0	Excellent	1.0	Aggressive	3.0
WGL Holdings, Inc. (11)	A2	6.0	AA-	4.0	Excellent	1.0	Intermediate	2.0
Average	A3	7.0	A	5.6	Excellent	1.0	Intermediate	2.3
Southwest Gas Corporation	Baa3	10.0	BBB-	10.0	Strong	2.0	Aggressive	3.0

NA = Not Available
NR = Not Rated

Notes:

(1) From Sheet 3 of this Schedule.
(2) From Standard & Poor's (S&P) "Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies, Strongest To Weakest", April 4, 2008.
(3) Moody's ratings are those of Atlanta Gas Light Co. S&P's ratings and business profile are a composite of those of Atlanta Gas Light Co. and Pivotal Utility Holdings (formerly NUI Utilities).
(4) Moody's ratings and S&P's business profile are those of Atmos Energy Corporation. S&P's ratings are a composite of those of Atmos Energy Corporation and United Cities Gas Company dba Atmos Energy Corporation.
(5) Ratings and profiles are those of Alabama Gas Corporation
(6) Ratings and profiles are those of Laclede Gas Company.
(7) Ratings and profiles are those of New Jersey Natural Gas Company.
(8) Ratings and profiles are those of NICOR Gas Company.
(9) Moody's ratings are those of South Jersey Natural Gas Company. S&P's ratings and profiles are not available.
(10) Ratings are those of UGI Utilities, Inc.
(11) Ratings and profiles are those of Washington Gas Light Company.
(11) Ratings and profiles are those of Washington Gas Light Company.
(12) This group is the same as the proxy group relied upon by Mr. Hanley.

Source of Information:
Moody's Investors Service
Standard & Poor's RatingsDirect

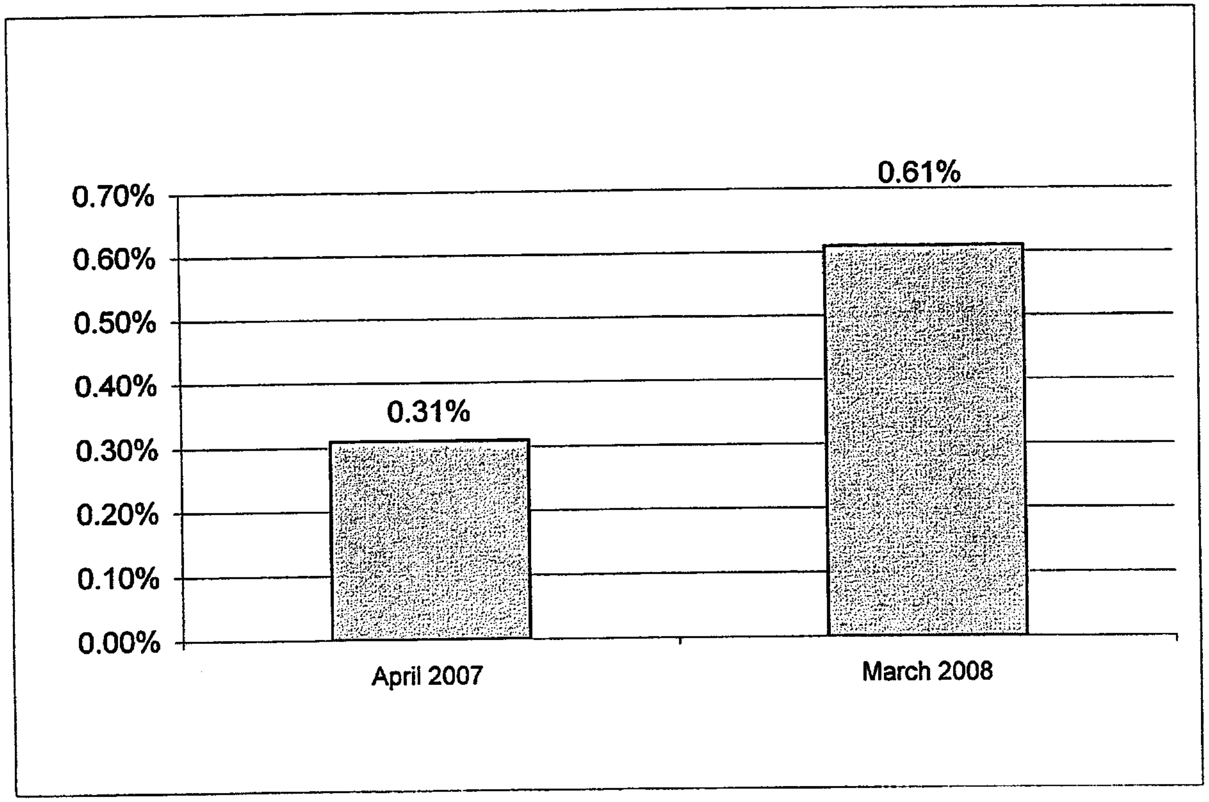
Southwest Gas Corporation
Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings
Standard & Poor's Business and Financial Risk Profiles

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-

Standard & Poor's

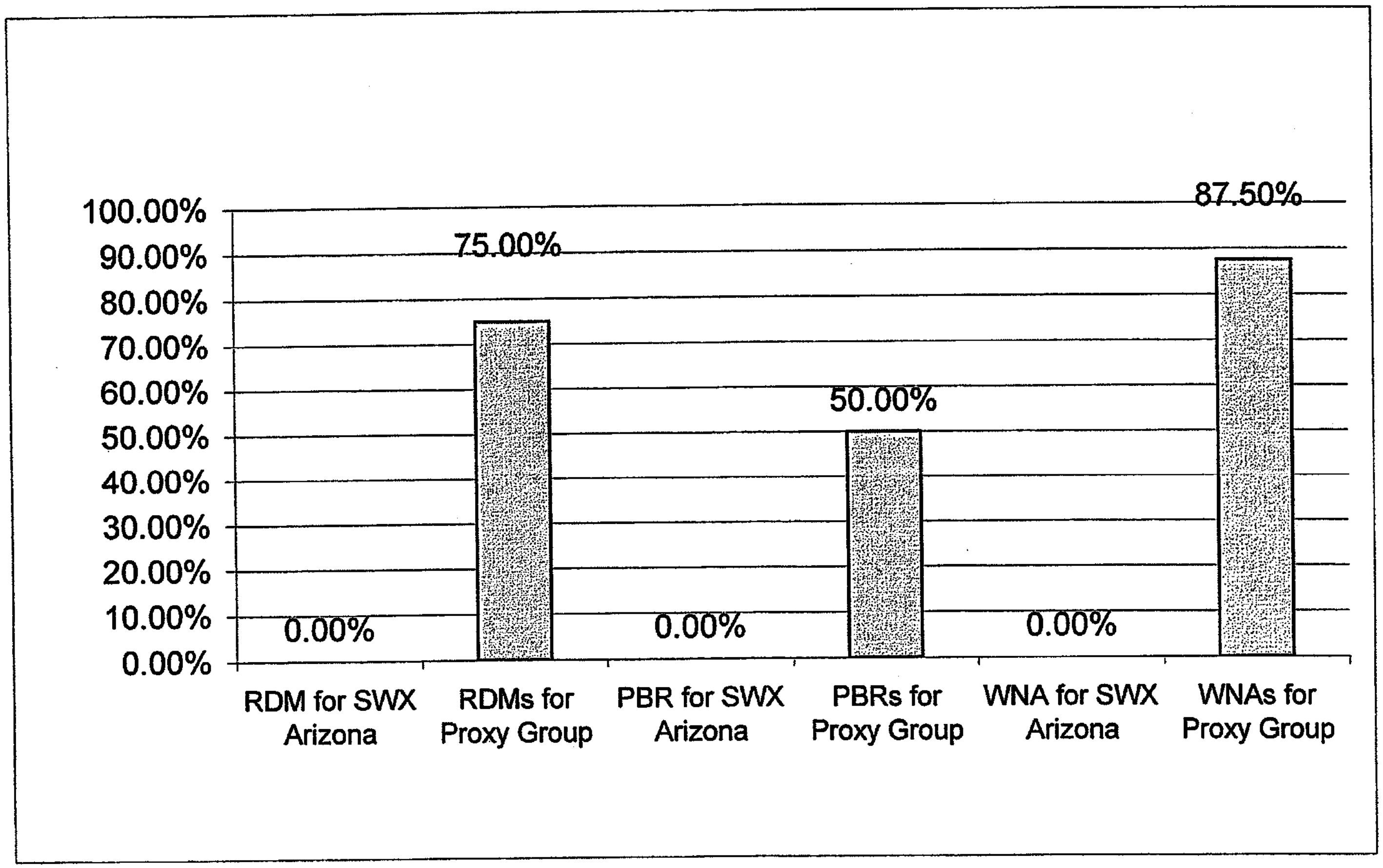
Business Risk Profile	Numerical Weighting	Financial Risk Profile	Numerical Weighting
Excellent	1	Modest	1
Strong	2	Intermediate	2
Satisfactory	3	Aggressive	3
Weak	4	Highly Leveraged	4
Vulnerable	5		

Southwest Gas Corporation
Estimated Bond Yield Spread Between Bonds Rated A3 and Baa3
for the Two Months Ending April 2007
Versus
the Two Months Ending March 2008



Source of Information: Mergent Bond Record Monthly Update, April 2008, Vol. 75, No. 4

Southwest Gas Corporation
Revenue Decoupling Mechanisms, Alternative Regulation Plans and Weather Normalization Adjustment Clauses
for Southwest Gas Corporation - Arizona Jurisdiction
and Mr. Hanley's Proxy Group of Eight Value Line Gas Distribution Companies (1)



Notes:
(1) Data from Sheet 2 of this Exhibit.

Southwest Gas Corporation
Revenue Decoupling Mechanisms, Alternative Regulation Plans and Weather Normalization Adjustment Clauses
for Southwest Gas Corporation - Arizona Jurisdiction
and the Proxy Group of Eight Value Line Gas Distribution Companies

Companies	Revenue Normalization Decoupling Mechanisms			Alternative Regulation Plans (ARPS), Performance Based Ratemaking Mechanisms (PBRs) and other Alternative Programs			Weather Normalization Adjustment Clauses (WNAs) and other Weather Innovative Rate Designs		
	Does company have it?	Type	State	Does company have it?	Type	State	Does company have it?	Type	State
Southwest Gas Corporation Arizona Jurisdiction	No	—	—	No	—	—	No	—	—
AGL Resources Inc.	Yes	Straight Fixed Variable Rate Design (SVF)	Georgia	Yes	PBR	Virginia	Yes	WNA	New Jersey Tennessee Virginia
Atmos Energy Corporation	Yes	Straight Fixed Variable Rate Design (SVF)	Missouri	Yes	PBR PBR GCI	Georgia Kentucky Tennessee	Yes	WNA WNA WNA WNA WNA WNA WNA WNA	Georgia Kansas Kentucky Louisiana Mississippi Tennessee Texas Virginia
The Laclede Group, Inc.	No	—	—	No	—	—	Yes (1)	No WNA, but Innovative Weather Rate Design.	Missouri
NICOR Inc.	No	—	—	No	—	—	No	—	—
Northwest Natural Gas Company	Yes	Conservation Adjustment Decoupling Mechanism (CADM)	Oregon	No	—	—	Yes	WNA	Oregon
Piedmont Natural Gas Company, Inc.	Yes (2)	Customer Utilization Tracker (CUT)	North Carolina	Yes	Rate Tracking Factor (RTF)	North Carolina	Yes (2)	Customer Utilization Tracker (CUT).	North Carolina
					Gas Cost Incentive Mechanism (GCI)	Tennessee		WNA	South Carolina
								WNA	Tennessee
South Jersey Industries, Inc.	Yes (3)	Conservation and Usage Adjustment Mechanism (CUA)	New Jersey	No	—	—	Yes (3)	Conservation Usage and Adjustment mechanism (CUA).	New Jersey
WGL Holdings, Inc.	Yes (4)	Revenue Normalization Adjustment mechanism (RNA)	Maryland	Yes	PBR	Virginia	Yes (4)	Revenue Normalization Adjustment mechanism (RNA)	Maryland
								WNA	Virginia

Notes:

(1) The Laclede Group does not have a WNA. However, the company has an innovative weather mitigation rate design that lessens the impact of weather volatility on Laclede Gas Company's customers during the peak cold months of December through March, and reduces the impact of weather, to a lesser extent, during the months of November and April.

(2) Until September 2006, Piedmont Natural Gas Company had a WNA Clause in the state of North Carolina. However, on September 14, 2006, the North Carolina Utilities Commission adopted a settlement reached by the Company and the North Carolina Attorney General on July 18, 2006, regarding the company's Customer Utilization Tracker (CUT). The CUT is a mechanism that decouples the recovery of authorized margins from sales levels. The CUT applies to changes in sales levels caused by any factor.

(3) On October 12, 2006, the New Jersey Board of Public Utilities approved a three-year pilot energy conservation program and revenue decoupling mechanism that had been proposed by South Jersey Gas Company (SJG). Under the programs, SJG will implement enhanced customer education and energy conservation programs. In place of the existing weather normalization clause, the company will implement a conservation and usage adjustment mechanism (CUA) mechanism that is designed to remove impact on company earnings and revenue of sales fluctuations due to weather variations and customer participation in the conservation program.

(4) In August 2005, Washington Gas Light Company received approval from the Public Service Commission of Maryland to implement a Revenue Normalization Adjustment mechanism (RNA). The RNA is a billing adjustment mechanism that is designed to stabilize the level of distribution charge revenues received from Maryland customers as a result of deviations in customer usage caused by variations in weather from normal levels and other matters such as conservation.

Source of Information:

Regulatory Research Associates, Inc., An SNL Energy Company.
AGA Rate Service, Published by AUS Utility Reports.
Company Annual Forms 10-K and Quarterly Forms 10-Q.
Company Forms 8-K, Company News Releases and News Releases Issued by Public Service Commissions.

Southwest Gas Corporation
Example of the Inadequacy of
DCF Return Rate Related to Book Value
When Market Value Exceeds Book Value

Line No.		Based on ACC Staff Witness Parcell's Two Proxy Groups of Gas Distribution Companies		Based on RUCO Witness Rigsby's Proxy Group of Natural Gas LDCs	
		Market Value	Book Value	Market Value	Book Value
1.	Per Share	$ 36.395 (1)	$ 19.375 (2)	$ 33.844 (3)	$ 19.668 (2)
2.	DCF Cost Rate (1)	9.90% (4)	9.90% (4)	9.73% (5)	9.73% (5)
3.	Return in Dollars	$ 3.603	$ 1.918	$ 3.293	$ 1.914
4.	Dividends	$ 1.401 (6)	$ 1.401 (6)	$ 1.540 (7)	$ 1.540 (7)
5.	Growth in Dollars	$ 2.202	$ 0.517	$ 1.753	$ 0.374
6.	Return on Market Value	9.90%	5.27% (8)	9.73%	5.66% (9)
7.	Rate of Growth on Market Value	6.05% (10)	1.42% (11)	5.18% (12)	1.11% (13)

Notes:

(1) Average market price of ACC Staff Witness Parcell's Value Line gas distribution companies and Mr. Hanley's proxy group of eight Value Line gas distribution companies as derived from Exhibit ___(DCP-6), page 1 of 4.

(2) From page 2 of this Exhibit.

(3) Average market price of RUCO Witness Rigsby's proxy group of natural gas LDCs as derived from Schedule WAR - 3.

(4) The midpoint of ACC Staff Witness Parcell's DCF common equity cost rates (9.90% = (10.40% + 9.30%) / 2), from Exhibit DCP-6, page 4 of 4.

(5) RUCO Witness Rigsby's DCF recommend common equity cost rate from Schedule WAR - 2.

(6) Dividends per share based upon a 3.85% dividend yield ((3.85% = (3.6% + 4.1%) / 2) from Exhibit DCP-6, page 4 of 4). $1.401 = $36.395 * 3.85%.

(7) Dividends per share based upon a 4.55% dividend yield ((4.55% from Schedule WAR - 3). $1.540 = $33.840 * 4.55%.

(8) 5.27% = $1.918 / $36.395.

(9) 5.66% = $1.914 / $33.840.

(10) Rate of Growth on Market Value is derived as follows: 6.05% = 9.90% - 3.85%.

(11) Actual rate of growth when DCF cost rate is applied to book value ($1.918 possible earnings - $1.401 dividends = $0.517 for growth / $36.395 market value = 1.42%).

(12) Rate of Growth on Market Value is derived as follows: 5.18% = 9.73% - 4.55%

(13) Actual rate of growth when DCF cost rate is applied to book value ($1.914 possible earnings - $1.540 dividends = $0.374 for growth / $33.840 market value = 1.11%).

Southwest Gas Corporation
Market-to-Book Ratios for
ACC Witness Parcell's Two Proxy Groups of Value Line Gas Distribution Companies,
and RUCO Witness Rigsby's Proxy Group of Natural Gas LDCs

Company	1 Common Stock Shares Outstanding at December 31, 2007 (1) (millions)	2 Book Value per Share at December 31, 2007 (2)	3 Total Common Equity at December 30, 2007 (1) (millions)	4 Average Prices (3)	5 Market-to-Book Ratio (4)
ACC Staff Witness Parcell's Proxy Group of Value Line Gas Distribution Companies					
AGL Resources, Inc.	76.400	$ 21.741	$ 1,661.000	$ 37.320	171.66 %
Atmos Energy Corporation	89.907	22.607	2032.483	27.430	121.33
Energen Corporation	70.817	19.468	1378.658	64.010	328.80
The Laclede Group, Inc.	21.762	20.237	440.397	33.790	166.97
New Jersey Resources Corp.	41.724	16.033	668.969	47.950	299.07
NICOR Inc.	45.130	20.944	945.200	41.280	197.10
Northwest Natural Gas Company	26.407	22.522	594.751	47.760	212.06
Piedmont Natural Gas Company, Inc.	73.395	12.550	921.125	26.000	207.17
South Jersey Industries, Inc.	29.607	16.249	481.080	36.160	222.54
Southwest Gas Corporation	42.806	22.980	983.673	28.640	124.63
UGI Corporation	106.757	13.145	1403.300	26.090	198.48
WGL Holdings, Inc.	49.449	20.491	1013.255	32.970	160.90
Average of Staff Witness Parcell's Proxy Group of Value Line Gas Distribution Companies.	56.180	$ 19.081	$ 1,043.658	$ 37.450	200.90 %
ACC Staff Witness Parcell's Proxy Group of Eight Gas Distribution Companies (5)	51.507	$ 19.668	$ 1,011.161	$ 35.339	182.47 %
Average of ACC Staff Witness Parcell's Two Proxy Groups of Value Line Gas Distribution Companies	53.844	$ 19.375	$ 1,027.410	$ 36.395	191.68 %
RUCO Witness Rigsby's Proxy Group of Natural Gas LDCs					
AGL Resources, Inc.	76.400	$ 21.741	$ 1,661.000	$ 35.970	165.448 %
Atmos Energy Corporation	89.907	22.607	2032.483	26.910	119.034
The Laclede Group, Inc.	21.762	20.237	440.397	34.390	169.936
NICOR Inc.	45.130	20.944	945.200	36.600	174.752
Northwest Natural Gas Company	26.407	22.522	594.751	44.740	198.650
Piedmont Natural Gas Company, Inc.	73.395	12.550	921.125	25.210	200.876
South Jersey Industries, Inc.	29.607	16.249	481.080	34.780	214.044
WGL Holdings, Inc.	49.449	20.491	1013.255	32.150	156.898
Average of RUCO Witness Rigsby's Proxy Group of Natural Gas LDCs.	51.507	$ 19.668	$ 1,011.161	$ 33.844	174.955 %

Notes:
(1) As of December 31, 2007, except Piedmont Natural Gas Co. which is at January 31, 2008.
(2) Column 3 / Column 1.
(3) Prices for ACC staff witness Parcell's two proxy groups of companies are the average high & low prices for the months of Nov. '07, Dec. '07 and Jan. '08, while the prices for RUCO witness Rigsby's proxy group of natural as LDCs are the average closing prices for the period 1/28/08 through 3/20/08.
(4) Column 4 / Column 2.
(5) This group is the same as the proxy group relied upon by Mr. Hanley.

Source of Information:
EDGAR Online's I-Metrix Database
Standard & Poor's Compustat Services, Inc., PC Plus / Research Insight Database
ACC Witness Parcell's Exhibit ___(DCP-6), page 1 of 4
RUCO Witness Rigsby's Schedule WAR - 3.

Exhibit__(FJH-18)
Sheet 1 of 5

Ibbotson® SBBI®
2008 Valuation Yearbook

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

SBBI

MORNINGSTAR®

The Market Benchmark and Firm Size

Although not restricted to include only the 500 largest companies, the S&P 500 is considered a large company index. The returns of the S&P 500 are capitalization weighted, which means that the weight of each stock in the index, for a given month, is proportionate to its market capitalization (price times number of shares outstanding) at the beginning of that month. The larger companies in the index therefore receive the majority of the weight. The use of the NYSE "Deciles 1–2" series results in an even purer large company index. Yet many valuation professionals are faced with valuing small companies, which historically have had different risk and return characteristics than large companies. If using a large stock index to calculate the equity risk premium, an adjustment is usually needed to account for the different risk and return characteristics of small stocks. This will be discussed further in Chapter 7 on the size premium.

The Risk-Free Asset

The equity risk premium can be calculated for a variety of time horizons when given the choice of risk-free asset to be used in the calculation. The 2008 *Ibbotson® Stocks, Bonds, Bills, and Inflation® Classic Yearbook* provides equity risk premia calculations for short-, intermediate-, and long-term horizons. The short-, intermediate-, and long-horizon equity risk premia are calculated using the income return from a 30-day Treasury bill, a 5-year Treasury bond, and a 20-year Treasury bond, respectively.

Although the equity risk premia of several horizons are available, the long-horizon equity risk premium is preferable for use in most business-valuation settings, even if an investor has a shorter time horizon. Companies are entities that generally have no defined life span; when determining a company's value, it is important to use a long-term discount rate because the life of the company is assumed to be infinite. For this reason, it is appropriate in most cases to use the long-horizon equity risk premium for business valuation.

20-Year versus 30-Year Treasuries

Our methodology for estimating the long-horizon equity risk premium makes use of the income return on a 20-year Treasury bond; however, the Treasury currently does not issue a 20-year bond. The 30-year bond that the Treasury recently began issuing again is theoretically more correct due to the long-term nature of business valuation, yet Ibbotson Associates instead creates a series of returns using bonds on the market with approximately 20 years to maturity. The reason for the use of a 20-year maturity bond is that 30-year Treasury securities have only been issued over the relatively recent past, starting in February of 1977, and were not issued at all through the early 2000s.

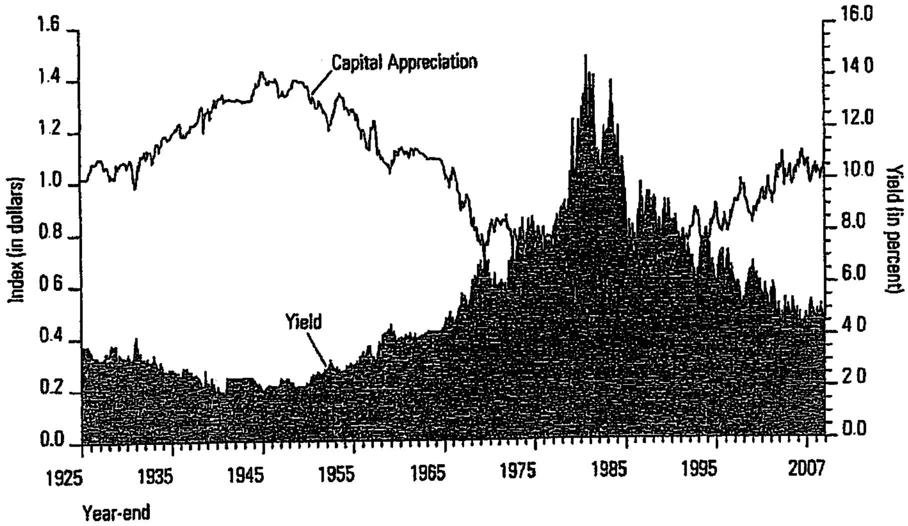
The same reason exists for why we do not use the 10-year Treasury bond; that is, a long enough history of market data is not available for 10-year bonds. We have persisted in using a 20-year bond to keep the basis of the time series consistent.

Income Return

Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[2]

Yields have generally risen on the long-term bond over the 1926–2007 period, so it has experienced negative capital appreciation over much of this time. This trend has turned around since the 1980s, however. Graph 5-2 illustrates the yields on the long-term government bond series compared to an index of the long-term government bond capital appreciation. In general, as yields rose, the capital appreciation index fell, and vice versa. Had an investor held the long-term bond to maturity, he would have realized the yield on the bond as the total return. However, in a constant maturity portfolio, such as those used to measure bond returns in this publication, bonds are sold before maturity (at a capital loss if the market yield has risen since the time of purchase). This negative return is associated with the risk of unanticipated yield changes.

Graph 5-2
Long-term Government Bond Yields versus Capital Appreciation Index
1925–2007



2 Please note that the appropriate forward-looking measure of the riskless rate is the yield to maturity on the appropriate-horizon government bond. This differs from the riskless rate used to measure the realized equity risk premium historically. Chapter 4 includes a thorough discussion of riskless rate selection in this context.

For example, if bond yields rise unexpectedly, investors can receive a higher coupon payment from a newly issued bond than from the purchase of an outstanding bond with the former lower-coupon payment. The outstanding lower-coupon bond will thus fail to attract buyers, and its price will decrease, causing its yield to increase correspondingly, as its coupon payment remains the same. The newly priced outstanding bond will subsequently attract purchasers who will benefit from the shift in price and yield; however, those investors who already held the bond will suffer a capital loss due to the fall in price.

Anticipated changes in yields are assessed by the market and figured into the price of a bond. Future changes in yields that are not anticipated will cause the price of the bond to adjust accordingly. Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return.The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Arithmetic versus Geometric Means

The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. Graph 5-3 shows the realized equity risk premium for each year based on the returns of the S&P 500 and the income return on long-term government bonds. (The actual, observed difference between the return on the stock market and the riskless rate is known as the realized equity risk premium.) There is considerable volatility in the year-by-year statistics. At times the realized equity risk premium is even negative.

Exhibit__(FJH-18)
Sheet 5 of 5

Table 2-1
Total Returns, Income Returns, and Capital Appreciation of the Basic Asset Classes
Summary Statistics of Annual Returns

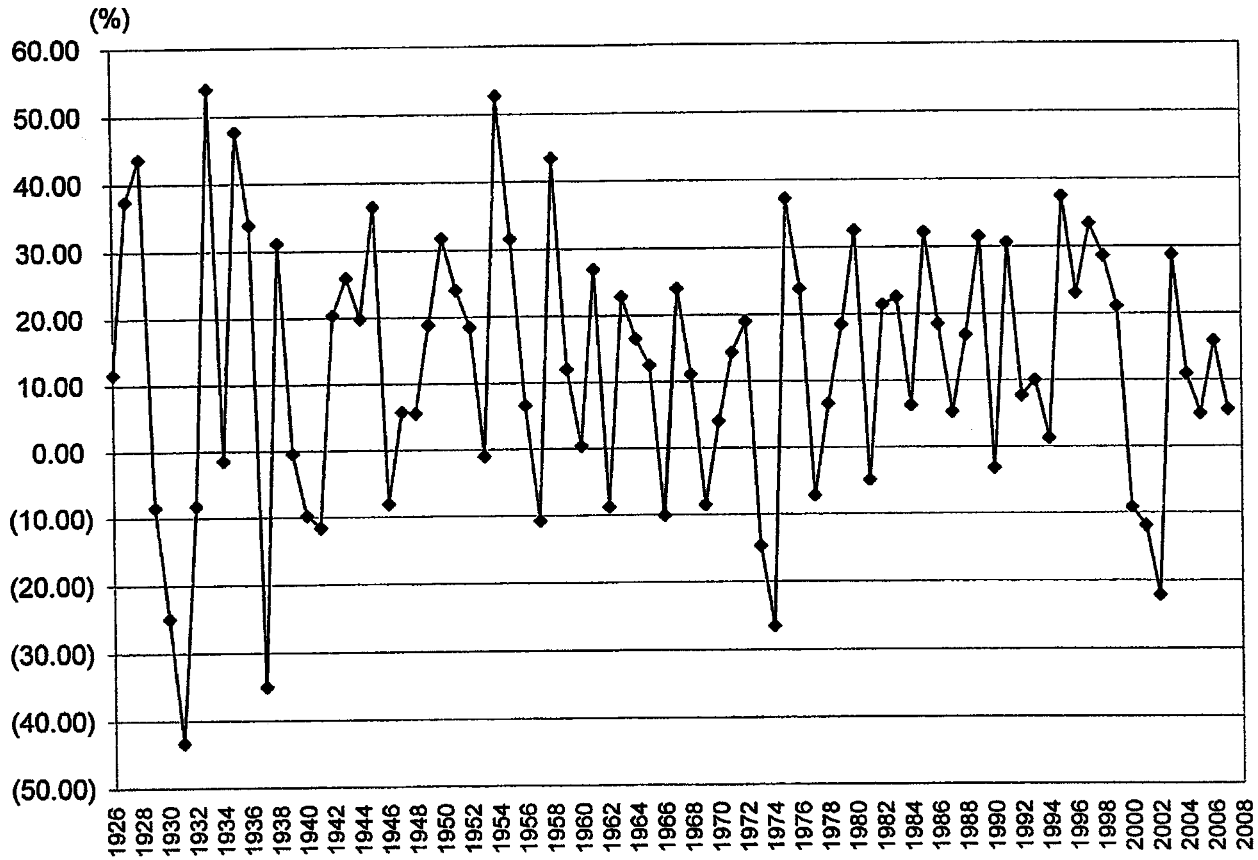
from 1926 to 2007

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Serial Correlation
Large Company Stocks				
Total Returns	10 4%	12 3%	20 0%	0 03
Income	4.2	4 2	1.6	0 89
Capital Appreciation	6 0	7 8	19.3	0.03
Ibbotson Small Company Stocks				
Total Returns	12.5	17 1	32 6	0 06
Mid-Cap Stocks*				
Total Returns	11.3	14 0	24 4	−0 02
Income	4 0	4 0	1 7	0 89
Capital Appreciation	7 1	9 8	23 7	−0 02
Low-Cap Stocks*				
Total Returns	11 7	15 5	29.0	0 03
Income	3 7	3 7	2.0	0 89
Capital Appreciation	7 9	11 6	28 4	0 02
Micro-Cap Stocks*				
Total Returns	12 5	18 5	38 8	0 08
Income	2 6	2 6	1.8	0 91
Capital Appreciation	9 9	15 8	38.3	0 07
Long-Term Corporate Bonds				
Total Returns	5 9	6 2	8 4	0 08
Long-Term Government Bonds				
Total Returns	5 5	5.8	9 2	−0 08
Income	5 2	5 2	2 7	0 96
Capital Appreciation	0 1	0 4	8.0	−0 23
Intermediate-Term Government Bonds				
Total Returns	5.3	5 5	5 7	0.15
Income	4.7	4 7	2 9	0 96
Capital Appreciation	0.5	0 5	4 4	−0.19
Treasury Bills				
Total Returns	3.7	3 8	3 1	0.91
Inflation	3.0	3.1	4.2	0 65

Total return is equal to the sum of three component returns: income return capital appreciation return, and reinvestment return

*Source: ©200801 CRSP®, Center for Research in Security Prices Graduate School of Business. The University of Chicago used with permission All rights reserved www crsp chicagogsb edu
See Chapter 7 for details on decile construction

Southwest Gas Corporation
Large Company Stock Returns
From 1926 to 2007



Source of Information:
Stocks, Bonds, Bills and Inflation - Valuation Edition 2008 Yearbook,
Morningstar, Inc., Chicago, Il

Southwest Gas Corporation
Total Returns on Large Company Stocks
1926 to 2007

Large Company Stocks

						2006				
						2004				
					2007	1988	2003	1997		
				1990	2005	1986	1999	1995		
				1981	1994	1979	1998	1991		
				1977	1993	1972	1996	1989		
				1969	1992	1971	1983	1985		
				1962	1987	1968	1982	1980		
				1953	1984	1965	1976	1975		
			2001	1946	1978	1964	1967	1955		
			2000	1940	1970	1959	1963	1950		
			1973	1939	1960	1952	1961	1945		
		2002	1966	1934	1956	1949	1951	1938	1958	
		1974	1957	1932	1948	1944	1943	1936	1935	1954
	1931	1937	1930	1941	1929	1947	1926	1942	1927	1928	1933

-50% -40% -30% -20% -10% 0% 10% 20% 30% 40% 50% 60%

Arithmetic Mean: $r_A = \sum_{t=1}^{n} r_t / n$

Source : Stocks, Bonds, Bills, and Inflation – Valuation Edition 2008 Yearbook, pp. 30-31, Morningstar, Inc., Chicago, IL

Southwest Gas Corporation
ACC Staff Witness Parcell's CAPM Cost Rates Corrected to Reflect a
Properly Calculated Historical Market Equity Risk Premium

Traditional Capital Asset Pricing Model (1)

	1	2	3	4	5
Company	Risk-Free Rate (2)	Beta (2)	R-Squared (3)	Market Premium (4)	CAPM Cost Rates
ACC Staff Witness Parcell's Value Line Gas Distribution Companies					
AGL Resources Inc.	4.49%	0.85	0.32	7.10%	10.53%
Atmos Energy Corp.	4.49%	0.85	0.41	7.10%	10.53%
Energen Corporation	4.49%	0.95	0.26	7.10%	11.24%
The Laclede Group, Inc.	4.49%	0.90	0.32	7.10%	10.88%
New Jersey Resources	4.49%	0.85	0.32	7.10%	10.53%
NICOR Inc.	4.49%	1.00	0.37	7.10%	11.59%
Northwest Natural Gas Co.	4.49%	0.80	0.25	7.10%	10.17%
Piedmont Natural Gas Co., Inc.	4.49%	0.85	0.31	7.10%	10.53%
South Jersey Industries, Inc.	4.49%	0.80	0.25	7.10%	10.17%
Southwest Gas Corp.	4.49%	0.90	0.35	7.10%	10.88%
UGI Corporation	4.49%	0.90	0.26	7.10%	10.88%
WGL Holdings, Inc.	4.49%	0.85	0.35	7.10%	10.53%
Mean					10.71%
Median					10.53%
ACC Staff Witness Parcell's Proxy Group of Eight Value Line Gas Distribution Companies (5)					
AGL Resources Inc.	4.49%	0.85	0.32	7.10%	10.53%
Atmos Energy Corp.	4.49%	0.85	0.41	7.10%	10.53%
The Laclede Group, Inc.	4.49%	0.90	0.32	7.10%	10.88%
NICOR Inc.	4.49%	1.00	0.37	7.10%	11.59%
Northwest Natural Gas Co.	4.49%	0.80	0.25	7.10%	10.17%
Piedmont Natural Gas Co., Inc.	4.49%	0.85	0.31	7.10%	10.53%
South Jersey Industries, Inc.	4.49%	0.80	0.25	7.10%	10.17%
WGL Holdings, Inc.	4.49%	0.85	0.35	7.10%	10.53%
Mean					10.62%
Median					10.53%

Mean for the R-Squared Correlations for ACC Staff Witness Parcell Proxy Group of Value Line Companies	0.31
Mean for the R-Squared Correlations for ACC Staff Witness Parcell's Proxy Group of Eight Value Line Gas Distribution Companies (5)	0.32
Mean for the R-Squared Correlations for ACC Staff Witness Parcell's Two Proxy Groups of Value Line Gas Distribution Companies	0.32

Notes:

(1) The traditional Capital Asset Pricing Model (CAPM) is applied as follows: Column 1 + (Column No. 2 * Column No. 4).

(2) From Exhibit DCP-8, page 1 of 1.

(3) The R-Squared Correlations (R2) are from Value Line, Inc., Proprietary database, March 14, 2008.

(4) The Ibbotson Associates calculated market premium of 7.10% for the period 1926-2007 results from a total market return of 12.30% less the average income return on long-term U.S. Government Securities of 5.20% (12.30% - 5.20% = 7.10%). From Stocks, Bonds, Bills, and Inflation – Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, Morningstar, Inc., Chicago, IL, 2008.

(5) This group is the same as the proxy group relied upon by Mr. Hanley.

Southwest Gas Corporation
ACC Staff Witness Parcell's CAPM Cost Rates Corrected to Reflect a
Properly Calculated Historical Market Equity Risk Premium

Empirical Capital Asset Pricing Model (1)

Company	1 Risk-Free Rate (2)	2 Beta (2)	3 Market Premium (3)	4 ECAPM Cost Rates
ACC Staff Witness Parcell's Value Line Gas Distribution Companies				
AGL Resources Inc.	4.49%	0.85	7.10%	10.79%
Atmos Energy Corp.	4.49%	0.85	7.10%	10.79%
Energen Corporation	4.49%	0.95	7.10%	11.32%
The Laclede Group, Inc	4.49%	0.90	7.10%	11.06%
New Jersey Resources	4.49%	0.85	7.10%	10.79%
NICOR Inc.	4.49%	1.00	7.10%	11.59%
Northwest Natural Gas Co.	4.49%	0.80	7.10%	10.53%
Piedmont Natural Gas Co., Inc	4.49%	0.85	7.10%	10.79%
South Jersey Industries, Inc.	4.49%	0.80	7.10%	10.53%
Southwest Gas Corp.	4.49%	0.90	7.10%	11.06%
UGI Corporation	4.49%	0.90	7.10%	11.06%
WGL Holdings, Inc.	4.49%	0.85	7.10%	10.79%
Mean				10.93%
Median				10.79%
ACC Staff Witness Parcell's Proxy Group of Eight Value Line Gas Distribution Companies (4)				
AGL Resources Inc.	4.49%	0.85	7.10%	10.79%
Atmos Energy Corp.	4.49%	0.85	7.10%	10.79%
The Laclede Group, Inc.	4.49%	0.90	7.10%	11.06%
NICOR Inc.	4.49%	1.00	7.10%	11.59%
Northwest Natural Gas Co.	4.49%	0.80	7.10%	10.53%
Piedmont Natural Gas Co., Inc.	4.49%	0.85	7.10%	10.79%
South Jersey Industries, Inc.	4.49%	0.80	7.10%	10.53%
WGL Holdings, Inc.	4.49%	0.85	7.10%	10.79%
Mean				10.86%
Median				10.79%

Notes:

(1) The empirical CAPM is applied is as follows: Column 1 + (0.25 * Column No. 3) + (0.75 * Column No. 2 * Column No. 3).

(2) From Exhibit DCP-8, page 1 of 1.

The Ibbotson Associates calculated market premium of 7.10% for the period 1926-2007 results from a total market return of 12.30% less the average income return on long-term U.S. Government Securities of 5.20% (12.30% - 5.20% = 7.10%). From Stocks, Bonds, Bills, and Inflation – Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, Morningstar, Inc., Chicago, IL, 2008.

(3) From Exhibit DCP-8, page 1 of 1.

(4) This group is the same as the proxy group relied upon by Mr. Hanley.

Exhibit__(FJH-21)
Sheet 2 of 5

NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

The model is analogous to the standard CAPM, but with the return on a minimum risk portfolio that is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who find a flatter than predicted SML, consistent with the model and other researchers' findings. An updated version of the Black-Jensen-Scholes study is available in Brealey, Myers, and Allen (2006) and reaches similar conclusions.

The zero-beta CAPM cannot be literally employed to estimate the cost of capital, since the zero-beta portfolio is a statistical construct difficult to replicate. Attempts to estimate the model are formally equivalent to estimating the constants, a and b, in Equation 6-2. A practical alternative is to employ the Empirical CAPM, to which we now turn.

6.3 Empirical CAPM

As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \acute{\alpha} + \beta \times (MRP - \acute{\alpha}) \qquad (6\text{-}5)$$

where $\acute{\alpha}$ is the "alpha" of the risk-return line, a constant, and the other symbols are defined as before. All the potential vagaries of the CAPM are telescoped into the constant $\acute{\alpha}$, which must be estimated econometrically from market data. Table 6-2 summarizes[10] the empirical evidence on the magnitude of alpha.[11]

[10] The technique is formally applied by Litzenberger, Ramaswamy, and Sosin (1980) to public utilities in order to rectify the CAPM's basic shortcomings. Not only do they summarize the criticisms of the CAPM insofar as they affect public utilities, but they also describe the econometric intricacies involved and the methods of circumventing the statistical problems. Essentially, the average monthly returns over a lengthy time period on a large cross-section of securities grouped into portfolios are related to their corresponding betas by statistical regression techniques; that is, Equation 6-5 is estimated from market data. The utility's beta value is substituted into the equation to produce the cost of equity figure. Their own results demonstrate how the standard CAPM underestimates the cost of equity capital of public utilities because of utilities' high dividend yield and return skewness.

[11] Adapted from Vilbert (2004).

TABLE 6-2
EMPIRICAL EVIDENCE ON THE ALPHA FACTOR

Author	Range of alpha
Fischer (1993)	−3.6% to 3.6%
Fischer, Jensen and Scholes (1972)	−9.61% to 12.24%
Fama and McBeth (1972)	4.08% to 9.36%
Fama and French (1992)	10.08% to 13.56%
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%
Pettengill, Sundaram and Mathur (1995)	4.6%
Morin (1989)	2.0%

For an alpha in the range of 1%–2% and for reasonable values of the market risk premium and the risk-free rate, Equation 6-5 reduces to the following more pragmatic form:

$$K = R_F + 0.25\ (R_M - R_F) + 0.75\ \beta(R_M - R_F) \qquad (6\text{-}6)$$

Over reasonable values of the risk-free rate and the market risk premium, Equation 6-6 produces results that are indistinguishable from the ECAPM of Equation 6-5.[12]

An alpha range of 1%–2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the

[12] Typical of the empirical evidence on the validity of the CAPM is a study by Morin (1989) who found that the relationship between the expected return on a security and beta over the period 1926–1984 was given by:

$$\text{Return} = 0.0829 + 0.0520\ \beta$$

Given that the risk-free rate over the estimation period was approximately 6% and that the market risk premium was 8% during the period of study, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, or 1/4 of 8%, and that the slope of the relationship is close to 3/4 of 8%. Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x(R_M - R_F) + (1 - x)\beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment. Moreover, the lowering of the tax burden on capital gains and dividend income enacted in 2002 may have decreased the required return for taxable investors, steepening the slope of the ECAPM risk-return trade-off and bring it closer to the CAPM predicted returns.[13]

To illustrate the application of the ECAPM, assume a risk-free rate of 5%, a market risk premium of 7%, and a beta of 0.80. The Empirical CAPM equation (6-6) above yields a cost of equity estimate of 11.0% as follows:

$$\begin{aligned} K &= 5\% + 0.25\,(12\% - 5\%) + 0.75 \times 0.80\,(12\% - 5\%) \\ &= 5.0\% + 1.8\% + 4.2\% \\ &= 11.0\% \end{aligned}$$

As an alternative to specifying alpha, see Example 6-1.

Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, recall from Chapter 3 that the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

[13] The lowering of the tax burden on capital gains and dividend income has no impact as far as non-taxable institutional investors (pension funds, 401K, and mutual funds) are concerned, and such investors engage in very large amounts of trading on security markets. It is quite plausible that taxable retail investors are relatively inactive traders and that large non-taxable investors have a substantial influence on capital markets.

Southwest Gas Corporation
Market-to-Book Ratios, Earnings / Book Ratios and Inflation for Standard & Poor's Industrial Index and the Standard & Poor's 500 Composite Index from 1947 through 2006

Year	Market-to-Book Ratio (1)		Earnings/ Book Ratio (2)			Earnings / Book Ratio - Net of Inflation	
	S&P Industrial Index (3)	S&P 500 Composite Index (3)	S&P Industrial Index (3)	S&P 500 Composite Index (3)	Inflation (4)		
1947	1.23 %	NA	13.0 %	NA	9.0 %	4.0 %	NA
1948	1.13	NA	17.3	NA	2.7	14.6	NA
1949	1.00	NA	16.3	NA	(1.8)	18.1	NA
1950	1.16	NA	18.3	NA	5.8	12.5	NA
1951	1.27	NA	14.4	NA	5.9	8.5	NA
1952	1.29	NA	12.7	NA	0.9	11.8	NA
1953	1.21	NA	12.7	NA	0.6	12.1	NA
1954	1.45	NA	13.5	NA	(0.5)	14.0	NA
1955	1.81	NA	16.0	NA	0.4	15.6	NA
1956	1.92	NA	13.7	NA	2.9	10.8	NA
1957	1.71	NA	12.5	NA	3.0	9.5	NA
1958	1.70	NA	9.8	NA	1.8	8.0	NA
1959	1.94	NA	11.2	NA	1.5	9.7	NA
1960	1.82	NA	10.3	NA	1.5	8.8	NA
1961	2.01	NA	9.8	NA	0.7	9.1	NA
1962	1.83	NA	10.9	NA	1.2	9.7	NA
1963	1.94	NA	11.4	NA	1.7	9.7	NA
1964	2.18	NA	12.3	NA	1.2	11.1	NA
1965	2.21	NA	13.2	NA	1.9	11.3	NA
1966	2.00	NA	13.2	NA	3.4	9.8	NA
1967	2.05	NA	12.1	NA	3.0	9.1	NA
1968	2.17	NA	12.6	NA	4.7	7.9	NA
1969	2.10	NA	12.1	NA	6.1	6.0	NA
1970	1.71	NA	10.4	NA	5.5	4.9	NA
1971	1.99	NA	11.2	NA	3.4	7.8	NA
1972	2.16	NA	12.0	NA	3.4	8.6	NA
1973	1.96	NA	14.6	NA	8.8	5.8	NA
1974	1.39	NA	14.8	NA	12.2	2.6	NA
1975	1.34	NA	12.3	NA	7.0	5.3	NA
1976	1.51	NA	14.5	NA	4.8	9.7	NA
1977	1.38	NA	14.6	NA	6.8	7.8	NA
1978	1.25	NA	15.3	NA	9.0	6.3	NA
1979	1.23	NA	17.2	NA	13.3	3.9	NA
1980	1.31	NA	15.6	NA	12.4	3.2	NA
1981	1.24	NA	14.9	NA	8.9	6.0	NA
1982	1.17	NA	11.3	NA	3.9	7.4	NA
1983	1.45	NA	12.2	NA	3.8	8.4	NA
1984	1.46	NA	14.6	NA	4.0	10.6	NA
1985	1.67	NA	12.2	NA	3.8	8.4	NA
1986	2.02	NA	11.5	NA	1.1	10.4	NA
1987	2.50	NA	15.7	NA	4.4	11.3	NA
1988	2.13	NA	19.0	NA	4.4	14.6	NA
1989	2.58	NA	18.5	NA	4.7	13.8	NA
1990	2.63	NA	16.3	NA	6.1	10.2	NA
1991	2.77	NA	10.8	NA	3.1	7.7	NA
1992	3.29	NA	13.0	NA	2.9	10.1	NA
1993	3.72	NA	15.7	NA	2.8	12.9	NA
1994	3.73	NA	23.0	NA	2.7	20.3	NA
1995	4.06	2.64	22.9	16.0 %	2.5	20.4	13.5 %
1996	4.79	2.99	24.8	16.8	3.3	21.5	13.5
1997	5.88	3.53	24.6	16.3	1.7	22.9	14.6
1998	7.13	4.16	21.3	14.5	1.6	19.7	12.9
1999	8.27	4.76	25.2	16.7	2.7	22.5	14.0
2000	7.51	4.51	23.9	15.6	3.4	20.5	12.2
2001	NA	3.50	NA	15.0	1.6	NA	13.4
2002	NA	2.93	NA	8.3	2.4	NA	5.9
2003	NA	2.78	NA	14.1	1.9	NA	12.2
2004	NA	2.91	NA	15.0	3.3	NA	11.7
2005	NA	2.78	NA	16.1	3.4	NA	12.7
2006	NA	2.75 (5)	NA	16.9	2.5	NA	14.4
Average	2.34 %	3.35 %	14.9 %	15.1 %	3.9 %	10.9 %	12.6 %

Notes: (1) Market-to-Book Ratio equals average of the high and low market price for the year divided by the average book value

(2) Earnings/Book equals earnings per share for the year divided by the average book value

(3) On January 2, 2001 Standard & Poor's released Global Industry Classification Standard (GICS) price indexes for all Standard & Poor's U S indexes. As a result, all S&P Indexes have been calculated with a common base of 100 at a start date of December 31, 1994. Also, the GICS industrial sector is not comparable to the former S&P Industrial Index and data for the former S&P Industrial Index has been discontinued.

(4) As measured by the Consumer Price Index (CPI).

(5) Ratios for 2006 are based upon estimated book values using the actual average price and the estimated book value calculated by adding the 2006 earnings per share to the 2005 book value per share and then subtracting the 2006dividends per share as provided by Standard & Poor's Statistical Record - Current Statistics, August 2007, p 29

Source of Information: Standard & Poor's Security Price Index Record, 2000 Edition, p. 40
Standard & Poor's Statistical Service, Current Statistics, August 2001, p 29
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Fourth Edition

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Portfolio Beta Coefficients

A portfolio consisting of low-beta securities will itself have a low beta, since the beta of any set of securities is a weighted average of the individual securities' betas:

$$b_p = \sum_{i=1}^{n} w_i b_i. \tag{6-5}$$

Here b_p is the beta of the portfolio, which reflects how volatile the portfolio is in relation to the market index; w_i is the fraction of the portfolio invested in the *i*th stock; and b_i is the beta coefficient of the *i*th stock.

If an investor holds a $100,000 portfolio consisting of $10,000 invested in each of 10 stocks, and if each stock has a beta of 0.8, then the portfolio will have $b_p = 0.8$. Thus, the portfolio is less risky than the market, and it should experience relatively narrow price swings and have small rate of return fluctuations.

Now suppose one of the existing stocks is sold and replaced by a stock with $b_i = 2.0$. This action will increase the riskiness of the portfolio from $b_{p1} = 0.8$ to $b_{p2} = 0.92$:

$$b_{p2} = \sum_{i=1}^{n} w_i b_i = 0.9(0.8) + 0.1(2.0) = 0.92.$$

Had a stock with $b_i = 0.2$ been added, the portfolio beta would have declined from 0.8 to 0.74. Adding this stock would, therefore, reduce the riskiness of the portfolio.

The Relationship between Risk and Rates of Return

In the preceding section, we saw that under the CAPM framework, beta is the appropriate measure of a stock's relevant risk. Now we must specify the relationship between risk and return—if beta rises by some specific amount, by how much must the stock's expected return increase to compensate for the increase in risk? To begin, let us define the following terms:

$\hat{k}_i$ = expected rate of return on the *i*th stock.

k_i = required rate of return on the *i*th stock. If $\hat{k}_i$ is less than k_i, then you would not purchase this stock, or you would sell it if you owned it.

R_F = riskless rate of return, generally measured by the rate of return on U.S. Treasury securities.

b_i = beta coefficient of the *i*th stock.

k_M = required rate of return on an average ($b = 1.0$) stock. k_M is also the required rate of return on a portfolio consisting of all stocks, or the market portfolio.

$RP_M = (k_M - R_F) =$ market risk premium. It is the additional return over the riskless rate required to compensate investors for assuming an "average" amount of risk.

$RP_i = b_i(k_M - R_F) =$ risk premium on the ith stock. The stock's risk premium is less than, equal to, or greater than the premium on an average stock, depending on whether its beta is less than, equal to, or greater than 1.0. If $b_i = 1.0$, then $RP_i = RP_M$.

The market risk premium, RP_M, depends on the degree of aversion that investors, in the aggregate, have to risk.[11] Let us assume that at the current time Treasury bonds yield $R_F = 8\%$, and an average share of stock has a required return of $k_M = 12\%$. Therefore, the market risk premium is 4 percent:

$$RP_M = k_M - R_F = 12\% - 8\% = 4\%.$$

It follows that, if one stock were twice as risky as some other, its risk premium would be twice as high, and, conversely, if its risk were only half as high, its risk premium would be half as high. Further, we can measure a stock's relative riskiness by its beta coefficient. Therefore, if we know the market risk premium, RP_M, and the stock's beta coefficient, b_i, we can find its risk premium as the product $b_i(RP_M)$. For example, if $b_i = 0.5$ and $RP_M = 4\%$, then RP_i is 2 percent:

$$\text{Risk premium for Stock i} = RP_i = b_i(RP_M) = 0.5(4\%) = 2.0\%. \qquad (6\text{-}6)$$

To summarize, given estimates of R_F, k_M, and b_i, we can find the required rate of return on Stock i:

$$\begin{aligned} k_i &= R_F + b_i(k_M - R_F) = R_F + b_i(RP_M) \qquad (6\text{-}7)\\ &= 8\% + 0.5(12\% - 8\%) = 8\% + 0.5(4\%) = 10\%. \end{aligned}$$

If some other stock, j, were more risky than Stock i and had $b_j = 2.0$, then its required rate of return would be 16 percent:

$$k_j = 8\% + 2.0(4\%) = 16\%.$$

An average stock, with $b = 1.0$, would have a required return of 12 percent, the same as the market return:

$$k_{Average} = 8\% + 1.0(4\%) = 12\% = k_M.$$

Equation 6-7 is often expressed as a graph called the *Security Market Line (SML)*; Figure 6-9 shows the SML when $R_F = 8\%$ and $k_M = 12\%$. Note the following points:

[11] This concept is discussed in some detail in Appendix 6B. It should be noted that the risk premium of an average stock, $k_M - R_F$, cannot be measured with great precision because it is impossible to obtain precise values for k_M. However, empirical studies suggest that, where long-term U.S. Treasury bonds are used to measure R_F and where k_M is the expected return on the S&P 400 Industrial Stocks, the market risk premium varies somewhat from year to year, and it has generally ranged from 3 to 6 percent during the last 20 years.

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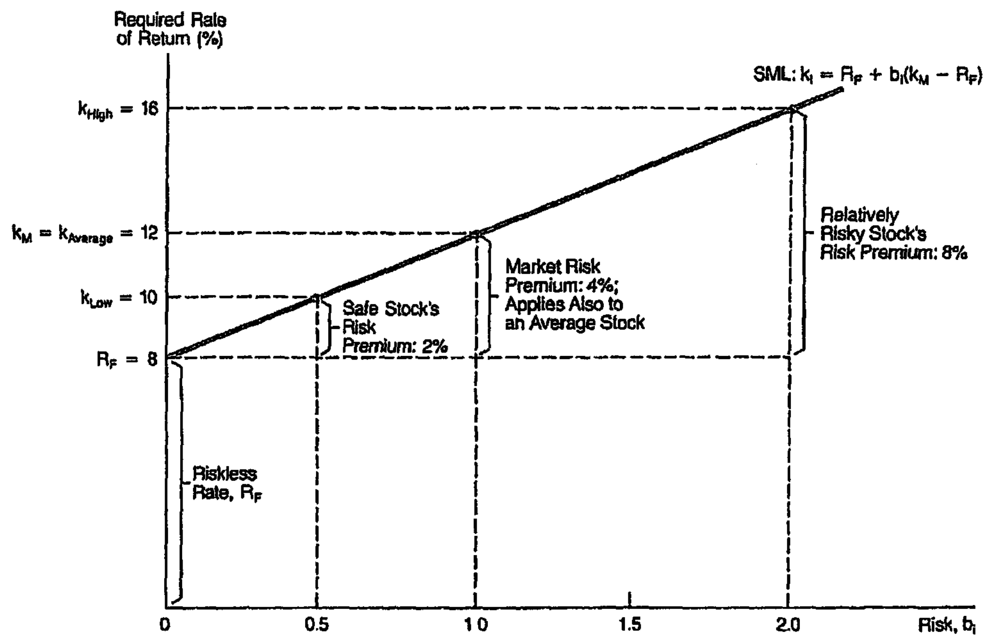
Figure 6-9
The Security Market Line (SML)



1. Required rates of return are shown on the vertical axis, while risk as measured by beta is shown on the horizontal axis.

2. Riskless securities have $b_i = 0$; therefore, R_F appears as the vertical axis intercept.

3. The slope of the SML reflects the degree of risk aversion in the economy—the greater the average investor's aversion to risk, then (1) the steeper is the slope of the line, (2) the greater is the risk premium for any risky asset, and (3) the higher is the required rate of return on risky assets.[12] These points are discussed further in a later section.

[12]Students sometimes confuse beta with the slope of the SML. This is a mistake. As we saw earlier in connection with Figure 6-8, and as is developed further in Appendix 6A, beta does represent the slope of a line, but *not* the Security Market Line. This confusion arises partly because the SML equation is generally written, in this book and throughout the finance literature, as $k_i = R_F + b_i(k_M - R_F)$, and in this form b_i looks like the slope coefficient and $(k_M - R_F)$ the variable. It would perhaps be less confusing if the second term were written $(k_M - R_F)b_i$, but this is not generally done.

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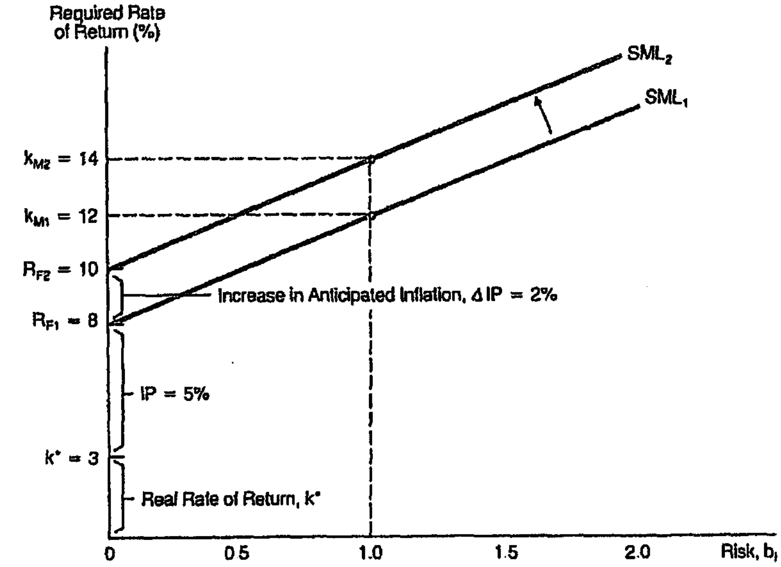
4. The values we worked out for stocks with $b_i = 0.5$, $b_i = 1.0$, and $b_i = 2.0$ agree with the values shown on the graph for k_{Low}, $k_{Average}$, and k_{High}.

The Security Market Line, and a company's position on the line, change over time as interest rates, investors' risk aversion, and individual companies' betas change. Such changes are discussed in the following sections.

The Impact of Inflation

As we saw in Chapter 3, interest amounts to "rent" on borrowed money, or the "price" of money. Thus, R_F is the price of money to a riskless borrower. The existing market risk-free rate is called the *nominal rate*, and it consists of two elements: (1) a *real*, or *inflation-free, rate of return*, k^*, and (2) an *inflation premium*, IP, equal to the anticipated rate of inflation. Thus, $R_F = k^* + IP$. The real rate on risk-free government securities has, historically, ranged from 2 to 4 percent, with a mean of about 3 percent. Thus, if no inflation were expected, risk-free government securities would tend to yield about 3 percent. However, as the expected rate of inflation increases, a premium must be added to the real rate of return to compensate investors for the loss of purchasing

Figure 6-10
Shift in the SML Caused by an Increase in Inflation



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Comparable Earnings: New Life for an Old Precept

by
Frank J. Hanley
Pauline M. Ahern

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Comparable Earnings: New Life for an Old Precept

Accelerating deregulation has greatly increased the investment risk of natural gas utilities. As a result, the authors believe it more appropriate than ever to employ the comparable earnings model. We believe our application of the model overcomes the greatest traditional objection to it — lack of comparability of the selected non-utility proxy firms. Our illustration focuses on a target gas pipeline company with a beta of 0.96 — almost equal to the market's beta of 1.00.

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Introduction

The comparable earnings model used to determine a common equity cost rate is deeply rooted in the standard of "corresponding risk" enunciated in the landmark *Bluefield* and *Hope* decisions of the U.S. Supreme Court.[1] With such solid grounding in the foundations of rate of return regulation, comparable earnings should be accepted as a principal model, along with the currently popular market-based models, provided that its most common criticism, non-comparability of the proxy companies, is overcome.

Our comparable earnings model overcomes the non-comparability issue of the non-utility firms selected as a proxy for the target utility, in this example, a gas pipeline company. We should note that in the absence of common stock prices for the target utility (as with a wholly-owned subsidiary), it is appropriate to use the average of a proxy group of similar risk gas pipeline companies whose common stocks are actively traded. As we will demonstrate, our selection process results in a group of domestic, non-utility firms that is comparable in total risk, the sum of business and financial risk, which reflects both non-diversifiable systematic, or market, risk as well as diversifiable unsystematic, or firm-specific, risk.

Embedded in the Landmark Decisions

As stated in *Bluefield* in 1922: "A public utility is entitled to such rates as will permit it to earn a return ... on investments in other business undertakings which are attended by corresponding risks and uncertainties ..."

In addition, the court stated in *Hope* in 1944: "By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

Thus, the "corresponding risk" precept of *Bluefield* and *Hope* predates the use of such market-based cost-of-equity models as the Discounted Cash Flow (DCF) and Capital Asset Pricing (CAPM), which were developed later and are currently popular in rate-base/rate-of-return regulation. Consequently, the comparable earnings model has a longer regulatory and judicial history. However, it has far greater relevance now than ever before in its history because significant deregulation has substantially increased natural gas utilities' investment risk to a level similar to that of non-utility firms. As a result, it is

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more important than ever to look to similar-risk non-utility firms for insight into common equity cost rate, especially in view of the deficiencies inherent in the currently popular market-based cost of common equity models, particularly the DCF model.

Despite the fact that the landmark decisions are still regarded as having set the standards for determining a fair rate of return, the comparable earnings model has experienced decreased usage by expert witnesses, as well as less regulatory acceptance over the years. We believe the decline in the popularity of the comparable earnings model, in large measure, is attributable to the difficulty of selecting non-utility proxy firms that regulators will accept as comparable to the target utility. Regulatory acceptance is difficult to gain when the selection process is arbitrary. Our application of the model is objective and consistent with fundamental financial tenets.

Principles of Comparable Earnings

Regulation is a substitute for the competition of the marketplace. Moreover, regulated public utilities compete in the capital markets with all firms, including unregulated non-utilities. The comparable earnings model is based upon the opportunity cost principle; i.e., that the true cost of an investment is the return that could have been earned on the next best available alternative investment of similar risk. Consequently, the comparable earnings model is consistent with regulatory and financial principles, as it is a surrogate for the competition of the marketplace, and investors seek the greatest available rate of return for bearing similar risk.

The selection of comparable firms is the most difficult step in applying the comparable earnings model, as noted by Phillips[2] as well as by Bonbright, Danielsen and Kamerschen[3] The selection of non-utility proxy firms should result in a sufficiently broad-based group in order to minimize the effect of company-specific aberrations. However, if the selection process is arbitrary, it likely would result in a proxy group that is too broad-based, such as the Standard & Poor's 500 Composite Index or the Value Line Industrial Composite. The use of such groups would require subjective adjustments to the comparable earnings results to reflect risk differences between the group(s) and the target utility, a gas pipeline company in this example

Authors' Selection Criteria

We base the selection of comparable non-utility firms on market-based, objective, quantitative measures of risk resulting from market prices that subsume investors' assessments of all elements of risk. Thus, our approach is based upon the principle of risk and return; namely, that firms of comparable risk should be expected to earn comparable returns. It is also consistent with the "corresponding risk" standard established in *Bluefield* and *Hope* We measure total investment risk as the sum of non-diversifiable systematic and diversifiable unsystematic risk. We use the unadjusted beta as a measure of systematic risk and the standard error of the estimate (residual standard error) as a measure of unsystematic risk. Both the unadjusted beta and the residual standard error are derived from a regression of the target utility's security returns relative to the market's returns, which takes the general form:

$$r_{it} = a_i + b_i r_{mt} + e_{it}$$

where:

r_{it} = tth observation of the ith utility's rate of return
r_{mt} = tth observation of the market's rate of return
e_{it} = tth random error term
a_i = constant least-squares regression coefficient
b_i = least-squares regression slope coefficient, the unadjusted beta.

As shown by Francis,[4] the total variation or risk of a firm's return, Var (r_i), comes from two sources:

Var (r_i)= total risk of ith asset

$= \mathrm{var}(a_i + b_i r_m + e)$ substituting $(a_i + b_i r_m + e)$ for r_i

$= \mathrm{var}(b_i r_m) + \mathrm{var}(e)$ since $\mathrm{var}(a_i) = 0$

$= b_i^2\,\mathrm{var}(r_m) + \mathrm{var}(e)$ since $\mathrm{var}(b_i r_m) = b_i^2\,\mathrm{var}(r_m)$

= systematic + unsystematic risk

Francis[5] also notes: "The term $\sigma^2(r_i|r_m)$ is called the *residual variance around the regression line* in statistical terms or *unsystematic risk* in capital market theory language. $\sigma^2(r_i|r_m)$ = ... = var (e). The residual variance is the squared standard error in regression language, a measure of unsystematic risk." Application of these criteria results in a group of non-utility firms whose average total investment risk is indeed comparable to that of the target gas pipeline.

As a measure of systematic risk, we use the Value Line unadjusted beta. Beta measures the extent to which market-wide or macro-economic events affect a firm's stock price. We use the unadjusted beta of the target utility as a starting point because it results from the regression of the target utility's security returns relative to the market's returns. Thus, the resulting standard deviation of beta relates to the unadjusted beta. We use the standard deviation of the unadjusted beta to determine the range around it as the selection criterion based on systematic risk.

We use the residual standard error of the regression as a measure of unsystematic risk. The residual standard error reflects the extent to which events specific to the firm's operations affect a firm's stock price. Thus, it is a measure of diversifiable, unsystematic, firm-specific risk.

An Illustration of Authors' Approach

Step One: We begin our approach by establishing the selection criteria as a range of both unadjusted beta and residual standard error of the target gas

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pipeline company.

As shown in table 1, our target gas pipeline company has a Value Line unadjusted beta of 0.90, whose standard deviation is 0.1250. The selection criterion range of unadjusted beta is the unadjusted beta plus (+) and minus (-) three of its standard deviations. By using three standard deviations, 99.73 percent of the comparable unadjusted betas is captured.

Three standard deviations of the target utility's unadjusted beta equals 0.38 (0.1250 x 3 = 0.3750, rounded to 0.38) Consequently, the range of unadjusted betas to be used as a selection criteria is 0.52 - 1.28 (0.52 = 0.90 - 0.38) and (1.28 = 0.90 + 0.38).

Likewise, the selection criterion range of residual standard error equals the residual standard error plus (+) and minus (-) three of its standard deviations. The standard deviation of the residual standard error is defined as: $\sigma/\sqrt{2N}$.

As also shown in table 1, the target gas pipeline company has a residual standard error of 3.7867. According to the above formula, the standard deviation of the residual standard error would be 0.1664 ($0.1664 = 3.7867/\sqrt{2(259)} = 3.7867/22.7596$, where 259 = N, the number of weekly price change observations over a period of five years). Three standard deviations of the target utility's residual standard error would be 0.4992 (0.1664 x 3 = .4992). Consequently, the range of residual standard errors to be used as a selection criterion is 3.2875 - 4.2859 (3.2875 = 3.7867 - 0.4992) and (4.2859 = 3.7867 + 0.4992)

Step Two: The step one criteria are applied to Value Line's data base of nearly 4,000 firms for which Value Line derives unadjusted betas and residual standard errors on a weekly basis. All firms with unadjusted betas and residual standard errors within the criteria ranges are then selected

Step Three: In the regulatory ratemaking environment, authorized common equity return rates are applied to a book-value rate base. Thus, the earnings rates on book common equity, or net worth, of competitive, non-utility firms are highly relevant provided those firms are indeed comparable in total risk to the target gas pipeline. The use of the return rates of other utilities has no relevance because their allowed, and hence subsequently achieved, earnings rates are dependent upon the regulatory

table 1

Summary of the Comparable Earnings Analysis for the Proxy Group of 248 Non-Utility Companies Comparable in Total Risk to the Target Gas Pipeline Company[1]

	1	2	3	4	5	6	7	8
			residual	rate of return on net worth				
	adj. beta	unadj. beta	standard error	3-year average[2]	4-year average[2]	5-year average[2]	5-year projected[3]	
average for the proxy group of 248 non-utility companies comparable in total risk to the target gas pipeline company	0.97	0.92	3.7705					
target gas pipeline company	0.96	0.90[4]	3.7867					
median				11.7%	12.0%	12.6%	15.5%	
average of the median historical returns					12.1%			
conclusion[5]								13.8%

[1] The criteria for selection of the non-utility group was that the non-utility companies be domestic and included in *Value Line Investment Survey*. The non-utility group was selected based on an unadjusted beta range of 0.52 to 1.28 and a residual standard error range of 3.2875 to 4.2859.
[2] Ending 1992.
[3] 1996-1998/1997-1999.
[4] The average standard deviation of the target gas pipeline company's unadjusted beta is 0.1250.
[5] Equal weight given to both the average of the 3-, 4- and 5-year historical medians (12.1%) and 5-year projected median rate of return on net worth (15.5%). Thus, 13.8% = (12.1% + 15.5% / 2).
Source: Value Line Inc., March 15, 1994
Value Line Investment Survey

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process. Consequently, we believe all utilities must be eliminated to avoid circularity. Moreover, we believe non-domestic firms must be eliminated because their reporting methods differ significantly from U.S. firms.

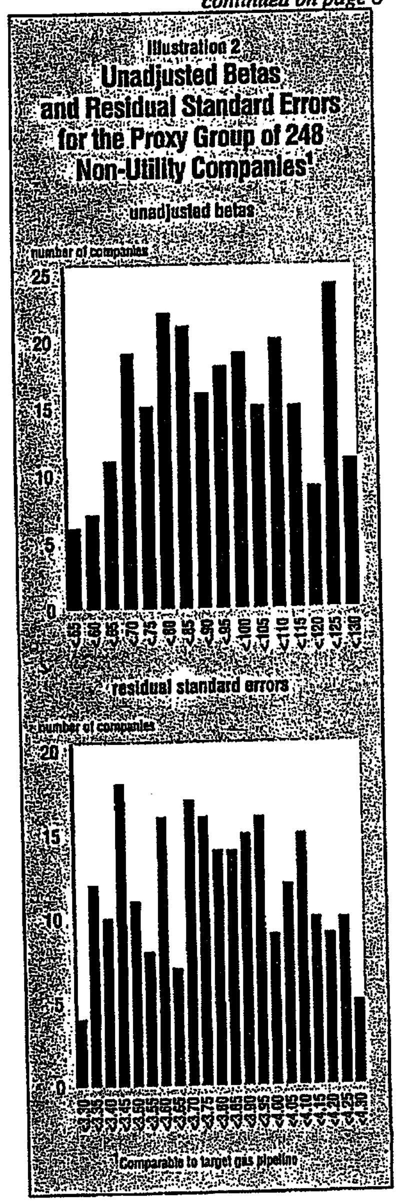
Step Four: We then eliminated those firms for which Value Line does not publish a "Ratings & Report" in *Value Line Investment Survey* so that the historical and projected returns on net worth[6] are from a consistent source. We use historical returns on net worth for the most recent five years, as well as those projected three to five years into the future. We believe it is logical to evaluate both historical and projected return rates because it is reasonable to assume that investors avail themselves of both when they are available from widely disseminated information services, such as Value Line Inc. The use of Value Line's return rates on net worth understates the common equity return rates for two reasons. First, preferred stock is included in net worth. Second, the net worth return rates are as of the end of each period. Thus, the use of average common equity return rates would yield higher results.

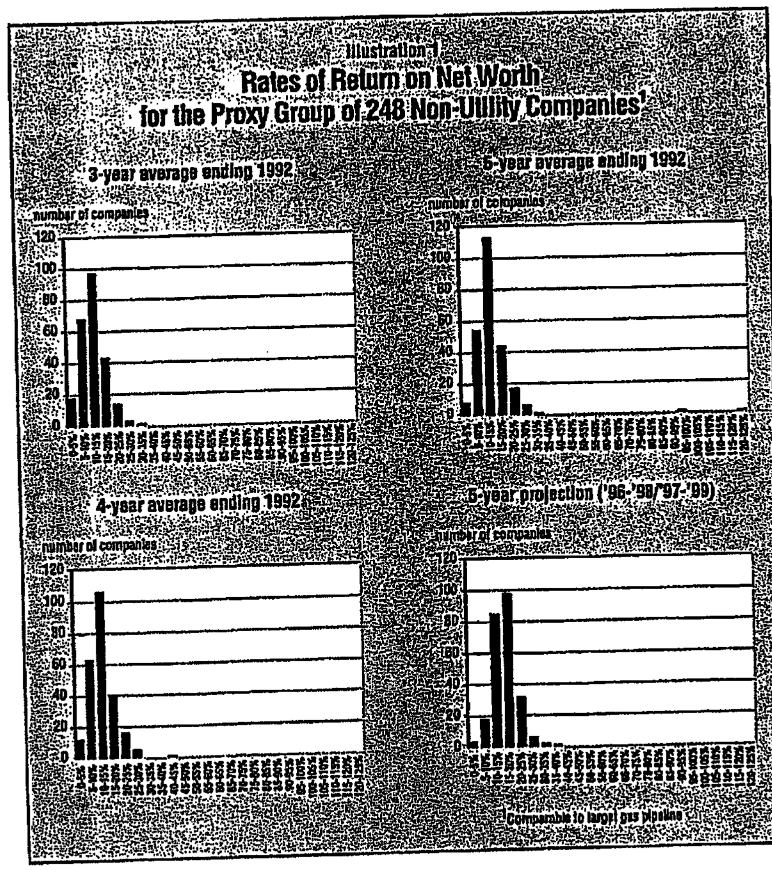
Step Five: Median returns based on the historical average three, four and five years ending 1992 and projected 1996-1998 or 1997-1999 rates of return on net worth are then determined as shown in columns 4 through 7 of table 1. The median is used due to the wide variations and skewness in rates of return on net worth for the non-utility firms as evidenced by the frequency distributions of those returns as shown in illustration 1.

However, we show the average unadjusted beta, 0.92, and residual standard error, 3.7705, for the proxy group in columns 2 and 3 of table 1 because their frequency distributions are not significantly skewed, as shown in illustration 2.

Step Six: Our conclusion of a com-

continued on page 8





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parable earnings cost rate is based upon the mid-point of the average of the median three-, four- and five-year historical rates of return on net worth of 12 1 percent as shown in column 5 and the median projected 1996-1998/1997-1999 rate of return on net worth of 15 5 percent as shown in column 7 of table 1. As shown in column 8, it is 13 8 percent.

Summary

Our comparable earnings approach demonstrates that it is possible to select a proxy group of non-utility firms that is comparable in total risk to a target utility. In our example, the 13.8 percent comparable earnings cost rate is very conservative as it is an expected achieved rate on book common equity (a regulatory allowed rate should be greater) and because it is based on end-of-period net worth A similar rate on average net worth would be about 20 to 40 basis points higher (i e., 14 0 to 14 2 percent) and still understate the appropriate regulatory allowed rate of return on book common equity.

Our selection criteria are based upon measures of systematic and unsystematic risk, specifically unadjusted beta and residual standard error. They provide the basis for the objective selection of comparable non-utility firms. Our selection criteria rely on changes in market prices over approximately five years. We compare the aggregate total risk, or the sum of systematic and unsystematic risk, which reflects investors' aggregate assessment of both business and financial risk. Thus, no adjustments are necessary to the proxy group results to compensate for the differences in business risk and financial risk, such as accounting practices and debt/equity ratios. Moreover, it is inappropriate to attempt a comparison of the target utility with any individual firm, or subset of firms, in the proxy group because only the average firm of the group is relevant.

Because the comparable earnings model is firmly anchored in the "corresponding risk" precept established in the landmark court decisions, it is worthy of consideration as a principal model for use in estimating the cost rate of common equity capital of a regulated utility. Our approach to the comparable earnings model produces a proxy group that is indeed comparable in total risk because the selection process is objective and quantitative It therefore overcomes criticism linked to arbitrary selection processes.

All cost-of-common-equity models, including the DCF and CAPM, are fraught with deficiencies, usually stemming from the many necessary but unrealistic assumptions that underlie them. The effects of the deficiencies of individual models can be mitigated by using more than one model when estimating a utility's common equity cost rate Therefore, when the non-comparability issue is overcome, the comparable earnings model deserves to receive the same consideration as a primary model, as do the currently popular market-based models. ■

[1]*Bluefield Water Works Improvement Co. v. Public Service Commission*. 262 U S 679 (1922) and *Federal Power Commission v Hope Natural Gas Co*. 320 U S 519 (1944).

[2]Charles F Phillips Jr , The Regulation of Public Utilities: Theory and Practice, Public Utilities Reports Inc . 1988. p 379

[3]James C Bonbright. Albert L Danielsen and David R Kamerschen. Principles of Public Utilities Rates. 2nd edition. Public Utilities Reports Inc 1988, p 329

[4]Jack Clark Francis. Investments: Analysis and Management, 3rd edition. McGraw-Hill Book Co , 1980, p 363

[5]Id . p. 548

[6]Returns on net worth must be used when relying on Value Line data because returns on book common equity for non-utility firms are not available from Value Line

Report Lists Pipeline, Storage Projects

More than $9 billion worth of projects to expand the nation's natural gas pipeline network are in various stages of development, according to an A.G.A. report. These projects involve nearly 8,000 miles of new pipelines and capacity additions to existing lines and represent 15.3 billion cubic feet (Bcf) per day of new pipeline capacity.

During 1993 and early 1994, construction on 3,100 miles of pipeline was completed or under way, at a cost of nearly $4 billion, says A.G.A. These projects are adding 5.4 Bcf in daily delivery capacity nationwide.

Among the projects completed in 1993 were Pacific Gas Transmission Co.'s 805 miles of looping that allows increased deliveries of Canadian gas to the West Coast; Northwest Pipeline Corp.'s addition of 433 million cubic feet of daily capacity for customers in the Pacific Northwest and Rocky Mountain areas; and the 156-mile Empire State Pipeline in New York.

In addition, major construction projects were started on the systems of Texas Eastern Transmission Corp. and Algonquin Gas Transmission Co. — both subsidiaries of Panhandle Eastern Corp. — and along Florida Gas Transmission Co.'s pipeline.

The report goes on to discuss another $5 billion in proposed projects, which, if completed, will add nearly 5,000 miles of pipeline and 9.8 Bcf per day in capacity, much of it serving Florida and West Coast markets.

A.G.A. also identifies 47 storage projects and says that if all of them are built, existing storage capacity will increase by more than 500 Bcf, or 15 percent.

For a copy of *New Pipeline Construction: Status Report 1993-94* (#F00103), call A.G.A. at (703) 841-8490. Price per copy is $6 for employees of member companies and associates and $12 for other customers.

Southwest Gas Corporation
RUCO Witness Rigsby's CAPM Costs of Equity Rates Corrected to Properly Reflect Only the Arithmetic Mean Equity Risk Premium and the Appropriate Long-Term Risk Free Rate of Return and Failure to also Include ECAPM (1)

Line No.		Traditional Capital Asset Pricing Model (CAPM) (2)	Empirical Capital Asset Pricing Model (ECAPM) (3)	Average of CAPM and ECAPM
1.	Risk Free Rate (1)	4.50 %	4.50 %	
2.	Arithmetic Mean Market Equity Risk Premium (4)	7.10	7.10	
3.	Adjusted Beta	0.86 (5)	0.86 (5)	
4.	Average Company-Specific Equity Risk Premium	6.11 % (6)	6.35 % (7)	
5.	CAPM Result (8)	10.61 %	10.85 %	10.73 %
6.	Mr. Rigsby's CAPM Conclusion (9)	10.02 %	10.02 %	10.02 %
7.	Understatement of Mr. Rigsby's CAPM Conclusion (10)	0.59 %	0.83 %	0.71 %

See Sheet 2 for notes.

Southwest Gas Corporation
the Arithmetic Mean Equity Risk Premium and the Appropriate
Long-Term Risk Free Rate of Return and Failure to also Include ECAPM (1)

Notes:

(1) Average forecast based upon six quarterly estimates of 30-year Treasury Note yields per the consensus of nearly 50 economists reported in the Blue Chip Financial Forecasts dated April 1, 2008 (See Sheet 22 of Exhibit 29). The estimates are detailed below:

	30-Year Treasury Note Yield
Second Quarter 2008	4.30%
Third Quarter 2008	4.30
Fourth Quarter 2008	4.40
First Quarter 2009	4.50
Second Quarter 2009	4.70
Third Quarter 2009	4.80
Average	4.50%

(2) The traditional Capital Asset Pricing Model (CAPM) is applied using the following formula:

$R_S = R_F + \beta (R_M - R_F)$

Where R_S = Return rate of common stock
R_F = Risk Free Rate
β = Value Line Adjusted Beta
R_M = Return on the market as a whole

(3) The empirical CAPM is applied using the following formula:

$R_S = R_F + .25 (R_M - R_F) + .75 \beta (R_M - R_F)$

Where R_S = Return rate of common stock
R_F = Risk-Free Rate
β = Value Line Adjusted Beta
R_M = Return on the market as a whole

(4) The Ibbotson Associates calculated market premium of 7.10% for the period 1926-2007 results from a total market return of 12.30% less the average income return on long-term U.S. Government Securities of 5.20% (12.30% - 5.20% = 7.10%). From Stocks, Bonds, Bills, and Inflation – Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, Morningstar, Inc., Chicago, IL, 2008

(5) From Schedule WAR - 7, page 1 of 2.

(6) Line No. 2 * Line No. 3.

(7) (0.25 * Line No. 2) + (0.75 * Line No. 2 * Line No. 3).

(8) Line No. 1 + Line No. 4.

(9) The midpoint of Witness Rigsby's CAPM results (10.02% = 9.20% + 10.83% / 2), from Schedule WAR – 1, pages 4 of 4.

(10) Line No. 5 – Line No. 6.

Source of Information: Blue Chip Financial Forecasts, April 1, 2008
RUCO Witness Rigsby's Schedule WAR – 7, pages 1 and 2
Stocks, Bonds, Bills, and Inflation– Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, Morningstar, Inc., Chicago, IL, 2008

Exhibit___(FJH-25)
Sheet 3 of 4

Ibbotson® SBBI®
2008 Valuation Yearbook

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

MORNINGSTAR®

However, an estimate of each of the above three variables must be formed. Like all components of the cost of capital, these variables should be measured on a forward-looking basis. Chapters 5 and 6 are devoted to estimating the equity risk premium and beta, respectively. Factors to consider in estimating the riskless rate are covered below.

Risk-Free Rate

The CAPM implicitly assumes the presence of a single riskless asset, that is, an asset perceived by all investors as having no risk. A common choice for the nominal riskless rate is the yield on a U.S. Treasury security. The ability of the U.S. government to create money to fulfill its debt obligations under virtually any scenario makes U.S. Treasury securities practically default-free. While interest rate changes cause government obligations to fluctuate in price, investors face essentially no default risk as to either coupon payment or return of principal.

The horizon of the chosen Treasury security should match the horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.

In February of 1977 the Treasury began to issue 30-year Treasury securities. Prior to this date, the longest-term Treasury security was 20 years, which was the standard Ibbotson used for its data series. To remain consistent with Ibbotson's historical data series, the *Ibbotson® Stocks, Bonds, Bills, and Inflation® Classic Yearbook* continued to base the yield for its long-term government bond on one with close to 20 years to maturity. Bonds with at least 20 years to maturity continued to trade and, therefore, a proxy for the yield on 20-year Treasury securities was readily available. In October of 2001 the U.S. Treasury announced that it would no longer issue 30-year Treasury bonds and the 10-year bond became the longest term Treasury security offered; in 2005 this decision was reversed, and the U.S. Treasury resumed issuing 30-year Treasury bonds in February of 2006. Throughout this period Ibbotson continued (and continues) to use the 20-year yield for data-consistency purposes. Presently, differences in the yields of the currently available long-term instruments tend to be relatively small. Table 4-1 shows the current yields for several different horizons.

Table 4-1
Current Yields or Expected Riskless Rates
December 31, 2007

	Yield (Riskless Rate)*
Long-Term (20-year) U S Treasury Coupon Bond Yield	4 5%
Long-Term (10-year) U.S. Treasury Coupon Bond Yield	4.0%
Intermediate-Term (5-year) U.S Treasury Coupon Note Yield	3 3%
Short-term (30-day) U S Treasury Bill Yield	2 8%

*Maturities are approximate

Pacific Gas and Electric Company

Decoupling in California: More Than Two Decades of Broad Support and Success

Workshop on Aligning Regulatory Incentives with Demand-Side Resources

San Francisco
August 2, 2006

Roland Risser. Director
Customer Energy Efficiency
Pacific Gas and Electric Company

Exhibit__(FJH-26)
Sheet 1 of 3

Decoupling at PG&E – A Long History

Pacific Gas and Electric Company®

- Decoupling of revenues/sales for non-fuel costs began in 1978 for natural gas; 1982 for electric:

  "...the adoption of an ERAM [Electric Revenue Adjustment Mechanism] ... will eliminate any disincentives PG&E may have to promote vigorous conservation measures and also be fair to ratepayers in assuring that PG&E receives no more or no less than the level of revenues intended to be earned."

  California Public Utilities Commission
  Decision 93887, **12/30/1981**

- Key goal: encourage conservation

- Broad stakeholder support at time: PUC staff, Energy Commission, environmentalists, PG&E, other utilities

Decoupling – Current View

Pacific Gas and Electric Company®

- Electric decoupling required by Public Utilities Code:

  "The Commission shall ensure that errors in estimates of demand elasticity or sales to not result in material over or undercollections of the electrical corporations."

  Section 739.10, April 2001

- Nearly all PG&E revenues now decoupled:
  - Electric revenues: about 6% at risk
  - Natural gas revenues: about 4.2% at risk
- California PUC considering further decoupling of natural gas revenues in Gas OIR proceeding
- Continuing widespread support for decoupling (with forward-looking revenue/rate setting) from broad stakeholder group throughout state

STANDARD & POOR'S RatingsDirect

RESEARCH

Pacific Gas & Electric Co.

Publication date: 19-Jun-2007
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Major Rating Factors

Corporate Credit Rating

BBB+/Stable/A-2

View Recovery Ratings >>

Strengths:

- The company's strengthened financial performance should continue.
- PG&E's business is limited to the operations of a regulated utility, and the utility's financial performance is not exposed to the financial vagaries of unregulated, competitive businesses.
- The company's growth initiatives are principally focused on investments that will enhance its existing regulated business. However, investments in additional regulated businesses are possible.
- The utility benefits from an increasingly supportive regulatory environment as well as the regulator's contractual and administrative commitments to preserve investment-grade ratings and cash flow in the face of rising costs.
- The recently settled rate case provides a measure of predictability of revenues in the coming four years, but, at the same time, the tenor of the settlement can leave the company exposed to changes in circumstances that result in cost increases that are outside of the balancing account mechanism.
- Although the five-year capital program is expected to exceed $14 billion, only about one-third of the expenditures will be debt financed. While the company expects to issue more than $4 billion of incremental long-term debt, which is twice the additions projected in 2005, the amount of incremental debt relative to the size of the utility and its balance sheet, is manageable.

Weaknesses:

- The company faces numerous operational issues, including substantial generation resource procurement needs, an exposure to volatile fuel prices, Calpine's bid to abrogate supply arrangements as part of its bankruptcy, the resumption of variable pricing for qualifying facilities contracts, and the need to resolve spent nuclear fuel storage issues as well as the need to respond to hurdles to steam generator replacements that are critical to ongoing nuclear operations.
- Rates remain frozen for about three-quarters of the residential customer base and about one-quarter of total retail customers, which could constrain ratemaking and financial flexibility as rate increases are borne by a fraction of the customer base.
- The company's five-year capital program is projected to exceed $14 billion
- The company has factored $138 million of unproven cost savings in its most recent request for rate relief for 2008 and 2009.
- A successful bid by one of the several locales seeking to municipalize portions of the company's electric system could encourage others to follow suit.
- Renewable resource and emissions mandates could drive up costs.

Rationale

The rating on Pacific Gas and Electric Co. (PG&E) reflects strengthening financial performance following emergence from bankruptcy, improved regulatory support, and a narrow strategic focus that is limited to regulated utility operations.

Additional strengths that support the ratings include:

- The recently settled rate case provides a measure of predictability of revenues in the coming four years, but, at the same time, the tenor of the settlement can leave the company exposed to changes in circumstances that result in increases in costs that are outside of the balancing account mechanism.
- As compared with many energy companies that are pursuing growth through expansion and diversification that might be inconsistent with the preservation of sound credit quality, PG&E's strategic goals are focused on achieving earnings growth through investments that should promote efficiencies as well as the improvement of existing processes. Outward-looking investments, such as a regulated natural gas pipeline, are under consideration, but represent a lesser priority.
- Only about one-third of a $14 billion-plus five-year capital program will be debt financed.
- Under the terms of a settlement agreement tied to the company's bankruptcy reorganization and that will remain in force until April 2013, the California Public Utilities Commission (CPUC) has committed to protect the investment-grade ratings that were assigned to PG&E when it emerged from bankruptcy in April 2004. The settlement agreement's terms may be enforced in bankruptcy court.
- The settlement agreement with the CPUC further requires the regulator to authorize an ROE of no less than 11.22% and an equity component of the capital structure for ratemaking purposes of no less than 52% until such time that PG&E is upgraded to 'A-' by Standard & Poor's Ratings Services or its equivalent by another rating agency. The current authorized ROE for most CPUC jurisdictional operations is 11.35%.

The rating also reflects the following credit exposures:

- Long-term electricity and fuel-procurement activities are ongoing and will define the utility's operational and financial profile. The expiration of California Department of Water Resources (CDWR) and qualifying facility (QF) contracts in coming years, as well as the risk of the abrogation of a Calpine CDWR contract in the context of its bankruptcy proceedings, will heighten financial exposure related to power procurement and will sharply increase procurement responsibilities.
- Financial performance remains exposed to volatile fuel and power-procurement costs and will hinge on the CPUC's response to material changes in utility costs.
- The extent to which the company may realize the $138 million of savings from capital investments and streamlined processes that were embedded in the request for rate relief made as part of the 2007 general rate case remains uncertain.
- The rapid exhaustion of spent fuel storage capacity at the Diablo Canyon nuclear power plant could curtail the operations of this important component of the utility's generation portfolio that represents one-third of owned capacity and accounted for nearly one-quarter of energy supply in 2005 and 2006.
- The replacement of steam generators at the Diablo Canyon nuclear power plant could be delayed by local opposition to elements of the steam generator replacement plan, which could raise costs and diminish this plant's important contribution to the utility's resource mix.
- Rates remain frozen for a large percentage of residential customers for usage that falls below legislatively prescribed benchmarks, which shifts costs to remaining electric customers and could, therefore, constrain ratemaking flexibility.
- A successful bid by one of the several municipalities and public power utilities that are seeking to municipalize portions of the PG&E electric utility system could trigger additional bids for portions of the PG&E service territory.
- Renewable resource and emissions mandates could drive up costs.

Although Standard & Poor's rates the utility, it does not rate the utility's parent, PG&E Corp., a holding company whose debt has been privately placed. However, the parent's $280 million 9.5% subordinated notes and the related debt service are consolidated with the utility's debt for purposes of assessing the utility's credit quality. The parent's notes represent less than 5% of the company's nearly $7 billion of consolidated debt, exclusive of securitization bonds.

PG&E's adjusted financial ratios correlate with the ratings after effect is given to the debt-like attributes of existing power-purchase obligations that represent operating leverage. These fixed commitments largely consist of contracts for energy from QFs. Over time, as the utility is required to assume responsibility for procuring electricity to replace expired CDWR contracts, there may be pressure on financial margins. Frozen rates for residential usage that falls below legislatively prescribed benchmarks and expectations of large increases in fixed purchased power obligations that will likely translate into additional debt imputation represent the most significant hurdles to positive rating actions.

Retail electric rates and energy-procurement practices are established by the CPUC. PG&E's financial performance remains exposed to volatile fuel and power-procurement expenses that require the CPUC to provide for the timely recovery of costs that have been recorded in balancing accounts for later recovery.

PG&E faces several significant litigations. They include legal proceedings challenging the bankruptcy settlement with the CPUC and the validity of several billions of dollars of distributions made by the utility to its parent. Litigations also include commercial, environmental, and personal injury claims that predate the bankruptcy and survived the Chapter 11 proceeding. The company assumes that the litigations will be resolved over time and adverse resolutions, if any, will be staggered events that will not materially affect financial results.

In April 2005, the utility released the first mortgage bonds' security interest in accordance with the provisions of the mortgage indenture and the 'BBB' rating was affirmed on the debt that was converted to senior unsecured obligations. The affirmation was tied to limitations on the company's ability to issue senior secured debt with priority over the unsecured debt.

Liquidity

PG&E Corp. and PG&E together recorded $456 million of cash and short-term investments on its balance sheet as of Dec. 31, 2006, which was down from $713 million as of fiscal year-end 2005. The reductions were anticipated. Only about 15% of the unrestricted liquid assets were held at the utility, which stands in sharp contrast to the prior year's 40%.

As of Dec. 31, 2006, PG&E Corp. and the utility had credit facilities totaling $200 million and $2 billion, respectively. The parent's facility was unused as of the fiscal year end. However, the utility had used about $900 million of available capacity. Our analysis of liquidity under stress situations, including market and credit events indicates that the company's liquidity is adequate.

Outlook

The stable outlook on PG&E reflects expectations that strong operating cash flows will support a substantial portion of a sizeable capital program while limiting the need for debt in support of the capital program. Preservation of the ratings will hinge on a demonstration of an ongoing ability to recover costs in a timely manner that protects cash flow, the development of a procurement strategy that is protective of credit metrics, the successful resolution of operational issues, and an absence of growth-related investments by PG&E Corp. that are detrimental to the consolidated companies' credit metrics. Frozen rates for residential usage that falls below legislatively prescribed benchmarks and expectations of large increases in fixed purchased power obligations that will likely translate into additional debt imputation represent the most significant hurdles to positive rating actions.

Business Risk Profile: Focus On Regulated Utility Operations

PG&E serves approximately 5 million retail electric customers and 4.2 million gas distribution customers in Northern California. In 2006, electric revenues totaled $8.75 billion, net of CDWR pass-through revenues, and there were $3.8 billion of gas revenues. Electric operations account for about three-quarters of the combined utility's gross margin, earnings, and cash flow. Net of securitization bonds, PG&E has nearly $7.9 billion of short and long-term debt obligations.

Gas operations consist of the transmission and distribution of natural gas. Customers' electric needs are met through a combination of owned generation resources, electricity purchased under QF and bilateral contracts, and electricity that PG&E conveys to retail customers in its role as agent for the delivery of electricity purchases made by CDWR under its long-term contracts.

In 2006, owned generation met 40% of customers' electricity needs. The balance of electricity supply is met through CDWR contracts and direct contracts with QFs, renewables, irrigation districts, and others. Over time, the CDWR contracts will expire and PG&E will need to shoulder additional financial responsibility for electricity and fuel procurement necessary to meet customers' electric demand. The obligation to meet CPUC resource adequacy and renewable directives also create additional financial and operational obligations.

PG&E faces both price and operational risks in serving its customers' electric needs. Legislation that protected cash flow through a trigger mechanism that compelled the CPUC to adjust retail rates if undercollections of procurement expenses exceeded 5% of the utility's previous-year generation revenues has expired. Yet, in a December 2004 decision, the CPUC administratively extended the 5% trigger through the life of the current 10-year resource planning horizon, which represents an important favorable regulatory development. Nevertheless, deferrals of less than 5% could still reach about $200 million pretax dollars without triggering rate adjustments. Deferrals that approach the cap but don't produce rate adjustments might sufficiently erode debt service coverage to impair credit quality. Moreover, even if triggered, the CPUC retains the right to establish the schedule for the amortization of amounts recorded in the balancing account. The need for timely responses to changes in procurement costs has become particularly important in light of Calpine's bid to terminate certain power supply agreements with the utility and with CDWR.

As demand grows and CDWR and QF contracts end in coming years, PG&E will need to either buy or build resources to replace expiring contracts and to meet the recently imposed obligations surrounding resource adequacy and renewable requirements. These additional commitments, as they are incurred, will also create the need for the reconciliation of revenues and expenses. Moreover, the use of power purchase agreements (PPAs) to meet demand might affect credit quality because currently only investments in owned assets contribute to rate base and yield a return that produces excess coverage margins that support credit quality.

Profitability
In coming years, net income will benefit from its authorized 11.35% ROE and the earnings power associated with planned rate base additions as the utility pursues a substantial capital program. Discretionary cash flow is expected to be negative during much of the forecast period. This result is largely a function of the $14 billion-plus five-year capital program as well as substantial dividends. At the same time, about $4.5 billion of incremental debt issuance over the five-year horizon is reasonable relative to the size of the capital program but will increase debt by about 50% to 60%.

Standard & Poor's expects that funds from operations coverage of interest expense should exceed 4.3x during the five-year forecast period. This range of coverage takes into account the debt service on the utility's debt, its parent's debt, and debt service imputed in connection with fixed obligations created under existing and anticipated bilateral power supply contracts. Coverage will likely be diluted after 2010 as the utility addresses capacity and energy needs following the expiration of CDWR contracts. This exposure has been factored into the rating and the rating outlook.

Business Description: Third Largest Utility In U.S.

PG&E is a vertically integrated, regulated, electric, and gas utility and is wholly owned by PG&E Corp. Retail electric and gas rates are subject to oversight by the CPUC. As measured by the number of customers served, PG&E is the country's third-largest retail electric utility in the U.S., after Exelon and American Electric Power Inc.

PG&E's gas operations transmit and distribute natural gas, providing both bundled and transportation gas service. Although the transportation customers procure their own commodity, PG&E procures and delivers the commodity to bundled customers.

In 2006, bundled customers accounted for 92% of gas system revenues, which was consistent with the prior two year's share of revenues. Bundled delivery customers account for about one-third of natural gas deliveries. Transportation customer revenues and volumes account for the balance. Costs incurred in connection with the procurement of natural gas commodity for bundled customers are fully recoverable if they are comparable with market-based benchmarks established by the CPUC. In addition, the utility embarked on a winter gas hedging program in 2005 to shield its retail gas commodity customers from gas price volatility during the peak winter months. The hedging program's costs are borne by the gas commodity customers.

PG&E's electric operations are vertically integrated. PG&E retained a portion of its generation following the CPUC's December 1995 restructuring decision that directed utilities to sell a portion of their generation assets and provided incentives for the sale of additional generation. PG&E retained about 6,500 MW of owned capacity and has contracts for 1,000 MW of hydroelectric capacity. PG&E is obligated to secure energy for its customers from owned and contracted resources However, CDWR contracts provide a portion of customers needs. Electric demand is met through a combination of the cited owned assets, bilateral contracts, market purchases, and power procured by the CDWR. Owned assets provided 40% of 2006's energy needs and the irrigation districts' hydroelectric capacity, about 6%. QF contracts with about 270 suppliers represent about another 4,200 MW of on-peak capacity that supplied 20% of 2006's energy needs. Peak electricity demand is in the vicinity of 18,000 MW for bundled and direct access customers.

In 2006, CDWR's electricity covered about 24% of the utility's customers' energy needs, which is about three percentage points lower than the prior year. Over time, however, as CDWR contracts expire, the utility will bear responsibility for replacing the CDWR energy. PG&E's responsibility for acquiring residual net short power will grow to about 10x 2004's levels and PG&E will bear additional financial responsibility for electricity and fuel procurement necessary to meet customers' electric demand. The most significant growth in the net short position will occur in 2008 and beyond. Consequently, the company is pursuing owned and contracted capacity additions.

PG&E's plans for additional owned generation capacity include the 675 MW Colusa plant, the 530 MW Gateway plant that was acquired as part of the settlement of claims against Mirant stemming from the California energy crisis, and the 163 MW repowered Humboldt Bay plant.

PG&E Corp. is a holding company with only one principal operating company subsidiary, PG&E. Consequently, PG&E is the only operating company that can support PG&E Corp.'s financial obligations, including dividends, debt service, and overhead. Parent debt is currently limited to $280 million of convertible notes that are due in 2010.

Rating Methodology: Ratings Are Based On Consolidated Entity

The ratings on PG&E reflect the consolidated financial and business risk profiles of PG&E and its parent, PG&E Corp. Because Standard & Poor's views capacity payments associated with long-term PPAs as having debt-like attributes, debt and debt service have been imputed to PG&E's historical and projected financial results to reflect the utility's reliance on QF and bilateral contracts to meet a portion of customers' energy needs. Future obligations will include increasing responsibility for securing generation and fuel resources to meet customers' electric needs as CDWR and QF electricity contracts expire, and as the utility responds to CPUC resource adequacy and renewable directives. Approximately $2 billion of debt is currently imputed in connection with existing contracts. We don't impute debt for the CDWR contracts because PG&E simply acts as a conduit for the delivery of CDWR power and for the collection and remittance of the retail revenues tendered by retail customers to pay for that power. Imputed debt is likely to increase as PG&E assumes responsibility for replacing CDWR contracts and pursues contracts to meet renewable mandates.

During their peak year, 2005, the 15 CDWR contracts operationally allocated to PG&E represented 4,650 MW of capacity. PG&E's customers' average annual peak electricity demand stands at about 18,000 MW. Standard & Poor's assumes that PG&E will replace expired CDWR contracts with more favorably priced contracts that will translate into less onerous debt imputation than would be associated with the assignment to PG&E of financial responsibility for the CDWR contracts. Regulatory authorization of the recovery of PPA costs reduces financial risk to the utility but does not eliminate the imputation of debt and debt service.

Financial Risk Profile: Strengthened Financial Performance Should Continue

Accounting

Our analysis of the pro forma financial statements includes several adjustments that we have made historically to assess PG&E's economic strength. The adjustments principally relate to the imputation of debt for fixed off-balance-sheet power purchase contracts. For 2006, we imputed nearly $2 billion of debt to the utility, which represents about a 25% increase over the $7.8 billion of 2006 short- and long-term balance sheet debt, net of rate reduction bond and energy recovery bond securitization debt. The imputed debt represents the present value of outstanding QF contracts and irrigation district contracts after applying a 30% risk factor to the contractual obligations. As the utility's net short position grows in coming years, particularly as CDWR contracts expire, the amount of off-balance-sheet obligations with operating leverage attributes could increase significantly.

Standard & Poor's financial analysis deducts from PG&E's revenues the amount the company collects to service principal and interest payment obligations on securitized bonds. Similarly, we adjust the company's debt ratios to remove the unamortized balance of the securitization bonds.

Corporate governance/Risk tolerance/Financial policies

PG&E Corp.'s investment policy moderated following aggressive, unsuccessful investments in merchant energy businesses in the 1990s. Management's appetite for creating or purchasing new growth vehicles will determine future financial policy. Management has announced an interest in pursuing the development of a new interstate gas transmission pipeline if a certain liquefied natural gas terminal is developed in Oregon, but management's current focus is on the enhancement of the current regulated utility through process and capital improvements.

Cash flow adequacy

Cash flow will be partially protected in the near term by CDWR contracts that should help reduce procurement-related risks and fuel price volatility. Gas price volatility is borne by CDWR. In 2006, energy prices became variable once again, which increased the utility's exposure to fuel price volatility and heightened its dependence on CPUC responses to changes in fuel prices. As CDWR and QF contracts expire, PG&E's residual net short obligation and its financial exposure to market resources will expand significantly.

The CPUC uses balancing accounts to track mismatches between revenues and expenses as part of its effort to preserve the correlation between the two. The administrative extension of the true-up mechanism should protect cash flow by compelling the CPUC to adjust retail rates if expenses rise above anticipated levels and deferrals recorded in the balancing accounts match 5% of the utility's previous-year generation revenues. In PG&E's case, this threshold could be a few hundred million pretax dollars and may grow as the utility's procurement obligations increase. Nevertheless, PG&E could experience substantial deferrals that approach but do not cross the 5% trigger. Deferrals that approach the cap but don't produce rate adjustments might sufficiently erode debt-service coverage margins so as to impair credit quality.

Discretionary cash flow is expected to be negative during the forecast period. This is largely a function of a sizable capital program and substantial dividends.

Standard & Poor's expects that funds from operations coverage of interest expense should exceed 4.3x during the five-year forecast period. This range of coverage takes into account the debt service on the utility's debt, its parent's debt, and debt service imputed in connection with fixed obligations created under bilateral power supply contracts. Thereafter, coverage will likely be diluted as the utility addresses capacity and energy needs following the expiration of CDWR contracts. This exposure has been factored into the rating.

Capital structure/Asset protection

Following adjustments for off-balance-sheet obligations, we expect the company to exhibit an adjusted debt to capitalization ratio of about 55% over the next five years. The adjusted ratio includes debt equivalents related to PPAs. We view CPUC regulations requiring PG&E to maintain a ratemaking capital structure with a 52% equity layer as protective of the utility's financial integrity. Nevertheless, the threshold ratemaking equity layer prescribed by the CPUC will still permit PG&E to pay substantial dividends to its parent. The CPUC's methodology for calculating the capital structure differs from Standard & Poor's methodology principally because the CPUC excludes short-term debt and PPA debt equivalents from its analysis of a utility's capital structure.

Table 1.

PG&E Corp. Peer Comparison*

	--Average of past three fiscal years--	
	PG&E Corp.	Edison International
Corporate credit rating	BBB+/Stable/A-2	BBB-/Stable/--
(Mil. $)		
Revenues	11,228.6	11,258.1
Net income from cont. oper	1,905.0	805.7
Funds from operations (FFO)	1,628.5	2,312.9
Capital expenditures	2,044.5	2,399.8
Cash and investments	1,373.7	2,125.3
Debt	9,918.4	15,256.3
Preferred stock	263.3	587.7
Common equity	7,096.9	6,373.7

Total capital	17,278.7	22,294 8
Adjusted ratios		
EBIT interest coverage (x)	2.9	2 3
FFO int cov (x)	2 7	2 7
FFO/debt (%)	16 4	15 2
Discretionary cash flow/debt (%)	(4 5)	(4.5)
Net cash flow/capital expenditures (%)	65.0	77 1
Debt/total capital (%)	57 4	68 4
Return on common equity (%)	25 4	11 9
Common dividend payout ratio (un-adj) (%)	11.9	58.8

*Fully adjusted (including postretirement obligations)

Table 2.

PG&E Corp. Financial Summary*

	--Fiscal year ended Dec. 31--				
	2006	2005	2004	2003	2002
Rating history	BBB/Stable/A-2	BBB/Stable/A-2	BBB-/Stable/--	D/Watch Pos/D	--/--/--
(Mil. $)					
Revenues	11,810 9	11,153.0	10,722.0	10,057 0	12,495 0
Net income from continuing operations	991.0	904 0	3,820 0	791 0	(32.0)
Funds from operations (FFO)	2,224.7	1,482.1	1,178.7	2,944.7	1,979.8
Capital expenditures	2,544.2	1,951.1	1,638.4	1,698 0	3,032.0
Cash and investments	456.0	713 0	2,952.0	4,061.0	4,603 0
Debt	9,409.7	9,598.7	10,747.9	4,827.6	11,808.9
Preferred stock	252.0	252.0	286.0	286 0	480 0
Common equity	7,811 0	6,045 4	7,434 4	3,173.1	2,316.9
Total capital	17,471 7	15,896 1	18,468 3	8,286.6	14,605.8
Adjusted ratios					
EBIT interest coverage (x)	3 0	3.2	2.6	2 2	0.9
FFO int cov. (x)	3 5	2 6	2 0	3 2	2.2
FFO/debt (%)	23.6	15.4	11 0	61.0	16.8
Discretionary cash flow/debt (%)	(8.2)	(3.2)	(2.3)	12.6	(24.2)
Net cash flow/capital expenditures (%)	69.5	58 0	68 4	173.4	65 3
Debt/total capital (%)	53.9	60 4	58 2	58.3	80.9
Return on common equity (%)	12 3	10 6	59 0	20.2	(1 4)
Common dividend payout ratio (un-adj) (%)	34.5	37 6	0.0	0.0	0.0

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of PG&E Corp. 2006 Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

PG&E Corp. reported amounts	Debt	Revenues	Operating income (before D&A)	Operating income (before D&A)	Operating income (after D&A)	Interest expense	Cash flow from operations	Cash flow from operations	Capital expenditures
Reported	10,303.0	12,539.0	3,817 0	3,817 0	2,108 0	738.0	2,714.0	2,714 0	2,402.0
Standard & Poor's adjustments									
Operating leases	229 2	--	153 0	15 9	15.9	15.9	137 1	137.1	162.2
Postretirement benefit obligations	58 5	--	(30 0)	(30 0)	(30 0)	--	158 6	158.6	--
Capitalized interest	--	--	--	--	--	20.0	(20 0)	(20 0)	(20 0)
Share-based compensation expense	--	--	--	65 0	--	--	--	--	--
Securitized utility cost recovery	(2,566 0)	(728.1)	(728.1)	(728.1)	(122 1)	(122.1)	(606 0)	(606 0)	--

Power purchase agreements	1,384 0	–	101 3	101 3	101 3	101 3	–	–	–
Reclassification of nonoperating income (expenses)	–	–	–	–	175.0	–	–	–	–
Reclassification of working-capital cash flow changes	–	–	–	–	–	–	–	(2 0)	–
US decommissioning fund contributions	–	–	–	–	–	–	(157 0)	(157 0)	–
Total adjustments	(894 3)	(728.1)	(503 8)	(576 0)	140 0	15 0	(487 3)	(489.3)	142.2

Standard & Poor's adjusted amounts

	Debt	Revenues	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Capital expenditures
Adjusted	9,408.7	11,810.9	3,313.2	3,241.0	2,248 0	753.0	2,226.7	2,224 7	2,544 2

*PG&E Corp reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysis. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively) Consequently, the first section in some tables may feature duplicate descriptions and amounts

Ratings Detail (As Of 19-Jun-2007)*

Pacific Gas & Electric Co.	
Corporate Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock	
Local Currency	BBB-
Senior Unsecured	
Local Currency	BBB+
Corporate Credit Ratings History	
31-May-2007	BBB+/Stable/A-2
28-Dec-2005	BBB/Stable/A-2
16-Feb-2005	BBB/Stable/NR
16-Apr-2004	BBB-/Stable/NR
19-Dec-2003	D/Watch Pos/D
Business Risk Profile	1 2 3 4 $\boxed{5}$ 6 7 8 9 10

*Unless otherwise noted, all ratings in this report are global scale ratings Standard & Poor's credit ratings on the global scale are comparable across countries Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country

"THE ATTACHED RRA REPORT MAY NOT BE USED
OUTSIDE OF THE CONTEXT OF THIS PROCEEDING"

The attached RRA reports "SNL Interactive Rate Case History – Summary for Pacific Gas & Electric from 3/15/2007" and "CALIFORNIA REGULATORY REVIEW – MARCH 19, 2008, pages 1 and 2" are being submitted as part of this exhibit with the authorization of Regulatory Research Associates, an SNL Company.

SNL Interactive
Interactive Alerts
SNL Financial LC
Phone: (888) 275-2822

SNL*i*

SNLFinancial

Rate Case History

Past Rate Cases

				Increase Requested						Increase Authorized								
State	Company	Case Identification	Service	Date	Rate Increase ($M)	Return on Rate Base (%)	Return on Equity (%)	Common Equity /Total Cap (%)	Rate Base ($M)	Date	Rate Increase ($M)	Return on Rate Base (%)	Return on Equity (%)	Common Equity /Total Cap (%)	Test Year End	Rate Base ($M)	Rate Base Valuation Method	Lag (months)
California	Pacific Gas and Electric Co.	A-05-12-002 (electric)	Electric	12/8/2005	359.1	8.79	11.35	52.00	10,848.6	3/15/2007	192.2	8.79	11.35	52.00	12/2007	10,254.3	Avg	15

Exhibit__(FJH-28)
Sheet 2 of 4

Regulatory Research Associates An SNL Energy Company

REGULATORY FOCUS

CALIFORNIA REGULATORY REVIEW – MARCH 19, 2008

California Public Utilities Commission (PUC)
California State Building
505 Van Ness Avenue
San Francisco, CA 94102-3298
(415) 703-2782

Please note that the sections below are updated through 3/19/08, but are maintained on a real-time basis in the Commission Profiles section of our website.

No. of Commissioners	5 full-time, minority party representation not required
Method of Selection	Governor appointment, Senate confirmation
Term of Office	6 years--staggered terms
President	Appointed by the governor
Governor	Arnold Schwarzenegger (R)--serving a second term extending to January 2011

Commissioners	**Party**	**Began Serv.**	**Term Ends**	**Background**
Michael R. Peevey (President)	D	3/02	1/09	CEO of TruePricing Inc.; Pres. of New Energy Inc.; Pres. of Edison Int'l. and Southern California Edison
Dian Grueneich	D	1/05	1/11	Energy and Environmental Law Consultant; Attorney
John Bohn	R	5/05	1/11	Businessman; President and CEO of Moody's; Special Assistant to former U.S. Treasury Secretary Regan
Rachelle Chong	R	1/06	1/09	Attorney; FCC Commissioner; attorney in private practice; mediator; arbitrator
Timothy Alan Simon	R	2/07	1/13	Securities and compliance attorney; appointment secretary in Gov. Schwarznegger's administration

Miscellaneous Issues: Minority party representation for commissioners is not required. (Section updated 3/19/08)

RRA EVALUATION	*Over the past few years, a reasonable degree of stability has been restored to the California regulatory environment. The state's three major electric utilities are financially healthy and accorded investment grade debt ratings. The state is operating under a largely traditional regulatory framework, with only a limited number of customers purchasing generation service competitively. In a pending proceeding, the PUC is considering whether and under what conditions the current direct access suspension should be lifted, but we believe that any substantive move to permit additional retail access will require enabling legislation. Recent PUC equity return authorizations have been above the industry averages, and certain utilities are operating under performance-based plans that have been in place since the early 1990s. Importantly, the PUC has implemented an Energy Resource Recovery Account that is designed to track and allow recovery of the difference between a utility's projected and actual generation revenues and costs. The state has approached generation resource adequacy in a realistic and constructive manner, and California's emphasis on modernizing and, where necessary, expanding the energy delivery system infrastructure is providing significant rate base growth opportunities for the state's electric utilities. In addition, the PUC has recently authorized an incentive framework that enables the utilities to retain a portion of the net savings achieved under their energy efficiency programs. While markets have stabilized and California's electric utilities have regained their financial health, we note that the state's electric rates are well above both the national and, especially, regional averages, and this rate disparity could cause large- and medium-sized customers to again press for lower rates and regulatory reform in the future. We are maintaining our Average/1 rating of California regulation.* (Section updated 3/19/08)

Services Regulated:	Privately-owned electric, natural gas, telecommunications, water, and sewer utilities; railroads, rail transit, and passenger transportation companies. (Section updated 3/19/08)
Commission Budget:	Fiscal 2008--Approximately $1.3 billion, of which approximately $152 million is allocated for the regulation of utilities. The budget is derived from fees imposed upon regulated utilities, common carriers, and related businesses. (Section updated 3/19/08)
Commissioner Salaries:	President--$132,200, Commissioners--$128,100 (Section updated 3/19/08)
Size of Staff:	Approximately 1000, almost all of whom are selected through and protected by the State Civil Service System. The PUC is structured into eight divisions: administrative law judges; energy; telecommunications; water; strategic planning; communication and public division; information and management services; and, legal. The PUC also includes a consumer advocacy group, the Division of Ratepayer Advocates. (Section updated 3/19/08)
Consumer Interest:	Largely represented by the Division of Ratepayer Advocates (DRA) (approximately 140 employees), which generally presents a full case in major rate proceedings. The DRA's director is appointed by, and serves at the pleasure of, the governor, subject to Senate confirmation. The current DRA director is Dana Appling. Other intervenors include various cities and industrial, commercial, residential, and environmental intervenors, and such consumer groups as The Utility Reform Network. (Section updated 3/19/08)
Rate Case Timing/ Interim Procedures:	State statutes set time limits for PUC completion of certain types of cases: ratesetting, 18 months; and, adjudicatory (i.e., complaints), 12 months. However, no penalty or enforcement mechanism exists. In the Commission's most recent general rate case (GRC), a Southern California Edison (SCE) proceeding decided in May 2006, the PUC took approximately 18 months to issue a final decision. SCE is a subsidiary of Edison International (EIX). While the PUC is permitted to authorize interim increases, such increases have not been requested or granted in recent years. In granting an interim increase, the Commission may specify whether the increase will be collected subject to refund or on a firm basis. (Section updated 3/19/08)
Return on Equity:	Prior to electric industry restructuring (see the Electric Regulatory Reform/Industry Restructuring section), the PUC reviewed the major energy utilities' cost of capital (COC) annually in a separate proceeding, and the Commission has returned to this framework for companies that are not operating under incentive plans (see the Alternative Regulation section). On Dec. 20, 2007, the PUC issued return on equity (ROE) determinations for 2008, adopting an 11.35% ROE for Pacific Gas and Electric (PG&E), an 11.5% ROE for Southern California Edison (SCE), and an 11.1% ROE for San Diego Gas & Electric (SDG&E). For 2007, PG&E, SCE, and SDG&E had been authorized ROEs of 11.35%, 11.6%, and 10.7%, respectively. We note that as a result of a settlement that was approved by the PUC in 2003 resolving PG&E's Chapter 11 bankruptcy proceeding, the utility is entitled to earn an ROE of at least 11.22% on an authorized 52% equity ratio, until PG&E's long-term credit ratings are at least A-/A3, or by the end 2012, whichever occurs first. PG&E and SDG&E are subsidiaries of PG&E Corporation (PCG) and Sempra Energy (SRE), respectively. On Dec. 21, 2007, the Southern California, Northern California, and South Lake Tahoe Divisions of Southwest Gas (SWX) filed base rate cases that incorporate an 11.5% ROE (FN 3/14/08). In the late 1990's, the PUC replaced SDG&E's and Southern California Gas' (SCG) annual COC proceeding with an automatic adjustment mechanism that is triggered if interest rates exceed a predetermined deadband. In addition, SCG's mechanism is triggered only if this new level of interest rates is forecasted to continue for the following year. If the mechanism is triggered, rates are automatically adjusted for any associated change in the COC according to a pre-established formula. The PUC permitted SDG&E to file a traditional 2008 test year COC application, and the

Southwest Gas Corporation
Summary of Cost of Capital and Fair Rate of Return
Based Upon a Hypothetical Regulatory Capital Structure

Assuming Approval of the Requested Tariff Tools

Type of Capital	Ratios (1)	Cost Rate	Weighted Cost Rate
Long-Term Debt	51.00	7.96 (1)	4.06
Preferred Equity	4.00	8.20 (1)	0.33
Common Equity	45.00	11.25 (2)	5.06
Total	100.00 %		9.45 %

Notes:

(1) From Schedule D-1, Sheet 1 of 1
(2) Mr. Hanley is keeping his recommendation of 11.25% unchanged despite an indicated higher cost of equity for Southwest reflected by the market in general, but especially in view of a higher yield spread required by the market between companies with bonds rated A3 and Baa3, the bottom of investment grade rating such as Southwest; and also because of Southwest's increased beta which has risen to 0.90.

Southwest Gas Corporation
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Southwest Gas Corporation	Proxy Group of Eight Value Line Gas Distribution Companies
1.	Discounted Cash Flow Model (1)	9.53 %	9.61 %
2.	Risk Premium Model (2)	11.63	11.24
3.	Capital Asset Pricing Model (3)	10.98	10.75
4.	Comparable Earnings Analysis (4)	12.37	13.02
5.	Indicated Common Equity Cost Rate before Investment Risk Adjustments	11.25 %	11.00 %
6.	Investment Risk Adjustment Due to Southwest Gas Corporation's Lower Bond Rating	- -	0.61 (5)
7.	Common Equity Cost Rate after Investment Risk Adjustment	11.25 %	11.61 %
8.	Recommendation	11.25%	

See Sheet 3 for notes.

Southwest Gas Corporation
Brief Summary of Common Equity Cost Rate

Notes:

(1) From Sheet 4 of this Exhibit.

(2) From Sheet 16 of this Exhibit.

(3) From Sheet 25 of this Exhibit.

(4) From Sheets 29 and 30 of this Exhibit.

(5) The 11.00% indicated common equity cost rate based upon the proxy group of eight LDCs is applicable to the average A3 Moody's bond rating of the group. As explained in Mr. Hanley's direct testimony, Southwest Gas Corporation has greater relative risk than the eight LDCs as evidenced by the Company's Baa3 Moody's bond rating. Therefore, an indication of the magnitude of the investment risk adjustment is based upon the yield spread between A3 and Baa3 rated public utility bonds. The investment risk adjustment of 0.61% equals two-thirds of the average spread between A and Baa rated public utility bonds of 43 basis points plus one-third of the estimated average spread between Baa and Ba rated public utility bonds of 95 basis points (from Sheet 19 of this Exhibit), (0.61% = (2/3 * 0.43%) + (1/3 * 0.95%) = (0.287%, rounded to 0.29%) + (0.317%, rounded to 0.32%) = 0.29% + 0.32% = 0.61%).

Southwest Gas Corporation
Indicated Common Equity Cost Rate through the use
of the Discounted Cash Flow Model for
Southwest Gas Corporation
and the Proxy Group of Eight Value Line Gas Distribution Companies

	1 Dividend Yield (1)	2 Dividend Growth Component (2)	3 Adjusted Dividend Yield (3)	4 Growth Rate (4)	5 Indicated DCF Return Rate (5)	6 "Recommended" DCF Return Rate (6)
Southwest Gas Corporation	3.28 %	0.10 %	3.38 %	6.15 %	9.53 %	9.53 %
Proxy Group of Eight Value Line Gas Distribution Companies						
AGL Resources Inc.	4.78 %	0.10 %	4.88 %	4.34 %	9.22 %	-- %
Atmos Energy Corp.	4.90	0.11	5.01	4.62	9.63	9.63
The Laclede Group, Inc.	4.30	0.08	4.38	3.50	7.88	--
NICOR Inc.	5.31	0.11	5.42	4.17	9.59	9.59
Northwest Natural Gas Company	3.44	0.10	3.54	5.95	9.49	--
Piedmont Natural Gas Company, Inc.	3.99	0.10	4.09	5.07	9.16	--
South Jersey Industries, Inc.	3.08	0.10	3.18	6.17	9.35	--
WGL Holdings, Inc.	4.36	0.08	4.44	3.75	8.19	--
Average	4.27 %	0.10 %	4.37 %	4.70 %	9.06 %	9.61 %

Notes:
(1) From Sheet 5 of this Exhibit.
(2) This reflects a growth rate component equal to one-half the average projected five-year growth rate in EPS (from Sheet 6 of this Exhibit) x Line No. 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Southwest Gas Corporation, 3.28% x (1/2 x 6.15%) = 0.10%.
(3) Column 1 + Column 2.
(4) From Sheet 6 of this Exhibit.
(5) Column 3 + Column 4.
(6) Includes only those indicated common equity cost rates (ROE) which are greater than 9.50% % (the lowest rate awarded to a gas distribution company or to the gas operations of a combination electric & gas company during the twelve months ended March 2008), from Sheet 1 of Exhibit__(FJH-29) as fully explained in Mr. Hanley's accompanying rebuttal testimony because Regulatory Research Associates noted that it is the lowest awarded ROE to an energy utility nationwide in at least 30 years. Also, as shown on Sheet 1 of Exhibit__(FJH-29), on January 17, 2008, National Fuel Gas Distribution Corporation (NFGDC) was authorized a ROE of 9.10%, which Mr. Hanley has excluded from the average of litigated cases and as the lowest ROE awarded for the 12-month period ended March 31, 2008 as fully explained in Mr. Hanley's accompanying rebuttal testimony. Consequently, he has assumed the 9.50% ROE authorized for Arkansas Western Gas Company on 7/13/07 as the lowest realistic ROE awarded for the 12-month period ended March 31, 2008.

Southwest Gas Corporation
Derivation of Dividend Yield for Use in the
Discounted Cash Flow Model

	Dividend Yield			
	Spot (4/4/08) (1)	Average Based Upon Average High / Low Market Prices (2) March 2008	February 2008	Average Dividend Yield (3)
Southwest Gas Corporation	3.22 %	3.37 %	3.25 %	3.28 %
Proxy Group of Eight Value Line Gas Distribution Companies				
AGL Resources Inc.	4.93 %	4.86 %	4.56 %	4.78 %
Atmos Energy Corp.	4.92	5.05	4.72	4.90
The Laclede Group, Inc.	4.20	4.29	4.40	4.30
NICOR Inc.	5.49	5.58	4.86	5.31
Northwest Natural Gas Company	3.47	3.53	3.31	3.44
Piedmont Natural Gas Company, Inc.	3.93	4.05	3.98	3.99
South Jersey Industries, Inc.	2.99	3.19	3.05	3.08
WGL Holdings, Inc.	4.37	4.45	4.25	4.36
Average	4.29 %	4.38 %	4.14 %	4.27 %

Notes: (1) The spot dividend yield is the current annualized dividend per share divided by the spot market price on 4/4/08.

(2) The average dividend yield was computed by relating the indicated annualized dividend rate and market price on the last trading day of each of the two months ended March 2008.

(3) Equal weight has been given to the spot, February 2008 and March 2008 dividend yields.

Source of Information: Standard & Poor's Compustat Services, Inc., PC Plus/Research Insight Database.
EDGAR Online's I-Metrix Database

Southwest Gas Corporation
Development of Projected Growth for Use in the Discounted Cash Flow Model

	1	2		3
	Value Line Projected 2010-'12 Growth Rate in EPS (1)	Reuters Mean Consensus Long-Term Growth Rate		Average Projected Five-Year Growth Rate in EPS (2)
		EPS	No. of Estimates	
Southwest Gas Corporation	7.50	4.80	[5]	6.15 %
Proxy Group of Eight Value Line Gas Distribution Companies				
AGL Resources Inc.	3.50 %	5.18 %	[5]	4.34 %
Atmos Energy Corp.	4.50	4.73	[7]	4.62
The Laclede Group, Inc.	3.50	3.50	[1]	3.50
NICOR Inc.	4.00	4.33	[3]	4.17
Northwest Natural Gas Company	7.00	4.90	[5]	5.95
Piedmont Natural Gas Company, Inc.	5.00	5.13	[6]	5.07
South Jersey Industries, Inc.	NMF	6.17	[3]	6.17
WGL Holdings, Inc.	3.50	4.00	[3]	3.75
Average	4.43 %	4.74 %		4.70 %

NMF = Not Meaningful Figure

Notes: (1) From Sheets 7 through 15 of this Exhibit.
(2) Average of Columns 1 and 2.

Source of Information: Value Line Investment Survey, (Standard Edition), March 14, 2008
Reuters/Market Guide, stocks.us.reuters.com, April 4, 2008.

Exhibit___(FJH-29)
Sheet 7 of 32

Exhibit___(FJH-9)
Sheet 2 of 10
(Update)

SOUTHWEST GAS NYSE-SWX

RECENT PRICE 25.87 | P/E RATIO 12.9 (Trailing: 13.3 Median: 19.0) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 3.5% | VBMVF MJOF

TIMELINESS 5 Raised 11/9/07
SAFETY 4 Lowered 1/4/91
TECHNICAL 3 Raised 2/15/08
CFUB /:1)2/11 > Nbd /t

1 jhl :	31/4	37/:	3: /8	34/1	35/8	36/4	34/7	37/3	39/2	4: /5	4: /:	41/6	
Mox :	27/2	28/4	31/5	27/:	29/7	28/2	2: /4	32/6	34/6	37/1	37/6	36/3	

Target Price Range
3122 | 3123 | 3124

2011-13 PROJECTIONS

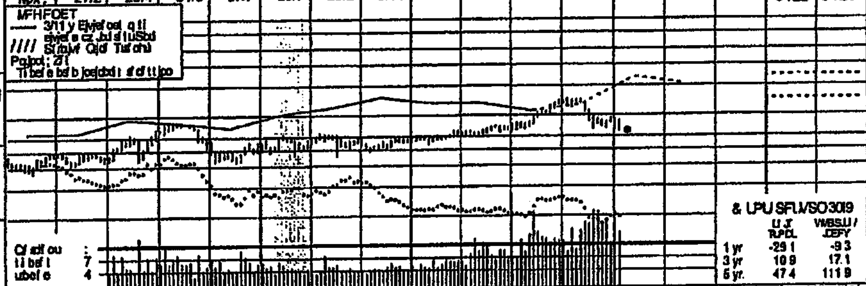
	Price	Gain	Ann'l Total Return
High	66	), 226&	34&
Low	51	), 66&	25&

Jbt jef s Ef djt jpot

	A	M	J	J	A	S	O	N	D
to Buy	1	1	1	1	1	1	1	1	1
Options	1	1	1	1	1	1	1	1	1
to Sell	1	2	2	1	1	2	1	1	2

Jbt ujuvujpobnEf djt jpot

	202007	302007	402007
to Buy	:4	96	93
to Sell	8:	:6	95
Hld's(000)	43289	43:51	45:86



& UPU SFUVSO 3019

	U J. TUPDL	WBSJ / JOEY
1 yr	-29 1	-9 3
3 yr	10 9	17.1
5 yr.	47 4	111 9

2::3	2::4	2::5	2::6	2::7	2::8	2::9	2:::	3111	3112	3113	3114	3115	3116	3117	3118	3119	311:	VALUE LINE PUB., INC.	11-13
25 93	25 68	28 16	23 03	24.09	26 73	30 17	30 24	32 81	42 98	39 68	35.96	40 14	43.59	48 47	50.00	52.95	55.55	Revenues per sh [B]	61.45
3 34	3 24	5.09	2 65	3 00	3 85	4 48	4 45	4 57	4 79	5 07	5.11	5 57	5 20	5 97	6 18	6.35	6.65	"Cash Flow" per sh	7.40
81	63	1 22	.10	25	77	1 65	1 27	1 21	1 15	1 16	1 13	1 66	1.25	1 98	1 95	2.05	2.20	Earnings per sh [B C]	2.65
.70	.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.94	Div'ds Decl'd per sh [D]	1.06
5 02	5.43	8.64	6 79	8 19	6 19	6.40	7 41	7 04	8 17	8.50	7 83	8.23	7 49	8.27	7 92	8.40	8.65	Cap'l Spending per sh	9.90
15.99	15.86	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.85	23.30	23.35	Book Value per sh	26.05
20.60	21.00	21.28	24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	43.04	44.00	45.00	Common Shs Outst'g [E]	48.00
16 8	26 5	14 0	NMF	69 3	24 1	13 2	21 1	16 0	19 0	19 9	19.2	14 3	20.6	15 9	17 3	Bold figures are	Value Line estimates	Avg Ann'l P/E Ratio	18.0
1 01	1 57	82	NMF	4 34	1 39	.69	1 20	1 04	.97	1 09	1.09	76	1 10	86	91			Relative P/E Ratio	1.20
5.2%	4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3 5%	3.2%	2.6%	2.6%			Avg Ann'l Div'd Yield	2.2%
						917.3	936.8	1034 1	1396 7	1320 9	1231 0	1477 1	1714 3	2024 7	2152 1	2330	2500	Revenues ($mill) [B]	2950
						47.5	39.3	38.3	37.2	38.6	38.5	58.9	48.1	80.5	83.3	90.0	100	Net Profit ($mill)	125
						43 4%	35.5%	28.2%	34 5%	32 8%	30.5%	34 8%	29 7%	37 3%	36.5%	35.0%	35.0%	Income Tax Rate	35.0%
						5.2%	4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	3.9%	4.0%	Net Profit Margin	4.2%
						60 2%	60.3%	60 2%	56.2%	62 5%	66.0%	64.2%	63 8%	60 6%	58.1%	57.0%	56.5%	Long-Term Debt Ratio	52.0%
						35.3%	35.5%	35.8%	39.8%	34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	43.0%	43.5%	Common Equity Ratio	48.0%
						1349.3	1424 7	1489 9	1417 6	1748 3	1851 6	1986 6	2076 0	2287 8	2349 8	2375	2400	Total Capital ($mill)	2600
						1459.4	1581.1	1686.1	1826.6	1979.5	2175.7	2336.0	2489.1	2688.1	2845.3	3000	3150	Net Plant ($mill)	3600
						5 8%	4.8%	4 6%	5 1%	4 3%	4 2%	5.0%	4 3%	5 5%	5.6%	6.0%	6.0%	Return on Total Cap'l	6.5%
						8 9%	7.0%	6 5%	6 0%	5.9%	6.1%	8 3%	6 4%	8 9%	8.5%	9.0%	9.5%	Return on Shr. Equity	10.0%
						10.0%	7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	9.0%	9.5%	Return on Com Equity	10.0%
						5.0%	2.8%	2.4%	1 9%	1.9%	1 7%	4.3%	2.2%	5 2%	4.8%	5.0%	5.5%	Retained to Com Eq	6.0%
						50%	64%	67%	71%	76%	72%	49%	65%	42%	44%	44%	42%	All Div'ds to Net Prof	41%

CAPITAL STRUCTURE as of 12/31/07

Total Debt $1413 1 mill Due in 5 Yrs $616 0 mill
LT Debt $1366 0 mill LT Interest $93 0 mill.
(Total interest coverage: 2.4x)

Pension Assets-12/07 $441.7 mill
Oblig. $546 4 mill

Pfd Stock None

Common Stock 43,044,024 shs
as of 2/15/08

MARKET CAP: $1.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	12/31/07
Cash Assets	29.6	18.8	32.0
Other	513.1	482.8	470.5
Current Assets	542 7	501 6	502.5
Accts Payable	259 5	265.7	220.7
Debt Due	107.2	27.5	47.1
Other	254.3	202.9	260.1
Current Liab.	621 0	496.1	527.9
Fix. Chg. Cov.	167%	220%	229%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	6.0%	4.5%	4.5%
"Cash Flow"	4.5%	4 0%	4.0%
Earnings	12 0%	6.0%	7 5%
Dividends	--	--	4.0%
Book Value	3.0%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	542.9	361 1	313 3	497.0	1714.3
2006	676.9	430.9	351.8	565.1	2024 7
2007	793.7	426.6	371 5	560.3	2152 1
2008	850	460	400	620	2330
2009	880	510	450	660	2500

Cal-endar	EARNINGS PER SHARE [C] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.88	d.07	d.43	.87	1.25
2006	1 11	02	d 26	1 11	1 98
2007	1.17	d.01	d.22	1.00	1.95
2008	1.20	Nil	d.20	1.05	2.05
2009	1.20	.05	d.15	1.10	2.20

Cal-endar	QUARTERLY DIVIDENDS PAID [D] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.205	.205	.205	.205	.82
2005	.205	.205	.205	205	.82
2006	205	.205	.205	205	82
2007	205	.215	.215	215	85
2008	.215	.225			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1 8 million customers in sections of Arizona, Nevada, and California Comprised of two business segments: natural gas operations and construction services 2007 margin mix: residential and small commercial, 86%; large commercial and industrial, 5%; transportation, 9% Total throughput: 2.4 billion therms Sold PriMerit Bank in July of 1996. Has 5,073 employees. Officers & Directors own roughly 1.4% of common stock (3/07 Proxy) Chairman: LeRoy C Hanneman, Jr. Chief Executive Officer: Jeffrey W. Shaw. Incorporated: California. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193 Telephone: 702-876-7237 Internet: www.swgas.com

Southwest Gas reported unimpressive performance for the fourth quarter. Share earnings fell roughly 10% from the prior year's period. The company experienced softness in heating demand, owing to warmer-than-usual temperatures during the period. This was partially offset by modest growth in the customer base. Overall, 2007 earnings came in slightly below the 2006 figure. Looking forward, conditions may remain somewhat challenging in the current year. We anticipate relatively slow customer growth, due partly to the downturn in the housing market. Thus, we have lowered our bottom-line estimate by $0.20 a share, to $2.05.

The company remains focused on procuring rate relief and improving rate design. In order to address weather-related volatility, Southwest has included several proposed rate design changes in its most recently filed Arizona rate case. The utility is seeking a rate hike of $50.2 million (nearly 5%). It has asked the commission to implement the new rates at the start of October. The company has also filed a rate case application with California, requesting a $9.1 million increase in operating revenues, beginning in January of 2009. Such approved revenue increases help Southwest Gas to cope with higher operating expenses, and provide the company with greater earnings stability. Indeed, a full year of rate relief in 2009 should produce healthy growth in earnings, to $2.20 per share.

The board of directors has increased the dividend. Starting with the June payout, the quarterly dividend is now $0.225 a share, an increase of 4.7%. This follows a similar increase last year. However, this issue's current dividend yield of roughly 3.5% is not a standout by utility standards.

Shares of Southwest Gas are ranked unfavorably in our momentum-based system. Looking further out, we anticipate solid share-earnings growth over the pull to 2011-2013. At the present quotation, this stock offers impressive total return potential for the coming years, and may appeal to patient investors. That said, conservative accounts are advised not to overweight this issue, considering the regulatory risks.

Michael Napoli, CPA *March 14, 2008*

(A) Incl. income for PriMerit Bank on the equity basis through 1994. (B) Based on avg shares outstand. thru. '96, then diluted Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Incl asset writedown: '93, 44¢ Excl. loss from disc ops.: '95, 75¢ Totals may not sum due to rounding. Next egs report due late April (C) Dividends historically paid early March, June, September, December ■ Div'd reinvest. plan avail (D) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	65

Exhibit___(FJH-29)
Sheet 8 of 32

Exhibit___(FJH-9)
Sheet 3 of 10
(Update)

AGL RESOURCES NYSE-ATG

RECENT PRICE 35.54 | P/E RATIO 12.4 (Trailing: 13.0 / Median: 14.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 4.7% | VALUE LINE

High:	21.8	23.4	23.4	23.2	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1
Low:	17.8	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0	34.4	35.2	34.4

Target Price Range 2011 | 2012 | 2013

TIMELINESS 3 Raised 3/14/08
SAFETY 2 New 7/27/90
TECHNICAL 3 Raised 12/21/07
BETA .85 (1.00 = Market)

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 12/95
Options: Yes
Shaded area indicates recession

2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+55%)	15%
Low	40	(+15%)	7%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	0	0	1	0	0	0	0

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	132	106	128
to Sell	101	112	99
Hld's(000)	50323	47302	47469

Percent shares traded 12 8 4

128 96 80 64 48 40 32 24 16 12

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr	-11.1	-9.3
3 yr	13.2	17.1
5 yr	91.5	111.8

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
20.43	22.73	23.69	19.32	21.91	22.76	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	*34.55*	*36.20*	Revenues per sh A	*41.25*
2.31	2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.88	3.31	3.39	3.47	3.29	4.20	4.60	4.77	*4.85*	*5.15*	"Cash Flow" per sh	*5.65*
1.13	1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	*2.80*	*2.90*	Earnings per sh A B	*3.20*
1.03	1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	*1.68*	*1.72*	Div'ds Decl'd per sh C■	*1.84*
2.74	2.49	2.37	2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	*3.50*	*3.60*	Cap'l Spending per sh	*3.65*
9.70	9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.62	14.66	18.06	19.29	20.71	21.74	*22.35*	*23.05*	Book Value per sh D	*22.50*
48.69	49.72	50.85	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	*76.00*	*76.00*	Common Shs Outst'g E	*80.00*
15.6	17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.94	1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.77	*Value Line*		Relative P/E Ratio	*1.00*
6.9%	6.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $2254.0 mill. Due in 5 Yrs $897.0 mill.
LT Debt $1674.0 mill. LT Interest $95.0 mill.

(Total interest coverage: 3.7x)
Leases, Uncapitalized Annual rentals $26.0 mill.

Pension Assets-12/07 $383.0 mill.
Oblig. $427.0 mill.

Pfd Stock None
Common Stock 76,439,305 shs
as of 1/31/08

MARKET CAP: $2.7 billion (Mid Cap)

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
1338.6	1068.8	607.4	1049.3	868.9	983.7	1832.0	2718.0	2621.0	2494.0	*2625*	*2750*	Revenues ($mill) A	*3300*
80.6	52.1	71.1	82.3	103.0	132.4	153.0	193.0	212.0	216.6	*215*	*225*	Net Profit ($mill)	*260*
32.5%	33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	37.6%	37.6%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
6.0%	4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	8.1%	8.4%	*8.2%*	*8.2%*	Net Profit Margin	*7.9%*
47.5%	45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
47.1%	49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
1388.4	1345.8	1288.2	1736.3	1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	*3400*	*3500*	Total Capital ($mill)	*3600*
1534.0	1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	3436.0	3556.0	*3700*	*3800*	Net Plant ($mill)	*4150*
7.6%	5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	8.0%	7.6%	*7.5%*	*8.0%*	Return on Total Cap'l	*8.5%*
11.1%	7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	*12.5%*	*13.0%*	Return on Shr. Equity	*14.5%*
12.3%	7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	*12.5%*	*13.0%*	Return on Com Equity	*14.5%*
4.4%	NMF	3.2%	4.2%	7.0%	5.6%	5.6%	6.2%	6.3%	5.3%	*5.0%*	*5.5%*	Retained to Com Eq	*6.5%*
64%	101%	72%	65%	52%	53%	49%	52%	52%	58%	*59%*	*58%*	All Div'ds to Net Prof	*57%*

CURRENT POSITION ($MILL.)	2005	2006	12/31/07
Cash Assets	30.0	20.0	21.0
Other	2002.0	1802.0	1790.0
Current Assets	2032.0	1822.0	1811.0
Accts Payable	264.0	213.0	172.0
Debt Due	522.0	539.0	580.0
Other	1153.0	875.0	893.0
Current Liab.	1939.0	1627.0	1645.0
Fix. Chg. Cov.	442%	397%	391%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	3.5%	13.5%	3.5%
"Cash Flow"	5.5%	7.0%	4.0%
Earnings	7.0%	15.0%	3.5%
Dividends	2.5%	4.0%	4.0%
Book Value	6.5%	10.5%	1.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	908	430	387	993	2718
2006	1044	436	434	707	2621
2007	973	467	369	685	2494
2008	*1000*	*475*	*400*	*750*	*2625*
2009	*1025*	*500*	*425*	*800*	*2750*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	1.14	.30	.19	.85	2.48
2006	1.41	.25	.46	.60	2.72
2007	1.29	.40	.17	.86	2.72
2008	*1.35*	*.35*	*.30*	*.80*	*2.80*
2009	*1.35*	*.40*	*.35*	*.80*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.28	.29	.29	.29	1.15
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37	.37	1.48
2007	.41	.41	.41	.41	1.64
2008	.42				

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Maryland. Engaged in nonregulated natural gas marketing and other allied services. Also wholesales and retails propane. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. Off./dir. own less than 1.0% of common; Barclays Global Investors, 5.0% (3/07 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources reported solid performance for the fourth quarter. Revenues declined slightly in the recent interim. However, the company enjoyed lower operating costs, and the bottom-line improved considerably. But share earnings for 2007 as a whole only matched the prior year's figure, owing to unfavorable comparisons in the first and third quarters. Operating earnings were lower at the company's Wholesale Services business, resulting from a significant decrease in commercial activity due to lower volatility in the natural gas market during the year. Performance was supported by solid earnings growth in the company's Distribution Operations, and a strong bottom-line advance in its Retail Energy Operations. The Distribution business benefited from modest customer growth and higher base rates at Chattanooga Gas. The Retail Energy line experienced higher average customer usage, a greater customer base, and increased late payment fees.

Earnings growth ought to resume in 2008. The company has initiated share-net guidance of $2.75 to $2.85 for the current year. Our estimate lies at the midpoint of this range. This assumes normal weather patterns and average volatility for gas prices in 2008. Earnings per share stand a good chance of advancing at about the same deliberate pace in 2009, as well.

The board of directors recently approved a modest dividend increase. The quarterly dividend will now increase to $0.42, beginning with the March payout. This represents slower growth than in the past few years, which makes sense, considering the company's flat earning comparison for 2007 and its lower cash balance in recent times. Nevertheless, this level of dividend growth will probably continue going forward.

These shares have improved a notch in Timeliness, and are now ranked 3 (Average). That said, this issue earns good marks for Safety and Price Stability, and we project steady earnings growth at AGL Resources over the pull to 2011-2013. Income-seeking investors may also find this stock attractive, considering its healthy dividend yield. Overall, these shares offer worthwhile total return potential for the coming years.

Michael Napoli, CPA *March 14, 2008*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, ($0.83); '99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07). Next earnings report due late April/early May.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available.
(D) Includes intangibles. In 2007: $420 million, $5.50/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	80

ATMOS ENERGY CORP. NYSE-ATO

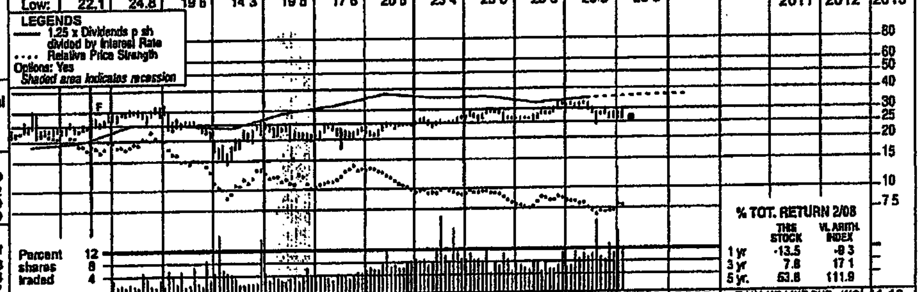
RECENT PRICE 26.34 | P/E RATIO 13.2 (Trailing: 14.5 Median: 16.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS 3 Raised 1/25/08
SAFETY 2 Raised 12/16/05
TECHNICAL 3 Lowered 3/7/08
BETA .85 (1.00 = Market)

High:	30.5	32.3	33.0	26.3	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3
Low:	22.1	24.8	19.6	14.3	19.6	17.8	20.8	23.4	25.0	25.5	23.9	25.8

Target Price Range 2011 | 2012 | 2013

LEGENDS
—— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+50%)	15%
Low	30	(+15%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	1	0	0	2	2
Options	0	1	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	3	0

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	115	100	113
to Sell	101	112	104
Hld's(000)	58169	56311	59007

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-13.5	-8.3
3 yr.	7.8	17.1
5 yr.	53.8	111.9

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
27.90	22.09	28.61	35.36	22.82	54.38	46.50	61.75	75.27	66.03	65.30	64.65	Revenues per sh A	76.50
3.38	2.62	3.01	3.03	3.39	3.23	2.91	3.90	4.26	4.14	4.25	4.35	"Cash Flow" per sh	4.65
1.84	.81	1.03	1.47	1.45	1.71	1.58	1.72	2.00	1.94	2.00	2.10	Earnings per sh A B	2.45
1.06	1.10	1.14	1.16	1.18	1.20	1.22	1.24	1.26	1.28	1.30	1.32	Div'ds Decl'd per sh C ■	1.40
4.44	3.53	2.36	2.77	3.17	3.10	3.03	4.14	5.20	4.39	4.85	5.00	Cap'l Spending per sh	6.20
12.21	12.09	12.28	14.31	13.75	16.66	18.05	19.90	20.16	22.01	22.75	22.50	Book Value per sh	25.15
30.40	31.25	31.85	40.79	41.68	51.48	62.80	80.54	81.74	89.33	94.00	99.00	Common Shs Outst'g D	115.00
15.4	33.0	18.9	15.6	15.2	13.4	15.9	16.1	13.5	15.9	Bold figures are		Avg Ann'l P/E Ratio	14.5
.80	1.88	1.23	.80	.83	.76	.84	.86	.73	.83	Value Line		Relative P/E Ratio	.95
3.7%	4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.6%	4.7%	4.2%	estimates		Avg Ann'l Div'd Yield	4.0%
848.2	690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	5898.4	6140	6400	Revenues ($mill) A	8800
55.3	25.0	32.2	56.1	59.7	79.5	86.2	135.8	162.3	170.5	180	210	Net Profit ($mill)	280
36.5%	35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	36.0%	36.0%	Income Tax Rate	38.0%
6.5%	3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	3.1%	3.3%	Net Profit Margin	3.2%
51.8%	50.0%	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	51.0%	52.0%	Long-Term Debt Ratio	51.0%
48.2%	50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.0%	48.0%	Common Equity Ratio	49.0%
769.7	755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4360	4640	Total Capital ($mill)	5900
917.9	955.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4040	4250	Net Plant ($mill)	5450
9.0%	5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	6.0%	6.0%	Return on Total Cap'l	6.5%
14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	9.0%	9.5%	Return on Shr. Equity	9.5%
14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	9.0%	9.5%	Return on Com Equity	9.5%
6.3%	NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.0%	3.5%	Retained to Com Eq	4.0%
58%	NMF	112%	79%	82%	70%	77%	73%	63%	65%	64%	62%	All Div'ds to Net Prof	58%

CAPITAL STRUCTURE as of 12/31/07
Total Debt $2330.8 mill Due in 5 Yrs $920.0 mill
LT Debt $2124.9 mill. LT Interest $125.0 mill
(LT interest earned: 2.9x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $16.9 mill
Pfd Stock None
Pension Assets-9/07 $389.1 mill.
Oblig. $335.6 mill
Common Stock 89,957,651 shs.
as of 1/30/08
MARKET CAP: $2.4 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2006	2007	12/31/07
Cash Assets	75.8	60.7	51.9
Other	1041.7	1008.2	1468.1
Current Assets	1117.5	1068.9	1520.0
Accts Payable	345.1	355.3	739.8
Debt Due	385.6	154.4	205.9
Other	388.5	410.0	389.9
Current Liab.	1119.2	919.7	1335.6
Fix. Chg. Cov.	408%	405%	400%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	8.5%	19.0%	2.0%
"Cash Flow"	4.0%	5.5%	2.0%
Earnings	3.5%	7.5%	4.5%
Dividends	2.5%	1.5%	2.0%
Book Value	7.0%	9.0%	3.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	1371.0	1687.8	909.9	1004.6	4973.3
2006	2283.8	2033.8	863.2	971.6	6152.4
2007	1602.6	2075.6	1218.2	1002.0	5898.4
2008	1657.5	2135	1280	1067.5	6140
2009	1600	1600	1600	1600	6400

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	.79	1.11	.06	d.21	1.72
2006	.88	1.10	d.22	.25	2.00
2007	.97	1.20	d.15	d.05	1.94
2008	.82	1.30	d.07	d.05	2.00
2009	.90	1.30	d.06	d.04	2.10

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.305	.305	.305	.31	1.23
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315	.32	1.27
2007	.32	.32	.32	.325	1.29
2008	.325				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2007 gas volumes: 297 MMcf. Breakdown: 56%, residential; 32%, commercial; 8%, industrial; and 4% other. 2007 depreciation rate 3.7%. Has around 4,470 employees. Officers and directors own approximately 1.8% of common stock (12/07 Proxy). Chairman and Chief Executive Officer: Robert W. Best. Incorporated: Texas. Address: P.O. Box 650205, Dallas, Texas 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com

Atmos Energy began fiscal 2008 (ends September 30th) on a sour note. That was attributable primarily to the nonregulated marketing segment, which experienced a drop in margins because of less volatility in natural gas prices. We look for this trend to continue, barring major storm activity.

But one bright spot was the utility unit, thanks to higher rates in Texas, Louisiana, Tennessee, and Kentucky. It should also be mentioned that mechanisms reducing exposure to possible adverse weather patterns during the 2007-2008 winter heating season are in place for virtually all operations.

Nonetheless, we think share net will advance only 3%, to $2.00, this fiscal year. The bottom line stands to increase at a somewhat stronger 5% pace, to $2.10 a share, in fiscal 2009, assuming additional expansion in operating margins. Please note that our estimates exclude amounts from pending rate cases in Texas, where Atmos is seeking a $52 million increase in annual revenues, and Kansas (where a $5 million boost in annual revenues is being sought).

We envision steady, albeit unspectacular, earnings gains out to 2011-2013. With the utility unit currently serving customers across 12 states, Atmos does not depend on the business climate in any one region of the country. Moreover, the nonregulated segments, particularly pipelines, possess healthy overall prospects. Lastly, management will undoubtedly stick to its winning strategy of purchasing less-efficient utilities and shoring up their profitability via expense-reduction initiatives, rate relief, and aggressive marketing efforts. (Future business combinations are not factored into our presentation, however.) In the present configuration, annual share-net growth may be in the mid-single-digit range over the 3- to 5-year horizon.

The good-quality stock offers an attractive dividend, which is well covered by the company's earnings. Further moderate increases in the distribution seem plausible.

Risk-adjusted total return possibilities are decent, too. But the shares are ranked only 3 (Average) for Timeliness.

Frederick L. Harris, III *March 14, 2008*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '99, d23¢; '00, 12¢; '03, d17¢; '06, d18¢; '07, d2¢. Next egs rpt. due early May. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions, adjusted for stock splits. (E) Qtrs may not add due to change in shrs outstanding. (F) ATO completed United Cities merger 7/97.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	80

LACLEDE GROUP NYSE-LG

RECENT PRICE 35.50 | P/E RATIO 15.1 (Trailing: 14.8 Median: 15.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.3% | VALUE LINE

High:	28.5	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3	37.6	38.0	35.5
Low:	20.3	22.4	20.0	17.5	21.3	19.0	21.8	26.0	25.9	29.1	28.8	31.9

Target Price Range 2011 | 2012 | 2013

TIMELINESS 3 Raised 9/14/07
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Lowered 2/29/08
BETA .90 (1.00 = Market)

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
... Relative Price Strength
Options: No
Shaded area indicates recession

2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	10%
Low	35	(Nil)	4%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	1	0	0	0	0	0	0	1
Options	0	0	0	0	2	1	0	0	1
to Sell	0	0	0	0	2	1	0	0	1

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	67	57	64
to Sell	50	57	61
Hld's(000)	9261	9337	9951

Percent shares traded 7.5 5 2.5

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr	14.8	-9.3
3 yr	24.5	17.1
5 yr	89.3	111.9

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	©VALUE LINE PUB., INC.	11-13
26.83	32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.85	58.59	75.43	93.51	93.40	92.75	91.55	Revenues per sh	107.85
2.32	2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.58	3.15	2.79	2.98	3.81	3.87	4.10	4.30	"Cash Flow" per sh	5.10
1.17	1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.35	2.35	Earnings per sh A B	2.70
1.20	1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	Div'ds Decl'd per sh C■	1.65
2.87	2.62	2.60	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.85	2.95	Cap'l Spending per sh	3.70
11.79	12.19	12.44	13.05	13.72	14.28	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	20.65	21.15	Book Value per sh D	24.95
15.59	15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	22.00	22.50	Common Shs Outst'g E	25.50
15.8	13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.8	14.2	Bold figures are		Avg Ann'l P/E Ratio	15.0
.96	.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	Value Line		Relative P/E Ratio	1.00
6.5%	5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	estimates		Avg Ann'l Div'd Yield	4.1%

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
547.2	491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2040	2060	Revenues ($mill) A	2750
27.9	26.9	26.0	30.5	22.4	34.6	36.1	40.1	50.5	49.8	51.5	53.0	Net Profit ($mill)	70.0
35.6%	35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	33.5%	34.0%	Income Tax Rate	35.0%
5.1%	5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.5%	2.6%	Net Profit Margin	2.5%
40.9%	41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	49.6%	45.3%	45.0%	45.0%	Long-Term Debt Ratio	47.0%
58.6%	57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.0%	55.0%	Common Equity Ratio	53.0%
438.0	488.6	519.2	574.1	546.6	605.0	737.4	707.9	798.9	784.5	825	865	Total Capital ($mill)	1200
490.6	519.4	575.4	802.5	594.4	621.2	646.9	679.5	763.8	793.8	820	850	Net Plant ($mill)	1150
8.1%	7.1%	6.7%	6.8%	6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	7.5%	7.5%	Return on Total Cap'l	7.0%
10.8%	9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.5%	11.0%	Return on Shr. Equity	11.0%
10.8%	9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.5%	11.0%	Return on Com Equity	11.0%
1.8%	1.0%	.2%	1.8%	NMF	3.1%	2.7%	3.1%	5.1%	4.3%	4.0%	4.0%	Retained to Com Eq	4.5%
83%	89%	98%	83%	113%	74%	73%	72%	59%	63%	64%	65%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 12/31/07
Total Debt $650.1 mill. Due in 5 Yrs $275.0 mill.
LT Debt $355.5 mill. LT Interest $20.0 mill.
(Total interest coverage: 3.0x)

Leases, Uncapitalized Annual rentals $ 9 mill.
Pension Assets-9/07 $260.3 mill. Oblig. $293.3 mill.

Pfd Stock $.6 mill. Pfd Div'd $.04 mill.
Common Stock 21,788,956 shs
as of 1/31/08

MARKET CAP: $775 million (Small Cap)

CURRENT POSITION ($MILL.)	2006	2007	12/31/07
Cash Assets	50.8	52.7	66.9
Other	409.0	414.6	495.5
Current Assets	459.8	467.3	562.4
Accts Payable	103.3	106.8	128.6
Debt Due	207.5	251.6	294.6
Other	120.1	115.3	129.0
Current Liab.	430.9	473.7	552.2
Fix. Chg. Cov.	285%	282%	280%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	11.5%	16.5%	3.5%
"Cash Flow"	1.5%	5.5%	6.5%
Earnings	3.0%	9.5%	3.5%
Dividends	1.0%	1.0%	2.5%
Book Value	3.0%	4.5%	5.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	442.5	576.5	311.3	266.7	1597.0
2006	689.2	708.8	330.6	269.0	1997.6
2007	539.6	700.8	457.9	323.3	2021.6
2008	541.4	708	447	343.6	2040
2009	515	515	515	515	2060

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	.79	1.06	.29	d.24	1.90
2006	1.23	1.05	.13	d.04	2.37
2007	.89	.97	.43	.03	2.31
2008	.97	.97	.36	.05	2.35
2009	.96	1.01	.33	.05	2.35

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.335	.34	.34	.34	1.36
2005	.34	.345	.345	.345	1.38
2006	.345	.355	.355	.355	1.41
2007	.365	.365	.365	.365	1.46
2008	.375				

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 632,000 customers. Purchased SM&P for approximately $43 million (1/02). Therms sold and transported in fiscal 2007: 1.12 mill. Revenue mix for regulated operations: residential, 60%; commercial and industrial, 24%; transportation, 1%; other, 15%. Has around 3,845 employees. Officers and directors own approximately 7.0% of common shares (1/08 proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede Group began fiscal 2008 (which ends September 30th) on a decent note. That can be attributed largely to Laclede Energy Resources, which enjoyed higher per-unit gas sales prices and increased volumes (held back a bit by a rise in operating expenses). Furthermore, results for Laclede Gas, the core subsidiary, benefited from a general rate hike that became effective on August 1st of last year, that, among other things, provides greater earnings stability and recovery of its distribution costs. But partial offsets here included a decline in margins within the service area (reflecting an unusually late start to the winter heating season) and increased maintenance costs. At this juncture, we look for earnings per share to advance at a moderate rate, to $2.35, this fiscal year. The bottom line may be relatively flat in fiscal 2009, given the utility operation's limited growth prospects.

Management intends to sell SM&P Utility Resources, the unregulated unit specializing in locating and marking services for underground facilities, to Stripe Acquisition. A portion of the $85 million in proceeds (nearly double what Laclede paid for SM&P in 2002) would be used to bolster the balance sheet. We think SM&P was not central to present corporate strategy, as it accounted for just around 6% of fiscal 2007 share net. (Our presentation will exclude the divestiture when it is completed shortly, pending customary closing conditions.)

Unexciting results appear to be in store for the company over the next three to five years. The market in which the natural gas division operates has encountered sluggish customer growth for some time because it is in a mature phase. Too, we don't see any major acquisitions on the horizon. Consequently, annual share-net gains may be between 4% and 5% out to 2011-2013.

Total return potential is limited. That's because Laclede shares are currently trading within our 3- to 5-year Target Price Range, and we assume moderate hikes in the dividend (just increased 2.7%). What's more, the equity is ranked to perform only in line with the broader market averages.

Frederick L. Harris, III *March 14, 2008*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Next earnings report due late April.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '07: $289.7 mill., $13.38/sh.
(E) In millions.
(F) Qtly egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	65

Exhibit___(FJH-29)
Sheet 11 of 32

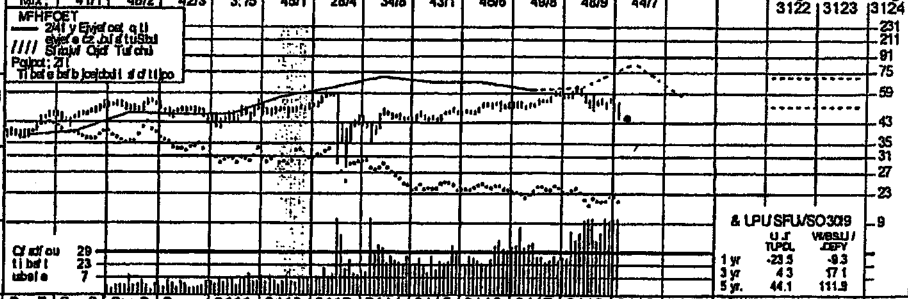
Exhibit___(FJH-9)
Sheet 6 of 10
(Update)

NICOR, INC. NYSE-GAS

RECENT PRICE 34.12 | P/E RATIO 13.7 (Trailing: 11.9* Median: 15.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 5.5% | VB MVF MOF

TIMELINESS 4 Raised 12/7/07
SAFETY 4 Lowered 6/17/05
TECHNICAL 4 Lowered 2/15/08
CFLB 2/11)2/11>Nbsfd

I]hl ; Mx ;	53/: 41/1	55/5 48/2	53/: 42/3	54/: 3: /5	53/5 45/1	5: /1 28/4	4: /4 34/8	4: /8 43/1	54/1 46/6	5: /: 49/8	64/8 48/9	53/8 44/7	Target Price Range 3122 | 3123 | 3124



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	71	), 86&*	2: &
Low	61	), 26&*	: &

.bt jef sEf djt jpot

	A	M	J	J	A	S	O	N	D
to Buy	1	1	1	1	2	2	1	1	1
Options	1	4	1	1	1	1	1	1	1
to Sell	1	4	1	1	1	1	1	1	1

.bt ujuvujpobnEf djt jpot

	2Q2007	3Q2007	4Q2007
to Buy	22:	:4	:7
to Sell	222	234	222
Hld's(000)	48129	47126	43:97

& LPU SFU/SO3O9

	U.T TUPDL	WBSU / JOEFY
1 yr	-23.5	-9.3
3 yr	4.3	17.1
5 yr.	44.1	111.9

2::3	2::4	2::5	2::6	2::7	2::8	2::9	2:::	3111	3112	3113	3114	3115	3116	3117	3118	3119	311:	VALUE LINE PUB., INC.	11-13
28.90	31.02	31.23	29.42	37.39	41.33	30.84	34.45	50.52	57.30	43.11	60.46	62.12	76.00	65.92	70.27	*74.45*	*77.80*	Revenues per sh	*80.45*
4.14	3.80	4.11	4.19	4.97	5.28	5.21	5.59	6.16	6.41	6.03	5.37	6.00	6.19	6.82	6.95	*6.70*	*7.25*	"Cash Flow" per sh	*8.00*
1.92	1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.27	2.87	2.74	*2.25*	*2.60*	Earnings per sh B	*3.25*
1.18	1.22	1.25	1.28	1.32	1.40	1.48	1.54	1.66	1.76	1.84	1.86	1.86	1.86	1.86	1.86	*1.86*	*1.90*	Div'ds Decl'd per sh C	*1.90*
3.12	2.62	3.34	3.12	2.42	2.34	2.87	3.28	3.48	4.18	4.37	4.12	4.32	4.57	4.17	4.45	*4.55*	*4.65*	Cap'l Spending per sh	*4.65*
12.76	13.05	13.26	13.67	14.74	15.43	15.97	16.80	15.56	16.39	16.55	17.13	16.99	18.36	19.43	20.40	*20.80*	*21.60*	Book Value per sh	*24.25*
55.77	53.96	51.54	50.30	48.49	48.22	47.51	46.89	45.49	44.40	44.01	44.04	44.10	44.18	44.90	45.20	*45.00*	*45.00*	Common Shs Outst'g D	*46.00*
11.6	14.1	12.5	13.1	12.5	14.2	17.6	14.8	11.9	12.8	13.1	15.8	15.9	17.3	15.0	16.3	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
70	83	82	.88	78	82	.92	83	77	66	72	90	84	92	81	86	*Value Line*		Relative P/E Ratio	*1.05*
5.3%	4.4%	4.8%	5.0%	4.4%	3.9%	3.6%	4.1%	4.7%	4.6%	4.9%	5.6%	5.3%	4.7%	4.3%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*
						1465.1	1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	3357.8	2960.0	3176.3	*3350*	*3500*	Revenues ($mill)	*3700*
						111.1	121.9	136.4	138.3	128.0	93.1	98.1	101.1	128.3	135.2	*108*	*115*	Net Profit ($mill)	*150*
						34.4%	34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	28.3%	30.0%	*31.0%*	*31.5%*	Income Tax Rate	*33.0%*
						7.6%	7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	4.3%	4.3%	*3.0%*	*3.3%*	Net Profit Margin	*4.0%*
						42.1%	35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	36.3%	30.0%	*27.0%*	*24.0%*	Long-Term Debt Ratio	*21.0%*
						57.4%	64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	70.0%	*73.0%*	*76.0%*	Common Equity Ratio	*79.0%*
						1322.6	1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	1370.7	1315	*1285*	*1250*	Total Capital ($mill)	*1400*
						1731.8	1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2659.1	2714.1	2850	*3000*	*3050*	Net Plant ($mill)	*3400*
						9.9%	10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	10.9%	11.0%	*9.5%*	*11.0%*	Return on Total Cap'l	*12.0%*
						14.5%	15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	14.7%	13.5%	*11.0%*	*12.0%*	Return on Shr. Equity	*13.5%*
						14.6%	15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	14.7%	13.5%	*11.0%*	*12.0%*	Return on Com Equity	*13.5%*
						5.4%	6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	5.2%	4.5%	*2.0%*	*3.5%*	Retained to Com Eq	*5.5%*
						63%	60%	56%	58%	63%	88%	84%	81%	65%	67%	*82%*	*73%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $867.4 mill Due in 5 Yrs $422.7 mill.
LT Debt $423.3 mill. LT Interest $32.0 mill
(Total interest coverage: 4.6x)

Pension Assets-12/06 $478.7 mill. Oblig. $262.2 mill.

Pfd Stock $ 6 mill. Pfd Div'd None

Common Stock 45,135,079 shares
as of 10/26/07
MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	12/31/07
Cash Assets	126.9	67.6	91.1
Other	1218.8	843.1	932.7
Current Assets	1345.7	910.7	1023.8
Accts Payable	658.2	564.5	662.7
Debt Due	636.0	350.0	444.0
Other	328.7	227.9	169.7
Current Liab.	1622.9	1142.4	1276.4
Fix. Chg. Cov.	367%	543%	544%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '11-'13
Revenues	7.5%	7.5%	2.5%
"Cash Flow"	3.5%	1.0%	3.5%
Earnings	1.5%	-3.0%	4.0%
Dividends	4.0%	2.5%	.5%
Book Value	3.0%	2.6%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	1179.9	484.4	336.0	1357.5	3357.8
2006	1319.4	451.3	351.1	838.2	2960.0
2007	1334.7	556.9	365.2	919.5	3176.3
2008	*1350*	*575*	*375*	*1050*	*3350*
2009	*1400*	*600*	*400*	*1100*	*3500*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.98	.35	d.06	1.02	2.29
2006	.94	.41	.39	1.29	3.03
2007	.93	.40	.32	1.09	2.74
2008	*.82*	*.33*	*.25*	*.85*	*2.25*
2009	*.90*	*.35*	*.30*	*1.05*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.465	.465	.465	.465	1.86
2005	.465	.465	.465	.465	1.86
2006	.465	.465	.465	.465	1.86
2007	.465	.465	.465	.465	1.86
2008	.465				

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.2 million customers in northern and western Illinois. 2007 gas delivered: 468.3 Bcf, incl. 212.1 Bcf from transportation. 2007 gas sales (256.2 bcf): residential, 79%; commercial, 19%; industrial, 2%. Principal supplying pipelines: Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested inland barging, 7/86; contract drilling, 9/86; oil and gas E&P, 6/93. Has about 3,900 employees. Off./dir. own about 1.7% of common stock (3/07 proxy). Chairman and CEO: Russ Strobel. Inc.: Illinois. Address: 1844 Ferry Road, Naperville, Illinois 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor posted disappointing results in 2007. Earnings were down in all four quarters year over year, due to higher costs and a decline in utility earnings. Additionally, the gas distribution segment struggled, which also hurt profitability. However, the company managed to post an increase on the top line as a result of a solid performance in the shipping business.

Management revised its guidance for 2008. Indeed, Nicor now expects the bottom line to be between $2.20 and $2.40 a share. The new outlook is notably lower than our $2.90 earnings estimate from our last report. Upon news of the revised guidance, GAS shares declined slightly. In response, we have dropped our share-net estimate to $2.25 for 2008.

The company may seek rate relief. Management is evaluating the need for a filing with the Illinois Commerce Commission. The process usually takes about a year, and a positive ruling would help Nicor meet its allowed return. The company would also likely seek a rate mechanism that decouples gas revenues from gas sales, which would further help results. Until Nicor gains rate relief, these shares may not show any special strength.

We are introducing our 2009 estimates. The company should post earnings of roughly $2.60 a share on sales of about $3.5 billion. Management's focus on cost controls should help GAS rebound.

This stock offers an above-average dividend yield. Nicor offers a yield that is double the *Value Line* median despite not raising its payout in recent years. What's more, we believe the board will increase the distribution in the coming years once the regulatory environment improves.

This issue has below-average capital appreciation potential over the 3- to 5-year pull. However, if the company receives rate relief and continues to improve its cost controls, the long-term picture should improve. Moreover, Nicor's other energy-related ventures may also help drive growth over this time frame.

These shares are ranked to mirror the market in the year ahead. Despite the company's solid balance sheet and diversified business, this issue has limited appeal at this time.

Richard Gallagher *March 14, 2008*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢); '07 (13¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Next egs. report due late April.
(B) Dividends historically paid mid February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	75

Exhibit___(FJH-29)
Sheet 12 of 32

Exhibit___(FJH-9)
Sheet 7 of 10
(Update)

N.W. NAT'L GAS NYSE-NWN

RECENT PRICE 43.28 | P/E RATIO 17.2 (Trailing: 16.1 Median: 16.0) | RELATIVE P/E RATIO 1.11 | DIV'D YLD 3.6% | VBMVF MJOF

TIMELINESS 5 Lowered 2/22/08
SAFETY 2 Raised 3/18/05
TECHNICAL 4 Lowered 2/29/08
CRB /91)2/11>Nbsf!u

I jhi ; Mpx;	42/5 34/1	41/9 35/4	38/: 2: /6	38/6 28/9	37/9 32/8	41/8 34/6	42/4 35/1	45/2 38/6	4: /7 43/5	54/8 43/9	63/9 4: /9	61/8 52/6

Target Price Range 3122 | 3123 | 3124

2011-13 PROJECTIONS

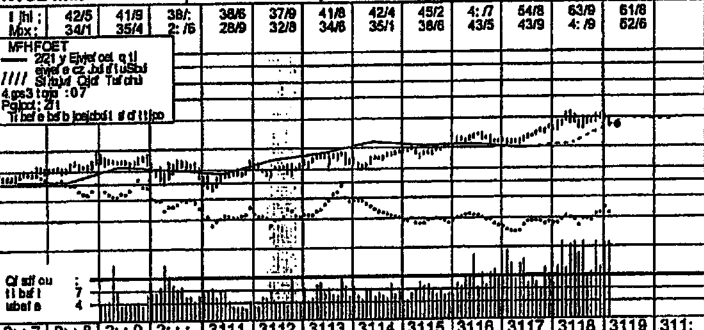
	Price	Gain	Ann'l Total Return
High	76	).61&	25&
Low	66	).36&	21&

.bl jef s Ef djt jpot

	A	M	J	J	A	S	O	N	D
to Buy	2	1	1	1	1	1	1	1	1
Options	1	2	1	1	1	1	1	5	1
to Sell	1	2	1	1	2	1	1	6	2

.bl ujuujpobmEf djt jpot

	2Q2007	3Q2007	4Q2007
to Buy	:5	77	:6
to Sell	76	99	71
Hld's(000)	27956	27150	27959



	THIS STOCK	VL ARITH. INDEX
1 yr	-2.0	-9.3
3 yr	28.3	17.1
5 yr.	108.0	111.9

2::3	2::4	2::5	2::6	2::7	2::8	2::9	2:::	3111	3112	3113	3114	3115	3116	3117	3118	3119	311:	© VALUE LINE PUB., INC	11-13
14 10	18 15	18.30	16 02	16 66	15 82	16 77	18 17	21.09	25 78	25 07	23 57	25.69	33.01	37 20	39 12	*41 35*	*42.90*	Revenues per sh	*48.20*
3 25	3.74	3 50	3.41	3 86	3 72	3 24	3 72	3 68	3 86	3.65	3 86	3.92	4 34	4 76	5 41	*5.40*	*5.70*	"Cash Flow" per sh	*6.60*
.74	1 74	1 63	1 61	1.97	1 76	1 02	1 70	1.79	1.88	1 62	1 78	1 86	2 11	2 35	2 76	*2.60*	*2.75*	Earnings per sh [B]	*3.35*
1.15	1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	*1.52*	*1.60*	Div'ds Decl'd per sh [C]■	*1.88*
3.73	3 61	4 23	3 02	3 70	5 07	4.02	4 78	3.46	3.23	3 11	4 90	5 52	3 48	3 56	4 48	*4.60*	*5.80*	Cap'l Spending per sh	*4.50*
12.41	13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	21.97	22.52	*23.00*	*23.76*	Book Value per sh	*26.50*
19.46	19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.28	26.41	*26.00*	*26.00*	Common Shs Outst'g [D]	*28.00*
27 0	12 9	13 0	12 9	11 7	14 4	26 7	14 5	12.4	12 9	17 2	15 8	16.7	17 0	15 9	16 7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
1 64	.76	.85	.86	.73	.83	1 39	.83	.81	.66	.94	.90	.88	.91	.86	.88			Relative P/E Ratio	*1.20*
6.7%	5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3 7%	3.1%			Avg Ann'l Div'd Yield	*3.1%*
						416.7	455.8	532.1	650.3	641 4	611 3	707.6	910 5	1013 2	1033 2	*1075*	*1115*	Revenues ($mill)	*1350*
						27.3	44.9	47.8	50.2	43.8	46.0	50.6	58.1	65.2	74.5	*68.0*	*71.5*	Net Profit ($mill)	*94.0*
						31.0%	35.4%	35.9%	35.4%	34 9%	33.7%	34 4%	36 0%	36 3%	37 2%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
						6.6%	9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	*6.1%*	*6.4%*	Net Profit Margin	*6.9%*
						45 0%	46.0%	45 1%	43.0%	47 6%	49.7%	46 0%	47.0%	46 3%	46 3%	*46.5%*	*46.5%*	Long-Term Debt Ratio	*47.0%*
						50.6%	49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	*53.5%*	*53.5%*	Common Equity Ratio	*53.0%*
						815.6	861 5	887 8	880.5	937.3	1006 8	1052.5	1108 4	1116 5	1106 8	*1150*	*1200*	Total Capital ($mill)	*1500*
						894.7	895.9	934.0	965.0	995.8	1205.9	1318.4	1373.4	1425.1	1495.9	*1550*	*1650*	Net Plant ($mill)	*2000*
						5.0%	6.8%	6.7%	6.9%	5 9%	5.7%	5 9%	6.5%	7 1%	8.5%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
						6 1%	9.7%	9.8%	10.0%	8.9%	9 1%	8 9%	9.9%	10 9%	12.5%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.0%*
						6.0%	9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.6%	10.9%	12.5%	*11.0%*	*11.0%*	Return on Com Equity	*11.0%*
						NMF	2.8%	3.1%	3 5%	1 9%	2 6%	2.7%	3 7%	4 5%	6.0%	*5.0%*	*5.0%*	Retained to Com Eq	*5.0%*
						118%	74%	70%	67%	79%	72%	69%	63%	59%	52%	*58%*	*56%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $660.1 mill Due in 5 Yrs $179.7 mill
LT Debt $512 0 mill LT Interest $31 0 mill

(Total interest coverage: 3 6x)

Pension Assets-12/06 $235 mill
Oblig. $289 mill
Pfd Stock None

Common Stock 26,407,000 shs

MARKET CAP $1.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	12/31/07
Cash Assets	7.1	5.8	6 1
Other	316.6	303.0	268.8
Current Assets	323 7	308 8	274 9
Accts Payable	135.3	113.6	119 7
Debt Due	134.7	129.6	148 1
Other	56.6	98.3	122.1
Current Liab.	326.6	341 5	389.9
Fx. Chg. Cov.	340%	349%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '11-'13
Revenues	6.5%	8.0%	*6.5%*
"Cash Flow"	2.0%	3.0%	*5.0%*
Earnings	2.0%	3 5%	*7.0%*
Dividends	1 0%	1 5%	*5.5%*
Book Value	4 0%	3.5%	*3.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	308.7	153 7	106.7	341.4	910 5
2006	390.4	171.0	114.9	336.9	1013 2
2007	394.1	183.2	124 2	331.7	1033 2
2008	*405*	*190*	*125*	*355*	*1075*
2009	*415*	*200*	*130*	*370*	*1115*

Calendar	EARNINGS PER SHARE [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	1.44	.04	d.31	.94	2.11
2006	1 48	.07	d.35	1.15	2.35
2007	1.77	.10	d.22	1.11	2.76
2008	*1.60*	*.10*	*d.30*	*1.20*	*2.60*
2009	*1.70*	*.10*	*d.30*	*1.25*	*2.75*

Calendar	QUARTERLY DIVIDENDS PAID [C]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.325	.325	.325	.325	1.30
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345	.355	1 39
2007	.355	.355	.355	.375	1.44
2008	.375				

BUSINESS: Northwest Natural Gas Co distributes natural gas to 90 communities, 652,000 customers, in Oregon (90% of customers) and in southwest Washington state Principal cities served: Portland and Eugene, OR; Vancouver, WA Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U S producers; has transportation rights on Northwest Pipeline system. Owns local underground storage Rev. breakdown: residential, 55%; commercial, 28%; industrial, gas transportation, and other, 17% Employs 1,100 Fidelity owns 14.9% of shares; Snyder Cap'l, 8.7%; off./dir., 2 0% (4/07 proxy). CEO: Mark S. Dodson Inc: Oregon Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www nwnatural.com

Northwest Natural benefited from unusually high gas cost savings in 2007. The company retains one-third of the difference between forecasted and actual gas costs in Oregon, passing on two-thirds to its customers. Last year, it earned a record $0.27 a share through skillful gas buying, mostly in the first and third quarters. While Northwest has usually made a small profit on gas purchasing, it has shared a loss on the activity about a quarter of the time. Ignoring the commodity profits and some other unusual items, NWN would have earned about $2.45 a share in 2007, a respectable but not extraordinary performance.

We look for a roughly 6% earnings gain, from normalized 2007 results, this year. Northwest's customer growth, at over 3% per year for many years, slowed to 2.4% in 2007. Customer growth will likely continue to ease in 2008 as the Portland area suffers a bit from the widespread housing problems but should remain above the national average. The company is increasing its marketing efforts directed at persuading people to switch to gas heat, and that should bear fruit this year. Operating costs, which rose just 1% on a normalized basis last year, will likely grow slower than revenues.

Another mild earnings gain is likely in 2009. By then, customer growth will probably be heading back toward the recent 3% average. Northwest will have completed its work reorganization program, including outsourcing some functions and centralizing others. And the company could start to benefit from enhanced automated meter-reading capacity.

Continued customer growth and two large projects should help boost earnings toward the end of our time horizon. Portland's high-density zoning has been expanded many times over the last 30 years, making it profitable to lay gas mains. An expansion to the southeast of the city should add substantially to customer growth over the next 10 years. And by 2011, NWN will probably invest around $300 million in a gas storage project in California and a new pipeline in Oregon.

These top-quality shares, though untimely, have worthwhile risk-adjusted total-return potential.

Sigourney B. Romaine *March 14, 2008*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0 15; '00, $0.11; '06, ($0.06). Next earnings report due late April.
(B) Dividends historically paid in mid-February, mid-May, mid-August, and mid-November
■ Dividend reinvestment plan available
(C) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	80

PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE 24.98 | P/E RATIO 16.7 (Trailing: 17.8; Median: 17.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 4.0%

TIMELINESS 4 Raised 6/15/07
SAFETY 3 New 7/27/90
TECHNICAL 4 Lowered 3/7/08

High:	29/3	29/2	29/4	2: /8	2: /1	2: /1	33/1	36/4	36/9	39/5	39/1	38/1	
Low:	22/1	24/:	25/4	22/9	25/7	24/8	27/7	2: /3	32/4	34/3	33/1	35/1	

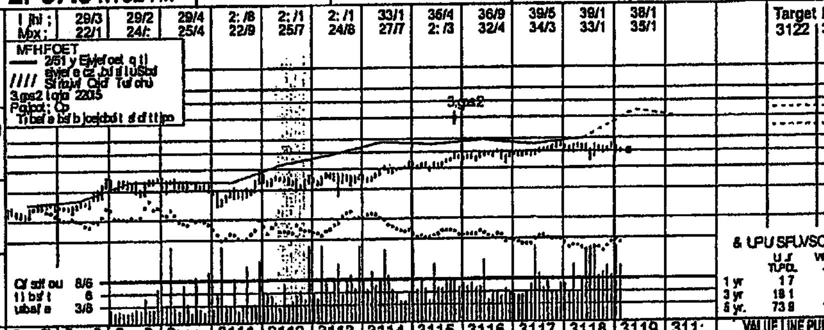
Target Price Range 3122 3123 3124

2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	56	),91&*	2: &
Low	46	),51&*	23&

	A	M	J	J	A	S	O	N	D
to Buy	1	1	1	2	1	1	1	1	1
Options	1	1	1	1	1	1	1	1	1
to Sell	2	1	1	1	1	1	1	1	1

	2Q2007	3Q2007	4Q2007
to Buy	95	89	98
to Sell	88	91	92
Hld's(000)	46375	46583	47581



	U.S. TOTAL	VL ARITH. INDEX
1 yr	17	-9 3
3 yr	18 1	17 1
5 yr.	73 8	111.8

2::3	2::4	2::5	2::6	2::7	2::8	2::9	2:::	3111	3112	3113	3114	3115	3116	3117	3118	3119	311:	VALUE LINE PUB., INC	11-13
8 91	10 57	10 82	8 76	11 59	12 84	12 45	10 97	13.01	17 06	12.67	18 14	19 95	22.96	25 80	23 37	24.20	24.95	Revenues per sh B	27.55
1 07	1.14	1 13	1 25	1 49	1 62	1 72	1 70	1 77	1 81	1 81	2 04	2 31	2 43	2 51	2 64	2.75	2.80	"Cash Flow" per sh	3.00
70	73	68	73	84	83	98	93	1.01	1 01	95	1 11	1 27	1 32	1 28	1 40	1.50	1.55	Earnings per sh C	1.78
.46	.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.04	1.08	Div'ds Decl'd per sh D■	1.20
1.41	1 58	1.95	1 72	1 64	1 52	1 48	1 58	1.65	1 29	1 21	1 16	1.85	2.50	2 74	1 85	2.00	2.05	Cap'l Spending per sh	2.30
5.13	5.45	5.68	6.18	6.53	6.96	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.45	12.85	Book Value per sh E	14.30
51.59	52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.00	72.75	Common Shs Outst'g F	72.00
12.3	15.4	15 7	13.8	13 9	13 6	16.3	17 7	14 3	16 7	18 4	16 7	16 6	17 9	19 2	18 7	Bold figures are		Avg Ann'l P/E Ratio	22.0
75	.91	1.03	92	.87	78	85	1 01	93	.86	1.01	95	.88	95	1 04	98	Value Line		Relative P/E Ratio	1.50
5.3%	4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4 1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	estimates		Avg Ann'l Div'd Yield	3.1%

CAPITAL STRUCTURE as of 10/31/07
Total Debt $1019.9 mill Due in 5 Yrs $150.0 mill
LT Debt $824 9 mill LT Interest $55 7 mill
(LT interest earned: 4.0x; total interest coverage: 4.0x)

Pension Assets-10/07 $225 0 mill Oblig. $188 7 mill

Pfd Stock None

Common Stock 73,233,664 shs as of 12/20/07

MARKET CAP: $1.8 billion (Mid Cap)

2::9	2:::	3111	3112	3113	3114	3115	3116	3117	3118	3119	311:	VALUE LINE PUB., INC	11-13
765.3	686.5	830 4	1107.9	832.0	1220.8	1529.7	1761 1	1924 6	1711.3	1765	1815	Revenues ($mill) D	1985
60.3	58.2	64.0	65.5	62.2	74.4	85.2	101.3	97.2	104.4	110	115	Net Profit ($mill)	125
39 2%	39 7%	34 7%	34 6%	33 1%	34.8%	35.1%	33 7%	34 2%	33 0%	35.0%	35.0%	Income Tax Rate	35.0%
7.9%	8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	6.2%	6.2%	Net Profit Margin	6.4%
44 7%	46.2%	46 1%	47 6%	43.9%	42.2%	43.6%	41 4%	48 3%	48.4%	48.1%	47.8%	Long-Term Debt Ratio	46.7%
55.3%	53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	51.9%	52.2%	Common Equity Ratio	53.3%
829.3	914.7	978.4	1069 4	1051 6	1090 2	1514 9	1509 2	1707 9	1703 3	1750	1790	Total Capital ($mill)	1930
990.8	1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2200	2250	Net Plant ($mill)	2400
9.2%	8.1%	8.3%	7.9%	7.8%	8 6%	7 8%	8 2%	7 2%	7.8%	7.5%	8.0%	Return on Total Cap'l	8.0%
13 2%	11.8%	12 1%	11.7%	10.6%	11.8%	11 1%	11 5%	11 0%	11 9%	12.0%	12.0%	Return on Shr. Equity	12.5%
13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.0%	12.0%	Return on Com Equity	12.5%
4.7%	3.3%	3.5%	3 0%	1 7%	3.1%	3 7%	3 6%	2 8%	3 5%	3.5%	3.5%	Retained to Com Eq	4.8%
65%	72%	71%	75%	83%	74%	66%	68%	74%	70%	69%	70%	All Div'ds to Net Prof	68%

CURRENT POSITION ($MILL.)	2005	2006	10/31/07
Cash Assets	7.1	8.9	7.5
Other	497.8	467.1	427.8
Current Assets	504.9	476 0	435.3
Accts Payable	182.8	80.3	97.2
Debt Due	193.5	170.0	195.0
Other	152.3	150.1	132.3
Current Liab	528.6	400.4	424.5
Fix. Chg. Cov.	271%	261%	225%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	8 0%	11.0%	2.5%
"Cash Flow"	5 5%	7.0%	3.0%
Earnings	5.0%	6.0%	5.0%
Dividends	5.0%	4 5%	4 0%
Book Value	6.0%	6.5%	3.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) B Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2005	680.6	508.0	232.9	339.6	1761.1
2006	921.4	483.2	237.9	282.1	1924.7
2007	677.2	531 5	224.4	278.2	1711.3
2008	685	540	240	300	1765
2009	697	553	250	315	1815

Fiscal Year Ends	EARNINGS PER SHARE B C G Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2005	.93	.52	d.06	d.07	1.32
2006	.94	57	d.16	d 08	1.27
2007	94	.69	d.12	d 11	1.40
2008	.95	.70	d.10	d.05	1.50
2009	1.00	.75	d.13	d.07	1.55

Cal-endar	QUARTERLY DIVIDENDS PAID D■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.208	.215	.215	.215	85
2005	.215	.23	23	.23	.91
2006	23	.24	24	24	.95
2007	.24	25	.25	.25	99
2009	.25				

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 932,097 customers in North Carolina, South Carolina, and Tennessee. 2007 revenue mix: residential (54%), commercial (30%), industrial (14%), other (2%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 69 4% of revenues. '07 deprec. rate: 3.4%. Estimated plant age: 8 7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,876 employees. Officers & directors own less than 1% of common stock (1/08 proxy). Chairman, CEO, & President: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas likely posted relatively unchanged earnings for the first quarter (ended January 31st). The company was scheduled to report earnings for its January interim after this report went to press. We have racheted down our top-line estimate for 2008, though, we look for some progress this year. During the first quarter, Piedmont's revenues likely advanced in the low single-digit range. The reduced expectations stem from slower growth in the residential construction market. Subsequently, in an effort to increase volumes, PNY has been working on converting users of other types of energy to natural gas. Meanwhile, the fourth quarter of 2007 experienced warmer-than-normal weather. But that interim is not subject to the weather normalization clause (WNC) for its Tennessee and South Carolina service areas. The WNC protects the bottom line against decreased usage. The adjustment should help during the January interim, though. Overall, we look for a nominal advance in share net for the first quarter.

The company ought to experience better volume comparisons as the year progresses. And its revenues ought to advance approximately 3% this year and next. Efforts to gain customers from the conversion markets should help this cause. Furthermore, the company intends to file a general rate case in North Carolina, its largest service area. Meanwhile, its non-utility business ought to pick up steam as the Hardy Storage joint venture (JV) contributes to both top and bottom lines for the whole of 2008. And, we expect solid performance to persist from its South Star Energy JV.

All told, we look for the bottom line to advance 7% and 3% for this year and next, respectively. This ought to stem from continued investments in its natural gas infrastructure. Further streamlining and consolidation of business processes and operations should help maintain margins, as well.

The equity offers a solid dividend yield and decent total return potential to 2011-2013. Meanwhile, these shares are ranked to perform in line with the broader market averages for the year ahead.

Bryan Fong *March 14, 2008*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early May.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2007: $23.9 million, 33¢/share.
(E) In millions, adjusted for stock split.
(F) Quarters may not add to total due to change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	80

Exhibit___(FJH-29)
Sheet 14 of 32

Exhibit___(FJH-9)
Sheet 9 of 10
(Update)

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 34.23 | P/E RATIO 15.3 (Trailing: 17.5 Median: 14.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.2% | VBMVF MOF

I Jhi ; Mx:	26/4 21/6	26/5 22/1	26/5 21/9	26/2 23/4	28/1 24/9	29/4 25/2	31/4 26/4	37/8 2:/8	43/5 35/:	45/4 36/7	52/4 42/3	49/5 44/7	Target Price Range 3122 | 3123 | 3124

TIMELINESS 5 Lowered 9/14/07
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 3/14/08
CFLB /91)2/11>Ntsl d

2011-13 PROJECTIONS

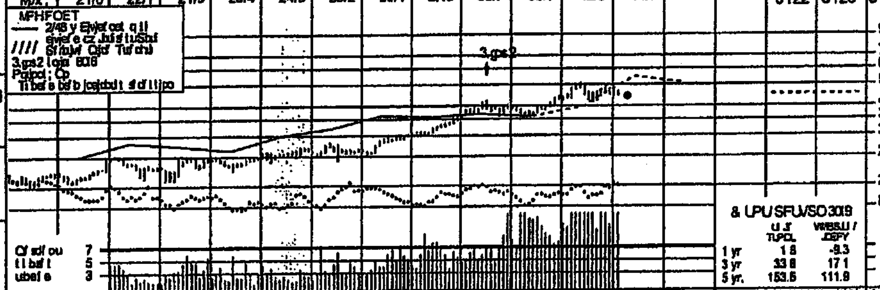
	Price	Gain	Ann'l Total Return
High	61	), 56& *	23&
Low	46	)Ojm	5&

.bl jef sEf djt jpot

	A	M	J	J	A	S	O	N	D
to Buy	1	1	1	1	1	1	1	1	2
Options	1	1	1	1	1	1	1	1	1
to Sell	1	4	1	1	2	1	1	3	1

.bl qjwujpobnEf djt jpot

	2Q2007	3Q2007	4Q2007
to Buy	7:	78	77
to Sell	75	69	6:
Hld's(000)	27: 66	27898	27: : 6



& LPU SFUVSO 3/19

	U J TUPDL	WBMVF JOEY
1 yr	1 8	-9.3
3 yr	33 8	17 1
5 yr.	153.6	111.9

2::3	2::4	2::5	2::6	2::7	2::8	2::9	2:::	3111	3112	3113	3114	3115	3116	3117	3118	3119	311:	VALUE LINE PUB., INC.	11-13
16.67	17 03	17 45	16.50	16 52	16 18	20 89	17 60	22 43	35 30	20 69	26.34	29 51	31 78	31.76	32 29	34.35	36.05	Revenues per sh	39.05
1 56	1 54	1 35	1 65	1 54	1 60	1.44	1.84	1.95	1 90	2 12	2 24	2.44	2 51	3 51	3.03	3.20	3.60	"Cash Flow" per sh	4.05
81	78	61	.83	85	86	64	1 01	1 08	1 15	1 22	1 37	1 58	1.71	2 46	2 09	2.25	2.45	Earnings per sh [B]	3 00
.71	.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.10	1.16	Div'ds Decl'd per sh [C]■	1.28
1 69	1 87	1 93	2.08	2 01	2 30	3.05	2 19	2.21	2 82	3.47	2 38	2.67	3 21	2 61	1 87	2.15	2.45	Cap'l Spending per sh	3.15
6.95	7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.24	17.35	18.35	Book Value per sh [D]	20.30
19.00	19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.98	29.33	29.62	30.00	30.50	Common Shs Outst'g [E]	32.00
13 2	15 8	16 1	12 2	13 3	13.8	21 2	13.3	13 0	13.6	13 5	13 3	14 1	18.6	11 9	17 2	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	14.0
.80	93	1 06	82	.83	80	1 10	.76	.85	.70	74	.76	74	.88	64	90			Relative P/E Ratio	.95
6.6%	5.9%	7.4%	7.2%	6 4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%			Avg Ann'l Div'd Yield	3.0%

CAPITAL STRUCTURE as of 12/31/07
Total Debt $476 3 mill. Due in 5 Yrs $156.1 mill
LT Debt $357 9 mill LT Interest $21 0 mill
(Total interest coverage: 4 8x)

Pension Assets-12/07 $120.4 mill
Oblig. $133.0 mill

Pfd Stock none

Common Stock 29,624,492 common shs
as of 2/23/08

MARKET CAP: $1.0 billion (Mid Cap)

2::9	2:::	3111	3112	3113	3114	3115	3116	3117	3118	3119	311:		11-13
450 2	392 5	515.9	837 3	505.1	696.8	819 1	921 0	931 4	958 4	1030	1100	Revenues ($mill)	1250
13.8	22.0	24.7	26.8	29.4	34.6	43.0	48.6	72.0	61.9	67.5	75.0	Net Profit ($mill)	95.0
46.2%	42.8%	43 1%	42 2%	41 4%	40.6%	40 9%	41 5%	41 3%	40.7%	40.0%	40.0%	Income Tax Rate	40.0%
3.1%	5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	6.6%	6.8%	Net Profit Margin	7.6%
57 3%	53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	44 9%	44 7%	42.7%	41.5%	40.5%	Long-Term Debt Ratio	41.0%
33.5%	37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	58.5%	59.5%	Common Equity Ratio	59.0%
401 1	405 9	443.5	516 2	512 5	608 4	675 0	710 3	801 1	839 0	890	945	Total Capital ($mill)	1100
504.3	533.3	562.2	607.0	666.6	748.3	799.9	877.3	920.0	948.9	980	1015	Net Plant ($mill)	1200
5 3%	7.4%	7.4%	6 9%	7 5%	7 3%	7 9%	8.3%	10.1%	8.5%	9.0%	9.0%	Return on Total Cap'l	10.0%
8.1%	11 7%	12 1%	12 1%	12 4%	11.5%	12.4%	12.4%	16 3%	12.9%	13.0%	13.5%	Return on Shr. Equity	14.5%
10.3%	14.6%	14.8%	12.8%	12.6%	11.6%	12.5%	12.4%	16.3%	12.9%	13.0%	13.5%	Return on Com Equity	14.5%
NMF	4 2%	4 8%	3 5%	4.7%	5 0%	5 9%	6 2%	10.2%	6 7%	6.5%	7.0%	Retained to Com Eq	6.5%
112%	72%	67%	76%	62%	57%	52%	50%	37%	48%	49%	47%	All Div'ds to Net Prof	43%

CURRENT POSITION ($MILL.)	2005	2006	12/31/07
Cash Assets	4.9	7.9	11.7
Other	352.6	363.8	316.6
Current Assets	357 5	371 7	328.3
Accts Payable	179 0	101.6	101.2
Debt Due	149.7	197.0	118.4
Other	74.4	124.2	108.7
Current Liab.	403.1	422 8	328.3
Fix. Chg. Cov.	486%	527%	476%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	6.5%	4.5%	3.5%
"Cash Flow"	6.5%	8.5%	NMF
Earnings	9 5%	12.0%	NMF
Dividends	2.0%	3.5%	5.5%
Book Value	8.0%	13.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	328 6	154.0	157.0	281.4	921.0
2006	372.6	153 8	154.7	250.3	931.4
2007	368.4	171.7	156 2	260.1	956 4
2008	390	190	170	280	1030
2009	405	205	190	300	1100

Cal-endar	EARNINGS PER SHARE [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.96	.27	.09	39	1.71
2006	1.06	20	.51	.69	2 46
2007	1 30	.21	d 05	.63	2.09
2008	1.25	.25	.10	.65	2.25
2009	1.30	.30	.15	.70	2.45

Cal-endar	QUARTERLY DIVIDENDS PAID [C]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	--	.202	.202	.415	.82
2005	--	.213	.213	.438	.86
2006	--	225	.225	470	92
2007	--	.245	.245	515	1.01
2008					

BUSINESS: South Jersey Industries, Inc is a holding company Its subsidiary, South Jersey Gas Co., distributes natural gas to 335,653 customers in New Jersey's southern counties, which covers 2,500 square miles and includes Atlantic City. Gas revenue mix '07: residential, 46%; commercial, 23%; cogeneration and electric generation, 8%; industrial, 23%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus Has 604 employees Off./dir cntrl 1 2% of com. shares; Dimensional Fund Advisors, 8 3%; Barclays, 6.0% (3/07 proxy). Chrmn. & CEO: Edward Graham Incorp.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037 Tel.: 609-561-9000. Internet: www.sjindustries.com.

South Jersey Industries reported a modest advance in revenues for 2007, although economic earnings increased roughly 14%. Utility South Jersey Gas benefited from continued growth in the customer base and lower interest costs. The company's nonutility operations also posted a solid performance. Readers are advised that our earnings-per-share figures are now based on economic earnings, a non-GAAP measure that excludes unrealized gains and losses from commodity derivative transactions. Thus, the share-net figures from 2007 onward are not directly comparable with those from previous years.

The company has solid long-term prospects. Natural gas remains the fuel of choice in the markets served by South Jersey Gas, as it enjoys a considerable price advantage over alternatives. Indeed, the vast majority of new homes built have chosen natural gas as their main heating source. Moreover, the company expects economic development in the Atlantic City area will boost housing demand in the coming years. In addition, this business ought to continue to benefit from the Conservation Incentive Program (CIP). This initiative allows South Jersey to promote energy conservation and insulate itself from the negative impact of lower customer usage. The CIP protected $7.5 million of net income during 2007, offsetting reduced customer utilization. Elsewhere, the performance of the nonutility Commodity Marketing business should continue to have an important impact on earnings. This unit maintains 10 billion cubic feet of gas storage capacity, which allows it to take advantage of volatility in natural gas pricing and lock in attractive profit margins. Looking forward, we anticipate moderate share-earnings and dividend growth in the current year. This pattern seems likely to continue in 2009, as well.

These shares are ranked to lag the broader market for the coming six to 12 months. Looking further out, we project solid bottom-line growth at South Jersey over the pull to 2011-2013. Moreover, this issue scores high marks for Price Stability and Earnings Predictability. Thus, this stock offers worthwhile total return potential for a natural gas utility.

Michael Napoli, CPA *March 14, 2008*

(A) Based on GAAP EPS through 2006, economic earnings thereafter. GAAP EPS: '07, $2.10. Excl. nonrecur. gain: '01, $0.13. Excl gain (losses) from discont ops.: '96, $1 14; '97, ($0.24); '98, ($0 26); '99, ($0 02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0 02). Next egs report due late April (B) Div'ds paid early Apr., Jul., Oct., and late Dec ■ Div reinvest. plan avail (C) Incl. regulatory assets. In 2007: $188 7 mill., $6 37 per shr. (D) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	85

WGL HOLDINGS NYSE-WGL

RECENT PRICE 31.83 | P/E RATIO 13.8 (Trailing: 14.9; Median: 15.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.3% | VB MVF MOF

TIMELINESS 4 Raised 5/25/07
SAFETY 2 Raised 4/2/93
TECHNICAL 4 Lowered 2/29/08
CFUB /86)2/11 > Nbd1 0

I jhi ; Mpx ;	42/5 31/:	41/9 34/2	3: /5 32/1	42/6 32/9	41/8 36/4	3: /8 2: /4	39/9 34/3	42/5 37/8	45/9 39/9	44/7 38/1	46/: 3: /9	45/7 41/:		Target Price Range 3122 | 3123 | 3124

2011-13 PROJECTIONS

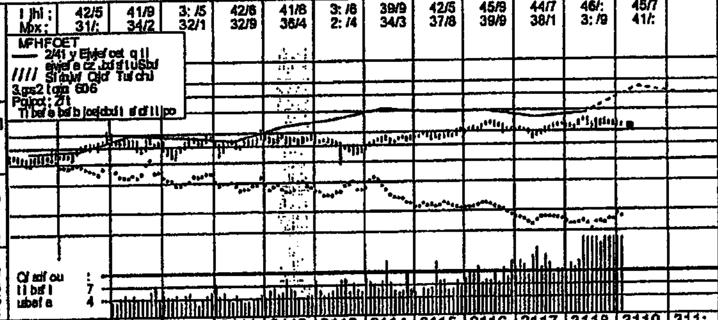
	Price	Gain	Ann'l Total Return
High	51	), 36&	21&
Low	46	), 21&	8&

Jbt jef s Ef djt jpot

	A	M	J	J	A	S	O	N	D
to Buy	1	1	1	1	1	1	1	1	1
Options	1	2	1	1	1	1	4	1	1
to Sell	1	2	1	1	1	1	4	1	2

Jbt ujuvujpobmEf djt jpot

	202007	302007	402007
to Buy	:5	:1	:3
to Sell	92	:7	:5
Hld's(000)	46421	45274	464:4



& LPU SFUVSO 3019

	UIJT TUPDL	WBM/ MJOF BSJUI/ JOEFY
1 yr.	3.2	-8.3
3 yr.	15.5	17.1
5 yr.	54.8	111.9

2::3	2::4	2::5	2::6	2::7	2::8	2::9	2:::	3111	3112	3113	3114	3115	3116	3117	3118	3119	311:	VALUE LINE PUB., INC.	11-13
18.37	21.55	21.69	19.30	22.19	24.18	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	*54.55*	*56.05*	Revenues per sh [B]	*60.70*
2.17	2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.93	3.89	*4.15*	*4.25*	"Cash Flow" per sh	*4.50*
1.27	1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.11	1.94	2.10	*2.30*	*2.35*	Earnings per sh [C]	*2.50*
1.07	1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.34	1.37	*1.40*	*1.44*	Div'ds Decl'd per sh [D]■	*1.58*
2.17	2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	*3.35*	*3.00*	Cap'l Spending per sh	*2.50*
10.66	11.04	11.51	11.85	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.28	19.83	*21.15*	*22.00*	Book Value per sh [E]	*24.95*
40.62	41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	*49.50*	*49.60*	Common Shs Outst'g [F]	*50.00*
13.6	15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.82	.92	.92	.85	.72	.73	.89	.89	.95	.75	1.26	.63	.75	.78	.84	.82	*Value Line*		Relative P/E Ratio	*1.00*
6.2%	5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
						1040.6	972.1	1031.1	1446.5	1584.8	2084.2	2089.6	2186.3	2637.9	2646.0	*2700*	*2780*	Revenues ($mill) [B]	*3035*
						68.6	68.8	84.6	89.9	55.7	112.3	98.0	104.8	95.1	102.9	*114*	*117*	Net Profit ($mill)	*125*
						35.6%	36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
						6.6%	7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	*3.9%*	*4.0%*	Net Profit Margin	*4.2%*
						40.3%	41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	38.5%	37.9%	*36.0%*	*35.0%*	Long-Term Debt Ratio	*32.0%*
						57.1%	56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	61.5%	60.3%	*62.5%*	*63.5%*	Common Equity Ratio	*66.5%*
						1064.8	1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1497.8	1625.4	*1675*	*1720*	Total Capital ($mill)	*1875*
						1319.5	1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	*2235*	*2325*	Net Plant ($mill)	*2615*
						8.0%	7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	7.7%	7.6%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
						10.8%	9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	10.3%	10.2%	*11.0%*	*10.5%*	Return on Shr. Equity	*10.0%*
						11.1%	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.2%	10.4%	*11.5%*	*11.0%*	Return on Com Equity	*10.5%*
						2.5%	1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	3.1%	3.5%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
						76%	82%	69%	67%	112%	55%	65%	62%	70%	66%	*61%*	*61%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 12/31/07
Total Debt $941.0 mill. Due in 5 Yrs $399.5 mill
LT Debt $593.6 mill LT Interest $40.1 mill
(LT interest earned: 6.7x; total interest coverage: 5.7x)
Pension Assets-9/07 $740.7 mill. Oblig. $680.3 mill.
Preferred Stock $28.2 mill Pfd. Div'd $1.3 mill.

Common Stock 49,464,057 shs as of 1/31/08

MARKET CAP: $1.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2006	2007	12/31/07
Cash Assets	4.4	4.9	19.0
Other	556.9	568.8	878.3
Current Assets	561.3	573.7	897.3
Accts Payable	208.5	216.9	331.4
Debt Due	238.4	205.4	347.5
Other	113.9	134.8	237.5
Current Liab	560.8	557.1	916.4
Fix. Chg. Cov.	465%	460%	460%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	9.0%	12.5%	3.0%
"Cash Flow"	3.5%	5.0%	2.5%
Earnings	2.0%	5.0%	3.5%
Dividends	1.5%	1.5%	2.5%
Book Value	4.0%	3.5%	5.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	623.4	929.8	349.0	284.1	2186.3
2006	902.9	1064.5	346.9	323.6	2637.9
2007	732.9	1119.9	467.5	325.7	2646.0
2008	751.6	*1140*	*458.4*	*350*	*2700*
2009	*770*	*1160*	*480*	*370*	*2780*

Fiscal Year Ends	EARNINGS PER SHARE [B C] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2005	.88	1.63	d.17	d.23	2.11
2006	.93	1.17	d.01	d.15	1.94
2007	.92	1.27	.22	d.31	2.10
2008	.95	*1.30*	*.20*	*d.15*	*2.30*
2009	*.97*	*1.33*	*.25*	*d.20*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID [D]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.32	.325	.325	.325	1.30
2005	.325	.333	.333	.333	1.32
2006	.333	.338	.338	.338	1.34
2007	.34	.34	.34	.34	1.36
2008	.34				

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,046,201 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century Inv. own 8.2% of common stock; Off./dir. less than 1% (1/08 proxy). Chrmn. & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Addr.: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings has been experiencing progress with its rate cases. The company recently received approval for a rate hike in the District of Columbia (DOC). The incremental cash flow from the rate hike, which was not expected to be approved until March, added approximately $0.05 per share to the bottom line in the first quarter (ended December 31st). Furthermore, the earlier-than-expected rate increase has prompted us to raise our annual estimate by 5%, to $2.30 per share.

The company's earnings will likely get a 2%-3% lift for the March interim. WGL's gas and light utility division has been experiencing higher usage volumes and system charges as a result of 12,310 new customers. And it is expected to add about 5,200 more accounts by the end of fiscal 2008. Furthermore, the asset management business likely continued to enjoy strong off-system sales as excess reserves are released in order to meet the heightened demand during the colder winter months. These results ought to be partially offset by increased operation and maintenance costs.

We look for the share net to advance approximately 10% this year. Lifts in the top-line volumes ought to stem from the heightened rates in the DOC, additional customer growth, and expansion of the company's asset management program. Meanwhile, gas sales at the Washington Gas Energy Services unit have been down as a result of warmer-than-normal weather patterns. However, this unit's margins have been widening on a per-therm basis, offsetting the lower volumes and boosting the bottom line.

In 2009, the bottom-line increase ought to moderate. The majority of benefits from efficiency initiatives and the effects of the recent DOC rate hike will have cycled through by next year. Therefore, we look for earnings advances to slow to a low single-digit rate.

These neutrally ranked shares may appeal to income-oriented accounts. The equity offers a solid dividend yield. Meanwhile, the stock garners our Highest Safety rank (1), and our best mark for Price Stability (100), indicating suitability for conservative accounts with an eye on capital preservation.

Bryan Fong *March 14, 2008*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢) discontinued operations: '06, (15¢). Next earnings report due late April. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles '07: $322.2 million, $6.51/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	65

Southwest Gas Corporation
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Based on Historical and Projected Market Risk Premium: Southwest Gas Corporation	Based on Historical and Projected Market Risk Premium: Proxy Group of Eight Value Line Gas Distribution	Based Only on Historical Market Risk Premium: Southwest Gas Corporation	Based Only on Historical Market Risk Premium: Proxy Group of Eight Value Line Gas Distribution
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.57 %	5.57 %	5.57 %	5.57 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A Rated Public Utility Bonds	0.69 (2)	0.69 (2)	0.69 (2)	0.69
3.	Adjusted Prospective Yield on A Rated Public Utility Bonds	6.26 %	6.26 %	6.26 %	6.26 %
4.	Adjustment to Reflect Bond Rating Difference	0.75 (3)	0.14 (4)	0.75 (3)	0.14 (4)
5.	Adjusted Prospective Bond Yield	7.01 %	6.40 %	7.01 %	6.40 %
6.	Equity Risk Premium (5)	5.65	5.81	4.63	4.84
7.	Risk Premium Derived Common Equity Cost Rate	12.66 %	12.21 %	11.64 %	11.24 %

Notes:
(1) Derived in Note (4) on Sheet 21 of this Exhibit.
(2) The average yield spread of A rated public utility bonds over Aaa rated corporate bonds of 0.69% from Sheet 19 of this Exhibit.
(3) The average spread between Moody's A and Baa rated public utility bond yields of 43 basis points plus one and one-third the estimated average yield spread of Baa over Ba rated public utility bonds to reflect Southwest Gas Corporation's Moody's bond rating of Baa3 as shown on Sheet 17 of this Exhibit. ((0.43% + (1/3 * 0.95%) = (0.43% + 0.317%, rounded to 0.32) = 0.75% (from Sheet 19 of this Exhibit)).
(4) One-third the average spread between Moody's A and Baa rated public utility bond yields of 43 basis points to reflect the proxy group's average Moody's bond rating of A3 as shown on Sheet 17 of this Exhibit. ((1/3 X 0.43% = 0.143%, rounded down to 0.14% (from Sheet 19 of this Exhibit)).
(5) From Sheet 20 of this Exhibit.

Southwest Gas Corporation
Comparison of Bond Ratings, Business and Financial Profiles
for Southwest Gas Corporation and
the Proxy Group of Eight Value Line Gas Distribution Companies

	Moody's Bond Rating March 2008		Standard & Poor's Bond Rating March 2008		Standard & Poor's			
	Bond Rating	Numerical Weighting (1)	Bond Rating	Numerical Weighting (1)	Business Risk Profile (2)	Numerical Weighting (1)	Financial Risk Profile (2)	Numerical Weighting (1)
Southwest Gas Corporation	Baa3	10.0	BBB-	10.0	Strong	2.0	Aggressive	3.0
Proxy Group of Eight Value Line Gas Distribution Companies								
AGL Resources Inc. (3)	A3	7.0	A-	7.0	Excellent	1.0	Intermediate	2.0
Atmos Energy Corp. (4)	Baa3	10.0	BBB	9.0	Excellent	1.0	Aggressive	3.0
The Laclede Group, Inc. (5)	A3	7.0	A	6.0	Excellent	1.0	Intermediate	2.0
NICOR Inc. (6)	A1	5.0	AA	3.0	Excellent	1.0	Intermediate	2.0
Northwest Natural Gas Company	A2	6.0	AA-	4.0	Excellent	1.0	Intermediate	2.0
Piedmont Natural Gas Company, Inc.	A3	7.0	A	6.0	Excellent	1.0	Intermediate	2.0
South Jersey Industries, Inc. (7)	Baa1	8.0	A	6.0	Excellent	1.0	Aggressive	3.0
WGL Holdings, Inc. (8)	A2	6.0	AA-	4.0	Excellent	1.0	Intermediate	2.0
Average	A3	7.0	A+	5.6	Excellent	1.0	Intermediate	2.3

NA = Not Available
NR = Not Rated

Notes:
(1) From Sheet 17 of this Exhibit.
(2) From Standard & Poor's (S&P) "Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies, Strongest To Weakest", April 4, 2008.
(3) Moody's ratings are those of Atlanta Gas Light Co. S&P's ratings and business profile are a composite of those of Atlanta Gas Light Co. and Pivotal Utility Holdings (formerly NUI
(4) Moody's ratings and S&P's business profile are those of Atmos Energy Corporation. S&P's ratings are a composite of those of Atmos Energy Corporation and United Cities Gas Company dba Atmos Energy Corporation.
(5) Ratings and profiles are those of Laclede Gas Company.
(6) Ratings and profiles are those of NICOR Gas Company.
(7) Ratings and profiles are those of South Jersey Natural Gas Company.
(8) Ratings and profiles are those of Washington Gas Light Company.

Source of Information:
Moody's Investors Service
Standard & Poor's RatingsDirect

Southwest Gas Corporation
Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings
Standard & Poor's Business and Financial Risk Profiles

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-

Standard & Poor's

Business Risk Profile	Numerical Weighting	Financial Risk Profile	Numerical Weighting
Excellent	1	Modest	1
Strong	2	Intermediate	2
Satisfactory	3	Aggressive	3
Weak	4	Highly Leveraged	4
Vulnerable	5		

Moody's
Comparison of Interest Rate Trends
for the Two Months Ending March 2008 (1)

	Corporate Bonds	Public Utility Bonds			Spread - Corporate v. Public Utility Bonds			Spread - Public Utility Bonds		
Years	Aaa Rated	Aa Rated	A Rated	Baa Rated	Aa (Pub. Util.) over Aaa (Corp.)	A (Pub. Util.) over Aaa (Corp.)	Baa (Pub. Util.) over Aaa (Corp.)	A over Aa	Baa over A	Estimated Ba over Baa (3)
February-08	5.53 %	6.04 %	6.21 %	6.60 %	0.51 %	0.68 %	1.07 %	0.17 %	0.39 %	0.89 %
March-08	5.51 %	5.99 %	6.21 %	6.68 %	0.48 %	0.70 %	1.17 %	0.22 %	0.47 %	1.00
Average Spread (2)					0.50 %	0.69 %	1.12 %	0.20 %	0.43 %	0.95 %

Notes:
(1) All yields are distributed yields.
(2) Equal weight has been given to the February 2008 and March 2008 spread.
(3) Estimated spread of Ba over Baa rated public utility bond yields calculated as (the spread of Baa over A rated public utility bond yields ÷ the spread of Aa over A rated public utilty bond yields) * (the spread of Baa over A rated public utility bonds).

Source of Information:
Mergent Bond Record Monthly Update, April 2008, Vol. 75, No. 4

Exhibit___(FJH-29)
Sheet 20 of 32

Exhibit___(FJH-10)
Sheet 5 of 9
(Update)

Southwest Gas Corporation
Judgment of Equity Risk Premium for
for Southwest Gas Corporation and
the Proxy Group of Eight Value Line Gas Distribution Companies

Line No.		Based on Historical and Projected Market Risk Premium: Southwest Gas Corporation	Based on Historical and Projected Market Risk Premium: Proxy Group of Eight Value Line Gas Distribution Companies	Based Only on Historical Market Risk Premium: Southwest Gas Corporation	Based Only on Historical Market Risk Premium: Proxy Group of Eight Value Line Gas Distribution Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	7.62 %	7.28 %	5.58 %	5.33 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with:				
	A3 rated bonds (2)		4.34		4.34
	Baa3 rated bonds (2)	3.68		3.68	
3.	Average equity risk premium	5.65 %	5.81 %	4.63 %	4.84 %

Notes: (1) From Sheet 21 of this Exhibit.
(2) From Sheet 23 of this Exhibit.

Southwest Gas Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
for Southwest Gas Corporation and
the Proxy Group of Eight Value Line Gas Distribution Companies

Line No.		Based on Historical and Projected Market Risk Premium: Southwest Gas Corporation	Based on Historical and Projected Market Risk Premium: Proxy Group of Eight Value Line Gas Distribution Companies	Based Only on Historical Market Risk Premium: Southwest Gas Corporation	Based Only on Historical Market Risk Premium: Proxy Group of Eight Value Line Gas Distribution Companies
1.	Arithmetic mean total return rate on the Standard & Poor's 500 Composite Index - 1926-2006 (1)	12.30 %	12.30 %	12.30 %	12.30 %
2.	Arithmetic mean yield on Aaa and Aa Corporate Bonds 1926-2006 (2)	(6.10)	(6.10)	(6.10)	(6.10)
3.	Historical Equity Risk Premium	6.20 %	6.20 %	6.20 %	6.20 %
4.	Forecasted 3-5 year Total Annual Market Return (3)	16.30 %	16 30 %	-- %	-- %
5.	Prospective Yield an Aaa Rated Corporate Bonds (4)	(5.57)	(5.57)	--	--
6.	Forecasted Equity Risk Premium	10.73 %	10.73 %	-- %	-- %
7.	A. Average of Historical and Forecasted Equity Risk Premium (5)	8.47 %	8.47 %		
	B. Historical Equity Risk Premium			6 20 % (6)	6.20 % (6)
8.	Adjusted Value Line Beta (7)	0.90	0.86	0.90	0.86
9.	Beta Adjusted Equity Risk Premium	7.62 %	7.28 %	5.58 %	5.33 %

Notes: (1) From Stocks Bonds Bills and Inflation - Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, Morningstar, Inc., 2008 Chicago, IL.

(2) From Moody's Industrial Manual and Mergent Bond Record Monthly Update.

(3) From Sheet 28 of this Exhibit.

(4) Average forecast based upon six quarterly estimates of Aaa rated corporate bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated April 1, 2008 (see Sheet 22 of this Exhibit). The estimates are detailed below.

Second Quarter 2008	5.40 %
Third Quarter 2008	5.40
Fourth Quarter 2008	5.50
First Quarter 2009	5.60
Second Quarter 2009	5.70
Third Quarter 2009	5.80
Average	5.57 %

(5) Average of the Historical Equity Risk Premium of 6.20% from Line No. 3 and the Forecasted Equity Risk Premium of 10.73% from Line No. 6 ((6.20% + 10.73) / 2 = 8.465%, rounded to 8.47%).

(6) As explained in Note 5, the average of the Historical Equity Risk Premium and the Forecasted Equity Risk Premium is 8.47%. Normally, Mr. Hanley would use this average in his Risk Premium Analysis. However, in Mr. Hanley's opinion, the current and recent substantial decline in the stock market is extraordinary and not representative of the expected long-term, thereby grossly overstating long-term future capital appreciation. Consequently, in this instance, Mr. Hanley will not consider what he believes is an extraordinary expected capital appreciation and instead will rely only upon the 6.20%

(7) From Sheet 24 of this Exhibit.

Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

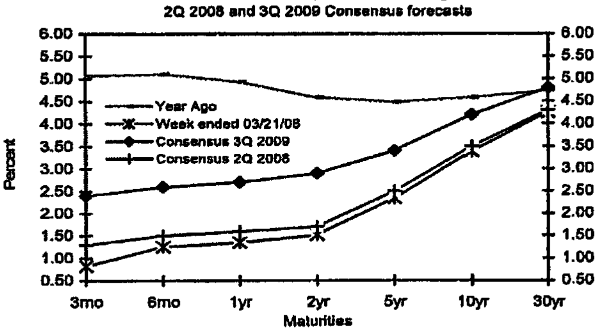
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week End				Average For Month			*Latest Q**	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	Mar.21	Mar.14	Mar.7	Feb.29	Feb.	Jan.	Dec.	*1Q 2008*	2008	2008	2008	2009	2009	2009
Federal Funds Rate	2.70	2.97	3.00	2.96	2.98	3.94	4.24	3.27	2.0	1.8	1.8	2.0	2.2	2.5
Prime Rate	5.79	6.00	6.00	6.00	6.00	6.98	7.33	6.30	5.0	4.9	4.9	5.0	5.3	5.6
LIBOR, 3-mo.	2.60	2.84	2.99	3.08	3.09	3.92	4.98	3.27	2.4	2.2	2.2	2.3	2.6	2.9
Commercial Paper, 1-mo.	2.18	2.47	2.69	2.84	2.90	3.61	4.25	2.99	2.2	2.1	2.1	2.3	2.5	2.8
Treasury bill, 3-mo.	0.82	1.37	1.55	2.01	2.17	2.82	3.07	2.08	1.3	1.4	1.5	1.7	2.0	2.4
Treasury bill, 6-mo.	1.26	1.49	1.70	2.00	2.10	2.84	3.34	2.14	1.5	1.6	1.7	1.9	2.3	2.6
Treasury bill, 1 yr.	1.35	1.52	1.66	1.98	2.05	2.71	3.26	2.09	1.6	1.7	1.8	2.0	2.4	2.7
Treasury note, 2 yr.	1.52	1.59	1.60	1.94	1.97	2.48	3.12	2.01	1.7	1.8	1.9	2.2	2.5	2.9
Treasury note, 5 yr.	2.34	2.47	2.51	2.80	2.78	2.98	3.49	2.73	2.5	2.6	2.7	2.9	3.2	3.4
Treasury note, 10 yr.	3.39	3.51	3.61	3.78	3.74	3.74	4.10	3.66	3.5	3.6	3.7	3.8	4.0	4.2
Treasury note, 30 yr.	4.26	4.44	4.53	4.59	4.52	4.33	4.53	4.42	4.3	4.3	4.4	4.5	4.7	4.8
Corporate Aaa bond	5.44	5.53	5.54	5.60	5.53	5.33	5.49	5.45	5.4	5.4	5.5	5.6	5.7	5.8
Corporate Baa bond	6.82	6.91	6.89	6.91	6.82	6.54	6.65	6.74	6.7	6.6	6.7	6.7	6.8	6.9
State & Local bonds	4.88	4.94	4.92	5.11	4.64	4.27	4.53	4.61	4.6	4.5	4.6	4.6	4.6	4.7
Home mortgage rate	5.87	6.13	6.03	6.24	5.92	5.76	6.10	5.90	5.8	5.8	5.8	5.9	6.0	6.2

	History								Consensus Forecasts-Quarterly Avg.					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	*1Q**	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2006	2006	2006	2007	2007	2007	2007	*2008*	2008	2008	2008	2009	2009	2009
Major Currency Index	82.2	81.7	81.6	81.9	79.3	77.0	73.3	*72.0*	70.8	70.9	71.2	71.9	72.5	73.5
Real GDP	2.4	1.1	2.1	0.6	3.8	4.9	0.6	*0.0*	0.0	1.6	1.7	1.9	2.4	2.7
GDP Price Index	3.5	2.4	1.7	4.2	2.6	1.0	2.4	*3.0*	2.5	2.3	2.2	2.4	2.2	2.2
Consumer Price Index	3.9	3.8	-1.6	3.8	4.6	2.7	5.1	*4.1*	2.9	2.6	2.2	2.4	2.3	2.3

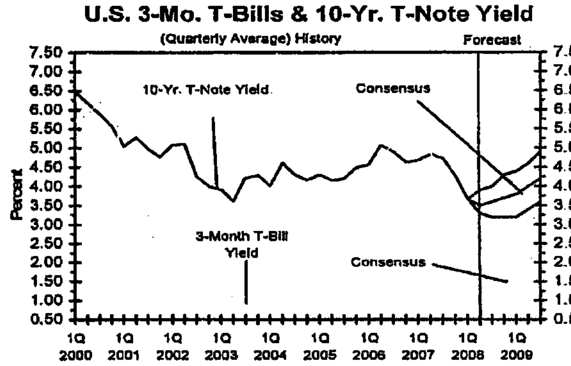
Individual panel members' forecasts are on pages 4 through 9. Historical data for interest rates except LIBOR is from Federal Reserve Release (FRSR) H.15. LIBOR quotes available from *The Wall Street Journal*. Definitions reported here are same as those in FRSR H.15. Treasury yields are reported on a constant maturity basis. Historical data for the U.S Federal Reserve Board's Major Currency Index is from FRSR H.10 and G.5. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS). ****Interest rate data for 1Q 2008 based on historical data through the week ended March 21st. *Data for 1Q 2008 Major Currency Index also is based on data through week ended March 21st. Figures for 1Q 2008 Real GDP, GDP Chained Price Index and Consumer Price Index are consensus forecasts based on a special question asked of the panelists (see page 14).***

U.S. Treasury Yield Curve

Week ended March 21, 2008 and Year Ago vs. 2Q 2008 and 3Q 2009 Consensus forecasts

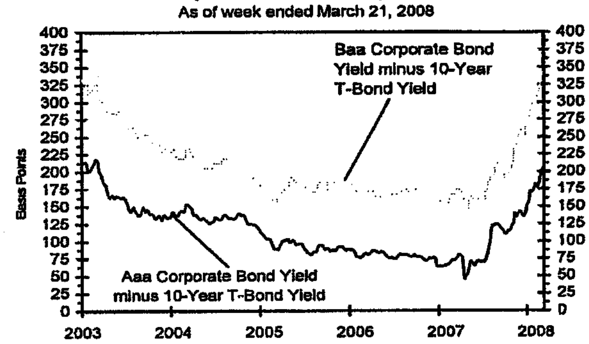


U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield



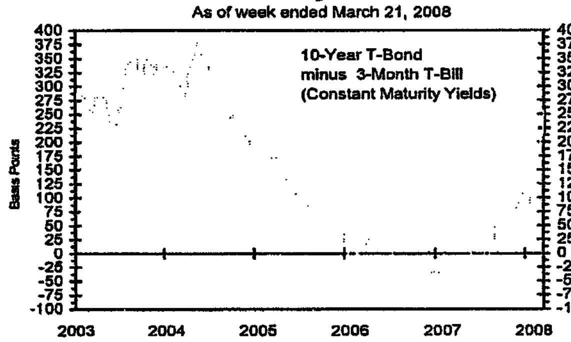
Corporate Bond Spreads

As of week ended March 21, 2008



U.S. Treasury Yield Curve

As of week ended March 21, 2008



Southwest Gas Corporation
Derivation of Mean Equity Risk Premium Based on a Study
Using Holding Period Returns of Public Utilities

Line No.			1	2
			Southwest Gas Corporation	Proxy Group of Eight Value Line Gas Distribution Companies
			AUS Consultants Risk Premium Study (1)	AUS Consultants Risk Premium Study (1)
Time Period			1928-2006	1928-2006
1.		Arithmetic Mean Holding Period Returns (2): Standard & Poor's Public Utility Index	11.11 %	11.11 %
2.		Arithmetic Mean yield on:		
	A.	Baa rated Public Utility Bonds	(7.12)	
	B.	A rated Public Utility Bonds		(6.60)
3.		Adjustment to reflect Company or proxy group specific average Moody's bond rating	(0.31) (3)	(0.17) (4)
4.		Equity Risk Premium	3.68 %	4.34 %

Notes: (1) S&P Public Utility Index and Moody's Public Utility Bond Average Annual Yields, 1928-2006 (AUS Consultants, 2007).

(2) Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

(3) One-third the average 1928 - 2006 estimated spread between Baa and Ba rated Moody's public utility bond yields of 93 basis points to reflect Southwest Gas Corporation's Moody's bond rating of Baa3 as shown on Sheet 2 of this Exhibit. ((1/3 x 0.93% = 0.31%). (AUS Consultants, 2007).

(4) One-third the average 1928 - 2006 spread between A and Baa rated Moody's public utility bond yields of 52 basis points to reflect the proxy group's average Moody's bond rating of A3 as shown on page 2 of this Exhibit. ((1/3 x 0.52% = 0.173%, rounded to 0.17%). (AUS Consultants, 2007).

Southwest Gas Corporation
Value Line Adjusted Betas
for Southwest Gas Corporation and
the Proxy Group of Eight Value Line Gas Distribution Companies

	Value Line Adjusted Beta
Southwest Gas Corporation	0.90
Proxy Group of Eight Value Line Gas Distribution Companies	
AGL Resources Inc.	0.85
Atmos Energy Corp.	0.85
The Laclede Group, Inc.	0.90
NICOR Inc.	1.00
Northwest Natural Gas Company	0.80
Piedmont Natural Gas Company, Inc.	0.85
South Jersey Industries, Inc.	0.80
WGL Holdings, Inc.	0.85
Average	0.86

Source of Information: Value Line Investment Survey, (Standard Edition)
March 14, 2008

Southwest Gas Corporation
Indicated Common Equity Cost Rate Through Use of the
Capital Asset Pricing Model for
Southwest Gas Corporation
and the Proxy Group of Eight Value Line Gas Distribution Companies

No.		Based on Historical and Projected Market Risk Premium: Southwest Gas Corporation	Based on Historical and Projected Market Risk Premium: Proxy Group of Eight Value Line Gas Distribution Companies
1.	Traditional Capital Asset Pricing Model Derived Company Equity Cost Rates (1)	13.01 %	12.65 %
2.	Empirical Capital Asset Pricing Model Derived Company Equity Cost Rate (1)	13.24 %	12.98 %
3.	CAPM Results	13.13 %	12.82 %

No.		Based Only on Historical Market Risk Premium: Southwest Gas Corporation	Based Only on Historical Market Risk Premium: Proxy Group of Eight Value Line Gas Distribution Companies
1.	Traditional Capital Asset Pricing Model Derived Company Equity Cost Rates (2)	10.89 %	10.63 %
2.	Empirical Capital Asset Pricing Model Derived Company Equity Cost Rate (2)	11.07 %	10.87 %
3.	CAPM Results	10.98 %	10.75 %

Notes: (1) Developed on Sheet 26 of this Exhibit.
(2) Developed on Sheet 27 of this Exhibit.

Southwest Gas Corporation
Indicated Common Equity Cost Rate Through Use of the Capital Asset Pricing Model
Based on Historical and Projected Market Risk Premium

	Value Line Adjusted Beta	Company-Specific Risk Premium Based on Market Premium of 9.45% (1)	CAPM Result Including Risk-Free Rate of 4.50% (2)	Recommended CAPM Result (3)
Traditional Capital Asset Pricing Model (4)				
Southwest Gas Corporation	0.90	8.51 %	13.01 %	13.01 %
Proxy Group of Eight Value Line Gas Distribution Companies				
AGL Resources Inc.	0.85	8.03 %	12.53 %	12.53 %
Atmos Energy Corp.	0.85	8.03	12.53	12.53
The Laclede Group, Inc.	0.90	8.51	13.01	13.01
NICOR Inc.	1.00	9.45	13.95	13.95
Northwest Natural Gas Company	0.80	7.56	12.06	12.06
Piedmont Natural Gas Company, Inc.	0.85	8.03	12.53	12.53
South Jersey Industries, Inc.	0.80	7.56	12.06	12.06
WGL Holdings, Inc.	0.85	8.03	12.53	12.53
Average	0.86	8.15 %	12.65 %	12.65 %
Empirical Capital Asset Pricing Model (5)				
Southwest Gas Corporation	0.90	8.74 %	13.24 %	13.24 %
Proxy Group of Eight Value Line Gas Distribution Companies				
AGL Resources Inc.	0.85	8.39 %	12.89 %	12.89 %
Atmos Energy Corp.	0.85	8.39	12.89	12.89
The Laclede Group, Inc.	0.90	8.74	13.24	13.24
NICOR Inc.	1.00	9.45	13.95	13.95
Northwest Natural Gas Company	0.80	8.03	12.53	12.53
Piedmont Natural Gas Company, Inc.	0.85	8.39	12.89	12.89
South Jersey Industries, Inc.	0.80	8.03	12.53	12.53
WGL Holdings, Inc.	0.85	8.39	12.89	12.89
Average	0.86	8.48 %	12.98 %	12.98 %

See Sheet 28 of this Exhibit for notes.

Southwest Gas Corporation
Indicated Common Equity Cost Rate Through Use of the Capital Asset Pricing Model
Based Only on Historical Market Risk Premium

	Value Line Adjusted Beta	Company-Specific Risk Premium Based on Historical Premium of 7.10% (1)	CAPM Result Including Risk-Free Rate of 4.50% (2)	Recommended CAPM Result (3)
Traditional Capital Asset Pricing Model (4)				
Southwest Gas Corp.	0.90	6.39 %	10.89 %	10.89 %
Proxy Group of Eight Value Line Gas Distribution Companies				
AGL Resources Inc.	0.85	6.04 %	10.54 %	10.54 %
Atmos Energy Corp.	0.85	6.04	10.54	10.54
The Laclede Group, Inc.	0.90	6.39	10.89	10.89
NICOR Inc.	1.00	7.10	11.60	11.60
Northwest Natural Gas Company	0.80	5.68	10.18	10.18
Piedmont Natural Gas Company, Inc	0.85	6.04	10.54	10.54
South Jersey Industries, Inc.	0.80	5.68	10.18	10.18
WGL Holdings, Inc.	0.85	6.04	10.54	10.54
Average	0.86	6.13 %	10.63 %	10.63 %
Empirical Capital Asset Pricing Model (5)				
Southwest Gas Corp.	0.90	6.57 %	11.07 %	11.07 %
Proxy Group of Eight Value Line Gas Distribution Companies				
AGL Resources Inc.	0.85	6.30 %	10.80 %	10.80 %
Atmos Energy Corp.	0.85	6.30	10.80	10.80
The Laclede Group, Inc.	0.90	6.57	11.07	11.07
NICOR Inc.	1.00	7.10	11.60	11.60
Northwest Natural Gas Company	0.80	6.04	10.54	10.54
Piedmont Natural Gas Company, Inc.	0.85	6.30	10.80	10.80
South Jersey Industries, Inc.	0.80	6.04	10.54	10.54
WGL Holdings, Inc.	0.85	6.30	10.80	10.80
Average	0.86	6.37 %	10.87 %	10.87 %

See Sheet 28 of this Exhibit for notes.

Southwest Gas Corporation
Development of the Market-Required Rate of Return on Common Equity Using the Capital Asset Pricing Model for Southwest Gas Corporation and the Proxy Group of Eight Value Line Gas Distribution Companies
Adjusted to Reflect a Forecasted Risk-Free Rate and Market Return

Notes:

(1) From the two previous month-end (February '08 – March '08), as well as a recently available (April 11, 2008), Value Line Summary & Index, a forecasted 3-5 year total annual market return of 16.30% can be derived by averaging the February 2008, March 2008, and spot forecasted total 3-5 year total appreciation, converting it into an annual market appreciation and adding the Value Line average forecasted annual dividend yield.

The 3-5 year average total market appreciation of 70%, produces a four-year average annual return of 14.19% $(((1.70^{0.25}) - 1)*100)$. When the average annual forecasted dividend yield of 2.11% is added, a total average market return of 16.30% (14.19 + 2.11%) is derived.

The average February 2008, March 2008 and spot forecasted total market return of 16.30% minus the risk-free rate of 4.50% (developed in Note 2) is 11.80% (16.30% - 4.50%). The Ibbotson Associates calculated market premium of 7.10% for the period 1926-2007 results from a total market return of 12.30% less the average income return on long-term U.S. Government Securities of 5.20% (12.30% - 5.20% = 7.10%). This is then averaged with the 11.80% Value Line market premium resulting in a 9.45% market premium. The 9.45% market premium is then multiplied by the beta in column 1 of Sheet 26 of this Exhibit. In Mr. Hanley's opinion, the current and recent substantial decline in the stock market is extraordinary and not representative of the expected long-term, thereby grossly overstating long-term future capital appreciation. Consequently, in this instance, Mr. Hanley will not consider what he believes is an extraordinary expected capital appreciation and instead will rely only upon the 7.10% historical market premium which will be then multiplied by the beta in column 1 of Sheet 27 of this Exhibit.

(2) Average forecast based upon six quarterly estimates of 30-year Treasury Note yields per the consensus of nearly 50 economists reported in the Blue Chip Financial Forecasts dated April 1, 2008 (See Sheet 22 of this Exhibit). The estimates are detailed below:

	30-Year Treasury Note Yield
Second Quarter 2008	4.30%
Third Quarter 2008	4.30
Fourth Quarter 2008	4.40
First Quarter 2009	4.50
Second Quarter 2009	4.70
Third Quarter 2009	4.80
Average	4.50%

(3) Includes only those indicated common equity cost rates which are greater than 9.50% for reasons fully explained in Mr. Hanley's direct testimony.

(4) The traditional Capital Asset Pricing Model (CAPM) is applied using the following formula:

$R_S = R_F + \beta\,(R_M - R_F)$

Where R_S = Return rate of common stock
R_F = Risk Free Rate
β = Value Line Adjusted Beta
R_M = Return on the market as a whole

(5) The empirical CAPM is applied using the following formula:

$R_S = R_F + .25\,(R_M - R_F) + .75\,\beta\,(R_M - R_F)$

Where R_S = Return rate of common stock
R_F = Risk-Free Rate
β = Value Line Adjusted Beta
R_M = Return on the market as a whole

Source of Information: Value Line Summary & Index (Standard Edition)
Blue Chip Financial Forecasts, April 1, 2008
Value Line Investment Survey, March 14, 2008
Stocks, Bonds, Bills, and Inflation– Market Results for 1926-2007 - 2008 Yearbook Valuation Edition, Morningstar, Inc., Chicago, IL, 2008

Exhibit___(FJH-29)
Sheet 29 of 32

Exhibit___(FJH-13)
Sheet 1 of 4
(Update)

Southwest Gas Corporation
Comparable Earnings Analysis
for a Proxy Group of Twenty-Three Non-Utility Companies Comparable to
Southwest Gas Corporation (1)

Proxy Group of Twenty-Three Non-Utility Companies Comparable to Southwest Gas Corporation (1)	Adj. Beta	Unadj. Beta	Standard Error of the Regression	5-Year Projected Rate of Return on Net Worth, Equity or Partners' Capital (2) Percent (5)	Student's T-Test
Air Products & Chem.	0.95	0.86	2.1299	23.00 %	1.95
Allstate Corp.	0.90	0.78	2.0690	15.00	0.18
BOK Financial	0.90	0.82	2.1199	12.00	(0.49)
Bemis Co.	0.90	0.84	2.0646	11.00	(0.71)
Chevron Corp.	0.90	0.82	2.0979	20.50	1.40
City National Corp.	0.80	0.67	2.2257	12.50	(0.38)
Compass Bancshares	0.95	0.86	1.9176	NA	--
Danaher Corp.	0.95	0.86	2.2117	13.50	(0.16)
Ecolab Inc.	0.80	0.68	2.1285	22.00	1.73
Exxon Mobil Corp.	0.90	0.80	2.0725	23.50	2.06
First Horizon National	0.95	0.88	2.2203	11.50	(0.60)
Gannett Co.	0.85	0.70	2.0446	12.50	(0.38)
Mercury General	0.90	0.78	2.1867	13.50	(0.16)
Old Nat'l Bancorp	0.80	0.65	2.0447	12.50	(0.38)
Protective Life	0.95	0.85	2.2237	11.00	(0.71)
Reinsurance Group	0.90	0.82	2.0891	11.50	(0.60)
Scripps (E.W.) 'A'	0.80	0.69	2.1521	12.50	(0.38)
Sigma-Aldrich	0.90	0.77	2.2097	20.00	1.29
Tootsie Roll Ind.	0.75	0.62	2.1315	9.00	(1.15)
Transatlantic Hldgs.	0.80	0.64	2.1720	10.00	(0.93)
Valspar Corp	0.85	0.76	2.1707	12.00	(0.49)
Washington Federal	0.90	0.81	1.9170	14.50	0.07
Webster Fin'l	0.90	0.81	2.0271	9.00	(1.15)
Average for the Non-Utility Group	0.88	0.77	2.1142		
Southwest Gas Corporation	0.85	0.75 (3)	2.0519 (4)		
Mean (5)				14.20 %	
Conclusion (6)				12.37 %	

NA = Not Available

See sheets 30 and 31 for notes.

Southwest Gas Corporation
Comparable Earnings Analysis
for a Proxy Group of Thirty-Four Non-Utility Companies Comparable to
the Proxy Group of Eight Value Line Gas Distribution Companies (7)

Proxy Group of Thirty-Four Non-Utility Companies Comparable to the Proxy Group of Eight Value Line Gas Distribution Companies (7)	Adj. Beta	Unadj. Beta	Standard Error of the Regression	5-Year Projected Rate of Return on Net Worth, Equity or Partners' Capital (2) Percent	Student's T-Test
3M Company	0.80	0.67	2.2583	27.00 % (10)	2.09
Air Products & Chem.	0.95	0.86	2.1299	23.00	1.39
Allstate Corp.	0.90	0.78	2.0690	15.00	(0.01)
AptarGroup	0.95	0.90	2.3049	13.50	(0.27)
BOK Financial	0.90	0.82	2.1199	12.00	(0.53)
Bemis Co.	0.90	0.84	2.0846	11.00	(0.70)
Buckeye Partners L.P.	0.80	0.66	2.2861	18.00	0.52
Chevron Corp.	0.90	0.82	2.0979	20.50	0.95
City National Corp.	0.80	0.67	2.2257	12.50	(0.44)
Danaher Corp.	0.95	0.86	2.2117	13.50	(0.27)
Du Pont	0.95	0.90	2.1124	26.50 (10)	2.00
Ecolab Inc.	0.80	0.68	2.1285	22.00	1.21
Exxon Mobil Corp.	0.90	0.80	2.0725	23.50	1.48
Fifth Third Bancorp	0.90	0.81	2.2783	15.50	0.08
First Horizon National	0.95	0.88	2.2203	11.50	(0.61)
Gannett Co.	0.85	0.70	2.0446	12.50	(0.44)
Hudson City Bancorp	0.95	0.86	2.2946	11.00	(0.70)
Lee Enterprises	0.80	0.68	2.2978	5.50	(1.66)
Markel Corp.	0.80	0.66	2.2668	10.00	(0.88)
Mercury General	0.90	0.78	2.1867	13.50	(0.27)
New York Times	0.90	0.83	2.3134	23.00	1.39
Old Nat'l Bancorp	0.80	0.65	2.0447	12.50	(0.44)
Plum Creek Timber	0.95	0.86	2.2579	21.50	1.13
Praxair Inc.	0.95	0.89	1.9889	18.00	0.52
Protective Life	0.95	0.85	2.2237	11.00	(0.70)
Reinsurance Group	0.90	0.82	2.0891	11.50	(0.61)
SAFECO Corp.	0.85	0.71	2.2767	10.50	(0.79)
Scripps (E.W.) 'A'	0.80	0.69	2.1521	12.50	(0.44)
Sigma-Aldrich	0.90	0.77	2.2097	20.00	0.87
Sonoco Products	0.95	0.91	2.1003	16.50	0.26
UDR Inc.	0.85	0.77	2.2800	3.00 (10)	(2.10)
Union Pacific	0.90	0.82	2.2342	12.50	(0.44)
Valspar Corp.	0.85	0.76	2.1707	12.00	(0.53)
Webster Fin'l	0.90	0.81	2.0271	9.00	(1.05)
Average for the Non-Utility Group	0.89	0.79	2.1776		
Average for the Proxy Group of Eight Value Line Gas Distribution Companies	0.88	0.78 (8)	2.1404 (9)		
Mean (10)				14.66 %	
Conclusion (5)				13.02 %	

See sheets 30 and 31 for notes.

Southwest Gas Corporation
Comparable Earnings Analysis

Notes:

(1) The criteria for selection of the proxy group of twenty-three non-utility companies was that the non-utility companies be domestic and have a meaningful projected 2010 – 2012 rate of return on net worth or partners' capital as reported in Value Line Investment Survey (Standard Edition). The proxy group of twenty-three non-utility companies was selected based upon Southwest Gas Corporation's unadjusted beta range of 0.62 – 0.88 and standard error of the regression range of 1.8715 – 2.2323. These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression as detailed in Mr. Hanley's accompanying direct testimony. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and standard errors of the regression.

(2) 2010-2012.

(3) The standard deviation of Southwest Gas Corporation's unadjusted beta is 0.0644.

(4) The standard deviation of Southwest Gas Corporation's standard error of the regression is 0.0902. The standard deviation of the standard error of the regression is calculated as follows:

Standard Deviation of the Standard Error of the Regression =

$$\frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

Where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

Thus, $0.0902 = \frac{2.0519}{\sqrt{518}} = \frac{2.0519}{22.7596}$

(5) None of the projected returns exceed 2.080 at the 95% level of confidence with twenty-one (21 = 22 observations (Excluding Compass Bancshares) –1) degrees of freedom. Therefore, none have been excluded, as outliers, to arrive at a proper mean projected return as fully explained in Mr. Hanley's direct testimony. Please note that at the time of preparation of this update, Compass Bancshares was not included in Value Line Investment Survey (Standard Edition), and therefore has been excluded from the Student's T-statistic.

(6) Average of 5-year projected rates of return excluding those 20% and above as well as those below 9.50% for reasons fully explained in Mr. Hanley's direct testimony

(7) The criteria for selection of the proxy group of thirty-four non-utility companies was that the non-utility companies be domestic and have a meaningful projected 2010 – 2012 rate of return on net worth or partners' capital as reported in Value Line

Southwest Gas Corporation
Comparable Earnings Analysis

Investment Survey (Standard Edition). The proxy group of thirty-four non-utility companies was selected based upon the proxy group of eight Value Line gas distribution companies' unadjusted beta range of 0.65 – 0.91 and standard error of the regression range of 1.9524 – 2.3284. These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression as detailed in Mr. Hanley's accompanying direct testimony. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and standard errors of the regression.

(8) The standard deviation of the proxy group of eight Value Line gas distribution companies' unadjusted beta is 0.0672.

(9) The standard deviation of the proxy group of eight Value Line gas distribution companies' standard error of the regression is 0.0940 = (2.1404 / 22.7596).

(10) The Student's T-statistic associated with this projected return exceeds 1.960 at the 95% level of confidence. Therefore, it has been excluded, as an outlier, to arrive at a proper mean projected return as fully explained in Mr. Hanley's direct testimony.

Source of Information: Value Line, Inc., Proprietary database, June 15, 2007
Value Line Investment Survey (Standard Edition)

Southwest Gas Corporation
Authorized Returns on Common Equity and Common Equity Ratios
for Gas Distribution Companies and the Gas Operations of Combination Electric & Gas Companies
for the Twelve Months Ended March 31, 2008

Company	1 Date	2 Jurisdiction	3 Type	4 Authorized Return on Common Equity	5 Authorized Common Equity Ratio	6 Moody's A Rated Public Utility Bond Yields (10)	7 Spread between Authorized Return on Common Equity and Moody's A Rated Public Utility Bond Yields (11)
Cascade Natural Gas Corporation (A Sub of MDU Resources)	06/05/07	OR	Gas	10.10 % (2)	45 00 %	5.97 %	4.13 %
Northern States Power (A Sub of Xcel Energy)	06/13/07	ND	Gas	10.75 (2, 3)	51.59	5.99	4 76
Yankee Gas Services (A Sub of Northeast Utilities)	06/29/07	CT	Gas	10 10 (2)	50 30	5.99	4 11
Public Service Company of New Mexico (A Sub of PNM Resources)	06/29/07	NM	Gas	9.53	51 80	5.99	3 54
Public Service Company of Colorado (A Sub of Xcel Energy)	07/03/07	CO	Gas	10 25 (2)	60 17	5.99	4 26
Arkansas Western Gas Co. (A Sub of Southwestern Energy)	07/13/07	AR	Gas	9 50 (2)	34 29 (4)	6.30	3 20
Aquila Networks (Gas Division)	07/24/07	NE	Gas	10 40 (3)	50 73	6 30	4 10
Southern Indiana Gas & Electric Co. (A Sub of Vectren Corp)	08/01/07	IN	Gas	10 15 (2)	47.05 (4)	6.30	3 85
Columbia Gas of Kentucky (A Sub of NiSource Inc.)	08/29/07	KY	Gas	10.50 (2)	-- (5)	6 25	4 25
Northern States Power-Minnesota (A Sub of Xcel Energy)	09/10/07	MN	Gas	9.71 (3)	51.98	6 24	3 47
Washington Gas Light Company	09/19/07	VA	Gas	10 00 (2, 3)	-- (5)	6 24	3.76
Consolidated Edison Company of New York	09/25/07	NY	Gas	9.70 (2, 6)	48 00	6.24	3 46
Atmos Energy Corporation	10/08/07	TN	Gas	10.48 (2)	44 20	6 24	4 24
Delta Natural Gas Company	10/19/07	KY	Gas	10.00 (2)	-- (5)	6 18	3.82
CenterPoint Energy Resources (Gas Division)	10/25/07	AR	Gas	9 65 (2)	33 73 (4)	6.18	3 47
Washington Gas Light Company	11/15/07	MD	Gas	10 00	53 02	6.11	3 89
Arkansas Oklahoma Gas	11/20/07	AR	Gas	9 90 (2)	41 46 (4)	6.11	3 79
UNS Gas (A Sub of UniSource Energy Corp.)	11/27/07	AZ	Gas	10 00	50.00	6 11	3 89
Cheyenne Light, Fuel & Power Co (A Sub of Black Hills Corp.)	11/29/07	WY	Gas/Electric (1)	10 90 (2)	54.00 (7)	6 11	4 79
Madison Gas & Electric Company (A Sub of MG&E Energy)	12/14/07	WI	Gas/Electric (1)	10.80	57.36	5 97	4 83
NorthWestern Corporation (Gas Division)	12/18/07	NE	Gas	10 40 (2)	-- (5)	5 97	4 43
Avista Utilities (A Sub of Avista Corporation)	12/19/07	WA	Gas/Electric (1)	10.20 (2)	46 00	5 97	4 23
Brooklyn Union Gas Company (A Sub of National Grid)	12/21/07	NY	Gas	9.80	-- (8)	5 97	3 83
KeySpan Gas East Corporation (A Sub of National Grid)	12/21/07	NY	Gas	9 80	-- (8)	5 97	3 83
National Fuel Gas Distribution Corporation	12/21/07	NY	Gas	9 10 (9)	44.35	5 97	3 13
Pacific Gas & Electric Company (A Sub of PG&E Corp.)	12/21/07	CA	Gas/Electric (1)	11.35	52.00	5 97	5 38
San Diego Gas & Electric Company (A Sub of Sempra Energy)	12/21/07	CA	Gas/Electric (1)	11.10	49 00	5 97	5.13
Northern States Power-Wisconsin (A Sub of Excel Energy)	01/08/08	WI	Gas/Electric (1)	10.75	52 51	5 97	4 78
Wisconsin Electric Power (A Sub of Wisconsin Energy Corp)	01/17/08	WI	Gas/Electric (1)	10 75	54.36	6.16	4.59
Wisconsin Gas (A Sub of Wisconsin Energy Corp.)	01/17/08	WI	Gas	10 75	46 64	6 16	4.59
North Shore Gas (A sub of Integrys Energy Group)	02/05/08	IL	Gas	9.99	56 00	6.16	3.83
Peoples Gas Light & Coke (A sub of Integrys Energy Group)	02/05/08	IL	Gas	10 19	56 00	6 16	4 03
Indiana Gas (A Sub of Vectren Corporation)	02/13/08	IN	Gas	10.20 (2)	48.99 (4)	6.02	4.18
Average				10.21 %	49.28 %	6.10 %	4.11 %
Average of Litigated Cases				10.33 %	52.42 %	6.08 %	4.25 %

Prospective Yield on A Rated Public Utility Bonds (12)	6 26 %
Average Spread between Authorized Returns on Common Equity and Moody's A Rated Public Utility Bond Yields in Litigated Cases	4.25
Indicated Common Equity Cost Rate on Moody's Debt Rated A2	10 51 %
Spread between Moody's A2 and Bottom of Investment Grade Baa3 (13)	0.75
Indicated Common Equity Cost Rate Applicable to Southwest Gas Corporation with Moody's Debt Rated Baa3	11.26 %

Notes:
(1) Order issued by appropriate Public Service Commission applies to the gas and electric divisions
(2) Order followed stipulation or settlement by the parties Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body
(3) Interim rates implemented prior to issuance of final order (normally under bond and subject to refund)
(4) Capital structure includes cost-free items or tax credit balances at the overall rate of return
(5) Common equity ratio was not specified in settlement.
(6) Rate change implemented in multiple steps
(7) Hypothetical.
(8) The decisions for Brooklyn Union Gas Company and KeySpan Gas East Corporation were not settlements, but the common equity ratios were not specified
(9) As shown on sheets 3 through 7 of this Exhibit, on January 17, 2008, National Fuel Gas Distribution Corporation (NFGDC) was authorized a ROE of 9 10%, which Mr Hanley has excluded from the average of litigated cases and as the lowest ROE awarded for the 12-month period ended March 31, 2008 as fully explained in Mr Hanley's accompanying rebuttal testimony because Regulatory Research Associates noted that it is the lowest awarded ROE to an energy utility nationwide in at least 30 years Consequently, he has assumed the 9.50% ROE authorized for Arkansas Western Gas Company on 7/13/07 as the lowest realistic ROE awarded for the 12-month period ended March 31, 2008
(10) From Mergent Bond Record and Moody's Public Utility Manuals, various issues. Actual A rated public utility bond yield represents the yield of the prior month if the order was issued on or after the 10th of the month, or the yield of the second month prior if the order was issued before the 10th of the month For example, the yield for 6/5/07 is the A rated public utility bond yield for April 2007 and the yield for 6/13/07 is the A rated public utility bond yield for May 2007.
(11) Column 6 - Column 4
(12) From Line 3 of Sheet 16 of Exhibit__(FJH-29)
(13) From Note 3 on Sheet 16 of Exhibit__(FJH-29)

Source of Information:
Major Rate Case Decisions - January 2006 - December 2007, Supplemental Study, January 8, 2008, Published by Regulatory Research Associates, Inc , An SNL Energy Company.
Major Rate Case Decisions - January 2008 - March 2008, Special Report, Regulatory Study, April 2, 2008, Published by Regulatory Research Associates. Inc., An SNL Energy Company
Mergent Bond Record Monthly Update, April 2008, Vol 75, No 4

"THE ATTACHED RRA REPORT MAY NOT BE USED
OUTSIDE OF THE CONTEXT OF THIS PROCEEDING"

The attached RRA report "FINAL REPORT, January 17, 2008, STATE: New York, COMPANY: National Fuel Gas Distribution Corporation, ACTION: $1.8 Million Gas Rate Increase Authorized" is being submitted as part of this exhibit with the authorization of Regulatory Research Associates, an SNL Company.

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Regulatory Research Associates An SNL Energy Company

REGULATORY FOCUS

FINAL REPORT January 17, 2008

STATE: NEW YORK
COMPANY: National Fuel Gas Distribution
ACTION: $1.8 Million Gas Rate Increase Authorized[1]

CASE HISTORY

		Millions
1/29/07	Gas Base Rate Increase Requested	$52.0
6/7/07	Rate Reduction Recommended by PSC Staff	(27.4)
9/28/07	Rate Increase Recommended by ALJ	2.5
12/12/07	Rate Increase Authorized	1.8[1]
12/21/07	Final Order Issued	1.8[1]
12/28/07	New Rates Become Effective	1.8[1]

	PRESENT CASE		
	Supported by Company	Authorized by Commission	Previous Decision 7/22/05[3]
Annual Revenues (millions)	$52.0	$1.8[1]	$21.0
% of Revenues	6.4%	0.2%	2.8%
Test Year End	12/31/08	12/31/08	7/31/06
Rate Base Value (millions)	$710.9	$698.8	--
Rate Base (Year-End or Average)	Average	Average	Average
Return on Common Equity	11.65%	9.1%	--[3]
Common Equity % of Capital	51.09%[2]	44.35%[2]	--
Return on Rate Base	9.03%	7.61%	--

1 Additional increase of $10.8 million to be collected through a surcharge. Also, a $4.1 million tax-related credit will be implemented.
2 Equity component of a hypothetical capital structure.
3 Order followed the adoption of a settlement that included an earnings sharing plan for earnings in excess of an 11.5% ROE. The most recent previous fully litigated rate case for National Fuel Gas Distribution in New York was decided in 1995, when the Commission adopted a 10.4% equity return (54.7% of capital) and a 9.1% overall return on a $574 million rate base.

RRA EVALUATION

This New York Public Service Commission (PSC) decision for National Fuel Gas Distribution (NFGD), a subsidiary of National Fuel Gas Corporation, is negative from an investor viewpoint. The PSC authorized a return on equity (ROE) that is well below the average of returns authorized energy utilities nationwide during the past 12 months. We note that the authorized ROE is equal to that authorized for Consolidated Edison subsidiary Orange & Rockland Utilities' (ORU's) electric operations in October 2007, following an earnings investigation. At that time, we indicated that to our *knowledge the 9.1% ROE was the lowest equity return authorized an energy utility nationwide in at least the last 30 years. We also noted that in cases without rate settlements, the New York PSC, historically, has authorized ROEs that were well below prevailing nationwide averages. For many years, it was a rarity for a proceeding before the PSC to be fully litigated; however, the last two major rate proceedings in New York (ORU electric and the instant case) were fully litigated, and it appears that the soon-to-be-decided electric case for Consolidated Edison of New York will be fully litigated as well. With respect to the instant case, the PSC adopted a hypothetical capital structure that contained an equity ratio that was well below that supported by the company. While the PSC adopted numerous rate base and net operating income adjustments, these should not significantly impact NFGD's opportunity to earn the authorized ROE during the first year of new rates. We continue to accord New York regulation an <u>Average/3</u> rating.*

<u>Rate Case Summary</u>

This case was initiated on Jan. 29, 2007, when NFGD filed for a $52 million rate increase based upon an 11.65% ROE. The request reflected increased operating expenses, an increase in the allowed rate of return, rate base additions, and an increase in taxes. NFGD proposed to establish a Conservation Incentive Mechanism (CIM), essentially a decoupling mechanism that would allow the company to implement a surcharge through which it would be able to recover lost margin associated with conservation savings generated during the 2008 test year.

On June 7, 2007, the PSC Staff filed testimony recommending that the PSC order NFGD to reduce rates by $27.4 million. The Staff's position was premised upon an 8.75% return on common equity (44.35% of a hypothetical capital structure) and a 7.43% return on an average rate base valued at $691.6 million for a calendar-2008 test year. On Sept. 28, 2007, the Administrative Law Judge (ALJ) recommended that NFGD be authorized a $2.5 million rate increase based upon a 9.4% return on equity (47.25% of a hypothetical capital structure) and a 7.8% return on a rate base valued at $702.6 million. The ALJ recommended that the company-proposed CIM be rejected – the Judge indicated that NFGD should provide the parties "readily verifiable calculations of the changes that occur in the amount of natural gas use per customer."

On Dec. 12, 2007, the PSC authorized NFGD a $1.8 million increase based upon a 9.1% ROE. A final order was issued Dec. 21, 2007, and the rate hike became effective Dec. 28, 2007. We note that the PSC permitted the company to establish a CIM, which will result in implementation of an incremental $10.8 million surcharge. Additionally, the PSC approved the implementation of a revenue decoupling mechanism through which NFGD is to collect from small volume customer classes its allowed margin on average weather normalized usage per customer. Additionally, customer rates will be impacted by a $4.1 million rate credit related to the company's over-collection of state income taxes.

We also note that the PSC adopted a Staff-proposed adjustment to reallocate proceeds from a 1999 insurance settlement received by parent National Fuel Gas Corporation related to manufactured gas sites. These proceeds were distributed to the subsidiary companies. The Staff believed that NFGD should have received a greater portion of the proceeds. The ALJ concurred with the allocation used by the company; however, the PSC accepted the view of the Staff, and found that proper allocation of the insurance proceeds should have been made in proportion to the companies' respective exposure to liabilities. As such, the PSC determined that the 46% allocation of the insurance proceeds to NFGD was "unjust and unreasonable at the time it was made and that the proper allocation in 1999 should have been 64% of the total proceeds to [NFGD]." As a result, the company has indicated that it will be required to take a write-off of about $6 million ($3.7 million net-of-tax).

The table below outlines the reasons for the $50 million difference between the $52 million rate increase requested by NFGD and the $1.8 million increase authorized by the PSC.

RATE CASE DISALLOWANCES (Approximate)

Disallowances Related To:		(Millions)
Rate of Return		$17
Rate Base	(Millions)	2
Pension Reserve	$6	
Working Capital	(4)	
Miscellaneous Rate Base (net)	-0-	
Net Operating Income		31
Gas Sales	(11)	
Late Payment Charge	(4)	
Uncollectibles	16	
Conservation Incentive Program	12	
Labor & Benefits	5	
Depreciation	9	
Miscellaneous NOI (net)	4	
Total Disallowed		$50

Rate of Return

NFGD sought an 11.65% ROE; the Staff proposed an 8.75% ROE; and, the ALJ recommended a 9.4% equity return. To determine the return on equity in this proceeding, each of the parties used a comparable earnings approach. The company proposed two natural gas company proxy groups, with one containing six companies and the other seven. The Staff proposed a 13-company proxy group composed of gas and electric transmission and distribution companies for which regulated revenue accounted for at least 86% of the total. The ALJ utilized a proxy group composed of the Staff's group and NFGD's seven-company group. The company and the Staff supported the PSC's long-standing practice of determining the authorized ROE via a discounted cash flow (DCF) approach and the Capital Asset Pricing Model, with two-thirds weight to the DCF and one-third to the CAPM. The ALJ recommended that an equal weighting be applied.

The PSC used the Staff's proxy group, and indicated that "the parties' controversy over the composition of the proxy group does not appear to have influenced the indicated results." With respect to the ROE methodology, the PSC also sided with the Staff and used its two-thirds DCF, one-third CAPM methodology to determine the equity return in this proceeding. The PSC indicated that this approach resulted in a 9.2% ROE, and factoring in a 10-basis-point reduction to account for the Commission's adoption of a revenue decoupling mechanism (the CIM), resulted in a 9.1% authorized ROE. As noted earlier in this report, we believe that this return is the lowest adopted in any state in more than 30 years.

With respect to capital structure, the PSC generally develops a subsidiary's capitalization by first looking at the parent's capital structure, and then removing capital associated with competitive operations. However, the Commission noted that neither NFGD nor the Staff employed this approach; both parties proposed a hypothetical capital structure. NFGD supported a capital structure for an A-rated firm with a Standard & Poor's business profile of "4." (S&P uses a 1-10 business profile scale with 10 indicating substantial risk.) The Staff used a bond rating of BBB+/A- and business profile of "3" to develop its recommended capitalization. The ALJ also assumed a bond rating of BBB+/A, but used a business profile of "4."

The PSC stated that NFGD's bond-rating target was not reasonable, and stated that by having ratepayers support a bond rating that was higher than the overall corporate rating, "there is the potential for ratepayers to provide a disproportionately higher amount of financial support for [the parent company's] financial standing than its other operations." The PSC indicated that the lower-risk companies should be authorized a lower equity ratio, and concluded that the Staff's 44.35% equity ratio was more compelling than NFGD's 51.09%, as the profile ranking of "3" was already at the high end of the risk range for distribution companies. The 9.1% authorized ROE, in combination with the adopted capital structure, resulted in a 7.61% overall return. The PSC's adoption of a lower overall return than that requested by NFGD reduced the company-proposed revenue requirement by about $17 million. The hypothetical capital structure and corresponding cost rates approved by the Commission are detailed in the table below.

Type of Capital	Percent of Capitalization	Cost Rate
Long-Term Debt	45.54%	6.57%
Preferred Stock	9.32	5.98
Customer Deposits	0.79	3.76
Common Equity	44.35	9.10
	100.00%	7.61%

Rate Base

The PSC's adjustments to rate base reduced the proposed revenue requirement by roughly $2 million. The Commission adopted a Staff-proposed, ALJ-supported, adjustment to remove about $35 million from the proposed rate base that represented NFGD's pension reserve -- pension amounts placed in an external reserve by the company that exceeded the amount included in rates. This adjustment reduced the revenue requirement by roughly $6 million. However, the PSC concluded that NFGD should be permitted to accrue a non-cash return on the internal debit balance at a rate equal to the actuarial-assumed long-run return on pension plan assets. Additionally, the Commission stated that this balance should be reduced by any portion of the balance that causes the plan assets to be in excess of the benefit obligation. The PSC updated NFGD's working capital balance, which increased the revenue requirement by approximately $4 million. Other miscellaneous adjustments were revenue-neutral on a net basis.

Net Operating Income

The Commission adopted adjustments to net operating income (NOI) that, in aggregate, reduced the revenue requirement by about $31 million. Updates to test period gas sales revenues increased the revenue requirement by about $11 million. The elimination of late payment charges for customers who are on a deferred payment plan, for accounts that are in arrears, increased the revenue requirement by roughly $4 million. Adjustments to uncollectibles expense accounted for $16 million of the revenue requirement shortfall in the case, with about $4 million of this adjustment stemming from the above-mentioned elimination of late payment charges for customers on the deferred payment plan. An additional $9 million of this adjustment is associated with the adoption of the Staff's proposal that this amount is related to commodity costs, and as such, should be recovered through the commodity charge. The remaining $3 million of this adjustment stems from the correction of an error in NFGD's uncollectibles calculation.

About $12 million of difference stemmed from the adoption of a recommendation to remove the costs associated with the new Conservation Incentive Program, and allow NFGD to recover such costs through a separate surcharge. Additionally, the PSC reduced the recoverable CIP costs by $1.2 million (limiting the recoverable amount to 1.23% of operating revenues). As a result, the initial CIM charge was set at $10.8 million.

Adjustments to labor and benefits expense reduced the revenue requirement by about $5 million. A portion of this adjustment flows from the PSC's application of a general escalation factor (that is applicable to other company expenses) to health care expense, rather than a health care-specific higher escalation factor. Additionally, the Commission adopted a variety of other adjustments to reduce the recoverable labor expense. Depreciation expense adjustments accounted for roughly $9 million of the revenue requirement shortfall. The Commission accepted the Staff-proposed adjustments related to average service lives and net salvage values, and rejected the company-proposed remaining life methodology in favor of the more commonly used whole-life calculation. Miscellaneous adjustments accounted for the remaining $4 million of shortfall related to NOI differences.

Case No. 07-G-0141
Robert Schain

Tab

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IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY

OF

WILLIAM N. MOODY

ON BEHALF OF

SOUTHWEST GAS CORPORATION

May 9, 2008

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of
Prepared Rebuttal Testimony
of
WILLIAM N. MODY

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
WILLIAM N. MOODY

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is William N. Moody. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 By whom are you employed and in what capacity?

A. 2 I am employed by Southwest Gas Corporation (Southwest or Company) as the Vice President / Gas Resources.

Q. 3 Did you provide direct testimony in this proceeding on behalf of Southwest?

A. 3 No.

Q. 4 Please state your educational background and business experience.

A. 4 A summary of my educational background and business experience is attached hereto as Appendix A.

Q. 5 Have you previously testified before any regulatory commissions?

A. 5 Yes. I have testified before the Arizona Corporation Commission (Commission or ACC) and the Public Utilities Commission of Nevada (PUCN).

Q. 6 What is the purpose of your prefiled rebuttal testimony?

A. 6 The purpose of my prefiled rebuttal testimony is to respond to specific aspects of the direct testimony of Stephen L. Thumb and Rita R. Beale, witnesses for the Arizona Corporation Commission's Utilities Division Staff (Staff), pertaining to natural gas procurement.

Q. 7 Please summarize your rebuttal testimony.

A. 7 My rebuttal testimony will address the 15 recommendations made in the below-mentioned testimony of Staff. They include:

(1) Southwest should continue seeking access to storage capacity, particularly market-area storage capacity.

(2) Southwest should increase the documentation requirements for its transportation-only (T-1) customers.

(3) Southwest should make its Daily Forecasting Accuracy Improvement Task Force a permanent entity. Southwest's policies should also require ongoing validation and back-testing of its daily load forecast, along with its required frequency.

(4) Until the point that market-area storage becomes a reality in Arizona, it is recommended that the ACC develop and implement policies that would promote the sharing of gas supplies among the major users of interstate pipeline capacity in Arizona during extreme conditions, including gas LDCs and electric utilities.

(5) While Southwest has taken efforts to diversify its future pipeline capacity portfolio, it is recommended that Southwest carefully track the likelihood of liquefied natural gas (LNG) imports entering the Company's gas

market and consider gaining access to such supplies, in an effort to diversify its gas supplies and reduce its dependence on the San Juan basin.

(6) Consolidate all strategies, policies, and procedures into a minimal number of documents with sufficient detail such that new employees could read and immediately perform the bulk of their work.

(7) Clarify the Arizona Price Stability Program (APSP) supply element by documenting required timing and volumes for the next one to two years forward. If there is uncertainty, then windows of time and ranges of volume or duration can be established instead.

(8) Clarify the precise nature of the APSP strategy. The precise strategy should be recognized and declared in Company policies and procedures to guide employees and decision makers, as well as the ACC's oversight.

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

(10) Company policies regarding the 'unbuying' of gas, as well as the reasons for the policies, should be reevaluated, and then explicitly documented in official Company policies and procedures.

(11) Ensure all confirmations with gas suppliers include deal transaction dates.

(12) Ensure all confirmations with suppliers include dates of

the internal approval next to the signature authorization.

(13) Considerably shorten the time lapse between deal execution and deal confirmation with gas supplier.

(14) Include a list of attendees present during the solicitation and purchase of the APSP fixed price gas supply element (as well as during selection and approval of the index gas supply element) to ensure independence, proper monitoring, and to improve the quality of the audit trail.

(15) Update any old master supply agreements that cap the buyers' liquidated damages at 50 cents per MMBtu into supply agreements that are based on true up to actual market during non-performance.

II. STAFF RECOMMENDATIONS ACCEPTED BY SOUTHWEST

Q. 8 Are there recommendations that witnesses Stephen L. Thumb and Rita R. Beale have made that Southwest can accept and implement without discussion?

A. 8 Yes. If approved by the Commission, Southwest would implement the following recommendations as soon as practicable within 60 days of an order in this case: Recommendations numbered 1, 3, 4, 7, 8, 10, 11, 12, 13, and 14.

III. DOCUMENTATION AND REQUIREMENTS FOR ITS TRANSPORTATION-ONLY (T-1) CUSTOMERS

Q. 9 Do you have comments regarding recommendation number 2, that Southwest should increase the documentation and requirements for its transportation-only (T-1) customers?

A. 9 Yes. First, I would like to scope the documentation that is referred to in this statement. In his prefiled direct testimony on Page 17, Mr. Thumb suggests that Southwest require detailed documentation of both supply contracts and interstate capacity contracts for transportation-only customers.

Q. 10 What is the current process to track transportation customers' capacity rights?

A. 10 Southwest works diligently with the upstream pipeline (El Paso Natural Gas Company or El Paso), the transportation customers, and where applicable, their supplier agents to document and confirm all upstream capacity rights. Southwest's Key Accounts Management (KAM) Department maintains a documented procedure for acquiring and updating this information on a quarterly basis. KAM and Southwest's Planning Department personnel together work closely with El Paso to determine rights that have been secured by and assigned to transportation customers. Southwest's Arizona Gas Tariff clearly establishes that transportation customers are responsible for any upstream charges or penalties occasioned by their actions and Southwest's billing system includes those costs in transportation-only customer bills.

Q. 11 Can you summarize Southwest's position on this issue?

A. 11 Southwest believes its existing practice of quarterly verification of customer interstate capacity contracts is an efficient and effective method of collecting the necessary information to ensure allocations of charges and penalties incurred by Southwest as a point operator are accurate and should not be modified.

IV. ACCESSING LNG SUPPLIES

Q. 12 Please comment on Staff's recommendation number 5, that the Company carefully track the likelihood of LNG imports entering the Southwest market and consider gaining access to such supplies.

A. 12 Southwest has commented in past proceedings on the developing nature of the western LNG market and supplies and agrees it should continue to monitor the progress and likelihood of LNG imports entering Southwest's Arizona gas market. However, at this time, there is continuing uncertainty about the regularity and reliability of supplies that may be available from this source. Issues of price competition with international markets and the timing of production area liquefaction facilities remain, at best, cloudy.

Q. 13 How do you propose that Arizona customers participate in these developing supplies?

A. 13 In the short term, 1 to 3 years, this participation should be indirect. In other words, if and when LNG flows into the western gas market, it will simply increase the available supplies to the market and become indirectly available through displacement or reduced demand on traditional producing basins. As the LNG market matures with pricing and reliability in full view, then the direct acquisition of this supply for diversity should be reviewed and considered.

V. COMPANY POLICIES AND PROCEDURES

Q. 14 What recommendations will you specifically discuss in this section of testimony?

A. 14 I would like to comment on recommendations 6 and 9. Each of these recommendations revolves around documentation of the policies and procedures used when purchasing gas for the customer portfolio.

Q. 15 Please discuss your views of recommendation 6 to consolidate all strategies, policies, and procedures into a minimal number of documents with sufficient detail such that new employees could read and immediately perform the bulk of their work.

A. 15 In Exhibit SLT-2 on Page 3-17, Mr. Thumb notes as curious and implies criticism of the fact that Southwest policies, strategies, and procedures are grouped in the annual documentation filed with the Commission (Annual Gas Procurement Plan), rather than in some other consolidated form. Southwest believes that is a logical and convenient place and format for such documentation. It is easily and readily accessible to Staff and Southwest personnel. The Commission has never found this practice to be deficient.

Q. 16 Do you agree that this form of documentation is sufficient to guide a new employee in their task to develop and execute their portion of the portfolio process each day?

A. 16 No. Although I agree that quality documentation is important for consistency, controls, and ongoing compliance with established policies and procedures, such a goal as stated in the recommendation is unrealistic. The complexity of the work that must be accomplished by both Planning Department and Gas Purchases Department personnel and the institutional knowledge of interstate pipeline and market area matters that must attend this work is such that no new employee should be expected, nor would any new employee be allowed, to attempt to perform the "bulk of their work" from a procedural document.

Q. 17 Recommendation 9 states that Southwest should "Designate the *Arizona Dispatch Guidelines* as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement in company policies and procedures". Please discuss Southwest's position on this issue.

A. 17 Southwest believes that Mr. Thumb has mistakenly viewed a monthly internal worksheet titled "Arizona Dispatch Guidelines", prepared by Planning Department staff, as a document which designates gas buyers' "limits and authorization to execute" in meeting daily demand requirements in accordance with Company policies and procedures. The referenced monthly document does not serve such a purpose and was never designed to do so. It is no more than a listing of firm supply contracts, detailing volumes and prices, allowing Planning Department and Gas Purchase Department personnel to compare and confirm that each of their respective data systems have available contract data correctly entered.

Q. 18 Does a document exist that accomplishes the intent of Mr. Thumb's recommendation?

A. 18 Yes. A more detailed procedural document for Planning Department and Gas Purchasing Department personnel, titled "DEPARTMENT AND STAFF RESPONSIBILITIES-PORTFOLIO SELECTION PROCEDURES" exists today. Among other things, it includes an itemization of many things that a buyer must review and consider in arranging supply for a daily demand. This document has been supplied to the Commission in the past and was also provided in this docket in response to Staff Data Request 4.25. (Attached is Rebuttal Exhibit No.__(WNM-1))

VI. LIQUIDATED DAMAGES IN SUPPLY CONTRACTS

Q. 19 Recommendation 15 calls for Southwest to update any old master supply agreements that cap the buyers' liquidated damages at 50 cents per MMBtu into supply agreements that are based on true-up to actual market during non-performance. Has Southwest completed a review of all Arizona master supply contracts?

A. 19 Yes.

Q. 20 Please discuss the results of this effort.

A. 20 Southwest's "old master supply agreements", other than NAESB standard format contracts, which are solely based upon market/contract differentials, provide for liquidated damages equal to the greater of $0.50 or the market/contract price differential. Southwest finds no contract modifications are necessary to comply with Staff's recommendation.

Q. 21 Does this conclude your prepared rebuttal testimony?

A. 21 Yes, it does.

SUMMARY OF QUALIFICATIONS
WILLIAM N. MOODY

<u>**Experience**</u>
Southwest Gas Corporation **Las Vegas, Nevada**

Vice President/Gas Resources **05/06/04 to present**
Director/Gas Supply **01/27/03 to 05/06/04**

Direct the negotiation and administration of all gas purchase contracts, spot purchase activities, and capacity and transportation agreements. Direct the planning and execution of the annual gas portfolios for each regulatory jurisdiction. Also, direct medium to long term interstate infrastructure planning, gas scheduling activities, gas control functions, gas system support staff for the Company.

Director/Customer Relations/
Southern Nevada Division **11/98 to 01/03**

Directed the Customer Service, Meter Reading, Customer Assistance/Call Center functions for the Las Vegas and Bullhead City Districts.

Director/Corporate Development **09/96 to 11/98**

Responsible for new business development activities. Oversaw preparation of financial feasibility of potential acquisitions or projects; conducted due diligence activities; prepared recommendations for senior management.

Director/Facilities and Resource Development **12/93 to 09/96**

Responsible for conducting operations analysis and benchmarking activities focused on productivity enhancement and measurement. Conducted new subsidiary development and direct business plan preparation.

Manager/Administration/
Central Arizona Division **10/91 to 12/93**

Responsible for management of central support functions for Division Operations including: Warehouse, Transportation/Auto Shop, Division Accounting, Risk Management, Materials Management, and Facilities departments.

Management Development Program **04/91 to 10/91**

Participated in comprehensive training program that required training and short-term participation in every department in the Company.

Director/Planning and Financial Services **05/89 to 04/91**

Directed the annual budget and multi-year planning process for the corporation. Produced long-term earnings and cash forecasts for use with bond rating agencies, appropriate public utilities commissions, and industry financial analysts.

Manager/Administrator/Budget **03/85 to 05/89**

Developed and conducted the corporate annual budget. Developed new corporate Budget Department as an independent function.

Cost Analyst/Rate Department **05/81 to 03/85**

Responsible for collecting, analyzing, and preparing information for all regulatory filings with the Arizona, California, and Nevada public utilities commissions and the Federal Energy Regulatory Commission. This included cost analysis, forecasting, and written testimony. Provided testimony at commission proceedings as an expert witness.

Gas Accountant/Accounting Department **11/80 to 05/81**

Conducted allocations and prepared monthly journal entries to the corporate general ledger for gas cost by rate jurisdiction.

Accountant/Accounting Department **10/79 to 11/80**

Calculated unitized cost of property units for all capital plant.

Education

University of Nevada, Reno **05/1978**

Bachelor of Science degree in Business Administration with a major in Accounting.

DEPARTMENT AND STAFF RESPONSIBILITIES
PORTFOLIO SELECTION PROCEDURES

Solicitation of Firm Term Bids

1. Gas Purchases and Transportation (GPT) will consult with Gas Resources Planning to identify input variables required by the computer model or other analyses to be used in the upcoming portfolio evaluation process.

2. In consideration of Gas Resources Planning modeling and other analytical needs, requisite non-modeled contractual details, and concerns for respondent understandability, GPT will fashion a bid solicitation designed to maximize the quantity, quality, and diversity of proposals received and Southwest's ability to effectively evaluate such proposals.

3. The firm term bid solicitation will request index-based supply pricing.

4. Gas Resources Planning will attempt to evaluate all responsive term proposals received. The primary tool used for evaluating the proposals is a computer-based optimization modeling program. When a proposal cannot be modeled as submitted, it will be evaluated using other available tools. In cases where a proposal is submitted with attributes that cannot be entered into the model a surrogate is used that conforms to the parameters outlined in the bid solicitation guidelines, subject to any model design limitations.

5. GPT will seek supplier clarification on proposals that appear incomplete, unclear, internally inconsistent, or not within the scope of the solicitation. Proposals that cannot be clarified sufficiently for evaluation will be removed from further consideration. Gas Resources Planning and GPT will maintain appropriate documentation as to the reason(s) any proposal is removed from evaluation.

6. Fixed-price proposals for the portfolio will be requested as part of the Nevada Volatility Mitigation Program (VMP) and Arizona Price Stability Program (APSP), apart from this firm term bid solicitation. Similar programs may be conducted for other rate jurisdictions as deemed appropriate by management.

   The VMP and APSP will involve periodic solicitations for various future purchase periods. GPT and Gas Resources Planning will jointly decide the exact dates for issuing the solicitations. The fixed-price solicitation and requested responses will be briefer and narrower in scope than

Southwest's general firm term bid solicitation. The structure of the solicitation will be tailored to minimize evaluation time and acceptance response time for Southwest, and also allow for respondent suppliers to minimize risk, therefore encouraging participation. GPT will create a bid request that is applicable to each specific fixed-price solicitation and distribute the request to suppliers. The bid request will identify market areas, receipt locations and purchase periods, as well as setting forth the bid and response date and time deadlines.

Results from each fixed price bid solicitation will be reviewed jointly by GPT and Gas Resources Planning to confirm that all bids are appropriate to the solicitation and entered into the records correctly. Multiple suppliers will be contacted to provide up to the minute price quotes for final selection of the requested supplies.

Evaluation of Firm Term Supplies

1. Preparation for Evaluation

(a) Evaluation Engineers from Gas Resources Planning will create a new model set-up for the rate jurisdictions that require models. Space will be reserved in the model for existing and future fixed-price contract commitments. The minimum daily quantities will be dependent on each rate jurisdiction's needs. However, the quantity may be revised at anytime during the analysis to reflect changing market conditions and experienced management judgment.

(b) Electronic bid forms will be held in a database as created by an interactive bid program.

(c) Evaluation Engineers review bids for clarity and convert price statements into modeling equation coefficients. All bids that appear incomplete, unclear or internally inconsistent will be returned to GPT for clarification, as noted above. Any proposal that cannot be clarified sufficiently for evaluation will be removed from further consideration.

(d) All bids accepted for consideration will be sorted by rate jurisdiction, term and type to facilitate modeling.

(e) Special cases will receive appropriate treatment.

2. At this point, all offers or surrogates are presented and the iterative selection and negotiation process can begin to identify and secure the best cost portfolio considering price, reliability, and resource mix.

3. Modeling will identify the lowest cost portfolio components from the available bids, based upon portfolio requirements.

   (a) Demand forecasts developed by the Demand Planning department will be used in the modeling with minor exceptions as deemed necessary to meet supply reliability goals.
   (b) Monthly price levels for modeling will be based upon forward market conditions with adjustments necessary for specific location or seasonal decision support.

4. Bids will be authorized for inclusion in the portfolio based upon model results and qualitative consideration with and without negotiated improvement. At such time as a bid is authorized, GPT will contact the supplier to confirm purchase and/or negotiate specific provisions prior to confirming. All firm supply arrangements are authorized with approval of executive management.

5. Supplies already contracted and bids authorized during the evaluation process will be converted to "existing" status as the iterative selection process continues.

Monthly/Daily Spot Purchases

1. Monthly spot gas (typically baseload for one month) purchase requirements for each jurisdiction will be determined by GPT based on economic, contractual, and operational considerations prior to the first of each month. Based on these considerations and the forecasted demand requirements, GPT will determine if monthly baseload spot gas is applicable for the next month. If so, a bid solicitation will be sent to suppliers and results will be reviewed in conjunction with observation of monthly supplies posted as available on the Intercontinental Exchange (ICE) electronic trading platform. Supply selections, if any, may be made from either the bids received or ICE postings with a representative from Gas Resources Planning as an independent observer and participant in the process. Bids received and bids selected (or ICE purchases acquired) will be recorded for each applicable

jurisdiction. This process may be repeated on an as needed basis depending upon shifting economic, contractual, and operational considerations.

2. Daily spot gas purchase requirements for each jurisdiction will be determined by GPT daily, based on economic, contractual, and operational considerations, as set forth below.

Daily Spot Purchase and Nomination Procedures

The following constitutes the general procedure for GPT in acquiring and nominating daily supplies. These steps are followed after the previously detailed firm term supplies, firm fixed-price supplies, and monthly spot purchases have been contracted and are available for nomination.

1. Survey current spot market prices.

2. Review daily system demand forecast, as available, from Central Gas Dispatch.

3. Review pipeline imbalance activity to determine if a deviation from Central Gas Dispatch's daily system demand forecast is necessary or desired to counteract any imbalance trends.

4. Determine if any further deviation from Central Gas Dispatch's daily system demand forecast is necessary to accommodate any requests or demands for action communicated from upstream pipelines or to comply with pipeline balancing tariffs.

5. Review available upstream pipeline capacity availability for the flow day for which volumes are being purchased.

6. Review past nomination activity and results.

   (a) Review most recent pipeline scheduling reports to identify any instances of nonperformance on nominated supplies.

   (b) In cases of nonperformance, identify the cause of the nonperformance.

   (c) Determine if it is necessary or desirable to have the involved supplier re-nominate the shortfall.

   (d) Contact supplier if re-nomination has been deemed desirable.

(e) Contact Central Gas Dispatch scheduler to verbally advise of intent to re-nominate supplies.

(f) Enter re-nominations into internal nomination systems.

(g) Review pipeline reports for results of any prior re-nomination attempts.

(h) If re-nomination efforts were partially unsuccessful, repeat Steps 6(c) through 6(g), as appropriate.

7. Determine estimated daily spot gas requirement in light of the preceding steps.

8. Gather market intelligence by receiving calls from and making calls to prospective suppliers and monitoring electronic messaging, internet trading platform(s), and other industry pricing information to determine daily price parameters available in the marketplace.

9. Monitor market price fluctuations throughout the daily trading period and modify offer acceptance threshold based on these market fluctuations.

10. Review available firm term, firm fixed-price, and monthly spot supplies/prices and determine what, if any, nomination changes from prior day should be made in consideration of opportunities to flex firm term contract volumes up or down based on prevailing spot market prices.

11. Modify daily spot purchase volume target arrived at in Step 7 based on price observations made in Steps 8, 9, and 10.

12. Enter daily nomination information in internal systems and advise respective system Central Gas Dispatch scheduler of its availability.

13. Print daily spot gas confirmation letters, review for accuracy, and sign them.

14. Provide signed daily spot gas confirmation letters to administrator for faxing to respective suppliers.

15. Review any confirmation letters independently sent by supply representatives for accuracy, and follow up with supplier on any perceived errors.

Tab

I

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

PREPARED REBUTTAL TESTIMONY
OF
FRANK J. MAGLIETTI, JR.

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
FRANK J. MAGLIETTI, JR.

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
Frank J. Maglietti, Jr.

Q. 1 Are you the same Frank J. Maglietti, Jr. who submitted prepared direct testimony in this Docket before the Arizona Corporation Commission (the Commission) on behalf of Southwest Gas Corporation (Southwest)?

A. 1 Yes, I am.

Q. 2 What is the purpose of your rebuttal testimony?

A. 2 The purpose of my rebuttal testimony is to respond to the direct testimony presented by Commission Staff witness Mr. Robert G. Gray concerning the increase of the purchased gas adjustment mechanism (PGA) bandwidth.

Q. 3 Please summarize your rebuttal testimony.

A. 3 My rebuttal testimony will discuss why Southwest's proposed bandwidth is better for customers and superior to unnecessarily prolonging gas cost credit or debit balances into future periods.

Q. 4 Have you reviewed Mr. Gray's direct testimony concerning Southwest's proposal to increase the PGA mechanism to 24-cents per therm?

A. 4 Yes. Mr. Gray agrees that the natural gas market has seen increased volatility, and that Southwest is justified to request that the Commission increase the bandwidth. However, he notes that the bandwidth Southwest is requesting would provide Southwest with the ability to increase rates $0.24 per therm (over a 12 month period) without a formal Commission review or approval, and instead suggests Southwest employ the implementation of a gas cost surcharge to adjust rates in times of increasing or decreasing gas costs to protect customers.

Q. 5 How would customers benefit if the gas cost rate more closely followed the historical 12 month rolling average cost?

A. 5 An advantage of allowing the tariff gas cost rate to more closely track the twelve month rolling average gas cost is the minimization of the need for and the length of time that gas cost balances are either recovered from, or returned to, customers. Rebuttal Exhibit No.__(FJM-1) illustrates the affect on customers of not allowing the gas cost rates to more closely reflect the market price of gas. The graph is a representation of the actual deferral balances Southwest booked from December 2005 through March 2008 compared to the balances that would have occurred if the gas cost rate had not been limited by the bandwidth. As illustrated by the graph, Southwest will remove the current $0.11 gas cost surcharge on June 1 of this year. However, if the proposed $0.24 bandwidth would have been in place over the same time period, Southwest would have removed the surcharge in October

2007 - eight months earlier. The removal of the surcharge before the winter months would have provided customers reduced rates just before the high use winter season.

Q. 6 Why is Mr. Gray's proposal that Southwest file for a surcharge or surcredit to clear the bank balance if the natural gas market prices are changing faster than the mechanism is allowing the tariff gas cost to adjust inferior to Southwest's proposal to expand the bandwidth?

A. 6 Increasing the bandwidth of the PGA would allow continued price gradualism while sending a more correct price signal to customers since the tariff gas cost would be more reflective of the market price of gas. As illustrated in Rebuttal Exhibit No.__(FJM-1), limiting the gas cost rate may have provided customers with a lower rate initially, however the trade-off is higher rates for an extended period of time. The more correct price signal will lead to a more efficient use of resources. This may, in turn, have a positive effect on conservation.

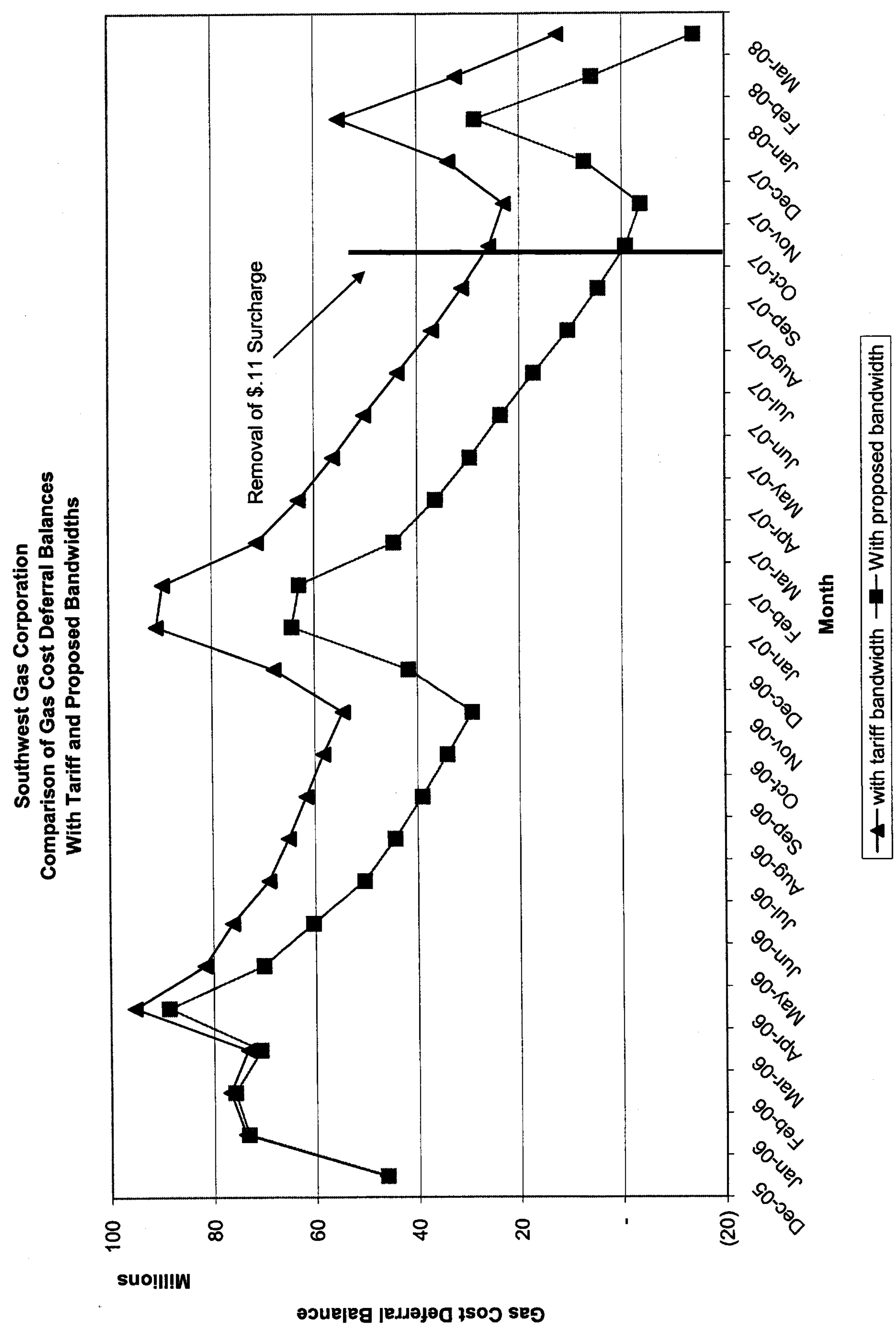
Q. 7 Mr. Gray proposes the bank balance threshold for over-collections be increased to $55.78 million and that the bank balance threshold for under-collections be eliminated. Does Southwest oppose these changes?

A. 7 No. Southwest does not oppose making Mr. Gray's proposed changes to the bank balance thresholds.

Q. 8 Does this conclude your prepared rebuttal testimony?

A. 8 Yes, it does.

Rebuttal Exhibit No.__(FJM-1)
Sheet 1 of 1



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J

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY

OF

JAMES L. CATTANACH

ON BEHALF OF

SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
JAMES L. CATTANACH

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
James L. Cattanach

Q. 1 Please state your name and business address.

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

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

A. 2 Yes, I am.

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

A. 3 The purpose of my prepared rebuttal testimony is to reply to the direct testimonies presented by Residential Utility Consumer Office (RUCO) witness Mr. William A. Rigsby and Arizona Corporation Commission Utilities Division Staff (Staff) witness Mr. Frank Radigan regarding their statements related to declining residential consumption per customer.

Q. 4 Did you prepare exhibits to support your rebuttal?

A. 4 Yes. I prepared the exhibits identified as Rebuttal Exhibit No.___(JLC-1) through Rebuttal Exhibit No.__(JLC-3).

Q. 5 Please summarize your rebuttal testimony.

A. 5 I will reply to the statement made by RUCO witness Mr.

Rigsby that "This data indicates that there is a limit to the amount customers can conserve and that this phenomenon is abating" (William A. Rigsby, Direct Testimony, Page 6, Lines 20 - 22, April 11, 2008). I will also rebut the statement made by Staff witness Mr. Frank Radigan that "With relatively low per-customer total usage, the losses from conservation will also likely be small" (Frank Radigan, Direct Testimony, Page 11, Lines 15 - 16, March 28, 2008). I will provide quantitative evidence that residential consumption per customer continues to decline at a significant rate and has had a significant impact on the annualized volumes in the test year.

Q. 6 Do you agree with Mr. Rigsby's testimony that the phenomenon related to declining residential consumption per customer is abating?

A. 6 No, I do not. The most recent data suggests that declines in residential consumption per customer have not abated and have actually accelerated.

Q. 7 What is the most recent trend in residential consumption per customer?

A. 7 Since the test year in the current rate case, weather normalized residential consumption per customer has declined from 332 to 319 therms per customer. This is a decline of 13 therms or 3.9 percent over the last 11 months. The attached Rebuttal Exhibit No.___(JLC-1) presents a time series plot that depicts 12-month moving totals of weather normalized consumption per customer for the period January 1995 through March 2008. The graph illustrates both the long-term decline in consumption per customer and the recent acceleration in declines that commenced in January 2007.

Q. 8 Do you agree with Mr. Radigan's statement that "With relatively low per-customer total usage, the losses from conservation will also likely be small."

A. 8 No, I do not. Since the 2004 rate case, residential consumption per customer has declined from 347 therms to 332 therms (current rate case) to 319 therms (March 2008). In my opinion, these declines of 15 therms and 13 therms, respectively, are not small. In fact, I would not consider declines of 3 therms per customer to be insignificant. With a relatively low residential consumption per customer in Arizona, any decline in residential consumption that is experienced by the Company from its current levels is deemed to be significant.

Q. 9 Have you performed any other analysis that quantifies the impact of continuing declines in residential consumption per customer since the end of the test year?

A. 9 Yes, I updated the test year weather normalized residential consumption per customer for the months of May 2006 through March 2007 with weather normalized consumption per customer for May 2007 through March 2008. I performed the consumption per customer updates for the

Single-Family Residential (G-5), Multi-Family Residential (G-6), Single-Family Low Income Residential (G-10) and Multi-Family Low Income Residential (G-11) rate schedules. With the residential consumption per customer updates, the annualized test year volumes decline by 11,930,476 therms or 3.9 percent. A summary of the impact of declining residential consumption on the test year volumes is presented in the attached Rebuttal Exhibit No.__(JLC-2). The details of the adjustments are presented in the attached Rebuttal Exhibit No.__(JLC-3). The negative financial implications of the decline in residential average usage since the test year is quantified and discussed in the rebuttal testimony of Southwest witnesses A. Brooks Congdon and Theodore Wood.

Q. 10 Could you please summarize your conclusions based on the information presented?

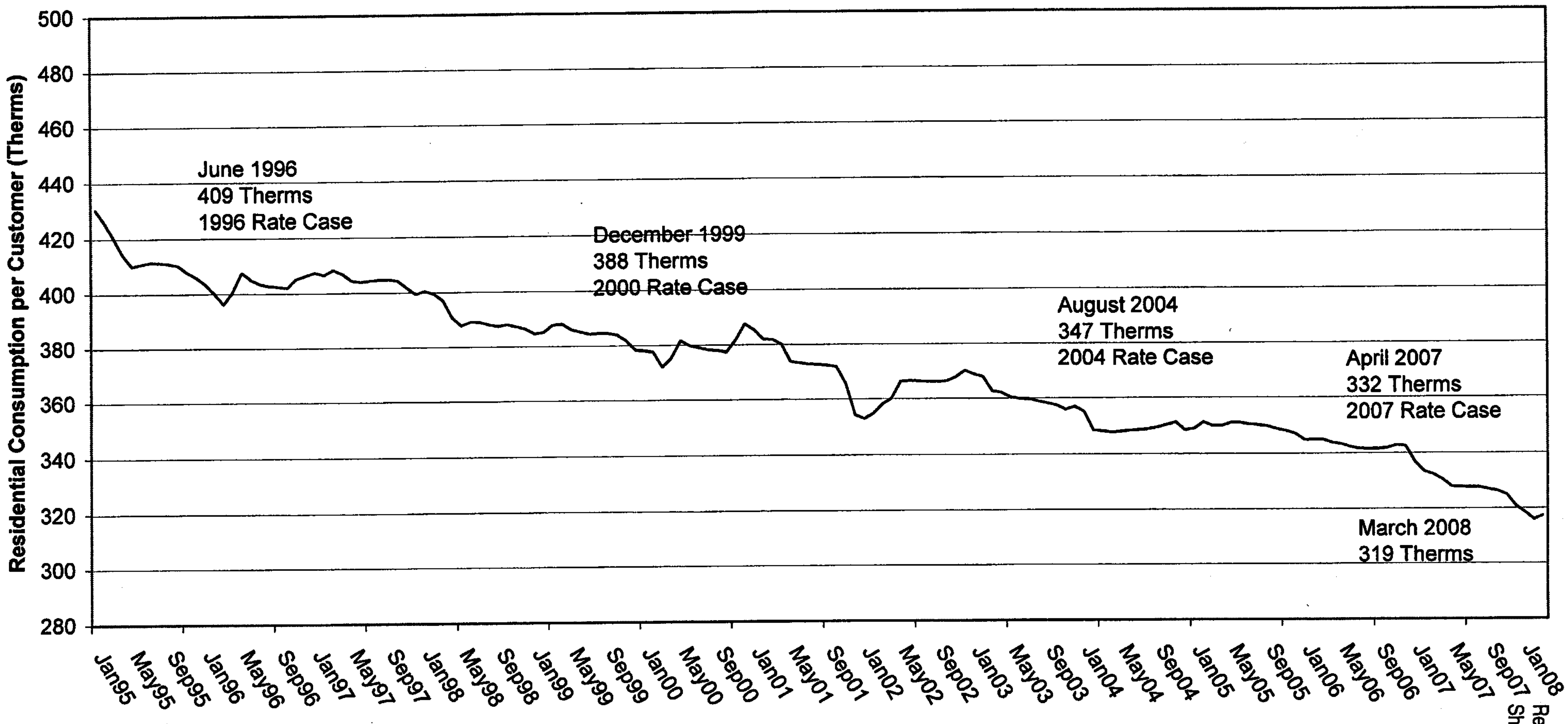
A. 10 Yes. Southwest continues to experience significant declines in residential consumption per customer. In fact, the most recent data suggests that the decline has accelerated. The continued declines in residential consumption per customer since the end of the test year in the current rate case has reduced the annualized volumes by 11,930,476 therms.

Q. 11 Does this conclude your prepared rebuttal testimony?

A. 11 Yes, it does.

Rebuttal Exhibit No. __(JLC-1)
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
RESIDENTIAL CUSTOMER CLASS (G-5 & G-6)
12-MONTH WEATHER NORMALIZED CONSUMPTION PER CUSTOMER
JANUARY 1995 - MARCH 2008



10-Year Normal HDDs: 2007 Rate Case

SOUTHWEST GAS CORPORATION
ARIZONA
UPDATED ANNUALIZED SALES VOLUMES (THERMS)
TEST YEAR - 12 MONTHS ENDED APRIL 2007

Description	Rate Schedule	Test Year Sales Volumes	Updated Test Year Sales Volumes	Difference from Test Year Amount	Difference from Test Year Percent
Single-Family Residential	G-5	289,056,115	277,828,428	-11,227,687	-3.9%
Multi-Family Residential	G-6	6,508,059	6,107,019	-401,040	-6.2%
Single-Family Low Income Residential	G-10	8,658,972	8,379,460	-279,512	-3.2%
Multi-Family Low Income Residential	G-11	552,643	530,406	-22,237	-4.0%
Total		304,775,789	292,845,313	-11,930,476	-3.9%

Notes:
(1) Test year weather normalized residential consumption per customer (May 2006 - March 2007) updated with the months of May 2007 through March 2008.
(2) The test year number of bills were not updated.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
TWELVE MONTHS ENDED APRIL 2007
ANNUALIZED DELIVERIES (THERMS) AND CUSTOMERS

WEATHER NORMALIZED RESIDENTIAL CONSUMPTION PER CUSTOMER UPDATE: MAY 2007 - MARCH 2008

Rate Schedule	Description	May 2006	June 2006	July 2006	August 2006	September 2006	October 2006	November 2006	December 2006	January 2007	February 2007	March 2007	April 2007	TOTAL
G-5	Residential Gas Service													
	Weather Normalized Sales	14,224,761	10,422,997	8,454,311	7,977,298	8,157,569	9,719,048	15,562,959	37,920,974	53,696,625	46,031,619	39,531,765	23,136,346	274,836,272
	Customers	827,021	827,222	828,854	830,548	832,405	837,849	845,813	854,076	859,146	865,256	868,830	860,591	10,137,611
	Sales/Customer	17.2	12.6	10.2	9.6	9.8	11.6	18.4	44.4	62.5	53.2	45.5	26.9	321.9
	April 2006 Customers												831,424	
	Annual Customer Growth												29,167	
	Customer Adjustment	26,736	24,306	21,875	19,445	17,014	14,584	12,153	9,722	7,292	4,861	2,431	0	160,419
	Therm Adjustment	459,859	306,256	223,125	186,767	166,737	169,174	223,615	431,657	455,750	258,605	110,611	0	2,992,156
	Annualized Sales	14,684,620	10,729,253	8,677,436	8,164,065	8,324,306	9,888,222	15,786,574	38,352,631	54,152,375	46,290,224	39,642,376	23,136,346	277,828,428
	Annualized Customers	853,757	851,528	850,729	849,993	849,419	852,433	857,966	863,798	866,438	870,117	871,261	860,591	10,298,030
	Sales/Customer	17.2	12.6	10.2	9.6	9.8	11.6	18.4	44.4	62.5	53.2	45.5	26.9	321.9
G-6	Multi-Family Residential Gas Service													
	Weather Normalized Sales	398,122	327,424	287,271	269,505	265,087	293,716	403,243	753,326	937,980	824,694	775,199	541,683	6,077,250
	Customers	30,391	30,317	30,239	29,945	29,785	29,971	30,319	30,748	31,266	31,719	32,033	31,549	368,282
	Sales/Customer	13.1	10.8	9.5	9.0	8.9	9.8	13.3	24.5	30.0	26.0	24.2	17.2	196.3
	April 2006 Customers												31,135	
	Annual Customer Growth												414	
	Customer Adjustment	380	345	311	276	242	207	173	138	104	69	35	0	2,280
	Therm Adjustment	4,978	3,726	2,955	2,484	2,154	2,029	2,301	3,381	3,120	1,794	847	0	29,769
	Annualized Sales	403,100	331,150	290,226	271,989	267,241	295,745	405,544	756,707	941,100	826,488	776,046	541,683	6,107,019
	Annualized Customers	30,771	30,662	30,550	30,221	30,027	30,178	30,492	30,886	31,370	31,788	32,068	31,549	370,562
	Sales/Customer	13.1	10.8	9.5	9.0	8.9	9.8	13.3	24.5	30.0	26.0	24.2	17.2	196.3
G-10	Low Income Residential G.S.													
	Weather Normalized Sales	431,216	316,742	265,720	251,826	246,728	285,787	491,764	1,170,442	1,596,405	1,397,351	1,248,026	681,870	8,383,877
	Customers	26,951	26,177	25,550	25,437	24,922	25,069	25,090	25,063	25,707	26,718	27,369	27,090	311,143
	Sales/Customer	16.0	12.1	10.4	9.9	9.9	11.4	19.6	46.7	62.1	52.3	45.6	25.2	321.2
	April 2006 Customers												27,133	
	Annual Customer Growth												(43)	
	Customer Adjustment	(39)	(36)	(32)	(29)	(25)	(22)	(18)	(14)	(11)	(7)	(4)	0	(237)
	Therm Adjustment	(624)	(436)	(333)	(287)	(248)	(251)	(353)	(654)	(683)	(366)	(182)	0	(4,417)
	Annualized Sales	430,592	316,306	265,387	251,539	246,480	285,536	491,411	1,169,788	1,595,722	1,396,985	1,247,844	681,870	8,379,460
	Annualized Customers	26,912	26,141	25,518	25,408	24,897	25,047	25,072	25,049	25,696	26,711	27,365	27,090	310,906
	Sales/Customer	16.0	12.1	10.4	9.9	9.9	11.4	19.6	46.7	62.1	52.3	45.6	25.2	321.2
G-11	Multi-Family Low Income Residential G.S.													
	Weather Normalized Sales	30,653	25,894	22,040	21,020	21,059	22,756	32,175	63,455	82,946	75,801	70,535	46,110	514,444
	Customers	2,174	2,140	2,099	2,130	2,085	2,107	2,145	2,151	2,206	2,311	2,391	2,381	26,320
	Sales/Customer	14.1	12.1	10.5	9.9	10.1	10.8	15.0	29.5	37.6	32.8	29.5	19.4	231.2
	April 2006 Customers												2,187	
	Annual Customer Growth												194	
	Customer Adjustment	178	162	146	129	113	97	81	65	49	32	16	0	1,068
	Therm Adjustment	2,510	1,960	1,533	1,273	1,141	1,048	1,215	1,918	1,842	1,050	472	0	15,962
	Annualized Sales	33,163	27,854	23,573	22,293	22,200	23,804	33,390	65,373	84,788	76,851	71,007	46,110	530,406
	Annualized Customers	2,352	2,302	2,245	2,259	2,198	2,204	2,226	2,216	2,255	2,343	2,407	2,381	27,388
	Sales/Customer	14.1	12.1	10.5	9.9	10.1	10.8	15.0	29.5	37.6	32.8	29.5	19.4	231.2

Rebuttal Exhibit No.__(JLC-3)
Sheet 1 of 1

Tab K

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

PREPARED REBUTTAL TESTIMONY
OF
RALPH E. MILLER

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
RALPH E. MILLER

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
RALPH E. MILLER

A. Introduction

Q. 1 Please state your name and business address.

A. 1 My name is Ralph E. Miller. My office is at 5502 Western Avenue, Chevy Chase, Maryland 20815.

Q. 2 Have you presented other testimony in this proceeding?

A. 2 Yes. My direct testimony was part of Southwest Gas Corporation's (Southwest or the Company) filing on August 31, 2007.

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

A. 3 I am responding to the March 28, 2008 testimony of Arizona Corporation Commission Utilities Division Staff (Staff) witness Frank Radigan on Revenue Decoupling; to the Volumetric Rate Design portion of Mr. Radigan's April 11, 2008 testimony; and to the Rate Design testimony of Residential Utility Consumer Office (RUCO) witness William A. Rigsby, which was also filed on April 11, 2008. All of this testimony addresses aspects of the revenue decoupling issue, which I supported in my direct testimony.

The remainder of my testimony is in four parts: a response to Mr. Radigan on the principles of revenue decoupling; a response to Mr. Radigan on the proposed weather normalization provision and the Southwest residential rate design; a response to Mr. Rigsby on Southwest's proposed revenue decoupling mechanism; and a response to Mr. Rigsby on the proposed weather normalization provision.

Q. 4 Before proceeding with your response to specific points in the testimony of Messrs. Radigan and Rigsby, do you have any general comments about the way the revenue decoupling issue has developed in this proceeding?

A. 4 Yes. There appears to be general agreement that Southwest's actual annual sales per customer in future years will differ from its test year sales; that these differences in sales per customer have a variety of causes; and that the largest variations in annual sales per customer are typically caused by differences between actual and normal weather.

Southwest has proposed three distinct rate design changes to attempt to break the linkage between these unavoidable variations in annual sales per customer and Southwest's <u>non-gas</u> revenues <u>per customer</u>. The first is the Weather Normalization Adjustment Provision (WNAP). It operates on a real-time basis, eliminating the variations in each customer's non-gas charges that are caused by differences between actual and normal weather for the month. The WNAP does not achieve complete revenue decoupling, but it goes most of the way towards this goal by eliminating the largest source of annual variations in revenue. The failure of Messrs. Radigan and Rigsby to recognize the advantages of the WNAP for Southwest's residential and small commercial customers is a major flaw in their argument against revenue decoupling.

The second proposed change of Southwest's decoupling proposal is the Revenue Decoupling Adjustment Provision (RDAP). It could provide complete revenue decoupling, even without the WNAP, but it operates with a one-year lag. If sales per customer are higher in some future year (2010, for example) because the weather in that year is colder than normal, then the RDAP will not provide a rate reduction until the following year (*i.e.*, 2011).

When the RDAP is combined with the WNAP, as Southwest is proposing, the WNAP provides a real-time adjustment for the relatively large variations in sales per customer that can be caused by large differences between actual and normal weather, and the RDAP surcharges and credits will be much smaller because the non-gas revenue effects of weather will already have been eliminated by the WNAP.

The third change of Southwest's decoupling proposal is a modification to its volumetric rate design, which combines a declining block rate for non-gas charges with an inverted block rate for purchased gas cost recovery. (Herein referred to as "Southwest's Volumetric Rate Design".) This rate design would achieve much of the decoupling effect of the WNAP, but it would involve some lag based on the operation of the purchased gas adjustment (PGA) mechanism. Southwest's Volumetric Rate Design would also achieve some of the effects of the RDAP, and it would thus make the annual RDAP surcharges and credits smaller than they would otherwise be.

B. Response to Staff Witness Radigan — Revenue Decoupling Principles

Q. 5 At page 4 of his March 28 testimony, Mr. Radigan states, "There has been no showing that Revenue Decoupling is fair to customers." Is that a valid criticism?

A. 5 It is a valid criticism of my direct testimony, but not of Southwest's revenue decoupling proposal. I asserted at page 4 of my direct testimony that revenue decoupling is fair to customers, but I did not support that statement elsewhere in the testimony, and I shall therefore correct that omission here in my rebuttal.

Q. 6 What is the basis for your opinion that revenue decoupling is fair to customers?

A. 6 In this proceeding, the Commission will determine Southwest's non-gas revenue requirement, which is Southwest's annual cost for everything but purchased gas and some relatively small items such as expenditures on demand-side management programs. The Commission will also establish rates designed to recover that non-gas revenue requirement from Southwest's test year sales quantities.

Now suppose that in some future year such as 2010, while the rates established in the present proceeding are still in effect, existing customers (as a group) purchase less gas than in the test year. Southwest's non-gas costs of continuing to serve these customers will <u>not</u> decrease as a result of this reduction in sales per customer, but — absent revenue decoupling — Southwest's non-gas (or "margin") revenues <u>will</u> decrease. Existing customers will thus (by reducing their gas purchases) avoid paying the full amount of the costs that Southwest must continue to incur to provide service to them. And there is nothing fair about that result.

Quite to the contrary, it is eminently fair that the Commission adopt revenue decoupling so that existing customers continue to pay the full amount of the non-gas costs that the Commission itself establishes as Southwest's non-gas revenue requirement in this proceeding.

Finally, it should also be noted that the revenue decoupling proposed by Southwest is a two-way street. If existing customers purchase more gas per customer in some future year than in the test year, then Southwest's revenue decoupling proposals will provide them with rate reductions, so that they pay no more than Southwest's test year non-gas costs per customer.

Q. 7 Mr. Radigan also states, "there have (*sic*) been no showing in this case that the lack of Revenue Decoupling is a major obstacle to the promotion of energy efficiency." (March 28, page 4.) Do you agree?

A. 7 No. As I explained at pages 8-9 of my direct testimony, traditional rate designs provide a strong financial incentive for a utility to avoid any reduction in sales per customer. This same regulatory lag in responding to changes in sales per customer also provides a strong financial incentive for a utility to promote increased sales per customer, in whatever way it can. Mr. Radigan apparently considers these financial incentives to be irrelevant. I, with my training and experience in economics, do not share that view. One of the major advantages of the U.S. economy is that we rely as much as we can on the "invisible hand" of financial incentives to guide the behavior of business firms, including utilities such as Southwest. Centuries of experience, here in the United States and around the world, have amply demonstrated that financial incentives are much more effective than any kind of command structure in guiding the actions of business firms. So it is with energy efficiency and conservation. If the Commission wants to maximize results, it should at least remove completely the financial penalty imposed on Southwest when sales per customer decrease, and also the financial incentive for Southwest to achieve higher sales per customer. The Commission should therefore remove the regulatory lag in responding to changes in sales per customer, and the way to achieve this goal is through revenue decoupling.

Q. 8 In the same place on page 4 of his March 28 testimony, Mr. Radigan states, "ratepayers don't like clauses that are designed to automatically increase their bills." What is your response?

A. 8 Customer distaste for rate increases is simply not a valid reason for rejecting them. If it were, then no utility would ever receive a rate increase, and there would be no purchased gas adjustment mechanisms or other cost-tracking clauses in utility rates. The relevant standards are whether a rate adjustment clause is <u>fair</u> to customers, not whether the customers "like" it, and whether it is reasonably structured to achieve its specific objective without interfering with other rate design objectives. I have shown that Southwest's revenue decoupling proposals pass both of these tests. Mr. Radigan has offered no evidence to the contrary.

Q. 9 At page 8 of his March 28 testimony, Mr. Radigan disputes your showing of broad support for revenue decoupling, including support from NARUC, and he claims instead "NARUC has also advised caution." Is that a fair characterization of NARUC's position on revenue decoupling?

A. 9 No, it is not. Mr. Radigan's claim that "NARUC has also <u>advised caution</u>" (<u>emphasis</u> added) is a distortion of NARUC's actual statement, which Mr. Radigan himself quotes in the same answer on page 8 of his March 28 testimony:

> [I]t makes sense <u>to approach implementation with caution</u>, considering corrective mechanisms to ensure that the change ... has the intended effects and avoids harmful unintended consequences." (<u>Emphasis</u> added.)

There is a major difference between "advising caution" about revenue decoupling and "approaching implementation with caution". The former implies doubts about whether revenue decoupling should be implemented at all, which is what Mr. Radigan's unfair characterization suggests, and that is <u>not</u> what the NARUC statement says. NARUC's actual recommendation, to "approach implementation with caution," addresses the <u>way</u> decoupling should be implemented, **not** <u>whether</u> it should be implemented.

Further insight into the NARUC position and its implications for Southwest can be gleaned by examining page 10 of NARUC's September 2007 "FAQ sheet", which is the source of Mr. Radigan's quotation, and which he provides as his Exhibit FWR-2. The NARUC statement that Mr. Radigan characterizes as "advising caution" is the beginning of a boxed insert or sidebar addressing the question, "What off-ramps and adjustments are possible?" The clear purpose of that sidebar is to explain how revenue decoupling can be implemented with appropriate caution, not to suggest in any way that NARUC has doubts about whether it should be implemented. If one looks at the off-ramps that NARUC actually suggests there, one notices that Southwest's proposed RDAP already incorporates the first of them, a balancing account. I am informed by Southwest's management that the Company would also be willing to have the RDAP treated as a pilot program, subject to a reporting requirement and reconsideration in Southwest's next general rate case, and that it would also be willing to consider other "off-ramps" if that is what the Commission requires for the implementation of revenue decoupling.

Q. 10 The NARUC "FAQ sheet" quoted by Mr. Radigan is dated September 2007, which is after Southwest's filing of its direct testimony. Did other expressions of broad support appear at that time?

A. 10 Yes. In September 2007, a large number of energy conservation organizations, led (in alphabetical order) by the Alliance to Save Energy, issued "A Response to the NASUCA 'Decoupling' Resolution". A copy of that response is attached to this rebuttal testimony as Exhibit "3".

Q. 11 At page 8 of his March 28 testimony, Mr. Radigan asserts, "decoupling has had a varied past", and that the states of Washington, Maine, and New York have "adopted decoupling and then dropped it." Do you have a response?

A. 11 Yes. None of this decoupling experience is of any relevance to the present proceeding, because all of it involved electric utilities in the early 1990s, and the situation of electric utilities in the early 1990s is very different from the situation of the gas distribution industry today. A good indication of this difference is that the Washington State Utilities and Transportation Commission (WUTC) in 2007 approved a revenue decoupling arrangement for Cascade Natural Gas in Docket No. UG-060256. Clearly the WUTC did not consider its own experience with Puget Sound Power & Light Company in the 1990s to be an obstacle to revenue decoupling for a gas utility in 2007.

Q. 12 Can you provide further information about the current position of the New York PSC on revenue decoupling?

A. 12 Yes. In an order issued in April 2007, the NYPSC directed that state's major electric and gas utilities to develop revenue decoupling mechanisms and file them for consideration in their next rate cases. The NYPSC issued this order after extensive investigation of the revenue decoupling issue, initiated for electric utilities in 2003 and for gas utilities in 2006. In its press release announcing the order, the NYPSC stated:

> Based upon a thorough review of the comments, the Commission today determined that properly designed utility revenue decoupling mechanisms are needed at this time to address potential disincentives to utilities' promoting and implementing more efficient energy use. (Press release, page 2.)

A copy of the complete press release is attached to this rebuttal testimony as Exhibit "4".

Later in 2007, the NYPSC approved a revenue decoupling mechanism for National Fuel Gas Distribution Corporation in Case 07-G-0141.

Q. 13 How is the decoupling situation for electric utilities in the early 1990s different from and of no relevance to the situation for gas utilities today?

A. 13 There are at least two major differences between the revenue decoupling situation of the electric utilities in the early 1990s and that of the gas utilities today. The first and most important is that decoupling for gas utilities (specifically including Southwest) relates only to gas delivery or "distribution" charges; there is no attempt to include any gas supply cost recovery in the revenue decoupling mechanisms currently under consideration, because gas cost recovery is already addressed in PGA mechanisms. The situation of electric utilities in the 1990s was completely different, because the revenue decoupling mechanisms then encompassed the electric utilities' fixed costs for power production capacity, and power production costs are the electric utility analog to gas supply costs. This difference had an important bearing on the way revenue decoupling operated for electric utilities in the early 1990s.

The second major difference is that revenue decoupling for gas utilities under current conditions involves a much smaller percentage of the customer's total bill than electric revenue decoupling in the 1990s. Gas revenue decoupling therefore preserves a very strong conservation incentive for customers, because it allows them to achieve large reductions in their total gas bill by reducing their gas consumption. It is not clear whether electric utility revenue decoupling in the 1990s achieved this same benefit.

These differences may help explain why two of the three jurisdictions that Mr. Radigan cites as having "adopted ... and then dropped" decoupling — but only for electric utilities in the 1990s, it turns out — have recently adopted decoupling for gas utilities.

Q. 14 Why is the inclusion of power production costs in electric revenue decoupling mechanisms of the 1990s an important difference from the situation of gas utilities today?

A. 14 As Mr. Radigan himself explains, the problems with electric utility decoupling in Washington and in Maine in the 1990s both related to changes in the power supply situation. The changes in Washington were on the supply side, involving new power sources and drought conditions that reduced the Puget Sound's hydropower supply; in Maine, it was a recession affecting the demand for electricity. In the Puget Sound case, the WUTC identified the joining of decoupling with a "resource cost adjustment mechanism" — the analog of an electric fuel cost adjustment, but with a different name because of the importance of hydropower in the Pacific Northwest — as one of the problems with decoupling. But this problem arose precisely because the decoupling mechanism and the resource cost adjustment mechanism were both addressing power production costs.

For gas utilities, in contrast, the decoupling mechanism applies only to non-gas costs, which are distinct from purchased gas or fuel supply costs, and there is no problem of conflict between the two mechanisms. Also, any decrease in gas use is accompanied by a decrease in the PGA and other revenues for gas cost recovery, accompanied also by an almost proportional decrease in the gas utility's purchased gas costs, and the separate effect of the PGA preserves a strong conservation incentive in the gas rate structure no matter what the effect of revenue decoupling for non-gas costs.

Q. 15 What fraction of a Southwest customer's bill would be subject to the revenue decoupling that Southwest is proposing?

A. 15 For Southwest's residential customers, the total non-gas (or margin) revenue of $306 million at Southwest's proposed rates is only 52% of the total revenue of $591 million, and the remaining 48% of the proposed revenue is for recovery of purchased gas costs. (See Exhibit ___ (ABC-3) attached to Southwest witness Congdon's direct testimony.)

I do not have comparable data for electric utilities in the 1990s, but for some electric utilities currently, the cost of fuel is only around 30% of the total residential revenue requirement. In the 1990s, when fuel prices were much lower, fuel costs were most likely an even smaller percentage of total electric utility costs, with more than 70% of the total revenue needed for recovery of the utility's fixed costs. (For electric utilities that have sold much of their power production capacity, the total cost of fuel and purchased power may now be more than 30% of the residential revenue requirement, but that is irrelevant to the situation of the electric utilities in the early 1990s, because very few of them had then disposed of their generating plants.)

Q. 16 Can you summarize your analysis of Mr. Radigan's position on revenue decoupling?

A. 16 Mr. Radigan has presented only one affirmative reason for rejecting revenue decoupling, and that is his claim that customers "don't like" it because it could increase their rates. He does not allege that revenue decoupling is unfair to customers, or that it would be ineffective in helping to promote energy efficiency and conservation, which he himself supports, or that it would be ineffective in mitigating the impacts of declining use per customer; and he does not identify any adverse consequence likely to occur from revenue decoupling other than the possibility of a rate increase, which I have shown would be eminently fair and entirely just and reasonable if it occurred. Instead, Mr. Radigan claims merely that Southwest has failed to demonstrate the fairness and efficacy of revenue decoupling. I have responded to these claims in this rebuttal, and I have presented additional evidence on both questions to address these criticisms.

C. Response to Staff Witness Radigan — Weather Normalization and the Southwest Volumetric Rate Design

Q. 17 Can you provide an overview of Mr. Radigan's position on Southwest's proposed Weather Normalization Adjustment Provision (WNAP)?

A. 17 Yes and no. I cannot summarize his position on the WNAP because nowhere in his testimony does he state a position on the WNAP alone, as distinct from what he calls Southwest's "three pronged attempt to accomplish full Revenue Decoupling." Mr. Radigan first mentions this "three pronged" approach at page 6 of his April 11 testimony, where he describes Southwest's "Volumetric Rate Design". On the other hand, in his ensuing discussion of the Volumetric Rate Design, Mr. Radigan makes clear that he opposes it on the grounds that it would decouple Southwest's non-gas revenues from the effects of weather, and I think it is fair reading of his testimony that Mr. Radigan would oppose the WNAP on the same grounds.

Q. 18 Can you provide an overview of Mr. Radigan's arguments on the WNAP and on the decoupling of non-gas revenues from the effects of weather?

A. 18 Mr. Radigan discusses the WNAP in his March 28 testimony, but he does not address the merits of weather-related revenue decoupling from the perspective of customers or consumers. He begins by explaining Southwest's WNAP proposal at pages 3-4. Then Mr. Radigan changes his focus to the RDAP, and his testimony from page 4, line 5 through page 6, line 9 relates to <u>full</u> revenue decoupling, with no recognition that the WNAP and RDAP are separate proposals, and Mr. Radigan continues in this way through page 9.

At lines 1-8 on page 6, Mr. Radigan restates my demonstration that revenue decoupling is desirable in part because the coupling of revenues to sales under traditional rate designs hampers a utility's ability to recover its authorized non-gas costs. Then, at line 10, Mr. Radigan asks himself whether he agrees with my argument, and at line 11 he responds "No." But instead of explaining why he disagrees, Mr. Radigan restates the argument in favor of revenue decoupling at lines 11-13 and adds only "the Company has been vociferous on this subject." The remainder of this interlude on weather, to page 7, line 2, is nothing more than two extended quotations from Southwest's Form 10-K and its Annual Report to Shareholders. Nowhere in this long answer — and nowhere else in his March 28 testimony — does Mr. Radigan provide even one word of explanation why he disagrees with the analysis on page 3 of my direct testimony, which he has reproduced on page 6 of his own March 28 testimony. All we have is the one-word response, "No", stating without support that Mr. Radigan does not agree with my analysis.

Q. 19 Does Mr. Radigan's April 11 testimony provide a more reasoned discussion of the issue of decoupling non-gas revenue from weather?

A. 19 No. He begins at page 5 by restating Southwest witness A. Brooks Congdon's description of Southwest's Volumetric Rate Design. At page 6 he restates Mr. Congdon's explanation of Southwest's reasons for this rate design proposal, and then he asserts his own disagreement with Mr. Congdon.

Mr. Radigan's first objection is that Southwest's Volumetric Rate Design is part of Southwest's "attempt to accomplish full Revenue Decoupling", with the implication that it should be rejected for the reasons Mr. Radigan has presented in his March 28 testimony. But I have already demonstrated that nothing in Mr. Radigan's March 28 testimony provides any basis for rejecting Southwest's revenue decoupling proposals.

Mr. Radigan's second complaint (on page 7 of his April 11 testimony) is that Mr. Congdon has emphasized the conservation basis for Southwest's Volumetric Rate Design, rather than its decoupling effect, and Mr. Radigan responds, "the true intent behind the Company's proposed rate design is to substantially eliminate all risk from variation in sales due to weather" (page 7). This criticism is neither fair nor relevant. It is not fair because it ignores Part F of my direct testimony, where I explicitly identify Southwest's Volumetric Rate Design as an Alternative Form of Partial Revenue Decoupling in Q&A 31 on pages 13-14. And it is not relevant unless one also demonstrates that it is inappropriate to decouple non-gas revenues from the effects of weather, which Mr. Radigan has not done.

Q. 20 In the next paragraph on page 7, Mr. Radigan states, "The Company's proposal shifts substantial risk to customers by eliminating any risk of revenue collection due to variation in weather." Is this a valid reason for opposing Southwest's attempts to decouple non-gas revenues from the effects of weather?

A. 20 No, it is not. I agree that Southwest's Volumetric Rate Design would eliminate some of the risk of non-gas revenue collection due to variation in weather, and I agree that Southwest's WNAP would eliminate essentially all of that risk. I make this point about the WNAP myself, at page 12 of my direct testimony, where I state, "Weather normalization benefits utility companies because it eliminates fluctuations in non-gas revenue ...."

I do <u>not</u> agree that elimination of the weather-related non-gas revenue risk for Southwest would (as Mr. Radigan claims) shift that risk to customers. Quite to the contrary, the WNAP would <u>reduce</u> the risks to customers, just as it reduces risk for Southwest. My explanation of this result is also in my direct testimony, at page 11, and Mr. Radigan restates the main points of my argument at pages 3-4 of his March 28 testimony, as I have already noted.

But he fails to address this analysis when he makes the unsupported claim that Southwest's WNAP and Volumetric Rate Design proposals would shift risk to customers. Or perhaps Mr. Radigan fails to understand that moderating the weather-related fluctuations in a customer's bill (the language in my direct testimony, which Mr. Radigan reproduces at pages 3-4 of his March 28 testimony) is a reduction in risk. I shall return to this topic in my response to RUCO witness Rigsby, who also presents the risk-shifting claim. In response to Mr. Radigan, it suffices to note that he provides no support whatsoever for his claim that the WNAP or the Volumetric Rate Design shifts risk to customers, and this omission is especially damaging to his position because I had already presented the benefits to customers.

Q. 21 Do any of Mr. Radigan's responses to Southwest's data requests shed further light on his position on weather normalization?

A. 21 Yes. Question 4 in Southwest's third set of data requests to Staff asks Mr. Radigan to explain his belief that the WNAP shifts risk from Southwest to the customer, as opposed to mitigating risk for the benefit of both Southwest and the customer. Mr. Radigan answered as follows:

> Based on Mr. Radigan's experience customers have a hard time understanding financial security provisions like weather normalization because they require automatic increases/decreases in the customer bill. At time of warmer than normal temperatures, sales decrease and the company loses margin. The <u>next month</u>, customers see an automatic increase in their bill which they generally don't like. At the time of colder than normal temperatures, the bill is higher because of increase [*sic*] usage. While it is understood that the margin has increased and there will be a credit in <u>next months</u> [*sic*] bills, one must also recognize that since commodity cost are [*sic*] 65% of the bill, the increase in the bill due to colder weather will overshadow the credit. Thus, there is perception from the customers [*sic*] perspective that they lose either way or the utility always wins. (<u>Emphasis</u> added.)

This response suggests that Mr. Radigan does not fully understand the way the WNAP would operate, and his incomplete understanding leads him to the incorrect conclusion. Mr. Radigan clearly indicates that the WNAP adjustments to a customer's bill are lagged one month behind the weather that causes those adjustments. That is not correct. If the weather is warmer than normal, the customer will see an upward adjustment to his bill in the very same month as the warm weather, but the customer will still see a smaller bill because the decreased use will yield a decreased purchased gas charge. In colder weather, when the customer is experiencing a higher bill because his use has increased, he will see — on that very same bill — a WNAP credit, which he will readily observe is helping him to cope with the increased costs of higher gas use. I would agree with Mr. Radigan that a lag of even one month in applying the WNAP adjustment to customers' bills would make it harder for customers to understand that the WNAP reduces their risk and provides a real benefit in difficult months, but there is no lag at all in the application of Southwest's proposed WNAP adjustments, and Mr. Radigan's concerns about the customer's ability to understand the beneficial effects of the WNAP are unfounded.

Q. 22 Do you have any further response to Mr. Radigan's testimony on revenue decoupling?

A. 22 Yes. Mr. Radigan's opposition to revenue decoupling appears to be based primarily on the observation that revenue decoupling would be beneficial to Southwest (he and I agree on that point), and on the unstated but crucially important additional premise that anything which is good for Southwest is bad for customers. Instead of focusing directly on the way Southwest's revenue decoupling proposals would affect customers, he focuses much more on their benefits to Southwest, and then he construes these benefits to Southwest as reasons for rejecting the proposals. This attitude is, unfortunately, a major impediment to progress in utility regulation, especially in rate design.

I have devoted my entire career to advocacy for consumers, most of it in the area of utility regulation, principally as a consultant to consumer advocates and commission staffs, and I have much more extensive experience in this area than Mr. Radigan. All too often, I have seen a tendency of some customer advocates (and I use this term here to encompass commission staffs) to oppose whatever it is that a utility wants. This tendency is understandable because the interests of the utility and its customers almost always are diametrically opposed on revenue requirements issues, and it is certainly reasonable for customer advocates to be suspicious of utility proposals even in the rate design area. But it is also important for customer advocates to move beyond that suspicion and undertake a comprehensive and thoughtful analysis of what the utility wants, and how it affects customers. Failure to do so is treating regulation as a zero-sum game, in which customers cannot achieve any benefits except by punishing the utility. Failure to move beyond an analysis of the way a utility's proposal affects the utility, and to examine also its effect on customers, is tantamount to assuming — without investigation — that there is no such thing as a "win-win" solution in utility regulation. Most customer advocates recognize the need to take this additional step, and to fight their own tendency to oppose whatever it is that the utility proposes. Unfortunately, Mr. Radigan has failed to reach that step in his direct testimony on the revenue decoupling issue in this proceeding.

D. Response to RUCO Witness Rigsby on Southwest's Proposed RDAP

Q. 23 RUCO witness Rigsby recommends that the Commission reject Southwest's proposed RDAP. Does he provide a basis for that recommendation?

A. 23 Mr. Rigsby states three affirmative reasons for his opposition to the RDAP, but none is a sound basis for rejecting it. These three affirmative reasons are claims that the RDAP would (i) "pass the risk of variations in weather from shareholders to ratepayers"; (ii) "result in biased rates"; and (iii) be "counterproductive" for conservation efforts. (See pages 7-8 of Mr. Rigsby's Rate Design Testimony ("RDT"), filed April 11, 2008. All further page references to Mr. Rigsby's testimony are to this April 11 RDT.)

In addition to these affirmative reasons, Mr. Rigsby attacks Southwest's presentation in support of the RDAP, but these attacks have no substance. For example, at page 7 he characterizes the RDAP as a "radical departure from traditional rate design". This characterization adds nothing to the record, as I and other Southwest witnesses state in direct testimony that revenue decoupling is a departure from traditional rate design, and nowhere does Mr. Rigsby support his view that this departure is any more radical than Southwest's PGA or its DSM tracker.

Q. 24 Is there any justification for Mr. Rigsby's first claim, that the RDAP would "pass the risk of variations in weather from shareholders to ratepayers"?

A. 24 No, there is no justification for this claim, as I explain in my response to Mr. Rigsby on the issue of weather normalization.

Q. 25 Is there any merit in Mr. Rigsby's claim that the RDAP would "result in biased rates"?

A. 25 No, there is not. Mr. Rigsby makes the claim of bias in two places. At page 6, he states that the RDAP is "unfair and biased" because it is single issue ratemaking. At page 7, he claims it is biased because it "would require customers to pay for a predetermined level of gas service regardless of whether that level was actually used." Neither argument has any merit.

Single issue ratemaking is objectionable if and when a utility files a new application, outside of a general rate case, for a revenue increase related to a specific cost that happens to have increased. The objection is that the utility is picking and choosing the costs it knows to have increased, and that other parties are deprived of any opportunity to consider whether other costs may have decreased. This bias — and I would agree that this form of single issue ratemaking is apt to be biased — appears to be the objection in *Scates* v. *Arizona Corp. Commission*, 578 P.2d 612, 118 Ariz. 531 (1978), which RUCO cited in response to a data request from Southwest about single issue ratemaking. This general objection to single issue ratemaking vanishes when a regulatory commission considers and then adopts an automatic adjustment clause in a general rate case, providing rate adjustments for changes in specific costs elements identified in advance of the changes in those elements. The RDAP fits this latter situation.

Mr. Rigsby argues at pages 5-6 that it would be biased to permit Southwest to increase its rates through the RDAP without consideration of other factors that might indicate the need for a rate decrease. He ignores the ample evidence that the composite effect of all the other influences on Southwest's non-gas costs is to increase those costs, and that Southwest's rate of return will continue to have a tendency to decline even if the RDAP is adopted. Staff witness Radigan, for example, argues at page 5 of his March 28 testimony that decreases in sales per customer are a minor factor in Southwest's continuing need for rate increases.

Q. 26 At page 5, Mr. Rigsby claims that Southwest's declining sales per customer is "simply a regulatory lag issue". Do you agree?

A. 26 I agree that declining sales per customer is a problem for Southwest only because of regulatory lag. I do not agree with the apparent implication that the Commission should reject the RDAP because the problem it addresses is "only" or "simply" a problem of regulatory lag.

Regulatory lag is extremely important. It is the principal (and perhaps the only) direct financial incentive in the regulatory process for a utility to manage and control its costs. Regulatory lag is an incentive for the utility to prevent cost increases and even to achieve cost decreases, because the utility retains the financial benefit of any cost savings it achieves between rate cases, and it also retains the financial benefit of any cost increases it avoids.

The same analysis applies to sales per customer. If a utility can increase its sales per customer — or even if it can reduce the decline in sales per customer — the utility retains the financial benefit of any such changes that occur between rate cases. The financial losses that Southwest suffers from declines in sales per customer between rate cases are a problem for Southwest, but the financial incentive that this regulatory lag provides for Southwest to increase its sales per customer is an obstacle to energy efficiency and conservation, and that is a problem for the public and for the regulatory commission. The RDAP would eliminate this financial incentive by eliminating the regulatory lag in the way Southwest's Arizona rates respond to decreases in sales per customer. There is no reason for the Commission to reject the RDAP and preserve this regulatory lag, unless the Commission wants to preserve the financial incentive for Southwest to increase its sales per customer.

Q. 27 At page 5, Mr. Rigsby claims, "any decline in average consumption is <u>trued-up</u> in rates in [Southwest's] next rate case." (<u>Emphasis</u> added.) Do you agree?

A. 27 No. In common regulatory usage, revenues and costs are "trued-up" when there is an after-the-fact reconciliation and any difference is charged or credited back to customers. An example is Southwest's PGA, with its balancing account. There is no such reconciliation or true-up in a general rate case, as Mr. Rigsby's own testimony indicates. There is no more "true-up" in the next rate case for declines in consumption than there is for cost increases incurred and paid by Southwest between the end of the test year in one rate case and the effective date of a rate change in the following rate case. Mr. Rigsby appears simply to have chosen the incorrect word when he characterizes a general rate case as a "true-up", but in my view the incorrect impression created by this choice of words is important.

Q. 28 Is Southwest's proposed RDAP an automatic adjustment clause?

A. 28 The RDAP is an automatic adjustment clause in the way that this term is now generally used in utility regulation. The *Scates* decision indicates that an automatic adjustment clause is a device permitting rate adjustments "in relation to fluctuations in certain, narrowly defined, operating expenses." The RDAP does not adjust rates in response to fluctuations in any costs. Rather it adjusts non-gas rates in response to fluctuations in sales per customer. It does, however, satisfy the requirements mentioned in *Scates* of being "initially adopted as part of the utility's rate structure" and "designed to insure that ... the utility's profit or rate of return does not change" on account of the sales per customer fluctuations that it relates to. In my opinion, current usage of the term "automatic adjustment clauses" has extended beyond the narrow focus on specific cost elements to encompass also adjustments relating to specifically defined sales volumes.

Q. 29 Would Southwest's proposed RDAP increase Southwest's revenues above the level approved in this rate case?

A. 29 No. The RDAP would adjust Southwest's rates so as to preserve the same revenue per customer that the Commission approves for this rate case.

Q. 30 What is your response to Mr. Rigsby's claim that the RDAP is biased because it "would require customers to pay for a predetermined level of gas service regardless of whether that level was actually used" (page 7)?

A. 30 The RDAP does not require customers to pay for a predetermined level of gas service. As I have noted earlier, approximately half of Southwest's residential rates are for gas cost recovery (and the percentage is, if anything, larger for other classes of service). If a customer uses less gas, the charges for gas cost recovery are reduced in direct proportion to the reduction in usage, and nothing in the RDAP will affect this direct relationship of the customer's bill to the customer's gas usage.

With regard to non-gas costs, the RDAP only requires customers to pay for the level of gas service they actually use. Mr. Rigsby apparently concedes that Southwest's non-gas costs for a reduced level of service are the same as for a higher level of service, yet he finds a bias in expecting customers to continue paying those costs if they choose to take delivery on a smaller quantity of service. He reaches this incorrect conclusion by assuming implicitly that the "margin" or non-gas charge in a traditional rate design is unbiased, and then by noting that the RDAP would require customers to continue paying the margin on Southwest's total gas sales even if their actual use decreases. The problem is the assumption that the "margin" in a traditional rate design is an unbiased rate design that properly balances the utility's and the customers' interests. This assumption effectively begs the question whether the RDAP is biased, because it assumes that a traditional rate design is unbiased. In fact, the opposite is true and correct. Traditional rate designs (except for SFV) are biased because they associate a positive amount of margin (non-gas revenue) with all of the therms a customer uses, despite the undisputed fact that non-gas costs do not decrease to any significant degree when customer use decreases.

Q. 31 What is your response to Mr. Rigsby's claim (page 8) that the RDAP price would be "counterproductive to conservation because it would dilute the price message a customer receives when they reduce their demand"?

A. 31 The RDAP sends the correct price message, which is that conservation yields savings in purchased gas costs, but not in the non-gas costs that Southwest incurs for delivering the gas it purchases on behalf of its customers. Traditional rate designs send the incorrect price message, and they encourage customers to invest more in conservation than is economically efficient, because they give the erroneous impression that the cost of delivering gas can be reduced if the customer uses less gas.

Mr. Rigsby apparently agrees that if average gas use per customer declines, then Southwest's margin rates will increase in the next rate case because Southwest's non-gas costs will have to be recovered from a smaller sales volume. A proper price signal would make customers aware of this consequence of conservation, but a traditional rate design does not do so. The RDAP does a slightly better job, because it reduces the regulatory lag in adjusting rates to changes in user per customer. Under the RDAP, the regulatory lag is only one year, whereas under traditional rates without the RDAP, the lag lasts until Southwest's next rate case.

Q. 32 Would you agree that the effect of the RDAP on the conservation price signal for customers is as important as its effect on Southwest's incentives to support conservation and energy efficiency?

A. 32 No. The situation of Southwest and its customers is not symmetrical, and the asymmetry is due to the PGA provision in Southwest's rates. When customers conserve, their reductions in gas use yield a reduction in purchased gas costs. This reduction is the principal benefit that customers achieve through conservation, and any reduction in non-gas charges would add only a minor fraction to the benefit from reduced purchased gas costs. But Southwest gains no financial benefit from the reduction in purchased gas costs, because the PGA mechanism passes the entire reduction in purchased gas costs onward to customers. For Southwest, the only financial incentive for or against conservation is in the regulatory treatment of non-gas costs. That is why the positive effect of the RDAP on Southwest's incentive for supporting conservation is more important than the effect of the RDAP on price signals for customers.

E. Response to RUCO Witness Rigsby on Weather Normalization

Q. 33 Does RUCO witness Rigsby provide a basis for his recommendation that the Commission reject Southwest's proposed WNAP?

A. 33 Mr. Rigsby offers several arguments on this topic, but they are badly flawed, and none is a proper basis for rejecting the WNAP.

Mr. Rigsby's principal line of argument contains the following steps, together with several detours that I shall address later in this rebuttal:

- He begins by identifying weather (as opposed to conservation) "as the real cause for SWG's under-recoveries" of its allowed return (page 9).
- He claims that the WNAP would shift the risk of variations in weather from Southwest's shareholders to the customers (pages 11-12), and that this shift is improper.

In addition to this principal line of argument, Mr. Rigsby appears to believe that the WNAP fails his test for a "conservation rate design", which is that it "clearly send a message to ratepayers that the more natural gas they use, the higher their bills will be." (Page 12.)

I shall address these arguments in reverse order.

Q. 34 Do Southwest's proposed rates, including the WNAP, "clearly send a message to ratepayers that the more natural gas they use, the higher their bills will be"?

A. 34 Yes, definitely. There is no linkage between the WNAP adjustment to customer bills in any future month (such as February 2010) and the quantity of gas that Southwest's customers actually use in that month. If two customers ("A" and "B") have similar gas usage, but Customer A adopts a conservation measure such as improved insulation and Customer B does not, then Customer A will use less gas than Customer B. Customer A will have a lower bill under present rates, and the conservation benefit on Customer A's bill will remain if the WNAP is adopted.

No matter what the weather, Customer A will use less gas than Customer B, but the difference (due to A's improved insulation) will presumably be smaller if the weather is warmer than normal, and larger if the weather is colder than normal. Customer A will have a lower bill than Customer B because his purchased gas charges will be lower, and the presence or absence of the WNAP has no effect on Southwest's charges for the recovery of purchased gas costs.

Customer A will also have lower non-gas charges than Customer B, again because of his decreased use of gas owing to conservation, and the WNAP will not change this situation. If February 2010 is warmer than normal, then the WNAP will increase the February 2010 non-gas charges for both Customer A and Customer B, but Customer A's non-gas charges will remain smaller. If February 2010 is colder than normal, then the WNAP will decrease the non-gas charges for both customers, again leaving Customer A's non-gas charges smaller than those of Customer B.

Mr. Rigsby's concern about the pricing message sent by the WNAP would have some merit if the WNAP adjusted each customer's non-gas charges to reflect that customer's test year gas use, without regard to the customer's actual gas use in some future month such as February 2010. In this situation, Customer A would gain no benefit of reduced non-gas charges if he made his conservation investment after the conclusion of the test year. But <u>that is **not** what the WNAP does</u>. The WNAP does <u>not</u> base the customer's February 2010 non-gas charges on the customer's gas use in February of the test year. Instead it bases the February 2010 non-gas charges on the customer's actual gas use in February 2010, adjusted on a diluted percentage basis for the difference between actual February 2010 weather and normal weather for February. If the actual February 2010 weather is very close to normal, then there would be little or no adjustment that month for the WNAP. If the customer's actual February 2010 gas use is much less than that same customer's test year February gas use, then the customer's February 2010 non-gas charges will reflect the full benefit of this reduction in gas use, because the WNAP adjusts each customer's non-gas charges only for differences due to weather variations, <u>not</u> for differences from the customer's test year gas use.

Q. 35 What is the flaw in Mr. Rigsby's principal line of argument, that the WNAP would improperly shift the risk of variations in weather from Southwest's shareholders to the customers?

A. 35 This conclusion is devoid of support because it is based on the factually incorrect premise that variations in weather are the primary cause of Southwest's under-recoveries of the non-gas margins authorized by the Commission in Southwest's rate cases.

According to Mr. Rigsby, RUCO looked at Southwest's non-gas margins during the three-year period 2004-2006, and they found (using data provided by Southwest) that approximately 80% of Southwest's under-recoveries during this three-year period were due to weather, with only 20% due to conservation. The data that RUCO reviewed are contained in the schedules in Attachment 1 to RUCO's July 26, 2007 letter to the Commission, which Mr. Rigsby provides as Attachment A to his testimony. As Mr. Rigsby testifies at page 9:

> In RUCO's opinion, the data was conclusive: the real cause for SWG's under-recoveries was not conservation, but weather.

The problem is that RUCO has drawn a broad, sweeping conclusion from a data sample that is totally inadequate to support that conclusion. RUCO's analysis on this point is equivalent to drawing three cards from a full deck, observing that two of the three happen to be red cards, and concluding from this observation that the deck must have many more red cards than black cards. It does not take advanced training in statistical inference to see that the conclusion about the contents of the deck simply does not follow from the very limited three-card sample.

But that is exactly what RUCO did. It looked at results for three years. Two of them (2005 and 2006) were much warmer than normal and actual use per customer was much less than weather-adjusted use. One year (2004) was somewhat colder than normal, and actual use per customer was somewhat more than weather-adjusted use. RUCO averaged the results for these three years and drew the completely unwarranted and false conclusion that weather variations will continually cause Southwest to experience the large under-recoveries that happened to occur in a three-year period when the weather happened to be much warmer than normal.

Q. 36 Is there affirmative evidence that RUCO's conclusion about the cause of

Southwest's under-recoveries is incorrect?

A. 36 Yes. Table REM-1, which is attached to this rebuttal testimony, shows the effect of weather on gas use per customer for Southwest's residential customers in each year from 1998 through 2007. The effect of weather is developed the same way as in the data that RUCO relied on for its conclusion that weather is the principal cause of Southwest's under-recoveries of its allowed margin revenues. It includes the same information that RUCO relied upon for the years 2004-2006, but it also includes the six preceding years 1998-2003 and the most recent year, 2007, to complete a full ten-year period. During this ten-year period, the average effect of weather was to <u>increase</u> average use per customer, because the weather was, on average, colder than normal. For this ten-year period as a whole, weather did not cause any net under-recoveries for Southwest, and instead helped offset the under-recoveries caused by other factors. And this is not an artificially selected period, but simply the most recent ten complete years, including the three years in which RUCO found that weather caused very large under-recoveries.

Q. 37 At page 11, Mr. Rigsby suggests that Southwest's use of a ten-year period to determine normal weather for test year purposes "may well provide a truer picture of how weather impacts the Company." Does the use of a ten-year period negate the need for a weather decoupling mechanism?

A. 37 No. The only way to determine the impact of weather is to look at one year at a time, because Southwest does not accumulate and report its operating results for ten years at a time. But let us assume that what Mr. Rigsby meant to suggest was that defining normal test year weather as a ten-year average addresses Southwest's under-recovery problem. That is a reasonable suggestion, based on the expectation that a ten-year average would better reflect the effect of a long-term trend towards warmer weather, but it turns out that it does not help address year to year variations in weather.

Table REM-2 and the accompanying Charts REM-3 (Tucson) and REM-4 (Phoenix) show the ten-year normal data. They show that weather risk is due principally to the variations in HDDs from one winter heating season to the next. (There is also a risk from monthly variations, where the swings are even wider than on a seasonal basis, but I have not prepared any charts showing the monthly swings.) Some years are colder than normal, others are warmer than normal. Staff witness Radigan and RUCO witness Rigsby both agreed explicitly in responses to discovery questions from Southwest that absent the WNAP, customers bear the risk of colder than normal heating seasons, and Southwest bears the risk of warmer than normal heating seasons. (See questions 3-3 to Staff and 3-5 to RUCO.)

The WNAP moderates the risk of colder than normal winters for customers, because it provides a real-time downward adjustment of their bills when weather is colder than normal. In exchange, the customers pay an upward adjustment of their bills in warmer than normal winters, but even with these upward adjustments their bills remain lower than those bills would be with normal HDDs, and the upward adjustments moderate the risk of warmer than normal winters for Southwest. Southwest completes the circle by absorbing the revenue loss from the WNAP's downward adjustments to the customers' bills in colder than normal winters. Both sides thus experience a reduction in risk from the WNAP.

Q. 38 Does your analysis of the weather situation shed further light on the way RUCO and Mr. Rigsby may have reached the incorrect conclusion that the WNAP would shift risk away from Southwest and onto its customers?

A. 38 Yes, it does. Mr. Rigsby agrees that customers currently bear the risk of colder than normal weather, and he states at page 9 that the proposed WNAP "removes weather-related volatility from the non-gas component of customer bills". The only logical way to reconcile these premises with the RUCO position that the WNAP shifts risk onto customers is to assume that customers never receive much benefit from the WNAP in cold weather because colder than normal weather does not occur often enough to provide a significant benefit. Indeed, if one starts from RUCO's erroneous premise that most of the time the weather is warmer than normal, then it is easy to reach the conclusion that the WNAP hurts customers but does not help them. My analysis of the weather situation demonstrates that RUCO's view of the weather is badly flawed because it is based on much too small a sample of actual weather conditions, and that a reasonable statistical analysis indicates a completely different conclusion.

This same incorrect view of the weather may help to explain Staff witness Radigan's repeated characterization of the WNAP as an adjustment that customer's "don't like" because (they think) it increases their bills, and they apparently do not recognize that it also decreases their bills. If Mr. Radigan is also under the incorrect impression that warmer than normal weather is much more likely than colder than normal weather, then it is easy to see how he got from there to the conclusion that the WNAP is primarily a one-way street, just as RUCO did. The problem is not in their logic, but in their failure to have begun from a complete and accurate analysis of the weather situation.

Q. 39 Do any of Mr. Rigsby's responses to Southwest's data requests shed further light on his position on weather normalization?

A. 39 Yes. Question 6 in Southwest's third set of data requests to RUCO asks Mr. Rigsby to explain his belief that the WNAP shifts risk from Southwest to the customer, as opposed to mitigating risk for the benefit of both Southwest and the customer. Mr. Rigsby's revised response follows:

> The Company-proposed weather normalization adjustment provision shifts risk to the customer because the customer <u>will pay</u> the difference between actual temperature and weather adjusted heating degree days <u>regardless of weather conditions</u>. This in effect benefits SWG since it removes any weather-related risk that the Company faces. (<u>Emphasis</u> added.)

The fundamental error in this statement is the view that the customer "will <u>pay</u>", with no acknowledgement that the customer will receive a benefit from the WNAP if the actual degree-days are more than the normal degree-days. It is a gross misrepresentation of the WNAP to claim that the customer "will pay ... regardless of weather conditions." This misrepresentation is perhaps just an extension of RUCO's mistaken view that warmer than normal temperatures are the predominant condition for Southwest, but to claim that customers will pay "regardless of weather conditions" is to claim that actual weather can never be colder than normal.

If Mr. Rigsby's response is further revised to concede that the customer will pay <u>or receive</u> the difference between actual and normal weather, then it no longer follows that these WNAP adjustments cause an increase in risk. Quite to the contrary, as I have explained, the WNAP adjustments moderate the variations in customer bills and therefore reduce the customer's risk.

Q. 40 Do you have any further comments about Mr. Rigsby's testimony and exhibits?

A. 40 Attachment A to Mr. Rigsby's testimony is a July 26, 2007 letter from RUCO. It is RUCO's response to Southwest's report of the meetings among Southwest, ACC Staff, SWEEP, and RUCO to discuss rate design alternatives. One of the attachments to that letter is a slide presentation by LSU Professor David E. Dismukes to NASUCA in June 2007. The RUCO letter states that this presentation "covers the topic of incentives and energy efficiency more expansively" than an AGA paper attached to Southwest's report. So far as I am aware, the referenced AGA paper has not been filed as an exhibit in the present proceeding, but it is one of the sources that I used in preparing my direct testimony.

Mr. Rigsby does not state whether he agrees or disagrees with any of the material in Professor Dismukes' slide presentation, and the presentation itself does not indicate whether Professor Dismukes himself supports or opposes revenue decoupling. I have therefore refrained from addressing the substance of Professor Dismukes' slide presentation. I would note simply that I do not agree with all of the assertions there, and some of them are clearly incorrect.

Q. 41 Does this conclude your prepared rebuttal testimony?

A. 41 Yes, it does.

A RESPONSE TO THE NASUCA "DECOUPLING" RESOLUTION

ALLIANCE TO SAVE ENERGY [Jeffrey Harris]
AMERICAN COUNCIL FOR AN ENERGY EFFICIENT ECONOMY [Martin Kushler]
CONSERVATION LAW FOUNDATION [Seth Kaplan]
ENVIRONMENT NORTHEAST [Dan Sosland]
IZAAK WALTON LEAGUE OF AMERICA [William Grant]
NATURAL RESOURCES DEFENSE COUNCIL [Ralph Cavanagh]
NORTHWEST ENERGY COALITION [Nancy Hirsh]
ORION ENERGY [Steve Heins]
PACE ENERGY PROJECT [Fred Zalcman]
ROCKY MOUNTAIN INSTITUTE [Amory Lovins]
SOUTHERN ALLIANCE FOR CLEAN ENERGY [Stephen Smith]
WESTERN RESOURCE ADVOCATES [John Nielsen]

SEPTEMBER 2007

Introduction: The National Association of State Utility Consumer Advocates (NASUCA) adopted Resolution 2007-01 on June 12, 2007, expressing concerns about mechanisms that have been proposed in many states to remove financial obstacles to utility investments in energy efficiency and distributed resources. We offer this response in the spirit of constructive interchange between traditional allies and colleagues. Each section of the resolution is reprinted below, followed by our comments.

[TEXT OF NASUCA RESOLUTION 2007-1 FOLLOWS]

Whereas, the provision and promotion of energy efficiency measures are increasingly viewed by state commissions as a necessary component of utility service;

COMMENT: We agree, and because states have applied rigorous cost-effectiveness criteria to such programs, the result is to reduce energy bills for all customers.

Whereas, many states are now encouraging rate-regulated utilities to adopt energy efficiency programs and other demand-side measures to decrease the number of units of energy each utility's customers purchase from the utility;

COMMENT: We agree, and note that nowhere in this resolution does NASUCA dispute that utilities incur financial losses from these reduced sales, or that significantly expanded efforts to improve efficiency would boost such losses.

Whereas NASUCA has long supported the adoption of effective energy efficiency programs;

COMMENT: We acknowledge and appreciate the long-time support of many NASUCA members for investments in energy efficiency as an alternative to more costly generation and grid additions.

Whereas recent proposals by rate-regulated public utilities for the initiation or expansion of energy efficiency measures have featured utility rate incentives or revenue "decoupling" mechanisms that guarantee utilities a predetermined amount of revenues regardless of the number of units of energy sold;

Whereas, the utilities proposing decoupling measures seek guarantees from public utilities commissions that they will receive their allowed level of revenues;

COMMENT: Decoupling mechanisms don't "guarantee revenues" per se; they "guarantee" only recovery of fixed-cost revenue requirements that utility regulators have reviewed and authorized, "regardless of the number of units of energy sold." Decoupling does not affect revenues associated with variable charges like fuel payments.

Whereas, these utilities justify this departure from traditional rate-making principles on the theory they are being asked to help their customers purchase fewer energy units from them by promoting energy efficiency measures and other demand-side measures, thereby reducing their revenues and, consequently, their returns to their shareholders, and that decoupling mechanisms compensate utilities for revenues lost due to conservation;

COMMENT: First, it is not a "theory" that energy efficiency programs aim to reduce energy use, or that this hurts utilities financially if they recover authorized fixed costs through charges on energy use. Moreover, using periodic rate true-ups to make fixed-cost revenue recovery independent of sales is not a "departure from traditional rate-making practices" (see p. 7 below, reviewing the ample precedents for comparable "true-up" mechanisms). Decoupling removes a potent financial disincentive for utilities without (as too often has happened historically) reducing their customers' incentive to conserve and making more of their bill independent of consumption (by raising fixed charges and lowering variable charges). And the rationale for decoupling goes beyond encouraging utilities to support energy efficiency programs and distributed resources; the hope is that utilities also will endorse mandatory efficiency standards and other non-utility initiatives to help customers save energy cost-effectively, while opposing promotional rate structures that reward increased consumption ("the more you use, the less you pay").

Whereas, these utilities contend that because these measures reduce their revenues, they have a disincentive to encourage programs that aid their customers in purchasing fewer units of energy;

COMMENT: We agree that utilities believe this, and the resolution gives no reason to disagree.

Whereas, historically, rates have been set in periodic rate cases by matching test-year revenues with test-year expenses, adding pro forma adjustments and allowing the utilities an opportunity to earn a reasonable rate of return on their investments in exchange for a state-protected monopoly;

COMMENT: We agree.

Whereas revenue guarantee mechanisms allow rate adjustments to occur based upon one element that affects a utility's revenue requirement, without supervision or review of other factors that may offset the need for such a rate change;

COMMENT: Decoupling does not readjust utilities' authorized fixed-cost revenue requirements "without supervision or review of other factors;" it simply makes recovery of fully adjudicated revenue requirements independent of subsequent fluctuations in retail energy use. There is, as a result, no reason to review other rate case assumptions when decoupling adjustments are made; note that utilities may either gain or lose from each adjustment, depending on how rapidly retail sales are decreasing or increasing. Finally, unlike routinely applied "revenue guarantee mechanisms" such as fuel adjustment clauses, decoupling mechanisms focus specifically on removing a potent financial obstacle to cost-effective energy efficiency measures that benefit all customers.

Whereas, historically, rate-regulated utilities were not guaranteed they would earn the allowed return; rather, earnings depended on capable management operating the utilities in an efficient manner;

COMMENT: We agree, and decoupling in no way affects utilities' incentive to operate efficiently, as explained further below.

Whereas, many utilities proposing revenue decoupling request compensation for revenue lost per customer, implying that sales volumes are declining, when in fact these utilities' total energy sales revenues are stable or increasing;

COMMENT: Decoupling mechanisms based on authorized revenue requirements per customer do not "imply" declining sales volumes; they reflect a judgment that any growth in fixed cost revenue recovery between rate cases should reflect increases in the number of customer served. The alternative, without decoupling, is to tie such growth directly to increases in electricity and natural gas sales, which is the worst possible outcome from the standpoint of society's interest in maximizing cost-effective energy efficiency. We agree with the observation that "many utilities'" energy sales revenues are increasing, but that is because their retail energy sales keep rising in the face of pervasive market barriers to energy efficiency; the whole point of decoupling is to eliminate a perverse barrier to measures and policies that would reduce electricity and natural gas consumption.

Whereas, there are a number of factors that may cause a utility to sell fewer units of energy over a period of time, including weather, changing economic conditions, shifts in population, loss of large customers and switches to other types of energy, as well as energy efficiency and other demand-side measures;

COMMENT: We agree, but it is precisely the complexity of factors affecting energy use that make decoupling mechanisms appealing in their simplicity. The mechanisms do not attempt to disentangle all these intertwined causes and effects: decoupling merely ensures that recovery of authorized fixed costs is not affected by fluctuations in sales that regulators did not anticipate when they set the utility rates that are intended to recover those costs. Of course, for regulators who do not want to shift financial risk associated with unusual weather conditions from utilities to customers, retail sales can easily be weather-adjusted before decoupling adjustments are made.

Whereas many utilities have been offering cost-effective energy efficiency programs and actively marketing these programs for years without proposing or implementing rate incentives or revenue guarantee mechanisms such as decoupling, and have continued to enjoy financial health;

COMMENT: But precisely because utilities typically have a much stronger incentive to build and own power plants and transmission than to help customers conserve, utilities' energy efficiency record has been highly uneven over time, and on average utilities today are targeting average annual energy savings amounting to less than half of one percent of customers' annual consumption. In sum, and not at all surprisingly, most utilities' economic self-interest is wholly consistent with their relatively modest success in achieving energy savings.

Whereas past experience has shown that revenue guarantee mechanisms such as decoupling may result in significant rate increases to customers;

COMMENT: This is certainly true of fuel adjustment clauses, but the resolution provides no example of a decoupling mechanism that has resulted in "significant rate increases to customers," and such mechanisms can readily be designed with built-in rate impact safeguards. For example, PacifiCorp's most recent Oregon mechanism operated within a 2 percent annual rate impact limit, and Idaho Power's current mechanism constrains annual decoupling adjustments to 3 percent or less. Average annual rate impacts of decoupling in California over the policy's first decade were less than half of one percent annually. Finally, it bears emphasis that decoupling adjustments can go in either direction; adopting a mechanism does not mean automatic rate increases. In any year when electricity and gas consumption grow at unexpectedly high rates, utilities must give the additional revenues back in the form of rate reductions. Customers collectively win under either scenario, of course; cost-effective energy efficiency programs steadily reduce systemwide energy *bills*, regardless of the direction of each modest decoupling-related *rate* adjustment.

Whereas some utilities have referenced the benefit of encouraging energy efficiency programs as a justification for revenue guarantee mechanisms without in fact offering any energy efficiency programs, indicating that the revenue guarantee mechanisms are attractive to utilities for reasons other than their interest in promoting energy conservation;

COMMENT: We are not aware that this has ever occurred, but we agree that Commissions should link approval of decoupling mechanism to utilities' agreement to offer a robust portfolio of cost-effective energy efficiency programs.

Whereas past experience has shown that rate increases prompted by revenue guarantee mechanisms such as decoupling are often driven not so much by reduced consumption caused by utility energy efficiency programs, as by reduced consumption due to normal business risks such as changes in weather, price sensitivity, or changes in the state of the economy;

COMMENT: Other factors do indeed affect energy consumption, but why would society want unexpected changes in energy consumption to affect utilities' ability to recover authorized costs that are unrelated to consumption – particularly when the result is a palpable barrier to energy efficiency progress? Also, the resolution appears once again to be assuming incorrectly that decoupling can only increase rates, when in fact adjustments in both directions are routine, as explained above. Note, finally, that other factors affecting consumption include mandatory state and federal efficiency standards, rate designs that boost rewards for saving energy, and public education on the linkages between energy use and global warming pollution. Utility support for all these measures makes them more feasible and productive, and without decoupling all these measures automatically hurt utilities financially.

Whereas utilities are better situated than are consumers or state regulators to anticipate, plan for, and respond to changes in revenue prompted by normal business risks, and the shifting of normal business risks away from utilities insulates them from business changes and reduces their incentive to operate efficiently and effectively;

COMMENT: Utilities' incentives to "operate efficiently and effectively" are not affected by decoupling, since with or without it the company keeps any operating savings that it achieves between rate cases and absorbs any cost overruns. The true-ups associated with decoupling guarantee only recovery of an authorized revenue requirement, not any particular level of realized net revenues.

Whereas the traditional ratemaking process has historically compensated utilities for experiencing revenue variations associated with normal business risks;

COMMENT: We agree in general, but ratemaking processes typically also have made successful energy efficiency programs automatic financial losers for utilities, while creating a substantial earnings opportunity for investments in more expensive substitutes like generation and grid assets. Decoupling helps fix this misalignment; it does not enlarge authorized revenue requirements, and as indicated earlier it includes both upsides and downsides for utility shareholders (it eliminates under-recoveries of authorized costs due to reduced energy sales, but it simultaneously takes away the upside associated with over-recoveries due to increased energy sales, from which many utilities have profited handsomely for decades).

NOW THEREFORE NASUCA RESOLVES:

To continue its long tradition of support for the adoption of effective energy efficiency programs;

COMMENT: We applaud this tradition of support, but history shows that the full potential for such programs cannot be realized without a better alignment of shareholder and customer interests.

And to oppose decoupling mechanisms that would guarantee utilities the recovery of a predetermined level of revenue without regard to the number of energy units sold and the cause of lost revenue between rate cases;

COMMENT: Here and subsequently, this resolution hints that NASUCA might look favorably on recovery of lost revenues from kilowatt-hours and therms specifically determined to have been saved by utility conservation programs. We strongly encourage NASUCA to rethink this proposal, which introduce (as a substitute for decoupling) regular payments to utilities of lost revenues, based on estimates of kilowatt-hours saved by utility programs. The calculations themselves would be hugely contentious and the rate impacts increasingly significant, since each year's savings and lost revenues would add to the previous year's tally, and each stream of savings and payments could persist over decades, with steadily escalating financial consequences for all involved (often more than three-fifths of the retail value of kilowatt-hours and one-fourth of the retail value of therms represent "lost revenues" for this purpose). And the system would create additional perverse incentives for utilities, since the most lucrative programs would be those that looked good on paper while saving little or nothing in practice (allowing double recovery of "lost revenues"). Finally, the system would be inherently inequitable and asymmetrical, since the utility would be recovering its "lost revenues" from energy efficiency gains without being required to give up its "found revenues" from growth in sales associated with economic expansion elsewhere on the system.

BE IT FURTHER RESOLVED:

NASUCA urges Public Utilities Commissions to disallow revenue true-ups between rate cases that violate the matching principle, the prohibition against retroactive ratemaking, the prohibition against single-issue ratemaking, or that diminish the incentives to control costs that would otherwise apply between rate cases;

COMMENT: Traditional ratemaking makes ample provision for "trackers" and/or true-ups associated with, e.g., fuel costs; decoupling is no different in its "single issue" and "retroactive" implications, rate impacts are lower, and the public interest justification is at least as compelling. Ken Costello of the National Regulatory Research Institute has investigated whether decoupling mechanisms meet the traditional tests justifying state utility regulators' use of "tracking mechanisms that adjust rates and revenues whenever sales deviate from their targeted level," and has concluded that "[u]nless a state commission faces legal restrictions in implementing a 'sales tracker' or has a built-in policy of limiting trackers in general, [revenue decoupling] would seem to meet the

regulatory threshold for a tracker." Ken Costello, Briefing Paper: Revenue Decoupling for Natural Gas Utilities, p. 9 (National Regulatory Research Institute, April 2006).

NASUCA urges State legislatures and Public Utilities Commissions to, prior to using decoupling as a means to blunt utility opposition to energy efficiency and other demand-side measures, (1) consider alternative measures that more efficiently promote energy efficiency and other demand side measures; (2) evaluate whether a utility proposing the adoption of a revenue decoupling mechanism has demonstrated a commitment to energy efficiency programs in the recent past; and (3) examine whether a utility proposing the adoption of a revenue decoupling mechanism has a history of prudently and reasonably utilizing alternative ratemaking tools;

If decoupling is allowed by any state commission, NASUCA recommends that the mechanism be structured to (1) prevent over-earning and provide a significant downward adjustment to the utilities' ROE in recognition of the significant reduction in risk associated with the use of a decoupling mechanism, (2) ensure the utility engages in incremental conservation efforts, such as including conservation targets and reduced or withheld recovery should the utility fail to meet those targets, and (3) require utilities to demonstrate that the reduced usage reflected in monthly revenue decoupling adjustments are specifically linked to the utility's promotion of energy efficiency programs.

COMMENT: We agree with NASUCA that decoupling should be linked to utilities' energy efficiency commitments, but we disagree strongly with the proposal to link decoupling adjustments specifically to savings from conservation programs (as explained above on p. 6). Moreover, it is at best premature to link decoupling in any way to utilities' ROE. It is important to recognize that regulators and utilities have only limited experience with decoupling outside California (whose PUC has never invoked decoupling as an ROE consideration), and that decoupling creates both upside and downside exposure for company shareholders (they will no longer under-recover authorized fixed costs if retail sales drop below expectations, but they also will lose their longstanding opportunity for gains from sales increases). Whether the net result is a material change in the company's risk profile cannot be determined without company-specific and capital market experience. This is particularly true for mechanisms that are weather-adjusted to avoid affecting current allocation of weather-related risks. Finally, if the goal is to encourage utilities to devote more management resources and creativity to energy efficiency, tying decoupling to the immediate imposition of a reduction in shareholder returns would be wholly counterproductive.

STATE OF NEW YORK

Public Service Commission

Patricia L. Acampora, Chairwoman

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FOR RELEASE: IMMEDIATELY

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PSC SEEKS MORE EFFICIENT ENERGY USE

-Utility Revenue Decoupling Mechanisms to Eliminate Disincentives-

Albany, NY—4/18/07—The New York State Public Service Commission (Commission) today directed the state's major electric and gas utilities to develop proposals for true-up based delivery service revenue decoupling mechanisms. These ratemaking changes are intended to enhance the achievement of customer-initiated efficient energy use by reducing or eliminating disincentives that may discourage utilities from actively promoting customer investments in energy efficiency, renewable technologies and distributed generation. The proposals would be considered in ongoing and future rate cases.

"To the extent current design of utility delivery rates continue to link the recovery of utility fixed costs, including profits, to the volume of actual sales, disincentives exist that limit the utilities' interest in promoting efficient energy use," said Commission Chairwoman Patricia L. Acampora. "Creating a mechanism to reduce or eliminate the dependence of utilities' revenues on sales, would thereby increase the utilities' interest in the promotion of customer-initiated more efficient energy use. The resulting public benefits from new energy efficiency programs, renewable technologies and distributed generation could be substantial. Energy efficiency improvements, in particular, limit unnecessary load growth and delay or possibly avoid the installation of costly, new distribution, transmission or generation facilities."

The Commission initiated a proceeding in 2003 to investigate potential electric delivery rate disincentives against the promotion of energy efficiency, renewable technologies and distributed generation as part of an overall state program to facilitate customer access to existing and developing technologies for the clean production and/or conservation of energy. Subsequently in 2006, the Commission established a separate proceeding expanding its inquiry to include the gas utilities. A Notice of Proposed Rulemaking concerning each of the two proceedings was published in the State Register on July 12, 2006, in accordance with the State Administrative Procedure Act. Several interested parties filed comments in the proceedings.

Based upon a thorough review of the comments, the Commission today determined that properly designed utility revenue decoupling mechanisms are needed at this time to address potential disincentives to utilities' promoting and implementing more efficient energy use. The Commission will be requiring the utilities to develop mechanisms that true-up forecast and actual delivery service revenues resulting in significantly reduced or eliminated disincentives caused by the ongoing recovery of utility fixed delivery costs via volumetric (per kWh) rates and marginal consumption blocks. The true-up would include, among other things, any net lost revenues attributable to the achievement of more efficient energy use. The true-up would be considered no less frequently than once per year.

The Commission will be requiring the utilities to file revenue decoupling proposals in ongoing and new rate cases so that the utilities, staff of the Department of Public Service, and interested parties may consider utility-specific circumstances and customer bill impacts within service classifications before their implementation. Also, the utilities are encouraged to continue to implement cost-based delivery rate design improvements and hourly pricing tariffs for commodity service where appropriate.

In addition to the implementation of broad-based revenue decoupling mechanisms that incorporate appropriate true-ups, the Commission today stated that the promotion of customer-sited renewable resources and distributed generation technologies should be addressed through greater vigilance on the part of the utilities regarding the proper application and administration of their interconnection rules and procedures, as well as the expanded application of existing electric and gas standby delivery rate structures.

The Commission will issue a written order reflecting today's decision. That order, when available, can be obtained from the Commission's Web site at http://www.dps.state.ny.us by accessing the Commission Documents section of the homepage and referencing Cases 03-E-0640 and 06-G-0746. Many libraries offer free Internet access. Commission orders can also be obtained from its Files Office, 14th floor, Three Empire State Plaza, Albany, NY 12223 (518-474-2500).

Docket No. G–01551A–07–0504
Table REM-1

Southwest Gas Corporation

Actual and Weather-Adjusted Gas Use per [Residential] Customer, 1998 – 2007
and Corresponding Differences between Actual and Average Weather

	Weather – HDDs						Average Gas Use per Customer			
	Tucson			Phoenix						
Calendar Year	Actual	10-year Average	Variance	Actual	10-year Average	Variance	Actual	Adjusted for Weather	Effect of Weather	Year
1998	1,736.0	1,399.0	337.0	1,207.5	923.4	284.1	442.8	375.8	67.0	1998
1999	1,392.0	1,444.2	(52.2)	927.5	950.3	(22.8)	381.6	378.6	3.0	1999
2000	1,517.5	1,448.8	68.7	975.0	954.4	20.7	379.8	375.6	4.2	2000
2001	1,727.0	1,430.8	296.3	1,122.5	944.5	178.1	382.5	341.8	40.7	2001
2002	1,440.5	1,467.9	(27.4)	808.0	974.6	(166.6)	353.0	362.6	(9.6)	2002
2003	1,323.5	1,471.9	(148.4)	734.5	982.6	(248.1)	330.8	354.3	(23.5)	2003
2004	1,633.5	1,459.1	174.5	1,000.0	957.1	43.0	358.7	338.4	20.3	2004
2005	1,258.5	1,475.9	(217.4)	764.0	957.2	(193.2)	320.7	343.0	(22.3)	2005
2006	1,295.0	1,486.6	(191.6)	854.0	940.6	(86.6)	309.2	342.3	(33.1)	2006
2007	1,513.5	1,494.4	19.1	989.5	944.9	44.7	321.6	318.1	3.5	2007
Average	1,483.7	1,457.8	25.9	938.3	952.9	(14.7)	358.1	353.1	5.0	Average

Note: Actual HDDs are for calendar years, corresponding to Attachment 1 of Attachment A to Mr. Rigsby's Direct Testimony on Rate Design. The 10-year average is for the 10 heating seasons completed prior to the beginning of the calendar year.

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Table REM-2

Southwest Gas Corporation

Annual Heating Season (July – June) Heating Degree Days, Tucson and Phoenix and Lagged Ten-Year and 30-Year Averages

	Tucson			Phoenix		
Heating Season	Current Year	Ten-Year Average	30-Year Average	Current Year	Ten-Year Average	30-Year Average
1948 – 1949	2,186.0			2,047.0		
1949 – 1950	1,447.5			1,314.0		
1950 – 1951	1,453.0			1,182.5		
1951 – 1952	1,901.5			1,688.0		
1952 – 1953	1,727.0			1,543.5		
1953 – 1954	1,387.0			1,404.0		
1954 – 1955	1,774.0			1,474.0		
1955 – 1956	1,512.5			1,358.0		
1956 – 1957	1,389.5			1,273.5		
1957 – 1958	1,805.5	1,658.4		1,480.5	1,476.5	
1958 – 1959	1,500.5	1,589.8		1,146.5	1,386.5	
1959 – 1960	1,947.5	1,639.8		1,486.5	1,403.7	
1960 – 1961	1,712.5	1,665.8		1,408.5	1,426.3	
1961 – 1962	2,005.5	1,676.2		1,655.0	1,423.0	
1962 – 1963	1,563.0	1,659.8		1,307.5	1,399.4	
1963 – 1964	2,087.5	1,729.8		1,948.5	1,453.9	
1964 – 1965	1,894.5	1,741.9		1,862.0	1,492.7	
1965 – 1966	1,777.0	1,768.3		1,623.0	1,519.2	
1966 – 1967	1,489.0	1,778.3		1,482.0	1,540.0	
1967 – 1968	1,488.0	1,746.5		1,367.5	1,528.7	
1968 – 1969	1,713.5	1,767.8		1,612.5	1,575.3	
1969 – 1970	1,767.0	1,749.8		1,207.0	1,547.4	
1970 – 1971	1,766.0	1,755.1		1,365.5	1,543.1	
1971 – 1972	1,782.0	1,732.8		1,369.0	1,514.5	
1972 – 1973	2,442.0	1,820.7		1,594.5	1,543.2	
1973 – 1974	1,694.5	1,781.4		1,124.0	1,460.7	
1974 – 1975	2,271.5	1,819.1		1,605.0	1,435.0	
1975 – 1976	1,507.0	1,792.1		1,121.5	1,384.9	
1976 – 1977	1,672.0	1,810.4		1,074.5	1,344.1	
1977 – 1978	1,306.0	1,792.2	1,732.3	744.5	1,281.8	1,429.0
1978 – 1979	1,912.0	1,812.0	1,723.2	1,474.0	1,268.0	1,409.9
1979 – 1980	1,464.0	1,781.7	1,723.8	1,074.0	1,254.7	1,401.9
1980 – 1981	1,316.0	1,736.7	1,719.2	661.0	1,184.2	1,384.5
1981 – 1982	1,487.0	1,707.2	1,705.4	873.5	1,134.7	1,357.4
1982 – 1983	1,845.5	1,647.6	1,709.3	1,095.0	1,084.7	1,342.4
1983 – 1984	1,600.0	1,638.1	1,716.4	826.5	1,055.0	1,323.2
1984 – 1985	1,738.5	1,584.8	1,715.2	1,164.5	1,010.9	1,312.9
1985 – 1986	1,211.0	1,555.2	1,705.2	786.0	977.4	1,293.8
1986 – 1987	1,564.0	1,544.4	1,711.0	916.0	961.5	1,281.9
1987 – 1988	1,428.0	1,556.6	1,698.4	996.5	986.7	1,265.7
1988 – 1989	1,403.0	1,505.7	1,695.2	943.5	933.7	1,259.0
1989 – 1990	1,451.5	1,504.5	1,678.6	927.5	919.0	1,240.3
1990 – 1991	1,490.5	1,521.9	1,671.2	907.0	943.6	1,223.6
1991 – 1992	1,436.5	1,516.9	1,652.3	819.0	938.2	1,195.8
1992 – 1993	1,469.0	1,479.2	1,649.1	947.5	923.4	1,183.8
1993 – 1994	1,337.5	1,453.0	1,624.1	930.0	933.8	1,149.8
1994 – 1995	1,400.0	1,419.1	1,607.7	1,062.0	923.5	1,123.1
1995 – 1996	1,116.0	1,409.6	1,585.6	736.0	918.5	1,093.6
1996 – 1997	1,458.0	1,399.0	1,584.6	965.0	923.4	1,076.3
1997 – 1998	1,879.5	1,444.2	1,597.6	1,265.5	950.3	1,072.9
1998 – 1999	1,449.5	1,448.8	1,588.8	984.0	954.4	1,052.0
1999 – 2000	1,271.0	1,430.8	1,572.3	828.5	944.5	1,039.4
2000 – 2001	1,862.0	1,467.9	1,575.5	1,208.0	974.6	1,034.1
2001 – 2002	1,476.0	1,471.9	1,565.3	899.5	982.6	1,018.5
2002 – 2003	1,341.0	1,459.1	1,528.6	692.0	957.1	988.4
2003 – 2004	1,506.0	1,475.9	1,522.3	931.5	957.2	982.0
2004 – 2005	1,507.0	1,486.6	1,496.8	895.5	940.6	958.3
2005 – 2006	1,194.0	1,494.4	1,486.4	779.0	944.9	946.9
2006 – 2007	1,504.0	1,499.0	1,480.8	974.0	945.8	943.6

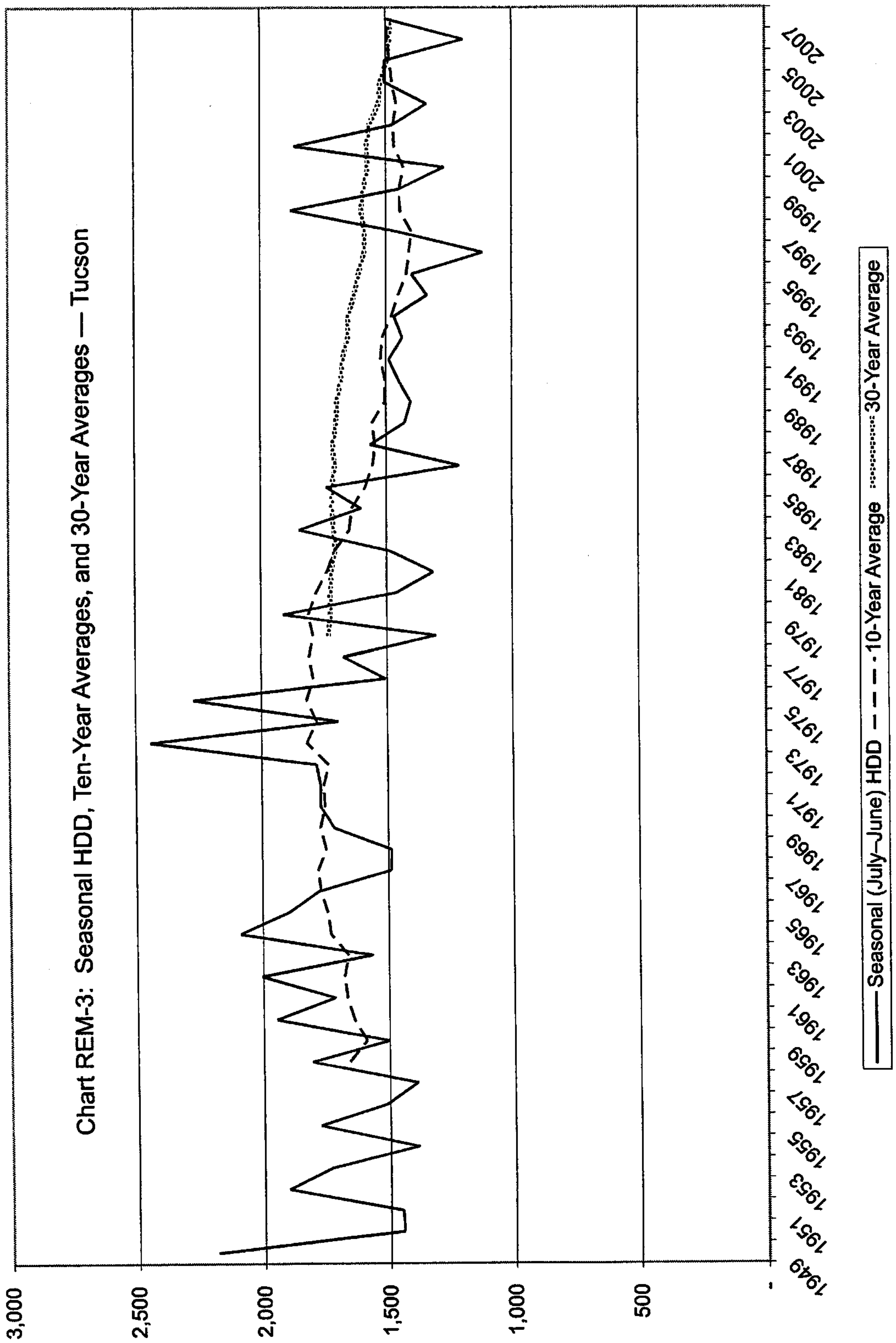
Chart REM-3: Seasonal HDD, Ten-Year Averages, and 30-Year Averages — Tucson
3,000
2,500
2,000
1,500
1,000
500
-
1949
1951
1953
1955
1957
1959
1961
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
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1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
Seasonal (July–June) HDD
10-Year Average
30-Year Average

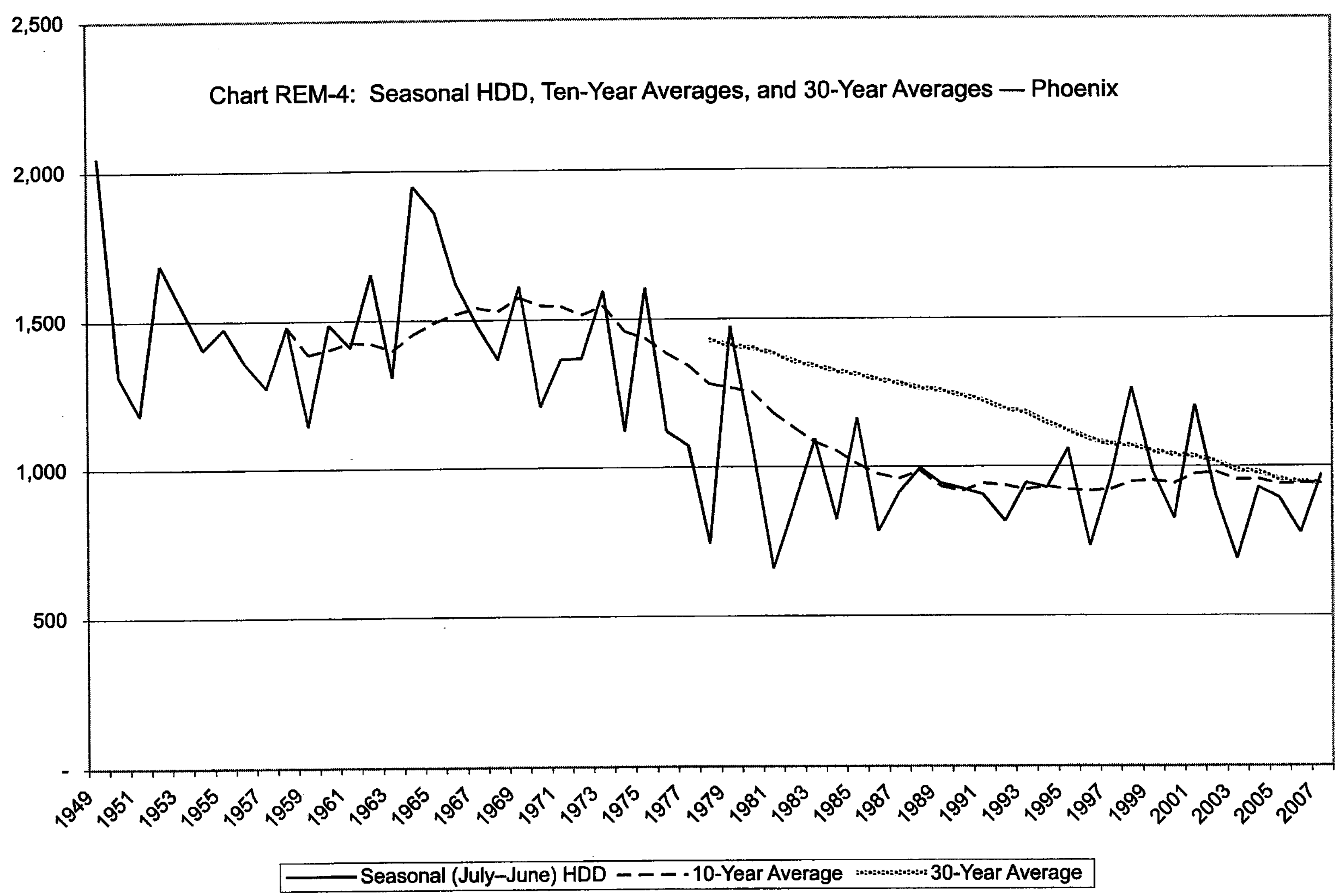
Chart REM-4: Seasonal HDD, Ten-Year Averages, and 30-Year Averages — Phoenix
2,500
2,000
1,500
1,000
500
-
1949
1951
1953
1955
1957
1959
1961
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
Seasonal (July–June) HDD
10-Year Average
30-Year Average

Tab

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

PREPARED REBUTTAL TESTIMONY
OF
A. BROOKS CONGDON

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Prepared Rebuttal Testimony
Of
A. BROOKS CONGDON

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
A. BROOKS CONGDON

I. INTRODUCTION

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

A. 1 My name is A. Brooks Congdon. I am the Manager/Pricing and Tariffs for Southwest Gas Corporation (Southwest or Company). My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q 2 Are you the same A. Brooks Congdon who submitted prepared direct testimony in this Docket?

A. 2 Yes, I am.

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

A. 3 The purpose of my rebuttal testimony is to respond to the direct testimony presented by the Residential Utility Consumer Office (RUCO); the Arizona Corporation Commission Utilities Division Staff (Staff); and the Southwest Energy Efficiency Project (SWEEP) with respect to their recommendations and comments concerning Southwest's proposed rate design, tariff mechanisms, and revenue allocation to customer classes, and demand side management funding levels.

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

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

Q. 5 Please summarize your rebuttal testimony.

A. 5 My rebuttal testimony will address the following topics:

1) Southwest's continued financial pressure resulting from declining customer usage and sensitivity to variations in weather.

2) Southwest's participation in the rate design collaborative process following the Commission's decision in Southwest's last general rate case, including how Southwest applied what it learned to its rate design proposals in this general rate case.

3) Staff's critique of Southwest's residential rate design proposals.

4) The reasons why Staff's and RUCO's proposed rate designs do not sufficiently address the continued financial pressure facing Southwest as a result of declining customer usage and sensitivity to variations in weather.

5) Staff's allocation of non-gas revenue to customer classes.

6) Why Southwest's proposed residential rate design does not require any change to the Company's purchased gas adjustment mechanism.

7) Increased demand side management (DSM) spending and

the need for full revenue decoupling.

II. SOUTHWEST'S CONTINUED FINANCIAL PRESSURE FROM DECLINING CUSTOMER USAGE AND WEATHER SENSITIVITY

Q. 6 Please identify and explain the two primary issues presently facing Southwest with respect to rate design?

A. 6 The two primary issues presently facing Southwest with respect to rate design are: (1) declining usage per customer and (2) sensitivity to weather.

Q. 7 Do the parties to this docket recognize these two issues?

A. 7 Yes. In one form or another, the parties, with the exception of Staff, recognize the challenges Southwest faces due to declining customer usage and usage variability due to weather. For instance, RUCO witness William Rigsby states:

> "this is not to say that the issues and concerns the Company cites for wanting these decoupling mechanisms do not have some validity. . . . these concerns include the continued decline in average customer consumption, the relative proportion between SWG's fixed and variable costs to the Company's existing fixed and variable rates, and the resultant strain that puts on SWG's opportunity to recover its authorized rate of return.[1]

AIC witness Hansen acknowledges the problems when he states "decoupling will likely reduce the frequency of rate cases" and that decoupling will reduce "the

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[1] Rigsby Rate Design Direct, p. 15, lns. 17-23 and p. 16, line1.

financial effects associated with changes in customer usage levels over time."[2] Mr. Hansen also recognizes the issue of sensitivity to weather when he notes that "when non-gas costs are recovered through volumetric rates, weather fluctuations lead to significant variability in customer payments for, and receipt of, non-gas revenue."[3] SWEEP witness Jeff Schlegel also recognizes the issue of declining use per customer when he states "The financial disincentive is particularly strong for natural gas utilities that have experienced an overall trend of declining gas usage per customer, which is the situation for Southwest Gas."[4]

Q. 8 Please explain how Southwest's rate design proposals provide the Commission with the tools necessary to address the two primary issues confronting Southwest?

A. 8 The Commission can use the rate design proposals presented by Southwest to achieve full revenue decoupling by implementing the WNAP and the RDAP. Implementation of the RDAP will protect Southwest and its customers from non-weather-related changes in cost recovery. Implementation of the WNAP eliminates weather-related risk for both Southwest and its customers equally, but does not protect customers or Southwest against non-weather-related variations in

[2] Hansen Rate Design Direct, p. 13, lns. 1-2.
[3] Id., p. 8, lns 8-10.
[4] Schlegel Direct, p. 4.

customer usage. Implementation of Southwest's proposed volumetric residential rate design methodology and increased basic service charge reduces, but does not eliminate, cost recovery variations due to weather-related and non-weather-related variations in customer use.

Q. 9. What do you mean by Southwest's proposed residential "Volumetric Rate Design"?

A. 9. By Volumetric Rate Design, I am referring to Southwest's proposal to combine a declining block rate for non-gas charges with an inverted block rate for gas costs for accounting purposes. The effect is that customers will see a single commodity rate applicable to all of their usage, while, through its accounting process, Southwest retains the benefit of a declining block rate to enhance its opportunity to recover its costs of providing service. These accounting changes, in conjunction with Southwest's proposals to flatten the commodity charge and increase the basic service charge constitute Southwest's proposed residential rate design.

Q. 10 You mentioned that in one form or another, all parties, except for Staff, recognize the challenges facing the Company with respect to declining customer usage and sensitivity to weather. Please explain.

A. 10 Staff's witness, Mr. Radigan, never acknowledges the problems, but instead summarily dismisses the Company's testimony, exhibits, and analysis by simply stating disagreement with the Company, without offering any relevant evidence or information to invalidate the information he cites from the Company.

Unlike Mr. Radigan's testimony, Southwest, RUCO, SWEEP, and AIC all recognize the Company's challenges of declining customer usage and weather sensitivity, and presented rate design alternatives in response to the Commission's directive in Decision No. 68487. For example:

1) Although RUCO's residential rate design proposal does not adequately address the Company's rate design issues, in order to provide Southwest a better opportunity to recover its fixed cost of providing service, RUCO proposes significantly greater movement in Southwest's residential basic service charge than Staff.
2) SWEEP supports Southwest's proposed RDAP.
3) AIC supports Southwest's proposed full revenue decoupling through the RDAP and WNAP.

In other words, every party to the case, with the exception of Staff, believes changes to the status quo are warranted and have offered alternatives for the Commission's consideration in this regard.

Q. 11 Do you take exception to Mr. Radigan's statements that "[t]he Commission also wanted evidence that declining customer usage would continue, to what level and whether conservation efforts are the cause. No evidence on either of these issues was presented in this case. No evidence was provided that showed that the Company needs 'full Revenue Decoupling.'"[5]

A. 11 Yes. Contrary to Mr. Radigan's contentions and conclusions, Southwest provided evidence that declining customer usage continues and to what level conservation is the cause. For example:

1) Company witness Jamie Cattanach presented direct testimony, at pages 9-14, demonstrating that average use per residential customer is continuing to decline at a rate of 6 therms per year and, for a variety of reasons, should be expected to continue to decline.

2) Company witness Robert Mashas presented direct testimony illustrating the significant dollar effect declining residential use per customer has had on the Company at pages 6-8 of his prefiled direct testimony.

3) Attached as Rebuttal Exhibit No.__(ABC-1) is an analysis Southwest performed and provided to all parties in the case in response to a RUCO data request which illustrates and quantifies the historical weather and conservation related losses experienced by the Company. Rebuttal Exhibit No.__(ABC-1) demonstrates that over the ten-year

[5] Radigan Decoupling Direct., p. 10, lns. 5-8.

period from 1998 thru 2007, Southwest experienced a $112.4 million shortfall in residential non-gas revenue from the amount rates were designed to recover. Of this amount, $118.2 million was non-weather-related (i.e., conservation and other possible variables). During this same time period, weather actually made a positive contribution to Southwest's recovery of margin in the amount of $5.8 million, which would have benefited customers if Southwest had a weather normalization adjustment mechanism similar to the WNAP.

4) Company witness Cattanach also filed rebuttal testimony indicating that since the close of the test period through the 12-month period ending March 2008, residential use per customer declined from an average of 332 therms to 319 therms on an annual basis.

Q. 12 Under Staff's or RUCO's proposed residential rate design, what will be the effect of using Southwest's as filed residential customer volumes to establish commodity rates?

A. 12 Under both Staff's and RUCO's proposed rate designs, residential commodity rates established using the filed customer volumes cannot reasonably be expected to recover the Commission's authorized cost of providing service. Therefore, from the day rates are placed into service, Southwest will be denied a reasonable opportunity to earn its authorized rate of return.

Q. 13 Please quantify the effect of Mr. Cattanach's most recent twelve-month weather normalized residential volumes on Southwest's test period revenue at presently effective rates.

A. 13 The reduction in residential volumes results in a $6,292,707 decrease to test period revenue at present rates as quantified in Rebuttal Exhibit No.__(ABC-2).

Q. 14 What are the financial consequences to the Company associated with the known and measurable change in residential use per customer usage from 332 therms to 319 therms on a going-forward basis?

A. 14 If the Commission approves Southwest's proposed RDAP there would be no financial consequences as the test period RDAP would capture the differences between authorized and actual weather-adjusted non-gas revenue. However, without the RDAP, failure to recognize the reduction in residential usage, from 332 therms to 319 therms average use per customer, will deprive Southwest of the reasonable opportunity to recover $6,292,707, plus an additional amount associated with whatever increase is ultimately authorized, in residential revenue.

<u>III. RATE DESIGN COLLABORATIVE PROCESS FOLLOWING DECISION No. 68487</u>

Q. 15 Please respond to Staff's contention that the Company's proposals should be rejected due to the lack of stakeholder support.[6]

A. 15 The fact that no consensus was reached in the collaborative should not be used as a basis to reject all of Southwest's rate design proposals in this case. Through the collaborative process, Southwest gained a better appreciation of the participating stakeholders' concerns and attempted to address those concerns in its rate design proposals.

Q. 16 Please describe how Southwest was able to utilitize the results of collaborative process in developing its rate design proposals.

A. 16 In response to RUCO's concern expressed during the collaborative that weather- and conservation-related changes in use per customer be separately addressed, Southwest proposed two separate and distinct tariff mechanisms to recover the non-gas portion of customer bills based on weather-adjusted volumes (the WNAP) and to recover or refund differences between actual and weather-adjusted non-gas revenues (the RDAP).

To respond to concerns expressed by Staff, RUCO and SWEEP (and the Commission in Decision No. 68487) regarding large increases in fixed charges, Southwest structured its Volumetric Rate Design proposal to include accounting changes for non-gas and gas costs. This rate design stabilizes residential cost recovery without large

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[6] Id., p. 10, line 18.

increases to the basic service charge as would otherwise be required under traditional approaches to rate design in order to do so.

Q. 17 Do you believe the rate design collaborative process and Southwest's rate design proposals fully respond to the direction provided by the Commission in Decision No. 68487?

A. 17 Yes. In Decision No. 68487, the Commission clearly recognized the problems facing the Company when it stated that "Southwest Gas is facing increased financial pressure due to declining usage on a per customer basis."[7] The Commission also directed Southwest and other parties to seek rate design alternatives when it stated "We encourage the parties to this proceeding to seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders."[8] As stated in my prepared direct testimony and more fully above, the Company considered the Commission's directives from Decision 68487 and the opinions expressed by the participating stakeholders at the rate design collaborative meetings when it developed its rate design proposals in this case. The Commission certainly has not stated that the inability of the stakeholders to reach settlement or consensus during the collaborative process

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[7] Decision No. 68487, p. 33, lns 26-27.
[8] Id. at p. 34, lns 14-15.

would be a basis for the Commission to reject or not thoroughly consider proposals that mitigate or eliminate many concerns raised by the various stakeholders. Indeed, if a consensus of the collaborative group is required for the Commission to implement revenue decoupling then the Commission has in effect delegated its decision making authority to the participating stakeholders. The Company finds that possibility highly unlikely and believes that the Commission always intended to evaluate future proposals on their merits.

<u>IV. RESPONSE TO STAFF'S CRITIQUE OF SOUTHWEST'S RESIDENTIAL RATE DESIGN PROPOSALS</u>

Q. 18 What are the three reasons Staff provided as support for its recommendation to reject Southwest's proposed residential Volumetric Rate Design?

A. 18 Mr. Radigan states that Southwest's proposed Volumetric Rate Design should be rejected for three reasons: 1) current rates are almost flat now and customers currently have no reason not to invest in conservation; 2) the Company's proposed rate design is intended to eliminate virtually all risk from weather-related variation in usage; and 3) the specific line item where customers can see the commodity cost and track changes from month to month will no longer appear on the bill and, as such, may have the unintended effect of discouraging conservation.

Q 19 Do you agree with Mr. Radigan's reasons for rejecting Southwest's proposed Volumetric Rate Design?

A 19 No. I believe that Mr. Radigan's reasons for rejecting Southwest's proposed Volumetric Rate Design are flawed and should not be used as a basis to reject Southwest's proposal for the following reasons:

1) The record in Southwest's last general rate case is replete with discussion of the need for a rate design to send price signals to encourage conservation. This record includes discussion by Staff in direct testimony of moving to a flat rate design in Southwest's next rate case (the instant case) to eliminate a possible disincentive for energy conservation (Robert Gray, page 35, lines 2-5), and discussion during the hearing establishing that residential customers have "less of an opportunity to take actions to conserve their usage and thereby reduce their overall bills." as commodity rates are reduced (Hearing transcript, Decision No. 68487, Volume II, page 315, lines 22-24). Now that Southwest proposes a rate design in which the customer sees a flat rate design, Mr. Radigan's testimony suggests that Staff's previous concerns with Southwest's declining block rates were not relevant.

2) Mr. Radigan also suggests that the reduction or elimination of risk with respect to declining use per customer and variations in weather for the Company is a negative. However, as discussed by Mr.

Miller in his rebuttal testimony, reduction of risk can be a "win-win" proposal for both customers and the Company.

3) Under Southwest's proposed rate design, customers still see the commodity rate on their bill, and it will likely be easier for customers to track changes in their rate because there will be fewer line items on the bill. In addition, showing customers a single rate per therm may encourage greater conservation, as it indicates the total amount per therm saved if consumption is reduced.

Q. 20 Do you believe that Mr. Radigan mischaracterized, or misunderstands how the Commission can use Southwest's rate design proposals (the RDAP, WNAP, and its Volumetric Rate Design) to achieve full or partial revenue decoupling?

A. 20 Yes. While Mr. Radigan is correct that Southwest would like full revenue decoupling, full revenue decoupling can be accomplished by implementing the RDAP and the WNAP without Southwest's proposed Volumetric Rate Design. However, Southwest's proposed residential Volumetric Rate Design would serve to reduce the dollar amount of the adjustments made through the WNAP and, to a lesser extent, through the RDAP. Furthermore, if the Commission is reluctant to approve full revenue decoupling at this time, partial revenue decoupling can be accomplished by approving either one of the RDAP, the WNAP or the proposed residential Volumetric Rate Design independently. Southwest specifically structured its rate design proposals to provide the Commission with as much flexibility as possible to address the Company's need for increased revenue stability without adversely affecting customers or the effective promotion of conservation and energy efficiency.

V. STAFF'S and RUCO's PROPOSED RESIDENTIAL RATE DESIGN PROPOSALS

Q. 21 Please comment on Staff's suggestion that most of the potential weather and conservation-related losses can be eliminated "by just adopting simple rate design changes such as increasing the customer charge."[9]

A. 21 While Staff is correct that increasing the customer charge can enhance the Company's ability to recover the authorized cost of service, Staff provides no analysis to demonstrate the level of increase that is necessary to achieve meaningful results. Southwest demonstrated to the participating stakeholders during the collaborative process that significant increases to the residential basic service charge were required to substantially affect fluctuations in margin associated with declining use per customer and weather. This analysis is included as Rebuttal Exhibit No.__(ABC-3). This exhibit quantifies the basic service charge that would be necessary to

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[9] Radigan Decoupling Direct p. 10, lns. 15-16.

eliminate most of weather- and conservation-related losses as Staff suggests can be accomplished by increasing the customer charge.

Q. 22 Staff and RUCO propose modest increases to the residential basic service charge and a flat commodity rate. What impact would such a rate design have on Southwest, if approved by the Commission in this rate case?

A. 22 As previously mentioned, Company witness Mr. Cattanach has demonstrated on rebuttal that, since the end of the test period in this case, through the 12-month period ending March 2008, Southwest's residential use per customer has declined on average from 332 therms to 319 therms. Staff's proposed commodity margin rate of $.56013 per therm results in an immediate shortfall of $6.7 million per year ($.56013 X 917,350 customers X 13 therms). This shortfall is almost 8.2 percent of Southwest's recorded net operating income during the test period, and is further compelling evidence that a significant change in rate design is necessary. RUCO's proposed residential rate design results in a $6.6 million shortfall at the time rates are implemented.

Q. 23 Has Southwest prepared an analysis similar to Rebuttal Exhibit No.__(ABC-3) reflecting the $6.7 million shortfall discussed above.

A. 23 Yes. Assuming Staff's proposed residential revenue requirement, the following table illustrates the effect that increasing the basic service charge has on the above mentioned $6.7 million shortfall associated with the 13 therm decrease in residential use per customer.

Basic Charge	$10.70	$11.50	$12.80	$15.00	$17.50	$20.00
Commodity*	$.560	$.532	$.488	$.411	$.325	$.238
Shortfall	$6.7	$6.3	$5.8	$4.9	$3.9	$2.8
% Net Income	8%	8%	7%	6%	5%	3%

*Commodity rate is based upon Staff's proposed residential revenue requirement.

The table demonstrates that without very large increases to the basic service charge, Southwest is deprived of a fair and reasonable opportunity to recover its Commission-authorized cost of service. As such, Staff's and RUCO's proposed approach to residential rate design are not viable alternatives to address the issues presently facing the Company. Rather, Southwest's tariff mechanisms and rate design proposals to further decouple revenue from sales, which are supported by AIC and SWEEP to a limited extent, should be accepted by the Commission in this case as they are responsive to the Commission's Decision No. 68487, and there is no evidence of any other viable alternatives that would provide Southwest a reasonable opportunity to recover its Commission authorized cost of service.

VI. STAFF'S ALLOCATION OF NON-GAS REVENUE TO CUSTOMER CLASSES

Q. 24 Please comment on the reasonableness of Staff's revenue allocation.

A. 24 Staff's position is that Southwest's proportional cost responsibility method (PCRM) allocation of revenues among customer classes should be "tempered," and Staff's allocation used. Three examples are cited to support this position: 1) the relatively large 12.2 percent increase proposed for Southwest's Special Residential Rate Schedule No. G-15; 2) the relatively small 1.5 percent increase proposed for Multi-Family Residential Rate Schedule No. G-6; and 3) the relatively large 10.4 percent increase proposed for Street Lighting Rate Schedule No. G-45.

Southwest's PCRM allocation methodology is intended to move class revenues closer to each class' allocated cost of service. Classes whose rates of return are further from the system average rate receive larger percentage changes in revenue than classes whose return is closer to the system average. Although Staff proposes a "two step process" where step-one is intended to bring class revenues closer to cost of service, the second step requires that no class receive an increase "more than 1 percent more or less than the overall increase."[10] As such, Staff's proposal effectively amounts to little more than an equal percentage increase to customer class revenue.

[10] Radigan Rate Design Direct, p. 4, ln 6.

Staff's proposal shifts more of the increase in non-gas costs to Southwest's high load factor customer classes, when these classes, in fact, cost less to serve on an average cents per therm basis. Thus, Staff's proposal effectively disregards Southwest's actual costs of providing service to its various classes of customers. In the long-run, mismatching the Company's cost of providing service with rates paid by customers increases the risk that customers will make uneconomical decisions with respect to their energy consumption.

Q. 25 Please explain why the examples Mr. Radigan cites do not provide a sufficient basis to reject Southwest's proposed allocation method.

A. 25 First, two of Mr. Radigan's three examples have nothing to do with Southwest's allocation methodology, but instead, result from how Southwest's residential rates are currently designed. Schedule G-15 currently has a steep declining block during the summer season. The 12.2 percent increase for Schedule G-15 results from Southwest's proposal to eliminate its declining block residential rate design. The relatively small 1.5 percentage increase for Schedule G-6 is the result of the design of Southwest's currently effective single-family and multi-family residential rates, which have identical commodity rates and Southwest's proposal not to change this relationship. These effects have nothing to do with Southwest's proposed revenue allocation methodology. The

10.4 percent increase to Schedule G-45 is necessary to increase that schedule's rate of return from <u>-0.71 percent</u> to (only) 0.17 percent at proposed rates, and demonstrates that Southwest's PCRM allocation method works as intended to move each customer class toward cost of service.

VII. SOUTHWEST'S PROPOSED RESIDENTIAL VOLUMETRIC RATE DESIGN AND ITS RELATIONSHIP TO THE PGA

Q. 26 Please comment on Staff witness Robert Gray's position that the existing PGA (PGA) mechanism must be changed prior to the implementation of any rate design decoupling mechanism (i.e., Southwest's proposed residential Volumetric Rate Resign).

A. 26 Southwest reviewed the structure and operation of the monthly PGA mechanism during the development of its Volumetric Rate Design proposal. Implementation of Southwest's Volumetric Rate Design would not require <u>any changes</u> to Southwest's current PGA process. Southwest's monthly gas cost will continue to be calculated exactly as it is today:

1) The current month's 12-month rolling average cost of gas will be calculated.

2) The current month's 12-month average cost of gas will be compared to the last twelve months, and the PGA bandwidth limit applied to determine the allowed cent per therm change in the monthly gas cost.

3) The resulting cent per therm change in gas cost will

be applied to the first and second tier gas costs in the rate design.

Q. 27 Has Southwest performed analyses showing the effects its proposed Volumetric Rate Design?

A. 27 Yes. Southwest performed analyses quantifying the dollar impacts of its proposal under both colder and warmer than normal weather conditions in response to Staff data request 6-28. Southwest also provided further explanation of its Volumetric Rate Design proposal in its response to RUCO Data Request 7-1. These responses are attached as Rebuttal Exhibit No.__(ABC-4).

Q. 28 Please describe the information reflected in Rebuttal Exhibit No.__(ABC-4).

A. 28 The dollar amounts reflected on Page 4 of 10 show that the Volumetric Rate Design's decoupling effect is significant in comparison to Southwest's net operating income but, at the same time, has a negligible percentage effect on Southwest's PGA mechanism. This is reflected in the table below which shows the rate design's decoupling effect as a percent of Southwest's recorded net operating income and recorded total purchased cost of gas.

$ Millions

	Colder Weather	Warmer Weather
Decoupling $ Amount	$1.0	$3.8
% Net Operating Income	1.2%	4.6%
% Total Gas Cost	0.2%	0.6%

It is also important to note that as long as no PGA surcharge is required to recover or return amounts in the PGA balancing account, the total amount of residential customers' bills is unaffected by the proposed Volumetric Rate Design. In that sense, Southwest's monthly PGA process compliments the proposed Volumetric Rate Design by limiting the need, except in periods of rapidly changing prices in the natural gas market place, for Southwest to have a surcharge to clear the gas cost balancing account.

Pages 6 through 10 of Rebuttal Exhibit No.__(ABC-4) discus how the Volumetric Rate Design impacts Southwest's accounting and also the benefits the rate design provides to the Company and to its customers.

VIII. INCREASED DSM PROGRAM SPENDING AND THE NEED FOR FULL REVENUE DECOUPLING

Q. 29 What is Southwest's position on increasing its DSM program spending to at least $12.0 million at this time as proposed by SWEEP?

A. 29 Southwest has not yet been authorized to spend the entire amount of its DSM program budget established in its last general rate case and therefore it would not be appropriate to significantly increase that budget prior to gaining additional experience under Southwest's current DSM programs.

Q. 30 In addition to SWEEP's proposal that Southwest increase its DSM program spending, SWEEP also supports Southwest's proposed RDAP, and correctly points out that lower per customer revenues that result from successful energy efficiency measures create a financial disincentive for Southwest to enthusiastically support increased energy efficiency efforts. Is there an approach the Commission could consider that addresses both SWEEP's interests in maximizing DSM program spending and Southwest's attendant financial concerns?

A. 30 Yes. The record is very clear that without revenue decoupling, Southwest has a distinct financial disincentive to promote reductions in customer use. However, Southwest understands that reducing the amount of energy consumed by customers and reducing the amount of money spent by customers for their energy requirements is a goal all parties need to support for a variety of economic and environmental reasons. Therefore, Southwest suggests that the Commission entertain an alternative approach in addressing SWEEP's proposal to increase DSM spending and Southwest's proposed full revenue decoupling.

Q. 31 Please explain your proposed alternative approach to SWEEP's proposal?

A. 31 Southwest proposes the following:

1) Remove the determination of the level of DSM program spending from Southwest's general rate case process and allow the level of spending to be established annually or bi-annually by Commission order based on

recommendations from the previously established Southwest DSM Collaborative. This process will allow more time to evaluate the effectiveness of Southwest's currently-authorized DSM programs and study the effectiveness of new programs and/or increased spending on existing programs, rather than attempting to determine a level of spending in this rate case.

2) Implement Southwest's proposed revenue decoupling provisions, the RDAP and the WNAP, on a pilot basis for three years or until Southwest's next general rate case, which ever occurs first. During this pilot period, the parties can study the resulting impacts of the RDAP and WNAP, and Southwest can provide Staff with reports detailing the dollar amounts collected/refunded by the respective provisions.

3) At the conclusion of the three year pilot period or at the next rate case, Southwest will engage the services of an independent third party to conduct a review of the mechanisms and will provide the Commission a copy of the consultant's report. At that time the effectiveness of the RDAP and WNAP could be reviewed in Southwest's next rate case, and these mechanisms could be extended or eliminated at that time based on their respective performance.

Q. 32 Are you aware of other utilities and state regulatory commissions that have utilized a similar approach?

A. 32 Yes. Questar Gas Company, cited by SWEEP in arriving at its proposed DSM spending for Southwest, had a revenue decoupling mechanism (the Conservation Enabling Tariff) approved on a three-year pilot basis as a part of that company's increased commitment to energy efficiency. Southwest believes that its alternative approach outlined above is a reasonable balance of the interests expressed to date by SWEEP, Staff, RUCO, and the Company.

Q. 33 Are there any other benefits associated with Southwest's decoupling proposals that the Commission should consider?

A. 33 Yes. Arizona Governor Janet Napolitano signed Executive Order 2005-02 establishing the Climate Change Advisory Group (CCAG) and directing the CCAG to, among other things, develop a climate change action plan. Page 50 of the climate change action plan discusses certain recommendations for energy savings goals for electricity and natural gas, and the implementation of the policy, program, and funding mechanisms that are needed to achieve these goals. One of the energy savings goals identified by CCAG for natural gas utility spending is to:

> ramp up to spending 1.5% of gas utility revenues on energy efficiency programs by 2015 pursuant to Arizona Corporation Commission (ACC) decoupling of gas sales and revenue. Further ***decisions by the ACC to decouple gas sales and revenues are viewed as central to achieving this target.*** Emphasis added.

Arizona Climate Change Action Plan, August 2006, p. 50.

As noted by the CCAG's recommendation, it is imperative that, despite the lack of support from RUCO and Staff for any form of decoupling, the Commission decouple gas sales and revenues as this is not only central to achieving the recommended target by CCAG, but it is also central to addressing the declining customer usage and weather sensitivity challenges that are negatively impacting Southwest.

Q. 34 Does this conclude your rebuttal testimony?

A. 34 Yes, it does.

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
****

RESIDENTIAL UTILITY CONSUMER OFFICE
DATA REQUEST NO. RUCO-8
(RUCO-8-1 THROUGH RUCO-8-2)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 27, 2008

Request No. RUCO-8-1:

Declining Consumption Follow-up to RUCO 7.3. Please indicate if the Exhibit RAM-1 Sheet 4, provided in response to RUCO 7.3 measures both weather related as well as conservation related short-fall. If the referenced Exhibit is applicable to both phenomena please provide similar exhibits showing the shortfall effect of weather and conservation separately.

Respondent: Pricing/Demand Planning

Response:

Yes. The exhibit provided by Southwest in response to RUCO 7.3 measures both weather and conservation effects.

The attached schedule, for the calendar years 1998 (the first year of combined rates for Southwest's Arizona service areas) through 2007, and for the most currently available 12-month period ending February 2008, shows the shortfall effect of weather and conservation separately.

The format of the schedule is similar to the schedule provided by Southwest in response to RUCO's Question 1 in the Decoupling Work Group meetings and matches the average use per customer used to set rates and resulting average commodity rates in effect in each of the eleven 12-month periods with: 1) the actual average use per customer; 2) the weather-adjusted average use per customer; and 3) the average number of residential customers served for each 12-month period included in the study.

Schedule RUCO-8 attached shows that weather (see Line 11) actually made a positive contribution to revenue of approximately $0.8 million per year on average (Line 11, Col (m)). However, Line 11 also shows approximate $15 - $16 million weather-related swings in revenue from year-to-year. In contrast to weather,

(Continued on Page 2)

Response to RUCO-8-1: *(continued)*

conservation has resulted in lost revenue of approximately $12.2 million on average (Line 10, Col (m)). In total (weather plus conservation), Southwest lost approximately $11.4 million per year on average during the study period. This equates to a loss of approximately 8% (Line 18, Col (m)) of total authorized residential margin over the study period. (The after-tax impact of an $11.4 million loss in revenue as a percent of Southwest's recorded Net Operating Income is also approximately 8%.)

Rebuttal Exhibit No.__(ABC-1)
Sheet 3 of 3

RESPONSE RUCO-8-1 AND 8-2

SOUTHWEST GAS CORPORATION
RESPONSE TO RUCO-8.1 and 8.2
($ MILLIONS)

Line No.	Description (a)	1998 (b) Rates Effective 9/1/1997	1999 (c)	2000 (d)	2001 (e)	2002 (f) Rates Effective 11/1/2001	2003 (g)	2004 (h)	2005 (i)	2006 (j) Rates Effective 3/1/2006	2007 (k)	Feb-08 (l)	Average Annual Impact (m)	Weather/ Conservation % of Total (n)	Line No.
	Total Arizona														
	Average Usage														
1	Actual	442.8	381.6	379.8	382.5	353.0	330.8	358.7	320.7	309.2	321.6	320.5			1
2	Weather Adjusted	375.8	378.6	375.6	341.8	362.6	354.3	338.4	343.0	342.3	318.1	313.4			2
3	GRC Authorized Amount	409.0	409.0	409.0	409.0	389.0	389.0	389.0	389.0	347.0	347.0	347.0			3
	Difference From Last GRC														
4	Weather + Conservation (Actual - GRC)	33.8	(27.4)	(29.2)	(26.5)	(36.0)	(58.2)	(30.3)	(68.3)	(37.8)	(25.4)	(26.5)			4
5	Conservation-Related (Weather Adj - GRC)	(33.2)	(30.4)	(33.4)	(67.2)	(26.4)	(34.7)	(50.6)	(46.0)	(4.7)	(28.9)	(33.6)			5
6	Weather-Related (Actual - Weather Adj)	67.0	3.0	4.2	40.7	(9.6)	(23.5)	20.3	(22.3)	(33.1)	3.5	7.1			6
7	Average No. of Customers	613,012	640,776	673,567	699,857	720,061	744,408	785,673	825,650	864,201	891,515	893,811			7
8	Average Commodity Rate	$ 0.42370	$ 0.42370	$ 0.42370	$ 0.42370	$ 0.45828	$ 0.45828	$ 0.45828	$ 0.45828	$ 0.52579	$ 0.52579	$ 0.52579			8
	Annual Dollar Impact of Change in Average Use														
9	Weather + Conservation (Actual - GRC)	$ 8.8	$ (7.4)	$ (8.3)	$ (7.9)	$ (11.9)	$ (19.9)	$ (10.9)	$ (25.8)	$ (17.2)	$ (11.9)	$ (12.5)	$ (11.4)	-100.0%	9
10	Conservation-Related (Weather Adj - GRC)	$ (8.6)	$ (8.3)	$ (9.5)	$ (19.9)	$ (8.7)	$ (11.8)	$ (18.2)	$ (17.4)	$ (2.1)	$ (13.5)	$ (15.8)	$ (12.2)	-107.3%	10
11	Weather-Related (Actual - Weather Adj)	$ 17.4	$ 0.8	$ 1.2	$ 12.1	$ (3.2)	$ (8.0)	$ 7.3	$ (8.4)	$ (15.0)	$ 1.6	$ 3.3	$ 0.8	7.3%	11
	Cumulative Dollar Impact of Change in Average Use [1]														
12	Weather + Conservation (Actual - GRC)	$ 8.8	$ 1.3	$ (7.0)	$ (14.9)	$ (26.7)	$ (46.6)	$ (57.5)	$ (83.3)	$ (100.5)	$ (112.4)			-100.0%	12
13	Conservation-Related (Weather Adj - GRC)	$ (8.6)	$ (16.9)	$ (26.4)	$ (46.3)	$ (55.0)	$ (66.9)	$ (85.1)	$ (102.5)	$ (104.6)	$ (118.2)			-105.1%	13
14	Weather-Related (Actual - Weather Adj)	$ 17.4	$ 18.2	$ 19.4	$ 31.5	$ 28.3	$ 20.3	$ 27.6	$ 19.2	$ 4.1	$ 5.8			5.1%	14
15	GRC Authorized Residential Margin														15
16	Basic Service Charge	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 9.70	$ 9.70	$ 9.70			16
17	Average Commodity Rate	$ 0.42370	$ 0.42370	$ 0.42370	$ 0.42370	$ 0.45828	$ 0.45828	$ 0.45828	$ 0.45828	$ 0.52579	$ 0.52579	0.52579			17
	GRC Authorized Margin	$ 110.5	$ 115.5	$ 121.4	$ 126.2	$ 134.1	$ 138.7	$ 146.3	$ 153.8	$ 166.1	$ 171.3	$ 171.7	$ 141.4		
18	Weather+Conservation % of Authorized Margin	7.9%	-6.4%	-6.9%	-6.2%	-8.9%	-14.3%	-7.5%	-16.8%	-10.3%	-7.0%	-7.3%	-8.0%		18

[1] For the 10-year period 1998 thru 2007 (excluding 12-months ended Februray 2008).
Note: Average usage and number of customers does not include Southwest's (approximately 30,000) low-income residential customers. This should not have significant effect on percent relationships.

Rebuttal Exhibit No.__(ABC-2)
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CHANGE IN MARGIN AT PRESENT RATES AS A RESULT OF REDUCED RESIDENTIAL CUSTOMER USAGE

Line No.	Description (a)	Schedule Number (b)	As Filed (c)	As Adjusted [1] (d)	Change in Margin (e)	Line No.
1	Residential Gas Service	G-5	$ 252,170,209	$ 246,255,287	$(5,914,922)	1
2	Multi-Family Residential Gas Service	G-6	6,635,205	6,424,992	(210,213)	2
3	Low Income Residential Gas Service	G-10	6,749,399	6,601,781	(147,618)	3
4	Low Income Multi-Family Residential	G-11	480,391	460,437	(19,954)	4
5	Special Residential Gas Service	G-15	70,281	70,281	0	5
6	Total Residential		$ 266,105,485	$ 259,812,778	$ (6,292,707)	6
7	All Other Rate Schedules		118,339,358	118,339,358	0	7
8	Total Sales and Full Margin Transportation		$ 384,444,843	$ 378,152,136	$(6,292,707)	8
9	Special Contract Service	B-1	2,528,029	2,528,029	0	9
10	Other Operating Revenue		12,261,805	12,261,805	0	10
11	Total Arizona Revenue		$ 399,234,678	$ 392,941,971	$(6,292,707)	11

[1] Residential customer margin based on udated annual sales reflected in Rebuttal Exhibit No._(JLC-2).

Rebuttal Exhibit No.__(ABC-3)
Sheet 1 of 1

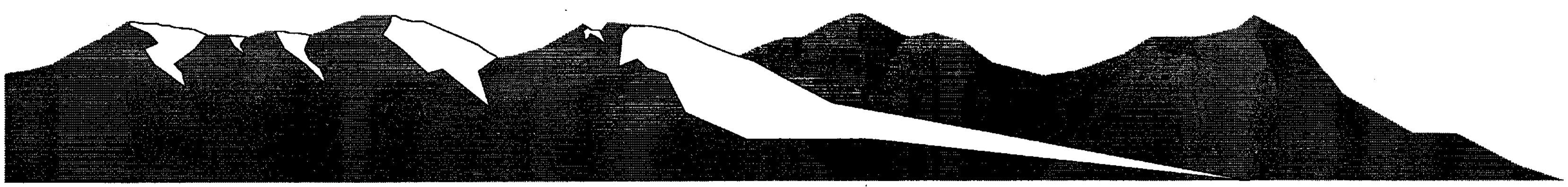
TRADITIONAL RATEMAKING AND SWG'S RESIDENTIAL COST RECOVERY DILEMMA

Monthly Basic Charge

Description	$10.00	$12.00	$15.00	$20.00
Margin Rate [1]	$.516	$.448	$.347	$.177
Lost SF Res Margin [2]	($16.1)	($14.0)	($10.8)	($5.5)
% Impact on ROE	(2.63)	(2.28)	(1.77)	(0.90)

[1] Rates calculated using GRC test year bills and volumes.

[2] Lost margin calculated using bills and volumes for 12 months ended August 2006.



SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 THROUGH ACC-STF-6-60)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 28, 2007

Request No. ACC-STF-6-28:

Please identify, quantify and explain in detail the "decoupling effect of a declining block rate for the recovery of non-gas costs" per Mr. Miller's testimony at page 14, line 3.

Respondent: Mr. Miller/Pricing & Tariffs

Response:

The above answer in Mr. Miller's testimony begins on page 13 and reads, "The important feature of this rate design is that the composite commodity charge for gas sales customers is a flat volumetric rate, but the offsetting block structures for the recovery of non-gas costs and gas costs provide Southwest with the partial decoupling effect of a declining block for its non-gas charges. This rate design is an innovative way of combining the desirable pricing features of a flat commodity charge rate with the desirable decoupling effect of a declining block rate for the recovery of non-gas costs." The partial decoupling effect for the recovery of non-gas costs of Southwest's proposed rate design is quantified in the Excel file on the enclosed CD. The calculations are based on Southwest's proposed single-family residential non-gas rates, bills and volumes.

Southwest's proposed rate design partially decouples the recovery of non-gas costs from both weather- and non-weather-related changes in sales. To quantify the decoupling effect of its proposed rate design, Southwest considered both the test year pro forma weather normalization adjustment to single-family residential customer volumes of <1,742,533> therms and the decline in weather adjusted use per residential customer of (approximately) 6 therms discussed by Southwest witness Mr. Cattanach. Southwest quantified the effects of 100% and 70% of the change in customer usage taking place in the second block of the rate design.

(Continued on Page 2)

<u>Response to STF-6-28</u>: *(continued)*

Page 1 of the spreadsheet analysis shows the adjusted single-family residential class test year volumes of 289,056,115 therms (line 1), the volumes purchased under the colder-than-normal test year weather conditions of 290,798,648 therms (lines 5-7), and the volumes customers would purchase in a warmer-than-normal year with an additional decrease of 6 therms per customer of 282,164,567 therms (lines 13-15).

Pages 2 and 3 show what customers would pay for non-gas delivery service in each of these three situations under Southwest's proposed rate design (Lines 1 - 6) and under a flat-rate commodity charge rate design (Lines 7 - 10). The difference between the two rate design approaches, which illustrates the partial decoupling effect of Southwest's proposed rate design for the recovery of non-gas costs, is shown on Line 11.

In the colder than normal test year, when customers used an additional 1,742,533 therms (page 1, line 2), their non-gas charges would increase by $966,287 with a flat commodity charge rate design for non-gas charges (pages 2 and 3, line 10). In contrast, under Southwest's proposed rate design, customers would not incur any additional non-gas charges if 100% of their additional usage is priced at the weather-sensitive rate (page 2, line 6), and their non-gas charges would increase by only $460,389 if 70% of the additional usage is priced at the weather-sensitive rate (page 3, line 6). Southwest's proposed rate design eliminates at least one-half or more of the additional non-gas charges customers would otherwise pay under a flat commodity charge rate design during colder than normal weather.

If usage per customer continues to decline by 6 therms and the weather is warmer than normal, then total usage would decrease by 6,891,548 therms (page 1, line 10). With a flat commodity charge rate design, Southwest's non-gas revenues would decrease by $3,821,570 (pages 2 and 3, line 10). However, the partial decoupling effect of Southwest's proposed rate design would completely eliminate the decrease in non-gas revenues if 100% of the decrease in usage is priced at the weather-sensitive rate (page 2, line 6), and would limit the decrease in non-gas revenues to $1,820,795 if 70% of the decrease in usage occurs in the weather-sensitive rate component (page 3, line 6). Southwest's proposed rate design reduces by at least one-half the decrease to non-gas revenue it would experience under a flat commodity rate design in warmer than normal weather.

SOUTHWEST GAS CORPORATION
PARTIAL DECOUPLING EFFECT OF SWG PROPOSED RATE DESIGN
G-5 SINGLE-FAMILY RESIDENTIAL GAS SERVICE VOLUMES

Line No.	Description	Weather-Sensitive Usage	Non-Weather-Sensitive Usage	Total	Line No.
	Number of single-family residential bills			10,298,030	
	Number of single-family residential customers			858,169	
1	Adjusted test year	182,004,997	107,051,118	289,056,115	1
2	Additional volumes for colder than normal weather			1,742,533	2
3	Assuming 70.000% in tail block	522,760	1,219,773		3
4	Assuming 100% in tail block	0	1,742,533		4
5	Total volumes for colder than normal weather			290,798,648	5
6	Assuming 70.000% of CTN increase in tail block	182,527,757	108,270,891		6
7	Assuming 100% of CTN increase in tail block	182,004,997	108,793,651		7
8a	Decremental volumes for additional conservation				8a
8b	of 6 therms per customer per year			(5,149,015)	8b
9	Decremental volumes for warmer than normal weather			(1,742,533)	9
10	Total decrement for WTN weather and conservation			(6,891,548)	10
11	Assuming 70.000% of decrement in tail block	(2,067,464)	(4,824,084)		11
12	Assuming 100% of decrement in tail block	0	(6,891,548)		12
13	Total volumes for WTN weather and conservation			282,164,567	13
14	Assuming 70.000% of decrement in tail block	179,937,533	102,227,034		14
15	Assuming 100% of decrement in tail block	182,004,997	100,159,570		15

SOUTHWEST GAS CORPORATION
PARTIAL DECOUPLING EFFECT OF SWG PROPOSED RATE DESIGN
G-5 SINGLE-FAMILY RESIDENTIAL GAS SERVICE
ASSUMING 100 PERCENT OF VOLUME CHANGE IS IN SECOND BLOCK OF RATE DESIGN

Line No.	Description	Non-Gas Charge Rates	Proposed Test Year, With Normal Weather		Colder Than Normal Weather		Warmer than Normal Weather and Additional Conservation		Line No.
			Bills/Volumes	Annual Cost	Bills/Volumes	Annual Cost	Bills/Volumes	Annual Cost	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Proposed Rate Design								
1	Basic Service Charge	$ 12.80	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	1
	Non-Gas Delivery Charge								
2	Weather-Sensitive Usage	$ 0.88069	182,004,997	160,289,981	182,004,997	160,289,981	182,004,997	160,289,981	2
3	Non-Weather-Sensitive Usage	0.00000	107,051,118	0	108,793,651	0	100,159,570	0	3
4	Total Commodity		289,056,115	$ 160,289,981	290,798,648	$ 160,289,981	282,164,567	$ 160,289,981	4
5	Total Non-Gas Revenue			$ 292,104,765		$ 292,104,765		$ 292,104,765	5
6	Change from Normal Weather			$ -		$ -		$ -	6
	Flat Commodity Charge Rate Design								
7	Basic Service Charge	$ 12.80	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	7
8	Non-Gas Delivery Charge (Average Rate)	$ 0.55453	289,056,115	$ 160,290,287	290,798,648	$ 161,256,574	282,164,567	$ 156,468,717	8
9	Total Non-Gas Revenue			$ 292,105,071		$ 293,071,358		$ 288,283,501	9
10	Change from Normal Weather			$ -		$ 966,287		$ (3,821,570)	10
11	Proposed Rate Design less Flat Commodity Charge Rate Design			$ (307)		$ (966,593)		$ 3,821,263	11

SOUTHWEST GAS CORPORATION
PARTIAL DECOUPLING EFFECT OF SWG PROPOSED RATE DESIGN
G-5 SINGLE-FAMILY RESIDENTIAL GAS SERVICE
ASSUMING 70.000% OF VOLUME CHANGE IS IN SECOND BLOCK OF RATE DESIGN

Line No.	Description	Non-Gas Charge Rates	Proposed Test Year, With Normal Weather		Colder Than Normal Weather		Warmer than Normal Weather and Additional Conservation		Line No.
			Bills/Volumes	Annual Cost	Bills/Volumes	Annual Cost	Bills/Volumes	Annual Cost	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Proposed Rate Design								
1	Basic Service Charge	$ 12.80	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	1
	Non-Gas Delivery Charge								
2	Weather-Sensitive Usage	$ 0.88069	182,004,997	160,289,981	182,527,757	160,750,370	179,937,533	158,469,186	2
3	Non-Weather-Sensitive Usage	0.00000	107,051,118	0	108,270,891	0	102,227,034	0	3
4	Total Commodity		289,056,115	$ 160,289,981	290,798,648	$ 160,750,370	282,164,567	$ 158,469,186	4
5	Total Non-Gas Revenue			$ 292,104,765		$ 292,565,154		$ 290,283,970	5
6	Change from Normal Weather			$ -		$ 460,389		$ (1,820,795)	6
	Flat Commodity Charge Rate Design								
7	Basic Service Charge	$ 12.80	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	7
8	Non-Gas Delivery Charge (Average Rate	$ 0.55453	289,056,115	$ 160,290,287	290,798,648	$ 161,256,574	282,164,567	$ 156,468,717	8
9	Total Non-Gas Revenue			$ 292,105,071		$ 293,071,358		$ 288,283,501	9
10	Change from Normal Weather			$ -		$ 966,287		$ (3,821,570)	10
11	Proposed Rate Design less Flat Commodity Charge Rate Design			$ (307)		$ (506,204)		$ 2,000,468	11

Rebuttal Exhibit No.__(ABC-4)
Sheet 5 of 10

302-001

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
RESIDENTIAL UTILITY CONSUMER OFFICE
DATA REQUEST NO. RUCO-7
(RUCO-7-1 THROUGH RUCO-7-10)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 7, 2008

Request No. RUCO-7-1:

Allocation of Gas/Non-gas Costs

Please provide the following information related to the cost allocation discussion on pages 10 through 12 of the testimony of Brooks Congdon:

a) Explain in detail (including illustrative journal entries) how the proposed cost allocation affects SWG's income statement and balance sheet:

b) Explain in detail what benefit SWG perceives the Company derives from the proposed allocation; and

c) Explain in detail what benefit(s) customers receive from the proposed allocation.

Respondent: Pricing & Tariffs

Response:

a. The proposed allocation of the non-gas (margin) and gas cost components of residential sales rates has no effect on Southwest's current accounting and journal entry procedures. The proposal only impacts the relative amounts of non-gas and gas cost collected through residential rates as actual use per customer varies from the level (332 therms per customer per Southwest's proposal) used in setting rates. The effects of Southwest's proposed residential rate design on the recovery of non-gas and gas costs versus a more conventional average cost rate design are illustrated below using the rates reflected in the table on page 10 of Mr. Congdon's Direct Testimony.

(Continued on Page 2)

Response to RUCO-7-1: *(continued)*

	Non-Gas Rate	Gas Cost Rate	Total
Average Rate Design	$.55376	$.93689	$1.49065
Proposed Rate Design			
Non-Weather-Sensitive Use	$.88069	$ .60996	$1.49065
Weather-Sensitive Use	.00000	1.49065	1.49065
Number of Residential Customers			917,350

Scenario 1 - Assuming that average use increases as a result of colder than normal weather by 10 therms per customer and all of the increase is in the weather-sensitive 2nd block of the proposed rate design, the effects under the average and proposed rate designs in millions of dollars are summarized below.

	Non-Gas Rate	Gas Cost Rate	Total
Average Rate Design	$5.1	$8.6	$13.7
Proposed Rate Design	0.0	13.7	13.7
Difference	<$5.1>	$ 5.1	$ 0.0

In Scenario 1, Southwest's net after tax income would be $3.1 million less ($5.1 million X (1 - $0.395292 tax rate)) under its proposed rate design and an additional amount of $5.1 million (excluding interest) would accrue to Southwest's PGA Balancing Account resulting in a lower PGA balance than under an average cost rate design. Also, it is important to note that total gas cost incurred would not change; therefore, the PGA impact is merely a timing difference resulting from more timely collection of gas cost. No change in the accounts or methods used to record these ratemaking impacts in the accounting records would result, but the decrease in net income, net of tax, would result in a reduction to revenue on the income statement (vis-à-vis an average cost rate design) for that given period, with an associated decrease to cash on the balance sheet. The timing difference in collecting gas cost from customers would reduce the 191 account but also increase cash for the period, resulting in no net effect on the balance sheet and no ultimate impact on the income statement.

(Continued on Page 3)

<u>Response to RUCO-7-1</u>: *(continued)*

Scenario 2 - Assuming that average use decreases as a result of warmer than normal weather by 10 therms per customer with 50% of the decrease in the weather-sensitive 2nd block and 50% in the non-weather-sensitive block of the proposed rate design, the effects under the average and proposed rate designs in millions of dollars are summarized below.

	Non-Gas Rate	Gas Cost Rate	Total
Average Rate Design	<$5.1>	<$8.6>	<$13.7>
Proposed Rate Design	<4.1>	<9.6>	< 13.7>
Difference	$1.0	<$ 1.0>	$ 0.0

In Scenario 2, Southwest's net after tax income would be $0.6 million more ($1 million X (1 - $0.395292 tax rate)) under its proposed rate design and there would be an immediate $1 million impact (excluding interest) to PGA sales customers. Again, total gas cost incurred would not change and the PGA impact is only a timing difference resulting from the collection of gas cost over a longer period of time. No change in the accounts or methods used to record these ratemaking impacts in the accounting records would result, but the increase in net income, net of tax, would result in an increase in revenue on the income statement for that given period, with an associated increase in cash on the balance sheet. The timing difference in collecting gas cost from customers would have an immediate increase to the 191 account but also decrease cash for the period, resulting in no net effect on the balance sheet and no ultimate impact on the income statement. The $0.6 million addition to after-tax income represents almost 1% of Southwest's recorded Net Operating Income (see Volume II, Schedule A-1), while the $1.0 million impact to the PGA is less than 0.2% of Southwest's recorded gas cost (see Volume II, Schedule C-1, Sheet 3).

Southwest's proposed residential rate design will stabilize the recovery of its fixed costs of providing service when use-per-customer increases or decreases from the level used to set rates. As explained above, the effect of the proposed rate design is to shift over-recoveries of authorized margin per customer that would otherwise accrue to Southwest's shareholders when usage per customer is greater than the level used to set rates, to the PGA Balancing Account where the net dollar impact will be reduced interest on the resulting PGA balance. Conversely, when usage per customer is less than the level used to set rates, under-recoveries of authorized

(Continued on Page 4)

Response to RUCO-7-1: *(continued)*

margin that would otherwise reduce shareholder earnings, are also shifted to the PGA Balancing Account resulting in slightly greater interest expense. Over time, with both colder and warmer weather, the measurable effect of the proposed rate design on PGA interest expense should be de minimus in comparison to total gas cost expense.

Please also refer to the Company's response to Staff data request no. STF-6-28 for additional discussion of the effects of Southwest's proposed residential rate design.

b. Southwest will benefit from the proposed rate design because the adverse financial impact of declining use per customer on non-gas revenues, i.e., the recovery of Southwest's fixed costs of providing service, is less than under an average cost rate design. Southwest's proposed rate design also has the desirable feature of better matching cost recovery with cost incurrence: 1) recovery of Southwest's fixed costs of providing service (the cost of pipes, meters, property taxes, etc.) is less dependent on the total volume of gas delivered to customers than under a more traditional rate design, and 2) Southwest recovers more gas cost revenue when use per customer increases and gas prices would also be expected to be increasing (use per customer increases with cold weather and cold weather helps drive up winter gas prices) than under an average cost rate design.

c. Customers benefit from Southwest's proposed rate design because: 1) conservation-related savings are increased by the elimination of the lower priced second block in Southwest's current declining block rate design; 2) enhanced recovery of Southwest's fixed cost of providing service will extend the timing of Southwest's rate cases, all other factors being equal, and may result in reduced capital costs; 3) improved fixed cost recovery discussed in parts a. and b. above, is achieved through a single commodity charge effective sales rate with no significant shifting of costs between small and large volume customers, as would be the case with a traditional declining block rate design and/or large increases in the basic service charge; and 4) the only cost/savings to achieve these customer benefits is the dollar impact to the PGA Balancing Account interest accrual.

Because the fixed costs of providing service are recovered through the basic service charge and less usage-sensitive components of the rate structure as compared to Southwest's currently effect residential rates, fixed cost recovery would be more evenly distributed across small and large volume residential customers. This result would allow Southwest to economically provide service to

(Continued on Page 5)

Response to RUCO-7-1: *(continued)*

residential customers whose volumes and resulting annual margin, given Southwest's current rate design, might not otherwise support the cost of establishing service. This effect is illustrated in the example below.

	Non-Gas Rate	Annual Usage [1]	Annual Non-Gas Revenue [2]
Average Rate Design	$.55376	300 therms	$166.13
Proposed Rate Design Non-Weather-Sensitive Use	$.88069	300 therms	$264.21
Difference			$ 98.08
Estimated Cost of Service Factor			20%
Additional Supportable Facilities Investment			$490.40

[1] 300 therms equals sum of proposed summer and winter rate blocks times six months (15 therms X 6 + 35 therms X 6).

[2] Excluding basic service charge revenue, which is assumed to be the same in both rate designs.