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Transcript Exhibit(s)

Docket #(s): G-01551A-16-0107

Arizona Corporation Commission
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Part 5 of 5

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

TOM FORESE – CHAIRMAN
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD W. DUNN

EXHIBIT
S-3
ADMITTED

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS.	DOCKET NO. G-01551A-16-0107 **STAFF'S NOTICE OF FILING SETTLEMENT AGREEMENT TESTIMONY OF ELIJAH O. ABINAH**

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission"), hereby files the Settlement Agreement Testimony of Elijah O. Abinah ("Agreement"), in the above-referenced matter.

RESPECTFULLY SUBMITTED this 30th day of January, 2017.

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Robert Geake
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On this 30th day of January, 2017, the foregoing document was filed with Docket Control as an Utilities Division Pre-Filed Testimony, and copies of the foregoing were mailed on behalf of the Utilities Division to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

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Commissioner
ANDY TOBIN
Commissioner
BOYD DUNN
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS ARIZONA OPERATIONS.	DOCKET NO. G-01551A-16-0107

DIRECT TESTIMONY

IN SUPPORT OF

SETTLEMENT AGREEMENT

ELIJAH O. ABINAH

ACTING DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 30, 2016

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

Mr. Abinah's testimony supports the adoption of the Settlement Agreement ("Agreement") as proposed by the Signatories in this case. This testimony describes the settlement process as open, candid, transparent and inclusive of all parties to this case. Mr. Abinah explains why Staff believes this Agreement is in the public interest.

Mr. Abinah's testimony recommends that the Commission adopt the Agreement as proposed.

SECTION I - INTRODUCTION

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

A. My name is Elijah O. Abinah. I am the Acting Director employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as the Acting Director.

A. As the Acting Director, I manage the day-to-day operations of the Utilities Division with the assistance of the Utilities Division Assistant Director and oversee the management of the Division. In addition, I am responsible for making policy decisions for the Division.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Accounting from the University of Central Oklahoma in Edmond, Oklahoma. I also received a Master of Management degree from Southern Nazarene University in Bethany, Oklahoma. Prior to my employment with the ACC, I was employed by the Oklahoma Corporation Commission for approximately eight and a half years in various capacities in the Telecommunications Division.

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

A. The purpose of my testimony is to support the Settlement Agreement ("Agreement"). I will also provide testimony addressing the settlement process, public interest benefits and general policy considerations.

Q. Did you participate in the negotiations that led to the executive of the Proposed Agreement?

A. Yes, I did.

Q. How is your testimony being presented?

A. My testimony is organized into five sections. Section I is this introduction, Section II provides discussion of the settlement process, Section III discusses the various parts of the Agreement, Section IV identifies and discusses the reasons why the Agreement is in the public interest and Section V addresses general policy considerations.

SECTION II – SETTLEMENT PROCESS

Q. Please discuss the Settlement process.

A. The Settlement process was open, transparent and inclusive. All parties received notice of the settlement meeting and were accorded an opportunity to raise, discuss, and propose resolution to any issue that they desired.

Q. How many Settlement meetings were held?

A. Settlement discussions were held and concluded on December 15, 2016.

Q. Who participated in those meetings?

A. In addition to Staff and Southwest Gas Corporation ("SWG" or "Company"), the Residential Utility Consumers Office ("RUCO"), Arizona Community Action Association ("ACAA"), Arizona Investment Council ("AIC"), the Property Owners and Residents Association ("PORA"), Desert Valley Natural Gas, LLC ("DVNG"), Pinal Energy, LLC ("Pinal Energy"), and Mr. Richard Gayer participated in the discussions.

Q. Could you identify some of the diverse interests that were involved in this process?

A. Yes. The participants represented very diverse interests and included Staff, RUCO, SWG, a shareholders association, consumer representatives, a low-income customer advocate, and a third-party gas marketer.

Q. How many of these parties executed the Agreement?

A. Seven parties executed the Agreement, namely Staff, SWG, RUCO, ACAA, PORA, DVNG and AIC ("Signatories").

Q. Were there parties who chose not to execute the Agreement?

A. Yes, NatureSweet USA, Pinal Energy and Mr. Gayer.

Q. In your opinion, was there an opportunity for all issues to be discussed and considered?

A. Yes. In my opinion, each party had the opportunity to raise and have their issues considered.

Q. Were the Signatories able to resolve all issues?

A. Yes, the Signatories were able to resolve and reach agreement on all issues.

Q. How would you describe the negotiations?

A. I believe that all participants zealously advocated and represented the interests of their constituents. I would characterize the discussions as candid but professional. While acknowledging that not all parties executed the Agreement, I must note that all parties had the opportunity to be heard and to have their issues fairly considered.

Q. Mr. Abinah would you describe the process as requiring give and take?

A. Yes, I would. As a result of the many varied interest represented in the settlement process, willingness to compromise was absolutely necessary. As evidenced by the Agreement, the Signatories compromised vastly different litigation positions.

Q. In your previous response you stated that the parties were able to settle despite different litigation positions. Is this correct?

A. Yes.

Q. In your opinion was the public interest unduly compromised?

A. No, not in my opinion. As I will discuss later in this testimony I believe that the compromises made by the various parties will actually further the public interest.

Q. Mr. Abinah you have indicated that the Agreement incorporates many diverse interests including those of low-income customers, residential customers, and third-party gas marketers. Please indicate how the Agreement takes these into account.

A. In the Agreement, there are specific provisions which address many of the concerns expressed by the above-referenced interest. For example, the low-income customer issues are addressed in Part XI. Another example is Part XIV, which addresses the interests of those concerned about promoting customer choice of gas suppliers while ensuring revenue neutrality and no interclass subsidies.

SECTION III – SETTLEMENT AGREEMENT

Q. Please describe Part I of the Agreement.

A. Part I is a general description of the settlement process and the Agreement itself.

Q. Please describe Part II of the Agreement.

A. In Part II of the Agreement, SWG agrees not to file its next general rate case prior to May 1, 2019.

Q. Please describe Part III of the Agreement.

A. This section addresses the base rate increase to SWG's customers. The signatories agreed that SWG should receive a base rate increase of $16 million over its adjusted test year margin of $481,681,406, for a total revenue requirement of $497,681,406. The Company's jurisdictional fair value rate base used to establish the rates agreed to herein is $1,801,065,079.

Q. Please describe Part IV of the Agreement.

A. When new rates become effective, residential customers will have, on average, a 1.09 percent annual bill increase.

Q. Please describe Part V of the Agreement.

A. A capital structure comprised of 48.3 percent long-term debt and 51.7 percent common equity is proposed. A return on common equity of 9.5 percent and an embedded cost of long-term debt of 5.2 percent are proposed. An overall fair value rate of return of 5.71 percent, which includes a return on the fair value increment of 0.93 percent, is proposed.

Q. Please describe Part VI of the Agreement.

A. This section deals with depreciation. The depreciation rates set forth on Attachment A to the Agreement shall be adopted. The estimated overall reduction in the Company's depreciation expense is $44,743,206. Moreover, the Company will perform a detailed and objective system cost of removal study in support of its depreciation rates to be used in its next general rate case application.

Q. Please describe Part VII of the Agreement.

A. This section addresses SWG's Customer Owned Yard Line ("COYL") program. The signatories agreed that SWG shall be allowed to expand its COYL program, and SWG will work with Staff to develop a Plan of Administration for the COYL program. The annual rate adjustment for the COYL program surcharge will continue to be capped at $0.01 per therm per year, and shall apply to all recorded full margin therms sold.

Q. Please describe Part VIII of the Agreement.

A. This section addresses SWG's Vintage Steel Pipe ("VSP") replacement program. The signatories agreed that SWG shall be allowed to implement its proposed VSP replacement program, and the annual rate adjustment for the VSP program surcharge will be capped at $0.015 per therm per year, and shall apply to all recorded full margin therms sold. Moreover, the Company, Staff and RUCO shall work to jointly develop a draft Plan of Administration that will be circulated to the parties to this docket and brought to the Commission for consideration.

Q. Please describe Part IX of the Agreement.

A. In Part IX of the Agreement the signatories agreed that SWG shall defer the revenue requirement associated with all costs flowing from the construction of the Tucson Liquefied Natural Gas ("LNG") Facility incurred before December 31, 2020, for recovery in the Company's next general rate case proceeding.

Q. Please describe Part X of the Agreement.

A. This section addresses SWG's full revenue decoupling. The signatories agreed that the Company shall continue to utilize a full revenue decoupling mechanism subject to the modification that the Energy Efficiency Enabling Provision ("EEP") will no longer utilize a monthly weather adjustor. The Company shall modify its tariff to change the name of its decoupling mechanism from "Energy Efficiency Enabling Provision" to "Delivery Charge

Adjustment Provision" and update its website and outreach materials to reflect changes to the decoupling mechanism.

Q. Please describe Part XI of the Agreement.

A. This section discusses SWG's low-income program. The signatories agreed that the Company shall increase its Low Income Ratepayer Assistance ("LIRA") program eligibility to customers whose incomes are less than or equal to 200% of the Federal Poverty Income Guidelines. The Company shall be allowed to collect 100% of the discount through the LIRA surcharge.

Q. Please describe Part XII of the Agreement.

A. Part XII addresses SWG's customer bill presentation. The Company will advise customers of their option to request a detailed bill, both on its website and on the bill insert that notifies customers of the rate changes approved in this proceeding. The Company shall also provide such advice to customers at least once a year. Moreover, the Company's full revenue decoupling adjustment will be included on customer bills as a separate line item.

Q. Please describe Part XIII of the Agreement.

A. This section of the Agreement addresses SWG's rate design. Staff's recommended rate design and cost allocation shall be adopted, subject to any conforming changes necessary to effectuate the overall cost of service adopted by the Agreement. Under Staff's rate design there is no increase to the monthly basic service charges and the rate increase is recovered through the volumetric rate. SWG shall file a minimum system study in its next general rate case to support the class cost of service study included in that filing.

The Company will not implement a Multi-Family Dwelling Service and Main extension tariff at this time.

The Company shall be allowed to implement its requested Compression Service tariff subject to 50/50 risk sharing between shareholders and ratepayers for any losses resulting from this tariff.

The Company shall be permitted to implement a Property Tax Mechanism to defer any changes in property tax expense for recovery in its next general rate case.

Q. Please describe Part XIV of the Agreement.

A. This section addresses SWG's customer choice gas supplier pilot implementation. SWG will work with DVNG and Staff to develop a new tariff, or modifications to the Company's existing tariff, as well as a Plan of Administration that will govern a pilot program for an expanded transportation service for certain qualifying SWG non-residential customers in Arizona. The Tariff and Plan of Administration must address four key principles, namely revenue neutrality, no interclass subsidies, governance structure and gradualism as presented in the Agreement. Moreover, once the Tariff and Plan of Administration are approved, a Beta Test will be utilized to test the pilot program framework on a group of five mutually agreed upon SWG commercial customers.

Q. Please describe Part XV of the Agreement.

A. The Company's proposed tariff changes are accepted, as modified by Staff.

Q. Please describe Part XVI of the Agreement.

A. This section addresses SWG's gas procurement. As recommended by Staff, the Company shall modify its Arizona Price Stability Purchases ("APSP") program to limit the amount of gas hedged to not more than 25 percent of the annual forecasted demand in Arizona for any forecast period, with the exception that the Company first sends a letter to Staff advising of its intent to hedge above this level.

Q. Please describe Part XVII of the Agreement.

A. This section of the Agreement addresses SWG's compliance matters. The signatories agreed that all compliance items identified in Staff Witness Bozzo's Pre-filed Direct Testimony shall be eliminated, including the quarterly decoupling reports. In addition, the Company should work with Staff to develop a Plan of Administration for each of its adjustor mechanisms.

SECTION IV – PUBLIC INTEREST

Q. Mr. Abinah, is the Proposed Settlement in the public interest?

A. Yes, absolutely. In Staff's opinion, the Proposed Settlement is fair, balanced and in the public interest.

Q. Would you briefly summarize the reasons that Staff to conclude that the Settlement is fair, balanced, and in the public interest?

A. The agreed upon revisions in each of these areas were the results of many hours of negotiation and a lot of give and take on the part of all the parties. The settlement process was open, transparent, and inclusive. In the end, the Agreement provides many benefits for customers including:

A) Commitments benefiting low-income customers.

B) Rate stability with a moratorium on general rate case applications for three years.

C) Continuation and expansion of the COYL program.

D) The establishment of a VSP Replacement Program.

E) An estimated overall reduction in depreciation expense of over $44 million.

F) Promotion of customer choice of gas suppliers while ensuring revenue neutrality and no interclass subsidies.

G) Rate design with no increase to the monthly basic service charge.

Q. Mr. Abinah, do you believe that the agreement results in just and reasonable rates for consumers?

A. Yes. In its Rate application, SWG proposed a rate increase in the amount of $31.9 million. Staff recommended a rate increase of $11.3 million. In the Agreement, the signatories recommend $16.0 million, which represents an increase that is $15.9 million less than the Company requested.

Q. Please discuss how the agreement is fair to the utility.

A. The revenue recommended will provide SWG with adequate funds to provide reliable and safe service, while at the same time ensuring the financial health of the Company. The continuation of a full revenue decoupling mechanism will also maintain SWG's revenue stability, which will have a positive impact on its financial profile and credit ratings. Moreover, approving the expansion of the COYL program and implementation of the VSP Replacement Program together with their cost recovery mechanisms will bolster the Company's ability to proactively ensure that their system continues to provide safe and reliable service.

Q. Mr. Abinah, what was Staff's goal when it agreed to be a signatory to the Agreement?

A. The primary goal of Staff in this matter, as in all rate proceedings before the Commission, is to protect the public interest by recommending rates that are just, fair and reasonable to the ratepayers and the Company. Also, Staff believes that the ratepayers will realize the important benefits from the Agreement. In addition, Staff's goal and desire is to apply proactive, forward thinking regulatory practices, provide regulatory support and allow a timely recovery of the Company's prudent and necessary investment. Staff believes we accomplished this goal by reviewing the facts presented and making the appropriate recommendations to the Commission for it consideration, which will balance the interest of the Company and the ratepayers.

SECTION V – POLICY CONSIDERATIONS

Q. Mr. Abinah, would you say that there was one major policy consideration presented in this Docket?

A. Yes, the major policy consideration presented in this matter was the replacement of Vintage Steel Pipe on an accelerated basis.

Q. Please describe the Company's proposal.

A. SWG proposed a Gas Infrastructure Mechanism ("GIM"), which is what SWG refers to as a "rebranding" of the COYL adjustor mechanism. As proposed by SWG, the GIM would be used to recover the costs associated with both the COYL and the VSP replacement programs. The cap for annual adjustment of the GIM surcharge was proposed to be $0.03 per therm.

Q. Mr. Abinah, what was Staff's recommendation on this issue in its Direct Testimony?

A. Staff recommended that the Commission deny the Company's request at this time. Staff also further recommended that the Company, at its discretion, file to request Commission approval to initiate an accelerated VSP replacement program and address cost recovery in a future filing or through a separate docket.

Q. Please briefly describe what is stipulated in the Settlement on the issue of Vintage Steel Pipe replacement.

A. The signatories agreed that SWG shall be allowed to implement its proposed VSP replacement program, and the annual rate adjustment for the VSP program surcharge will be capped at $0.015 per therm per year, and shall apply to all recorded full margin therms sold. Moreover, the Company, Staff and RUCO shall work to jointly develop a draft Plan of Administration that will be circulated to the parties to this docket and brought to the Commission for consideration.

Q. Mr. Abinah, please explain Staff's rationale for being a signatory to the Settlement which contains a different recommendation with regard to Vintage Steel Pipe replacement than the recommendation offered by Staff in its Direct Testimony.

A. The cap of annual rate adjustment on the surcharge was reduced from $0.03 per therm for a combined COYL/VSP adjustor mechanism to $0.015 per therm for the VSP adjustor mechanism alone (with the separate COYL adjustor cap being maintained at its current level of $0.01 per therm for annual rate adjustment). The lowered cap significantly reduces the level of rate impact ratepayers would experience from this type of pipeline replacement. In addition, the lower cap, if combined with appropriate safeguards and limitations built into the Plan of Administration, should enhance the potential cost benefits of replacing VSP on an accelerated and proactive basis, rather than when its condition necessitates immediate replacement. Further, this program will also provide enhanced safety and reliability of the distribution and transmission systems of SWG.

Q. Is there anything else you would like to add regarding the Settlement?

A. No.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

1

EXHIBIT
RUCO-1
ADMITTED

TOM FORESE
CHAIRMAN
BOB BURNS
COMMISSIONER
DOUG LITTLE
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ANDY TOBIN
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BOYD DUNN
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IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS COR{P DEVOTED TO ITS ARIZONA OPERATIONS.	Docket No. G-01551A-16-0107

NOTICE OF FILING

The RESIDENTIAL UTILITY CONSUMER OFFICE ("RUCO") hereby provides notice of filing the Direct Testimony of David Tenney in support of the Settlement Agreement, in the above-captioned proceeding

RESPECTFULLY SUBMITTED this 30th day of January, 2017.

Daniel W. Pozefsky
Chief Counsel

AN ORIGINAL AND THIRTEEN COPIES
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SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-16-0107

DIRECT TESTIMONY

OF

DAVID TENNEY

IN SUPPORT OF SETTLEMENT AGREEMENT

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 30, 2017

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EXECUTIVE SUMMARY

The Arizona Residential Utility Consumer Office ("RUCO") presents the direct testimony of David Tenney, Director of RUCO, in support of the Proposed Settlement Agreement ("Settlement" or "Agreement") on Southwest Gas Corporation's ("SWG" or "Company") request for a permanent rate increase. Mr. Tenney recommends that the Arizona Corporation Commission adopt the Proposed Settlement Agreement for the following reasons:

While RUCO does not agree on the issue of full revenue decoupling the Proposed Settlement Agreement does reflects an outcome that is fair to both the ratepayer and SWG and is in the public interest.

The Proposed Settlement Agreement is a comprehensive settlement agreement. Its terms settle a wide range of issues that were of interest to the parties.

RUCO supports the Proposed Settlement Agreement as it contains numerous benefits to the consumer which will be discussed in Mr. Tenney's testimony.

INTRODUCTION

Q. Please state your name, occupation and business address for the record.

A. My name David Tenney. I am Director for the Arizona Residential Utility Consumer Office ("RUCO"). My business address is 1110 W. Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Please state your background and qualifications for the record.

A. I joined RUCO in March of 2015. I served on the Navajo County Board of Supervisors, representing rural Arizona, from 2004 through 2015. I served as president of the County Supervisors Association of Arizona and was Chairman of the Navajo County Board of Supervisors. In addition, I have served on a number of local, state and national committees, including the Natural Resources Working Group, the Navajo County Regional Development Council, the Silver Creek Watershed Alliance Board, the County Supervisors' Association Legislative Policy Committee, Eastern Arizona Counties Organization, Environmental Economic Communities Organization and the Four Forest Restoration Initiative Steering Committee.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain why RUCO is a signatory to the Southwest Gas Corporation's Proposed Settlement Agreement ("Agreement").

Q. Have you, in your capacity as Director of RUCO, participated in other settlement negotiations?

A. Yes. I have participated in settlement negotiations in other matters that have come before the Arizona Corporation Commission ("ACC" or "Commission"). These negotiations have resulted in reaching an accord with the utility and the other settling parties, leading to the signing and support of a settlement agreement.

THE SETTLEMENT PROCESS

Q. Was the negotiation process that resulted in the Settlement Agreement a proper and fair process and did RUCO fully participate in the settlement negotiations?

A. Yes. RUCO fully participated in the settlement process. The Agreement is the result of many hours of negotiation among the parties to compromise. The negotiations were conducted in a fair and reasonable way that allowed each party the opportunity to participate and all parties were allowed to express their positions fully.

Q. Why is a negotiated settlement process an appropriate way to resolve this matter?

A. By its very nature, a settlement finds middle ground that the parties can support. All parties that participated in the settlement talks were sophisticated parties who participated fully in the ACC's regulatory processes. Settlement negotiations began only after each party had the opportunity to analyze Southwest Gases Application, file its direct testimony, and read the direct testimony of other Interveners. Of course, the Agreement in no way eliminates the ACC's constitutional right and duty to review this matter and to make its own determination whether the Agreement is truly balanced and the rates are just and reasonable.

Q. Did all the parties sign the Agreement?

A. No. All parties in this case have not agreed to this Settlement.

Q. Does RUCO support the Settlement Agreement?

A. Yes, RUCO believes the Settlement Agreement is in the public interest

SETTLEMENT PROVISIONS

Q. In summary, what are the more significant benefits to the residential consumer?

A. Among the more significant benefits to the residential consumer:

- The Company agreed to a revenue increase of $16 million when their original request was $31.9 million.
- Return on Equity of 9.50 percent was agreed to by SWG when 10.35 percent had been requested in its original application filing.
- The residential customer's average monthly bill will increase 1.09 percent compared to the Company's request of 2.53 percent.
- The Company's proposed expansion of the Customer Owned Yard Line (COYL) program was accepted.
- RUCO, Staff and the Company agreed to jointly develop a Plan of Administration for the Company's requested "Vintage Steel Pipe Replacement Program." ("VSP")
- SWG will continue to defer for future recovery the revenue requirement associated with costs incurred prior to December 31, 2020 related to construction of the Liquified Natural Gas ("LGN") facility previously approved by the Arizona Corporation Commission.
- Increase low income ratepayer assistance program to 200 percent of the federal poverty guideline level.
- The Company has agreed to a stay-out provision until May 1, 2019.
- SWG shall be permitted to implement a Property Tax mechanism that allows for the deferral of any changes in property tax expense for recovery in the next general rate case.
- The Company will continue to utilize a full revenue decoupling mechanism subject to certain agreed upon modifications.

Q. Has RUCO supported a full revenue decoupling mechanism in past rate case filings?

A. No. RUCO has not supported a full revenue decoupling mechanism in any past rate case filing.

Q. Can you please explain how RUCO can support the Settlement Agreement in this case but does not support revenue decoupling?

A. Revenue decoupling is just one issue in this case. It is an issue in the area of rate design. The Settlement takes into consideration of the many issues and considers them as a whole. Viewing the Agreement as a whole, the Agreement is a fair and reasonable resolution of all the issues. There are numerous issues in this case that RUCO does not agree with. However, as in any compromise, these issues are weighed against other issues where a solution has been proposed which RUCO finds favorable. Overall, the favorable solutions outweigh the unfavorable solutions from RUCO's perspective which allows RUCO to support the Settlement.

The spirit of this view is spelled out in Section 20.1 of the Settlement. There it states that to achieve consensus for Settlement, participants in the Settlement accept positions that they would otherwise be "...unwilling to accept". The Settlement goes further to state that acceptance by any Signatory of a specific element of this Agreement shall not be considered precedent for acceptance of that element in any other context. That is exactly RUCO's view here, RUCO does not support full revenue decoupling but accepts it in this case insofar as it is a necessary provision for Settlement.

Q. Please elaborate further why RUCO would support an Agreement that provides for full revenue decoupling.

A. Remaining consistent with RUCO's position in prior rate case filings on the full revenue decoupling issue in this case would be counter to the ratepayers' interests. First, there is a certain reality to rate cases – here the Company already has full revenue decoupling and the likelihood that the Commission will deny the Company its continuance is slim. Second, the Settlement provisions on revenue requirement, cost of capital and other rate case elements are fair and are in the ratepayer's best interests. Stated another way, should the matter go to hearing it is unlikely that ratepayers will do better and there is a good chance ratepayers would do worse. Finally, a prolonged litigation is expensive on many levels and could result in even higher rates.

Overall, the Settlement represents a fair and reasonable resolution of all the issues and should be approved.

PUBLIC INTEREST

Q. How is the public interest satisfied by the Agreement?

A. Even though RUCO does not agree with the concept of full revenue decoupling this Agreement satisfies the public interest from RUCO's perspective in that it provides favorable terms and protections for residential consumers as defined above. The Agreement also satisfies the public interest by providing a fair and balanced approach to addressing the Company's concerns on required costs and revenue.

Q. Does this conclude your testimony on the Agreement?

A. Yes it does.

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-16-0107

DIRECT TESTIMONY

OF

JEFFREY MICHLIK

ON

RATE DESIGN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 7, 2016

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SCHEDULES

EXECUTIVE SUMMARY

Southwest Gas Corporation ("SWG" or "Company") is an Arizona "C" Corporation. SWG is a for profit, certificated Arizona public service corporation that provides gas utility service to various communities throughout Arizona. On May 2, 2016, SWG filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. SWG also provides natural gas service to more than 1.9 million customers in Arizona, Nevada, and California. SWG corporate business office is located at 5241 Spring Mountain Road, PO Box 98510 Las Vegas, NV 89193-8510.

RUCO recommends approval of its rate design as shown in Schedule JMM-1.

The Company-proposed rates which includes all charges (Delivery, Rate, and Gas) would increase the monthly bill for a typical single-family residential customer, with an average summer usage of 11 Therms, by $0.49 or 2.06 percent, from $23.84 to $24.33; and for a typical single-family residential customer, with an average winter usage of 40 Therms, by $1.78 or 3.04 percent, from $58.50 to $60.28, as shown in Schedule JMM-2a.

Under the RUCO-recommended rate design for permanent rates which includes all charges (Delivery, Rate, and Gas), the monthly bill for a typical single-family residential customer, with an average summer usage of 11 Therms, by negative $(0.01) or negative (0.04) percent, from $23.84 to $23.83; and for a typical single-family residential customer, with an average winter usage of 40 Therms, by negative $(0.06) or negative (0.10) percent, from $58.50 to $58.44, as shown in Schedule JMM-2a.

I. INTRODUCTION

Q. Please state your name for the record.

A. My name is Jeffrey M. Michlik.

Q. Have you previously filed testimony in this docket?

A. Yes, I have. I filed direct testimony in this docket on November 30, 2016.

II. COST OF SERVICE STUDY

Q. Did you review the Company's Cost of Service Study ("COSS")?

A. Yes.

Q. Did you make any changes to the Company's Cost of Service Study?

A. No.

Q. What is a Cost of Service Study?

A. In very simple terms, a COSS is an estimation of cost-causation by customer class, i.e. how much does it cost the utility to provide its service to each specific customer class. The reason for determining the costs incurred by the utility to serve each customer class is to assist in allocating the revenue requirement for each customer class. For each type utility, there are several generally accepted methods for conducting a COSS. There is no one "correct" COSS method, but rather a range of reasonable alternatives. This is not to suggest that COSSs are arbitrary; some allocations are clearly more reasonable than others. This is the reason a COSS should only be used as a general guide and as one of several considerations in allocating revenue requirements and designing rates.

Q. Should the COSS be the sole factor used when developing a rate design?

A. No. The COSS should only be used as a general guide and as one of several considerations when designing rates.

Q. If RUCO did not rely solely on the COSS for developing rates, what other factors did RUCO consider?

A. In addition to using the results of the COSS as a general guideline, RUCO also considered factors such as promotion of efficient gas usage, gradualism in rate increase to mitigate rate shock, and uniformity of rates between customer classes.

Q. How did RUCO use the COSS as a guide in its rate design?

A. RUCO utilized the COSS as a basic tool, starting point or first step in its rate design. However, due to the other factors cited above, RUCO also incorporated these changes into its rate design.

III. RATE DESIGN

Q. Please briefly describe the Company's current rate design structure?

A. The present rate design is based on a delivery charge consisting of a monthly minimum charge and a commodity per therm charge, collectively a delivery charge. In addition, there is a rate adjustment charge and gas charge.

Q. Please further explain the rate adjustment charge and gas charge.

A. The rate charges are the current adjustment mechanisms and other programs that have been approved by the Commission on a per Therm basis. For example, the Demand Side Management ("DSM") Adjustor Mechanism recently approved by the Commission is $0.00838 per Therm. Not every customer class receives the same rate charge, rather it is based on customer classification. For example, the Electric Generation Gas Service G-60, does not include the Low-Income Ratepayer Assistance ("LIRA") and Efficiency Enabling Provision ("EEP") charge.

The Company's current cost of gas is $0.48556, which is applicable to all customer classes except Natural Gas Engine Gas Service.

Q. Can you please summarize the rate adjustment charges that are currently in effect for the single-family residential customer?

A. Yes, the total rate adjustment charge of $0.00628 consists of the following:

LIRA	$0.01437
DSM	0.00838
Gas Research Fund ("GRF")	0.00122
Department of Transportation ("DOT")	0.00425
EEP	(0.02626)
Customer Owned-Yard Lines ("COYL")	0.00432
Total	$0.00628

Q. Has RUCO also included the Company's current rate adjustment charge and gas charge in its rate design schedule, even though these adjustments will be reviewed by the Commission in separate proceedings?

A. Yes to be consistent with the Company's H-3 schedule, RUCO has included these charges.

Q. What changes has the Company proposed to the delivery charge component?

A. The Company has not proposed changes to the monthly minimum only to the Commodity charge.

Q. Is RUCO recommending changes to the current rate design structure for the delivery charge?

A. No, RUCO recommends only changing the commodity per Therm rate.

Q. Have you prepared schedules summarizing the present, Company proposed, and RUCO-recommended rates and charges?

A. Yes. RUCO has presented its recommended rates in the attached Rate Design Schedule JMM-1. A brief summary of the present, Company-proposed, and RUCO-recommended rates for the single-family residential customer is presented below.

Q. Would you please summarize the present rate design for the single family residential customer?

A. The present monthly minimum delivery charge for the single-family residential customer is $10.70. The delivery commodity rate per therm is $0.70314. The rate adjustment commodity rate per therm is $0.00628, and the gas commodity rate per therm is $0.48556.

Q. Would you please summarize the Company's proposed rate design for the single-family residential customer?

A. The Company-proposed monthly minimum delivery charge for the single-family residential customer is $10.70. The delivery commodity rate per therm is $0.75317. The rate adjustment commodity rate per therm is $0.00074, and the gas commodity rate per therm is $0.48556.

Q. Would you please summarize RUCO's recommended rate design for the single-family residential customer?

A. RUCO recommends a monthly minimum delivery charge for the single-family residential customer of $10.70. A delivery commodity rate of $0.70712 per therm. A rate adjustment commodity rate per therm of $0.00074, and a gas commodity rate per therm is $0.48556.

IV. TYPICAL BILL ANALYSIS

Q. What is the rate impact on a typical single-family residential customer?

A. The Company-proposed rates which includes all charges (Delivery, Rate, and Gas) would increase the monthly bill for a typical single-family residential customer, with an average summer usage of 11 Therms, by $0.49 or 2.06 percent, from $23.84 to $24.33; and for a typical single-family residential customer, with an average winter usage of 40 Therms, by $1.78 or 3.04 percent, from $58.50 to $60.28, as shown in Schedule JMM-2.

Under the RUCO-recommended rate design for permanent rates which includes all charges (Delivery, Rate, and Gas), the monthly bill for a typical single-family residential customer, with an average summer usage of 11 Therms, by negative $(0.01) or negative (0.04) percent, from $23.84 to $23.83; and for a typical single-family residential customer, with an average winter usage of 40 Therms, by negative $(0.06) or negative (0.10) percent, from $58.50 to $58.44.

A typical bill analysis is provided on Rate Design Schedule JMM-2a.

Q. Why is RUCO's typical bill negative while RUCO's revenue requirement was positive?

A. The typical bill analysis in Schedule JMM-2a contains the rate adjustment charges and the gas charge in addition to the delivery charge. The rate adjustment charge decreased from the present charge of $0.00628 to the proposed charge of $0.00074. For comparison purposes I have left these charges in. However, I have also provided the typical bill analysis with the delivery charge only in Schedule JMM-2b.

Q. Does this conclude your rate design direct testimony?

A. Yes, it does.

SCHEDULES

Line No.	Customer Charges	Present Delivery Charges	Present Rate Adjustment	Present Gas Cost	Company Proposed Rates Delivery Charges	Present Rate Adjustment	Present Gas Cost	RUCO Recommended Rates Delivery Charges	Present Rate Adjustment	Present Gas Cost
1										
2	G-5 **Single-Family Residential Gas Service**									
3	Basic Service Charge per Month	$ 10.70			$ 10.70			$ 10.70		
4	Commodity Charge per Therm									
5	All Usage	$ 0.70314	$ 0.00628	$ 0.48556	$ 0.75317	$ 0.00074	$ 0.48556	$ 0.70712	$ 0.00074	$ 0.48556
6										
7	G-6 **Multi-Family Residential Gas Service**									
8	Basic Service Charge per Month	$ 9.70			$ 9.70			$ 9.70		
9	Commodity Charge per Therm									
10	All Usage	$ 0.70314	$ 0.00628	$ 0.48556	$ 0.75317	$ 0.00074	$ 0.48556	$ 0.70712	$ 0.00074	$ 0.48556
11										
12	G-10 **Single-Family Low Income Residential Gas Service**									
13	Basic Service Charge per Month	$ 7.50			$ 7.50			$ 7.50		
14	Commodity Charge per Therm									
15	Summer									
16	All Usage	$ 0.70314	$ (0.01879)	$ 0.48556	$ 0.75317	$ (0.02001)	$ 0.48556	$ 0.70712	$ (0.02001)	$ 0.48556
17	Winter									
18	First 150 Therms	$ 0.35277	$ (0.01879)	$ 0.48556	$ 0.38815	$ (0.02001)	$ 0.48556	$ 0.36442	$ (0.02001)	$ 0.48556
19	Over 150 Therms	$ 0.70314	$ (0.01879)	$ 0.48556	$ 0.75317	$ (0.02001)	$ 0.48556	$ 0.70712	$ (0.02001)	$ 0.48556
20										
21	G-11 **Multi-Family Low Income Residential Gas Service**									
22	Basic Service Charge per Month	$ 7.50			$ 7.50			$ 7.50		
23	Commodity Charge per Therm									
24	Summer									
25	All Usage	$ 0.70314	$ (0.01879)	$ 0.48556	$ 0.75317	$ (0.02001)	$ 0.48556	$ 0.70712	$ (0.02001)	$ 0.48556
26	Winter									
27	First 150 Therms	$ 0.35277	$ (0.01879)	$ 0.48556	$ 0.38815	$ (0.02001)	$ 0.48556	$ 0.36442	$ (0.02001)	$ 0.48556
28	Over 150 Therms	$ 0.70314	$ (0.01879)	$ 0.48556	$ 0.75317	$ (0.02001)	$ 0.48556	$ 0.70712	$ (0.02001)	$ 0.48556
29										
30	G-15 **Special Residential Gas Service for Air Conditioning**									
31	Basic Service Charge per Month	$ 10.70			$ 10.70			$ 10.70		
32	Commodity Charge per Therm									
33	Summer									
34	First 15 Therms	$ 0.70314	$ 0.01817	$ 0.48556	$ 0.75317	$ 0.01263	$ 0.48556	$ 0.70712	$ 0.01263	$ 0.48556
35	Over 15 Therms	$ 0.13077	$ 0.01817	$ 0.48556	$ 0.13391	$ 0.01263	$ 0.48556	$ 0.12572	$ 0.01263	$ 0.48556
36	Winter									
37	All Usage	$ 0.70314	$ 0.01817	$ 0.48556	$ 0.75317	$ 0.01263	$ 0.48556	$ 0.70712	$ 0.01263	$ 0.48556
38										
39	G-20 **Master-Metered Mobile Home Park Gas Service**									
40	Basic Service Charge per Month	$ 66.00			$ 66.00			$ 66.00		
41	Commodity Charge per Therm									
42	All Usage	$ 0.47189	$ 0.03254	$ 0.48556	$ 0.48342	$ 0.02700	$ 0.48556	$ 0.45386	$ 0.02700	$ 0.48556
43										
44	G-25 **General Gas Service**									
45	Basic Service Charge per Month									
46	Small	$ 27.50			$ 27.50			$ 27.50		
47	Medium	$ 43.50			$ 43.50			$ 43.50		
48	Large-1	$ 80.00			$ 80.00			$ 80.00		
49	Large-2	$ 470.00			$ 470.00			$ 470.00		
50	Transportation Eligible	$ 950.00			$ 950.00			$ 950.00		
51	Commodity Charge per Therm									
52	Small, All Usage	$ 0.83914	$ (0.00809)	$ 0.48556	$ 0.90590	$ (0.01363)	$ 0.48556	$ 0.85051	$ (0.01363)	$ 0.48556
53	Medium, All Usage	$ 0.45834	$ (0.00809)	$ 0.48556	$ 0.47886	$ (0.01363)	$ 0.48556	$ 0.44958	$ (0.01363)	$ 0.48556
54	Large-1, All Usage	$ 0.41263	$ (0.00809)	$ 0.48556	$ 0.42547	$ (0.01363)	$ 0.48556	$ 0.39946	$ (0.01363)	$ 0.48556
55	Large-2, All Usage	$ 0.28856	$ (0.00809)	$ 0.48556	$ 0.29824	$ (0.01363)	$ 0.48556	$ 0.28001	$ (0.01363)	$ 0.48556
56	Transportation Eligible, All Usage	$ 0.10923	$ 0.01817	$ 0.48556	$ 0.11481	$ 0.01263	$ 0.48556	$ 0.10779	$ 0.01263	$ 0.48556
57	Demand Charge per Month									
58	Transportation Eligible	$ 0.08246			$ 0.08339			$ 0.07829		
59										

Line No.	Customer Charges	Present Delivery Charges	Present Rate Adjustment	Present Gas Cost	Proposed Rates Delivery Charges	Present Rate Adjustment	Present Gas Cost	Recommended Rates Delivery Charges	Present Rate Adjustment	Present Gas Cost
60	G-30 **Optional Gas Service**									
61	Basic Service Charge per Month	**As Specified on A.C.C. Sheet No. 27.**			As Specified on A.C.C. Sheet No. 27.			As Specified on A.C.C. Sheet No. 27.		
62	Commodity Charge per Therm									
63	All Usage	**As Specified on A.C.C. Sheet No. 28.**			As Specified on A.C.C. Sheet No. 28.			As Specified on A.C.C. Sheet No. 28.		
64										
65	G-40 **Air Conditioning Gas Service**									
66	Basic Service Charge per Month	**As Specified on A.C.C. Sheet No. 32.**			As Specified on A.C.C. Sheet No. 32.			As Specified on A.C.C. Sheet No. 32.		
67	Commodity Charge per Therm									
68	All Usage	$ **0.13077**	$ 0.01817	$ 0.48556	$ **0.13391**	$ 0.01263	$ 0.48556	$ **0.12572**	$ 0.01263	$ 0.48556
69										
70	G-45 **Street Lighting Gas Service**									
71	Commodity Charge per Therm									
72	of Rated Capacity									
73	All Usage	$ **0.69242**	$ 0.01817	$ 0.48556	$ **1.22494**	$ 0.01263	$ 0.48556	$ **1.15005**	$ 0.01263	$ 0.48556
74										
75	G-55 **Gas Service for Compression on Customer's Premises**									
76	Basic Service Charge per Month									
77	Small	$ **27.50**			$ **27.50**			$ **27.50**		
78	Large	$ **250.00**			$ **250.00**			$ **250.00**		
79	Residential	$ **10.70**			$ **10.70**			$ **10.70**		
80	Commodity Charge per Therm									
81	All Usage	$ **0.21470**	$ 0.01817	$ 0.48556	$ **0.22010**	$ 0.01263	$ 0.48556	$ **0.20664**	$ 0.01263	$ 0.48556
82										
83	G-60 **Electric Generation Gas Service**									
84	Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 40.			As Specified on A.C.C. Sheet No. 40.			As Specified on A.C.C. Sheet No. 40.		
85	Commodity Charge per Therm									
86	All Usage	$ **0.15421**	$ 0.01817	$ 0.48556	$ **0.16003**	$ 0.01263	$ 0.48556	$ **0.15025**	$ 0.01263	$ 0.48556
87										
88	G-75 **Small Essential Agriculture User Gas Service**									
89	Basic Service Charge per Month	$ **120.00**			$ **120.00**			$ **120.00**		
90	Commodity Charge per Therm									
91	All Usage	$ **0.28037**	$ 0.01817	$ 0.48556	$ **0.28870**	$ 0.01263	$ 0.48556	$ **0.27105**	$ 0.01263	$ 0.48556
92										
93	G-80 **Natural Gas Engine Gas Service**									
94	Basic Service Charge per Month									
95	Off-Peak Season (October - March)	$ -			$ -			$ -		
96	Peak Season (April - September)	$ **125.00**			$ **125.00**			$ **125.00**		
97	Commodity Charge per Therm									
98	All Usage	$ **0.22065**	$ 0.01817	$ 0.48556	$ **0.22488**	$ 0.01263	$ 0.48556	$ **0.21113**	$ 0.01263	$ 0.48556
99										
100	**Service Establishment Charge**									
101	Normal	$ **35.00**			$ **35.00**			$ **35.00**		
102	Expedited	$ **50.00**			$ **50.00**			$ **50.00**		
103										

104 [1] Present Margin rates effective January 1, 2012.
105 [2] Present Rate Adjustment and Gas Cost rates effective November 30, 2015.
106 [3] Calculated rates to recover proposed Margin per Schedule H-1, Sheet 2 of 2.

Southwest Gas Corporation
Docket No. G-0155A-16-0107
Test Year Ended November 30, 2015

Rate Design Schedule JMM-2a

Typical Bill Analysis
Single-Family Residential Gas Service with Effective Current Charges

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: Present Rates	Monthly Bill: Company Proposed Rates	Monthly Bill: RUCO Recommended Rates	Company Increase/(Decrease): Dollars	Company Increase/(Decrease): Percent	RUCO Increase/(Decrease): Dollars	RUCO Increase/(Decrease): Percent
1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
2									
3	Summer Season Bills								
4	75 Percent Average Use	8	$ 20.26	$ 20.62	$ 20.25	$ 0.36	1.78%	$(0.01)	-0.05%
5									
6	Average Summer Use	11	23.84	24.33	23.83	0.49	2.06%	(0.01)	-0.04%
7									
8	125 Percent Average Use	14	27.43	28.05	27.41	0.62	2.26%	(0.02)	-0.07%
9									
10	Winter Season Bills								
11	75 Percent Average Use	30	$ 46.55	$ 47.88	$ 46.50	$ 1.33	2.86%	$(0.05)	-0.11%
12									
13	Average Winter Use	40	58.50	60.28	58.44	1.78	3.04%	(0.06)	-0.10%
14									
15	125 Percent Average Use	50	70.45	72.67	70.37	2.22	3.15%	(0.08)	-0.11%
16									
17	Annual Average Use	26	41.33	42.47	41.29	1.14	2.76%	(0.04)	-0.10%
18									

Line No.	Description	Amount
19		
20	Effective Current Rates	Amount
21	Basic Service Charge per Month	$ 10.70
22	Commodity Charge	
23	Delivery All Usage	$ 0.70314
24	Rate Adjustment	$ 0.00628
25	Gas Cost	$ 0.48556
26	Total Commodity Charges	$ 1.19498
27		
28	Company Proposed Rates	
29	Basic Service Charge per Month	$ 10.70
30	Commodity Charge	
31	Delivery All Usage	$ 0.75317
32	Rate Adjustment	$ 0.00074
33	Gas Cost	$ 0.48556
34	Total Commodity Charges	$ 1.23947
35		
36	RUCO Recommended Rates	
37	Basic Service Charge per Month	$ 10.70
38	Commodity Charge	
39	Delivery All Usage	$ 0.70712
40	Rate Adjustment	$ 0.00074
41	Gas Cost	$ 0.48556
42	Total Commodity Charges	$ 1.19342

Southwest Gas Corporation
Docket No. G-0155A-16-0107
Test Year Ended November 30, 2015

Rate Design Schedule JMM-2b

Typical Bill Analysis
Single-Family Residential Gas Service with Delivery Charge Only

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: Present Rates	Monthly Bill: Company Proposed Rates	Monthly Bill: RUCO Recommended Rates	Company Increase/(Decrease): Dollars	Company Increase/(Decrease): Percent	RUCO Increase/(Decrease): Dollars	RUCO Increase/(Decrease): Percent
1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
2									
3	Summer Season Bills								
4	75 Percent Average Use	8	$ 16.33	$ 16.73	$ 16.36	$ 0.40	2.45%	$ 0.03	0.18%
5									
6	Average Summer Use	11	18.43	18.98	18.48	0.55	2.98%	0.05	0.27%
7									
8	125 Percent Average Use	14	20.54	21.24	20.60	0.70	3.41%	0.06	0.29%
9									
10	Winter Season Bills								
11	75 Percent Average Use	30	$ 31.79	$ 33.30	$ 31.91	$ 1.51	4.75%	$ 0.12	0.38%
12									
13	Average Winter Use	40	38.83	40.83	38.98	2.00	5.15%	0.15	0.39%
14									
15	125 Percent Average Use	50	45.86	48.36	46.06	2.50	5.45%	0.20	0.44%
16									
17	Annual Average Use	26	28.72	30.00	28.82	1.28	4.46%	0.10	0.35%
18									
19									

Line No.	Description	Amount
20	Effective Current Rates	
21	Basic Service Charge per Month	$ 10.70
22	Commodity Charge	
23	Delivery All Usage	$ 0.70314
24	Rate Adjustment	$ -
25	Gas Cost	$ -
26	Total Commodity Charges	$ 0.70314
27		
28	Company Proposed Rates	
29	Basic Service Charge per Month	$ 10.70
30	Commodity Charge	
31	Delivery All Usage	$ 0.75317
32	Rate Adjustment	$ -
33	Gas Cost	$ -
34	Total Commodity Charges	$ 0.75317
35		
36	RUCO Recommended Rates	
37	Basic Service Charge per Month	$ 10.70
38	Commodity Charge	
39	Delivery All Usage	$ 0.70712
40	Rate Adjustment	$ -
41	Gas Cost	$ -
42	Total Commodity Charges	$ 0.70712

EXHIBIT
RUCO-3
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-16-0107

DIRECT TESTIMONY

OF

JEFFREY MICHLIK

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 30, 2016

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ATTACHMENTS

EXECUTIVE SUMMARY

Southwest Gas Corporation ("SWG" or "Company") is an Arizona "C" Corporation, and for profit, certificated Arizona public service Corporation that provides gas utility service to various communities throughout Arizona. On May 2, 2016, SWG filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. SWG also provides natural gas service to more than 1.9 million customers in Arizona, Nevada, and California. SWG's corporate business office is located at 5241 Spring Mountain Road, PO Box 98510 Las Vegas, NV 89193-8510.

The Company utilized a test year ended November 30, 2015.

The Company-proposed rates, as filed, produce total operating revenue of $513,608,301, an increase of $31,926,895, or 6.63 percent, over adjusted test year revenue of $481,681,406. The Company-proposed revenue will provide operating income of $108,844,799 and a 6.01 percent rate of return on its proposed $1,812,414,666 fair value rate base ("FVRB").

The Residential Utility Consumer Office ("RUCO") recommends rates that produce total operating revenue of $492,286,354 an increase of $10,604,948 or 2.20 percent, from the RUCO-adjusted test year revenue of $481,681,406. RUCO's recommended revenue will provide operating income of $101,811,452 and a 5.67 percent return on the $1,795,171,759 RUCO-adjusted FVRB (see RUCO schedule JMM-1).

<u>Other Items</u>:

RUCO recommends denial of the continuation of the Energy Efficiency Enabling Provision ("EEP") at this time.

RUCO recommends denial of the Property Tax True-up Mechanism.

RUCO recommends denial of the Gas Infrastructure Modernization ("GIM") Mechanism.

I. INTRODUCTION

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

A. My name is Jeffrey M. Michlik. I am a Public Utilities Analyst V employed by the Arizona Residential Utility Consumer Office ("RUCO"). My business address is 1110 West Washington Street, Suite 220, Phoenix, Arizona 85007.

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

A. In my capacity as a Public Utilities Analyst V, I analyze and examine accounting, financial, statistical and other information and prepare reports based on my analyses that present RUCO's recommendations to the Arizona Corporation Commission ("Commission") on utility revenue requirements, rate design, and other matters. I also provide expert testimony on these same issues.

Q. Please describe your educational background and professional experience.

A. In 2000, I graduated from Idaho State University, receiving a Bachelor of Business Administration Degree in Accounting and Finance, and I am a Certified Public Accountant with the Arizona State Board of Accountancy. I have attended the National Association of Regulatory Utility Commissioners' ("NARUC") Utility Rate School, which presents for study and review general regulatory and business issues. I have also attended various other NARUC sponsored events.

I joined RUCO as a Public Utilities Analyst V in September of 2013. Prior to my employment with RUCO, I worked for the Arizona Corporation Commission in the Utilities Division as a Public Utilities Analyst for a little over seven years. Prior to employment with the Commission, I worked one year in public accounting as a Senior Auditor, and four years for the Arizona Office of the Auditor General as a Staff Auditor.

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

A. I am presenting RUCO's analysis and recommendations on Southwest Gas Corporation's ("SWG" or "Company") proposed revenue requirement for SWG's application for a permanent rate increase. I am also presenting testimony and schedules addressing rate base, operating revenues and expenses, and rate design. In addition, Mr. John Cassidy will be addressing Cost of Capital.

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

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

Q. How is your testimony organized?

A. My testimony is presented in six sections. Section I is this introduction. Section II provides a background of the Company. Section III is a summary of the Company's filing and RUCO's rate base and operating income adjustments. Section IV presents RUCO's rate base recommendations. Section V presents RUCO's operating income recommendations. Section VI presents RUCO's recommendations on other issues identified during RUCO's review of the application.

II. BACKGROUND

Q. Please review the background of this application.

A. SWG is an Arizona "C" Corporation, and for profit, certificated Arizona public service Corporation that provides gas utility service to various communities throughout Arizona. On May 2, 2016, SWG filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. SWG provides natural gas service to more than 1.9 million customers in Arizona, Nevada, and California. SWG corporate business office is located at 5241 Spring Mountain Road, PO Box 98510 Las Vegas, NV 89193-8510.

III. SUMMARY OF FILING, RECOMMENDATIONS, AND ADJUSTMENTS.

Q. Please summarize the Company's proposals in this filing.

A. The Company-proposed rates, as filed, produce total operating revenue of $513,608,301, an increase of $31,926,895, or 6.63 percent, over adjusted test year revenue of $481,681,406. The Company-proposed revenue will provide operating income of $108,844,799 and a 6.01 percent rate of return on its proposed $1,812,414,666 fair value rate base ("FVRB").

The Residential Utility Consumer Office ("RUCO") recommends rates that produce total operating revenue of $492,286,354 an increase of $10,604,948 or 2.20 percent, from the RUCO-adjusted test year revenue of $481,681,406. RUCO's recommended revenue will provide operating income of $101,811,452 and a 5.67 percent return on the $1,795,171,759 RUCO-adjusted FVRB (see RUCO schedule JMM-1).

Q. For the purposes of this rate case, has RUCO accepted the Company's gross revenue conversion factor of 1.6329?

A. No. As part of Arizona House Bill 2001, which was signed into law by Governor Jan Brewer on February 17, 2011 the State corporate income tax declines from 5.5 percent to 4.9 percent after December 31, 2016. This reduces the Company's gross revenue conversion factor to 1.6226 (See Attachment A), and RUCO schedule JMM-2.

Q. Please summarize RUCO's rate base adjustments.

A. The six rate base adjustments are presented below:

Rate Base Adjustment No. 1 – Post-Test Year Plant and Accumulated Depreciation – This adjustment removes post-test year plant in the amount of $6,111,843 that was placed into service six months after the test year. This adjustment also increases accumulated depreciation in the amount of $1,160,472 for post-test year plant that was placed into service within six months after the test year.

Rate Base Adjustment No. 2 – Post-Test Year Plant Retirements – This adjustment removes plant retirements and accumulated depreciation related to plant that was retired six months after the test year, which results in a decrease in plant of $23,418,708, and accumulated depreciation of $23,418,708.

Rate Base Adjustment No. 3 – Company-owned Aircraft, Aircraft Hanger, and Equipment – This adjustment removes Company-owned Aircraft, Aircraft Hanger, and Equipment that is not necessary to providing natural gas services in Arizona. This adjustment decreases plant in service by $5,139,070, decreases accumulated depreciation by $1,013,033 and increases deferred taxes by $1,475,972, Rate Base Adjustment No. 4 - Cash for Working Capital - This adjustment applies to cash working capital and changes the amount based on RUCO's operating adjustment, and increases cash working capital by $29,939.

Rate Base Adjustment No. 5 – Prepayments - Directors and Officers Insurance – This adjustment removes 50 percent of the prepayments related to director an officers insurance, as these prepayments benefit both ratepayers and shareholders, and results in an adjustment of $145,327.

Rate Base Adjustment No. 6 – Accumulated Deferred Income Taxes ("ADIT") related to Post-Test Year Plant Bonus Depreciation - This adjustment increases ADIT for the timing difference that occurs between the book amount and amount for tax purposes that occur as a result of bonus depreciation that will be taken by the Company on its Post-Test Year Plant, and increases deferred taxes by $6,462,859.

Q. Please summarize RUCO's operating revenue and expense adjustments.

A. The thirteen operating income adjustment(s) are presented below:

Operating Income Adjustment No. 1 – Investor Relations Expense – This adjustment removes $217,870 related to shareholder expenses.

<u>Operating Income Adjustment No. 2 – Benefit Expense</u> – This adjustment decreases expenses by $162,972 and removes officer tax and State planning, and vehicle compensation costs that are not necessary for the provision of natural gas services in Arizona.

<u>Operating Income Adjustment No. 3 – Directors and Officers Liability Insurance</u> – This adjustment recognizes that this expense benefits both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This reduces adjusted test year D&O expense by $333,962.

<u>Operating Income Adjustment No. 4 – Management Incentive Program ("MIP")</u> - This adjustment recognizes that this expense benefits both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This adjustment reduces adjusted test year MIP expense by $2,436,953.

<u>Operating Income Adjustment No. 5 – Supplemental Executive Retirement Plant ("SERP") Expense</u> – This adjustment removes SERP expenses that RUCO believes should not be borne by ratepayers, and is not necessary for the provision of natural gas services. This adjustment reduces SERP expense by $1,627,202.

Operating Income Adjustment No. 6 – Executive Deferral Plan ('EDP") – This adjustment removes expenses that RUCO believes should not be borne by ratepayers, and is not necessary for the provision of natural gas services. This adjustment reduces EDP expense by $1,510,554.

Operating Income Adjustment No. 7 – Restricted Stock/Unit Plan ("RSUP") – This adjustment removes expenses that RUCO believes should not be borne by ratepayers, and is not necessary for the provision of natural gas services. This adjustment reduces RSUP expense by $2,227,976.

Operating Income Adjustment No. 8 – Severance Pay – This adjustment removes expenses that RUCO believes should not be borne by ratepayers, and is not a necessary expense in providing natural gas services. This adjustment reduces severance pay by $133,207.

Operating Income Adjustment No. 9 – American Gas Association ("AGA") and Western Energy Institute ("WEI") Dues – This adjustment recognizes that this expense benefits both ratepayers and shareholders and therefore RUCO recommends a sharing of this cost. This adjustment reduces AGA and WEI dues by $145,184.

Operating Income Adjustment No. 10 – Rate Case Expense – This adjustment reduces estimated rate case expense by $44,000 to account for what RUCO has determined to be just and reasonable expense.

Operating Income Adjustment No. 11 – Depreciation Expense – This adjustment reduces depreciation expense by $824,156 and is related to the adjustments previously mentioned above in RUCO's summary of rate base adjustments.

Operating Income Adjustment No. 12 – Interest Synchronization Expense – This adjustment resynchronizes interest expense based on RUCO's recommended rate base and weighted cost of debt and decreases adjusted test year taxes by $8,923.

Operating Income Adjustment No. 13 – Income Tax Expense – This adjustment increases income tax by $3,690,212 to account for RUCO's adjustments to operating revenues and expenses.

IV. RATE BASE

Fair Value Rate Base ("FVRB")

Q. Did the Company prepare a schedule showing the elements of a Reconstruction Cost New Depreciated ("RCND") Rate Base?

A. Yes. The Company derived its FVRB by taking the average of the Original Cost Rate Base ("OCRB") and RCND. This methodology has been accepted by the Commission in prior decisions.

Q. Has RUCO presented its schedules to reflect OCRB, RCND and FVRB?

A. Yes. For purposes of this presentation, I have used the Company's OCRB information as the starting point for RUCO's determination of the Company's FVRB.

Rate Base Summary

Q. Please summarize RUCO's adjustments to the Company's OCRB base denoted in thousands.

A. RUCO's adjustments to the Company's rate base resulted in a net decrease of $16,500,627, from $1,336,049,260 to $1,319,548,633 the decrease was primarily due to following RUCO's adjustments: (1) Post-Test Year Plant and Accumulated Depreciation, (2) Post-Test Year Retirements, (3) Company owned aircraft, aircraft hangar & equipment, (4) cash working capital, (5) prepayments, and (6) ADIT related to Post-Test Year bonus depreciation, as shown on schedules JMM-4, and JMM-5.

Rate Base Adjustment No. 1 – Post-Test Year Plant and Accumulated Depreciation

Post-Test Year Plant

Q. Has the Company proposed to include plant that was not placed into service within six months post-test year?

A. Yes. The Company originally proposed post-test year plant in the amount of $23,274,450 in direct plant costs (i.e. Distribution $19,147,853 and General Plant $4,126,597), and $16,797,299 after allocation to the Arizona jurisdiction in systems allocable costs (i.e. Intangible $15,277,047 and General Plant $1,520,252) for a total of $40,071,749 in post-test year plant.

Q. Has the Company completed all of its post-test year plant that it requested in its application?

A. No, not at the date of this filing.

Q. Has RUCO trued-up the post-test year plant that was placed into service six months after the test year?

A. Yes. For plant that was completed, placed into service, and is used and useful, RUCO has updated the Company's estimated costs to reflect the actual costs at May 31, 2016.

Q. What is RUCO's policy in regards to the inclusion of post-test-year plant?

A. RUCO's general policy is to consider post-test year plant that was placed into service within six months after the end of the test year. This gives the Company sufficient time to complete projects that were not complete at the end of the test year. Anything longer distorts the meaning of a test year, and alters the regulatory matching of revenues, expenses, and rate base.

Accumulated Depreciation

Q. Did the Company include accumulated depreciation in its post-test year calculation?

A. No. Based on responses to RUCO data request 4.07 and 4.08 (See Attachment B), the Company states no adjustment was made.

Q. Why did the Company not include accumulated depreciation in its post-test year calculation?

A. Per Staff data request 2.04, and "At the end of the test year, the accumulated depreciation associated with any post-test year plant adjustments is $0."

Q. Do you agree with the Company's reasoning?

A. No. Especially since the Company has included estimated post-test year plant, and has calculated a full year of depreciation expense from these estimated post-test year plant costs, which both benefit the Company. To not calculate and record accumulated depreciation, which benefits ratepayers, is also contradictory to basic accounting principles. The purpose of using depreciation is to gradually reduce the recorded cost of the fixed asset to recognize a portion of the asset's expense at the same time that the company records the revenue that was generated by the fixed asset which is known as matching. The basic entry to record depreciation expense is a debit to depreciation expense, and a credit to accumulated depreciation. Accumulated depreciation serves as a contra account to the asset on the balance sheet, which in effect serves to reduce the value of the asset as it is used over time.

Q. Did the Company state what depreciation methodology it utilized to depreciate its assets that have been recently placed in service during the year (e.g. monthly convention, half-year convention, etc.)?

A. Not really, the Company responded in RUCO data request 4.08 by stating the following:

"The Company annualized depreciation expense so that a full year's worth of depreciation expense is reflected based on adjusted ending plant balances in the cost of service. Please refer to Adjustment No. 13."

Q. How do most Companies account for post-test year plant accumulated depreciation and depreciation expense when filing a rate case that you are familiar with?

A. Most companies record a half year of accumulated depreciation on the rate base side, and a full year of depreciation expense on the operating expense side.

Q. Please explain the half-year convention of depreciation?

A. The half-year convention treats all utility plant placed in service during the year as placed in service in the midpoint of the year. Thus, accumulated depreciation expense is only calculated for half a year, in the year that the asset is placed into service.

Q. Please elaborate.

A. In Docket No. W-01445A-10-0517, Arizona Water Company's witness Joel Reiker, Vice President of Rates and Revenue stated the following when talking about accumulated depreciation associated with post-test year plant: "This adjustment assumes that these items were placed into service on December 31, 2010, and assumes for ratemaking purposes that the Company recorded a half-year of depreciation on these additions, consistent with standard utility plant accounting practices." [1]

[1] See Docket No. W-01445-10-0517, page 12 of Mr. Reiker's application testimony.

Q. How does the half-year convention of depreciation expense affect the balance sheet plant accounts, or in regulatory accounting, the rate base?

A. A half-year of accumulated depreciation is recorded as a contra asset to the plant that was placed into service.

Q. How does this apply to post-test year plant?

A. The adjustment assumes the post-test year plant items were placed into service, and thus a half year of accumulated depreciation is recorded.

Q. What adjustment did RUCO make?

A. RUCO applied the half-year convention of depreciation to all post-test year plant that was completed within the first six months after the test year, using the individual depreciation rates for each FERC plant account.

Q. What is RUCO's recommendation?

A. RUCO recommends reducing post-test year direct plant by $3,905,569 from $22,620,591 to $18,715,022, and post-test year system allocable 303 costs by $2,174,887 from $15,277,047 to $13,102,160, and post-test year system allocable costs by $31,387 from $1,520,252 to $1,488,865, and increasing accumulated depreciation expense by $1,160,472 from $0 to $1,160,472, as shown on schedules JMM-5 and JMM-6.

Rate Base Adjustment No. 2 – Post-Test Year Plant Retirements

Q. Did the Company remove any retirements after the test year?

A. No, as with the accumulated depreciation and the ADIT adjustment to be discussed later, both of which benefit ratepayers, the Company failed to make any adjustments to post-test year plant retirements.

Q. To recognize the concept of a test year and the matching principle has RUCO also removed retirements to plant that were made six months post-test year?

A. Yes.

Q. But plant retirements do not effect rate base, since the plant amount equals the accumulated depreciation amount and therefore the net effect is zero?

A. Correct, however on the operating income side of the equation, depreciation expense must be removed which corresponds to the retirement otherwise the Company is unjustly enriched by the amount of the plant which it has retired. See RUCO operating adjustment No. 11 (Depreciation Expense) which reduces depreciation expense for the retirement of plant six months after the test-year.

Q. What is RUCO's recommendation related to the inclusion of these retirements?

A. As shown on RUCO schedule JMM-7, RUCO recommends decreasing plant by $23,418,708 and accumulated depreciation by $23,418,708.

Rate Base Adjustment No. 3 – Company-owned Aircraft, Aircraft Hanger, and Equipment

Q. Has the Company asked to have ratepayers pay for the costs of the Company-owned aircraft, aircraft hangar, and equipment?

A. Yes.

Q. Does RUCO agree?

A. No. The corporate aircraft, hanger, and equipment are unnecessary and are not required in order to provide natural gas services in Arizona. .

Q. What is RUCO's recommendation?

A. RUCO recommends a decrease in plant of $5,139,070, and a decrease in accumulated depreciation of $1,013,033 and an increase in deferred taxes of $1,475,972. The depreciation account details related to the corporate aircraft, hanger, and equipment, is shown in RUCO schedule JMM-8.

Rate Base Adjustment No. 4 – Cash Working Capital

Q. What is working capital?

A. Working capital measures the amount of investors' funds that must be used to sustain the day to day operations of the Company, in this case on average over a test year. In general the components of working capital are fuel inventory; materials and supplies inventories; prepayments; and cash working capital.

Q. Did the Company provide a lead/lag study to support its cash working capital component?

A. Yes.

Q. What is a lead-lag study?

A. A Lead/Lag Study measures the average length of time between the provision of the Company's utility services to the customers, and the subsequent payment for those services by customers, known as a revenue lag (or lead); and the average length of time between when a Company incurs an expense, and when the Company makes the cash payment, known as an expense lead (or lag).

A comparison is then made between the revenue lag (or lead) and the expense lead (or lag), the total of which if positive, results in an addition to rate base to compensate the Company's investors for additional cash working capital investments it has made. If the total is negative, this results in a deduction from rate base to compensate other investors (i.e. ratepayers) for their cash working capital investments.[2]

Q. As a result of RUCO's recommended changes to the Company's operating expenses, has this changed the cash working capital component of working capital?

A. Yes, RUCO has adjusted the Company's cash working capital component based on its operating income adjustments to flow through the Company's lead-lag summary, and increases the cash working capital allowance by $29,939 from negative $4,113,676 to negative $4,083,737, as shown in RUCO schedule JMM-9.

Rate Base Adjustment No. 5 – Prepayments – Directors and Officers Insurance

Q. Has RUCO made any adjustments to prepayments?

A. Yes. RUCO has reduced the Company's Directors and Officers ("D&O") Insurance prepayments reflected in the allowance for working capital – prepayments component. Similarly, RUCO has reduced the Company's D&O expense, which will be discussed in greater detail in RUCO's Operating Adjustment No. 3. RUCO recommends a sharing of these costs

[2] Paraphrased from excerpts from Public Utility Working Capital by Carl W. Dabelstein, CPA.

between ratepayers and shareholders. In this case, RUCO recommends a sharing of the D&O prepaid insurance of $290,653.

Q. What is RUCO's recommendation?

A. RUCO recommends reducing prepaid D&O liability insurance by $145,327 from $290,653 to $145,327, as shown in RUCO schedule JMM-10.

Rate Base Adjustment No. 6 – Accumulated Deferred Income Taxes ("ADIT") related to Post-Test Year Plant Bonus Depreciation

Q. Did the Company adjust its ADIT balance to account for the Bonus Depreciation related to its Post-Test Year Plant?

A. No.

Q. You eluded to the matching principal in your discussion of post-test year plant related to accumulated depreciation, please elaborate?

A. Yes, just as the Company did not include an adjustment to accumulated depreciation which benefits ratepayers the Company also neglected to include an adjustment to ADIT to account for the timing differences resulting from book versus tax accounting which also has a benefit to ratepayers.

Q. Have both RUCO and Staff asked the Company why they did not adjust ADIT to reflect post-test year bonus deprecation?

A. Yes.

Q. What was the Company's response?

A. Based on RUCO data request 5.16 the Company responded:

"In its response to RUCO 4.07, the Company explained that since no book depreciation had been recorded on the post-test year plant as of the end of the test year, there was no book-tax depreciation difference related to that post-test year plant at November 2015 (the end of the test year). As a result, there is no adjustment to the deferred tax balance for post-test year plant. The Company did deduct bonus depreciation on all eligible plant additions in its 2015 federal income tax return. Likewise, the Company will deduct all allowable bonus depreciation in its 2016 federal income tax return."

Q. Does the Company intend to make the bonus depreciation election on its 2016 tax return?

A. Yes.

Q. What is RUCO's response?

A. The bonus depreciation should be included now.

Q. Has the Commission ruled on this topic before?

A. Yes, In Decision No. 75268 (dated September 8, 2015), stated on page, 34, line 15. *"A fundamental tenet of ratemaking is that a utility should earn a return only on used and useful assets financed by investors. Since ADIT is a source of non-investor capital, matching of plant with ADIT in the* *calculation of rate base is appropriate. In this case, RUCO's ADIT recommendations provide the best matching. We also believe that ratepayers should not be deprived of rate base recognition of ADIT arising from income tax timing differences when bonus depreciation results in an NOL. The circumstances that result in an NOL are subject to decisions by utility management, not ratepayers, and since an NOL can be carried forward to future years, it represents an asset that a utility can use to provide a tax benefit in future years. Accordingly, we will adopt RUCO's proposed ADIT adjustments."*

Q. Are you aware of any internal revenue service private letter rulings that would preclude ADIT (resulting from bonus depreciation) from being applied to Post-Test Year?

A. No

Q. How is ADIT accounted for in regulatory accounting?

A. ADIT is a reduction to rate base.

Q. Has RUCO calculated the increase in ADIT as a result of including six months of post-test year plant?

A. Yes, as shown on RUCO schedule JMM-11, RUCO recommends increasing ADIT by $6,462,859.

V. OPERATING INCOME

Operating Income Summary

Q. What are the results of RUCO's analysis of test year revenues, expenses, and operating income?

A. RUCO's analysis resulted in adjusted test year operating revenues of $481,681,406, operating expenses of $386,405,623 and operating income of $95,275,783, as shown on schedules JMM-12 and 13. RUCO made thirteen adjustments to operating income, as presented below.

Operating Income Adjustment No. 1 – Investor Relation Expenses

Q. Did RUCO ask the Company to provide investor relations cost included in the Company's cost allocation (e.g. costs included to list the Company's stock on the New York Stock exchange, prospectuses, investment newsletters to stockholders, etc.)?

A. Yes.

Q. What was the Company's response?

A. In response to RUCO data request 3.06 the Company provided a listing of investor relation costs it seeks recovery of in this rate case from Arizona ratepayers.

Q. Does RUCO believe these costs should be allocated to ratepayers?

A. No, these costs are incurred for the benefit of shareholders and should not be paid by ratepayers.

Q. What is RUCO's recommendation?

A. RUCO recommends removing the travel, lodging, corporate aircraft travel and catering, etc. from operating expenses in the amount of $217,870, as shown in RUCO schedule JMM-14.

Operating Income Adjustment No. 2 – Benefit Expenses

Q. Did RUCO make an adjustment to operating expenses related to finance and estate planning?

A. Yes, based on Staff data request 2.28, "Officers are provided a $5,000 allowance once every three years to assist in financial and estate planning."

Q. Does RUCO agree that these costs should be borne by ratepayers?

A. No. These costs have nothing to do with providing natural gas service in Arizona. If the Company wants to include additional perks for its officers it should be at the shareholders expense, as a result RUCO has removed $7,586.

Q. Did RUCO also make an adjustment for vehicle compensation?

A. Yes. This seems to be a computational error. The Company stated in its response to Staff data request 10.28:

"The schedule supporting Adjustment No. 6 contains an error in the formula on line 4. The intent was to multiply the System Allocable portion of the adjustment of -\$302,089 by (1 – 4.13%) to determine the adjustment after the MMF allocation to the FERC jurisdictions. The corrected schedule is provided in Staff 10.28_Attachment 1.

The total Employee Vehicle Compensation adjustment should have reduced expenses on Line 7 by \$217,494, rather than \$62,108."

RUCO's adjustment of \$155,386 reconciles the difference between \$217,494 and \$62,108.

Q. What is RUCO's recommendation?

A. RUCO recommends that \$162,972 be removed from operating expenses, as shown in RUCO schedule JMM-15.

Operating Income Adjustment No. 3 – Directors and Officers ("D&O") Liability Insurance Expense

Q. What is D&O Liability Insurance?

A. D&O liability Insurance is liability insurance that covers directors and officers for claims made against them by shareholders or others for decisions they may make.

Q. Has the Company requested that ratepayers bear the full burden of this cost?

A. Yes.

Q. What is the total amount of D&O Liability Insurance included in adjusted test year expenses?

A. The Company is seeking recovery of $667,923.

Q. What is RUCO's recommendation?

A. RUCO recommends a 50/50 sharing between ratepayers and shareholders, since D&O Liability Insurance not only benefits ratepayers, but also shareholders. Shareholders benefit from insurance coverage in litigation cases brought against the company's directors and officers. Shareholders would also benefit from payments under this policy which may not be recoverable from ratepayers. Similarly, it can be argued that ratepayers benefit, since the Company can attract and retain directors and officers, and provides them with some degree of freedom from personal liability. Therefore, it is reasonable for shareholders to bear a portion of the cost for the D&O liability insurance. RUCO recommends reducing D&O liability insurance by $333,962 from $667,923 to $333,962, as shown in RUCO schedule JMM-16.

Operating Income Adjustment No. 4 – Management Incentive Program ("MIP") Expense

Q. Has the Company asked for ratepayers to fund 100 percent of its MIP?

A. Yes.

Q. Briefly describe the MIP?

A. The MIP consists of the following five components each weighted equally at 20 percent[3]:

Customer Satisfaction - designed to reward success in achieving a predetermined customer satisfaction percentage.

Customer-to-Employee Ratio - designed to reward success in improving the customer-to-employee ratio.

[3] Direct Testimony of Company witness Brian Holman, starting at page 5, line 22.

Safety - designed to reward success in minimizing damages per 1,000 tickets and incident response time.

Operating Cost Containment - designed to reward success in achieving a predetermined percentage of cost containment or operating costs.

Return on Equity (ROE) - designed to reward success in achieving the average authorized return on equity.

"In addition, for a select few an additional sixth component is used:
The MIP awards granted to the Company's President and CEO, its CFO and its SVP, Corporate Development include a sixth metric, Construction Services, which is tied to the Company's non-regulated construction services segment. For each of these three executives, the Construction Services metric represents 10% of the target MIP opportunity, ROE represents 10% of the target MIP opportunity, and the remaining four MIP metrics each represent 20% of the target MIP opportunity."[4]

Q. What is the amount of the MIP test year expense amount?

A. The Company is requesting $4,873,906 in test year expenses, as shown in RUCO schedule JMM-17.

[4] Ibid. page 6, line 7.

Q. Does MIP benefit both ratepayers and shareholders?

A. Yes.

Q. Has the Commission in the past recognized that the MIP and other short-term incentive plans benefit both ratepayers and shareholders?

A. Yes, see Commission Decision Nos. 68487 (February 23, 2006), 70665 (dated December 24, 2008), 70011 (dated November 27, 2007) and 71623 (April 14, 2010). These Commission Decisions recognized a 50/50 sharing of costs between ratepayers and shareholders.

Q. What is RUCO's recommendation?

A. RUCO recommends that incentive compensation expense be reduced by 50 percent from $4,873,906 to $2,436,953 after application of the ACC jurisdictional ratio, as shown in RUCO schedule JMM-17.

Operating Income Adjustment No. 5 – Supplemental Executive Retirement Plan ("SERP") expense

Q. What is a SERP?

A. According to the Company's response to Staff data request 2.31:

"The SERP supplements the basic retirement plan for qualifying executives by providing a normal retirement benefit at a level of 50% to 60% of base salary, without regard to the IRS limits applicable to the DBRP. SERP benefits are based on the 12-month average of the highest consecutive 36

months of salary. Generally, officers must be at least 55 years of age with 20 or more years of service to receive retirement benefits. Some reductions may apply, depending on an officer's age and years of service at the date of retirement.

The SERP is an unqualified plan and, as such, payments are not guaranteed (i.e., participants are general unsecured creditors of the Company). Benefits payable under the SERP are offset by benefits payable under the DBRP to avoid the double-payment of benefits.

As with the EDP, Southwest Gas maintains the SERP to attract and retain qualified executives in a competitive marketplace in which the majority of the Company's peer companies offer comparable executive retirement programs. The SERP provides participating executives the opportunity to receive retirement benefits available to other Company employees under the DBRP, thereby putting them on par with other employees with respect to the level of benefits received at retirement."

Q. What is the amount of SERP expense that the Company is seeking to recovery from ratepayers in this case?

A. The Company is seeking to recovery $1,627,202 (after Arizona jurisdictional allocation) from ratepayers in this case.

Q. Does RUCO agree that ratepayers should pay for these costs?

A. No, RUCO does not consider the cost of supplemental benefits for high-ranking officers necessary to the provision of gas service. Company officials are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. RUCO believes that any excess or additional perks given to a select group of employees should be borne by the Company's shareholders, and not ratepayers.

Q. Has the Commission disallowed SERP in prior rate case decisions?

A. Yes. See Southwest Gas (Decision No. 68487, dated February 23, 2006), Arizona Public Service, (Decision No. 69663, dated June 28, 2007), and UNS Gas (Decision No. 70011, dated November 27, 2007).

Q. What is RUCO's recommendation?

A. RUCO recommends that $1,627,202 in SERP expenses be removed, as shown on schedule JMM-18.

Operating Income Adjustment No. 6 – Executive Deferral Plan ("EDP")

Q. Please explain the EDP.

A. Based on the Company's response to Staff data request 2.31:

"The Executive Deferral Plan ("EDP"), allows executives at the vice president level and above to supplement their salary deferral opportunities by deferring up to 100 percent of their annual compensation and 100 percent of the cash portion of their variable at-risk compensation. As a part of the EDP, the Company provides matching contributions that parallel the contributions made under the Company's EIP. Payouts under the EDP begin six months after the retirement date based on pre-selected time periods or at some other employment terminating event. Interest on EDP deferrals and the matching contributions is accrued annually at 150 percent of the Moody's Seasoned Corporate Bond Rate.

The EDP is an unqualified plan and, as such, participant balances are not guaranteed (i.e., participants are general unsecured creditors of the Company and their contributions to this account are at risk).

Southwest Gas maintains the EDP to attract and retain qualified executives in a competitive marketplace in which the majority of the Company's peer companies offer comparable executive retirement programs. The EDP provides participating executives the opportunity to receive retirement benefits available to other Company employees under the EIP, thereby putting them on par with other employees with respect to the level of benefits received at retirement."

Q. What is the amount of EDP expense that the Company is seeking to recovery from ratepayers in this case?

A. The Company is seeking to recovery $1,510,555 (after Arizona jurisdictional allocation) from ratepayers in this case.

Q. Does RUCO agree that ratepayers should pay for these costs?

A. No, again as with the SERP, RUCO does not consider the cost of supplemental benefits for high-ranking officers necessary to the provision of gas service. Company officials are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. RUCO believes that any excess or additional perks given to a select group of employees should be borne by the Company's shareholders, and not ratepayers.

Q. What is RUCO's recommendation?

A. RUCO recommends that $1,510,555 in EDP expenses be removed, as shown on schedule JMM-19.

Operating Income Adjustment No. 7 – Restricted Stock/Unit Plan ("RSUP")

Q. Please explain the RSUP?

A. Based on the Company response to Staff data request 2.31:

"The Restricted Stock/Unit Plan ("RSUP") "is a long-term incentive plan designed to enhance the competitive position of the total direct compensation and to further align customer, management, and shareholder interests, while rewarding sustained performance with respect to the metrics the MIP measures on an annual basis.

The RSUP is available to officers and other key management employees. The RSUP is measured as a percentage of year-end base salary and varies by title, as follows:

Position % of Base Salaries	*% Value Range Distribution*
CEO 45	*22.5 to 67.5*
President 30	*15.0 to 45.0*
Executive VP 25	*12.5 to 37.5*
Senior VP 20	*10.0 to 30.0*
VP	*15 7.5 to 22.5*
Other Participants	*10 5.0 to 15.0*

As a measurement of long-term sustained performance, the average MIP award over the three-year period ending before the award date is the criteria used to calculate awards for officers and key employees. Amounts granted pursuant to the RSUP range from 50 to 150 percent of the target for each participant. The minimum three-year average MIP percent of target *achieved required to receive a distribution under the RSUP is 90 percent. The dollar amount distributed under the RSUP is converted to restricted share units using the market price on the date such awards are approved by the Company's Board of Directors. The units vest over a three-year period with 40 percent for the first year and 30 percent for the second and third years.*

The revised MIP metrics discussed above will impact RSUP awards beginning in 2016, as the new metrics apply to 2015 awards and 2015 is one of the three years that will be averaged to determine the 2016 RSUP award. As noted above, the metric related to the Company's non-regulated construction services segment applies only to three senior executives. As such, that metric applies solely to the RSUP awards granted to those same three senior executives."

Q. What is the amount of RSUP expense that the Company is requesting be recovered by ratepayers in this case?

A. The Company is requesting a total of $2,227,976 in RSUP be recovered from ratepayers in this case.

Q. What are the RSUP performance criteria?

A. Based on the Company's DEF 14A filing to the Securities and Exchange Commission on March 31, 2016, which is required by the SEC to help ensure shareholder rights are upheld:

"The RSUP includes the following performance criteria that may be considered by the Administrator when granting awards intended to qualify as performance-based awards: (i) increase in share price, (ii) earnings per share, (iii) total shareholder return, (iv) operating margin, (v) operating costs, (vi) gross margin, (vii) return on equity, (viii) return on assets, (ix) return on investment, (x) operating income, (xi) net operating income, (xii) pre-tax profit, (xiii) cash flow, (xiv) revenue, (xv) expenses, (xvi) earnings before interest, taxes and depreciation, (xvii) economic value added, (xviii) market share, (xix) gas segment return on equity, (xx) customer to employee ratio, (xxi) customer service satisfaction, (xxii) performance of the Company relative to a peer group of companies and/or indexes, (xxiii) individual performance, (xxiv) safety goals and (xxv) financial performance of subsidiaries or individual business segments and/or operating regions. **The performance criteria may be applicable to the Company, entities related to the Company, and/or any individual business units of the Company or any related entity**." (See Attachment C).

Q. When asked in RUCO data request 6.02(d) "Are union employees and employees of the Company's wholly owned subsidiaries eligible for the RSUP, or any other employee who does not work directly for the parent Company (i.e. Southwest Gas)?" what was the Company's response?

A. No. However, the statement above seems to indicate that related entities may be eligible for a RSUP.

Q. What is RUCO's interpretation of the RSUP?

A. RUCO's interpretation which is based on the Company's statement above, is that long-term incentive compensation is largely tied to the Company's financial results in the future.

Q. Did the Company point to any benefits for ratepayers?

A. Yes, as with all utility companies, the Company states it will keep management and reduce long-term operating costs in the future.

Q. What concerns does RUCO have with the RUSP expense?

A. First, the RSUP expense is already limited to adequately compensated employees. The Company stated "As of March 8, 2016, 11 directors and 58 managerial employees and officers were eligible to be RSUP participants, and 12 directors and 57 managerial employees and officers were RSUP participants for 2015." Even though, the Company states any employee can receive a RUSP the awards seem to be associated with upper management employees.

Second, unlike the short-term incentive MIP program mentioned above, the compensation is strongly tied to financial performance, and benefits the Company and its shareholders. The only two criteria even remotely tied to ratepayers are customer to employee ratio, and customer service satisfaction which may or may not benefit ratepayers. There is nothing tied to reliability and quality of service for its ratepayers.

Third, if the program is successful and generates earnings for the Company the Company should use its earnings to fund the on-going program, and not ask that the burden to be placed 100 percent on ratepayers.

Fourth, the Long-Term Incentive compensation of the Company executive is tied to a three year period of time related to the financial statements and to the Company's stock price, this creates an incentive for the employee to make business decisions from the perspective of shareholders, and therefore, there is an alignment of interest between the Company executive and its shareholder.

RUCO believes it is not appropriate to ask ratepayers to bear the costs of incentive plans designed to encourage utility executives and management to put the financial interest of its shareholders ahead of its ratepayers. Especially since the financial statements are strengthened by increases in utility rates and underlying adjustor mechanisms that may be adopted. Higher rates are generally beneficial for shareholders while higher rates are unfavorable to ratepayers.

While cost containment is important to ratepayers, RUCO expects the Company, as part of the regulatory compact to act in the best interest of its customers and control costs, along with customer service with or without an incentive compensation program.

Q. Does it matter if a Long-Term Incentive plan is reasonably benchmarked with other peers?

A. No it does not matter that the Company's financial-based incentives are set at a reasonable level, if it is determined by the Commission that these costs are not reasonable for ratemaking purposes, as this commission has done in the past.

Q. What is RUCO's recommendation?

A. RUCO recommends the removal of all RSUP expense, as shown in Schedule JMM-20.

Operating Income Adjustment No. 8 – Severance Pay

Q. Has the Company asked for severance pay in this case?

A. Yes, the Company has asked ratepayers to pay for $133,207 in severance pay expense in this case.

Q. What is severance payout?

A. An employee is given a severance pay package after the employee separates from the Company which may be the result of an early retirement, layoff, resignation or a termination.

Q. What percentage of the severance pay was related to Firings, Layoff's Resignations, and/or Retirements?

A. The Company stated in RUCO data request 6.05 (k) that the approximate percentages were as follows: Firing – 0%; Layoffs – 0%; Resignations – 25%; Retirements – 75%.

Q. Was the Severance pay related to any Company performance measures?

A. No, according to RUCO data request 6.05 (j).

Q. Does RUCO believe ratepayers should pay extra compensation to Company employees when they resign or separate from the Company?

A. No, this is a cost that ***should not be*** borne by ratepayers.

Q. What is RUCO's recommendation?

A. RUCO recommends the removal of $133,207 in severance pay, as shown in Schedule JMM-21.

Operating Income Adjustment No. 9 – American Gas Association ("AGA") and Western Energy Institute ("WEI") Dues

Q. Whose interest do these groups represent?

A. These groups represent the interest of Southwest Gas, membership is purely voluntary, many of which are political in nature, and may not be necessary for the provision of utility services.

Q. Has the Company already reduced AGA membership dues for lobbying activities?

A. Yes. The Company removed $13,156 or 4.5 percent.

Q. Did the Company cite any studies that show how the 95.5 percent of AGA and 100 percent of WEI dues benefit ratepayers of Arizona?

A. No studies were presented by the Company.

Q. Has the AGA provide a summary of expenses to the Committee on Utility Association Oversight in the past?

A. Yes.

Q. What was the purpose of this report?

A. The purpose of these reports as stated by Staff witness Ralph C. Smith on page 43, of his direct testimony in the Company's last rate case (G-01551A-10-0458) is to:

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

Q. Has RUCO updated this information from AGA?

A. Unfortunately RUCO cannot. The AGA no longer provides this summary to NARUC.

Q. Why is that?

A. Like AGA the Edison Electrical Institute ("EEI") provided similar information to NARUC but, after 2006, stopped providing this information. RUCO believes after a series of regulatory partial disallowances of AGA and EEI dues by Commissions across the nation, AGA and EEI decided not to provide this information to NARUC, which they had previously done.

Q. What has the Commission recommended in prior decisions regarding membership dues?

A. The Commission recommended a reduction in AGA dues of 40 percent in Decision No. 70665.

Q. Was the Company and similarly UNS gas warned in prior Commission decisions to provide more information regarding AGA dues?

A. Yes. On page 34 of Decision No. 7001 the Commission stated:

"As we indicated in the Southwest Gas Order, however, we expect UNS in its next rate case to provide more detailed support for the allowance of AGA

dues and how the AGA's activities benefit the Company's customers aside from marketing and lobbying efforts."

Q. Did RUCO ask the Company to have AGA and WEI provide a break-out of their expenses?

A. Yes in RUCO data request 5.19, the Company provided an expense break-out from AGA as follows for the calendar year 2015:

Programs Funded by Dues		
Communications	$3,007,579	8.71%
Corporate Affairs	$3,707,984	10.74%
General & Administrative	$6,542,602	18.95%
General Counsel	$1,450,754	4.20%
Government Relations: Federal	$2,289,860	6.63%
Government Relations: State	$1,678,605	4.86%
Industry Finance & Administrative Programs	$1,785,133	5.17%
Operations & Engineering	$7,475,797	21.66%
Policy, Planning & Regulatory Affairs	$4,743,963	13.74%
Policy Strategy & Demand Growth	$1,837,845	5.32%
Total Expense as of 12/31/2015	$34,520,122	100.00%

Q. Is this information helpful to RUCO?

A. The information is helpful to RUCO to the extent that it shows cost categories that ratepayers should not pay for such as corporate affairs, and Federal and State Government Relations. However, without a detailed expense journal it is hard to determine whether some of these programs benefit ratepayers in Arizona or not.

Q. What was the Company's response in regards to WEI dues?

A. The Company stated in response to RUCO data request 8.04 in regards to WEI expenses that:

"WEI does not categorize or account for its expenses by these functions. WEI has general and administrative expenses and meetings expenses. As stated in response to Staff 2-024, WEI does not engage in marketing or lobbying activities. A payment of $31,722 was made to WEI during the test year and was recorded to Account 930.2. The amount allocated to Arizona is $17,051. Please refer to RUCO 8.04_Attachment 1 for the invoice supporting the amount the Company is requesting to be recovered in this proceeding."

Q. What is RUCO's recommendation?

A. RUCO recommends a disallowance of 50 percent of the WEI dues and a 50 disallowance of AGA dues.

RUCO recommends that in the future it is incumbent on the Company to provide all of the expense categories to support its AGA and other dues categories, along with detailed expense journals. Further, the Commission should send a strong message to the Company that all AGA and other dues may be disallowed in the future if this information is not provided.

In summary, RUCO recommends a disallowance of AGA and WEI dues in the amount of $145,184, as shown in RUCO schedule JMM-22.

Operating Income Adjustment No. 10 – Rate Case Expense

Q. What has the Company requested as an estimate of rate case expense to be authorized in this case?

A. The Company has requested $576,000 in rate case expense to be amortized over 4 years or $144,000.

Q. What was the amount of Rate Case Expense requested and authorized by the Commission in prior cases?

A. Commission Decision No. 68487 (2004), authorized the amount of $235,000 amortized over 3 years or $78,333 per year. The Commission in Decision No. 70665 (2007) authorized the amount of $276,000 over 3 years or $92,000. Although, no specific rate case expense was authorized in Commission in Decision No.72723 (2010), which was the result of a settlement agreement the Company requested $460,000 amortized over 3 years or $153,333 per year.

Q. When asked, did the Company explain the difference between this case and the prior case that would necessitate an increase in rate case expense?

A. Yes. The Company in response to RUCO data request 5.01, stated that "The primary issues as it relates to rate case expense that is present in this case and not present in the Company's last three rate cases is the filing of a comprehensive depreciation study. The Company hired an outside consultant to prepare the depreciation study and to sponsor testimony regarding the results of the depreciation study."

Q. What else has the Company included in professional services for this rate case?

A. The Company has hired a consultant to determine its Cost of Capital. The Company hired a focus group to work on its COYL's program.

Q. Do you believe these services could have be done in house?

A. Yes.

Q. What does RUCO recommend as a reasonable allowance for rate case expense in this proceeding?

A. RUCO recommends $400,000 in rate case expense to be normalized over four years, as shown is RUCO Schedule JMM-23.

Operating Income Adjustment No. 11 – Depreciation Expense

Q. Please explain the adjustment to depreciation expense?

A. This adjustment removes depreciation expense associated with three of RUCO's Rate base adjustments:

1. RUCO's removal of direct and system post-test year plants explained earlier in Rate Base Adjustment No. 1.
2. RUCO's removal post-test year plant retirements explained earlier in Rate Base Adjustment No. 2, and
3. RUCO's removal of the Company's Aircraft, Aircraft Hanger, and Equipment explained earlier in Rate Base Adjustment No. 3

These adjustments are companion entries that adjust depreciation expense related to the three adjustments. As a result, RUCO has removed $824,156 from operating expenses as shown in RUCO Schedule JMM-24.

Operating Income Adjustment No. 12 – Interest Synchronization

Q. Please explain interest synchronization?

A. An interest synchronization adjustment is done to insure that the revenue requirement reflects the tax savings generated by the interest component of the revenue requirement. The interest synchronization expense is calculated by multiplying the rate base by the weighted average cost of debt. The combined state and federal income tax rates are then applied to the resulting interest deduction difference to determine the income tax expense adjustment.

Q. Has RUCO made an adjustment for interest synchronization?

A. Yes. Since the Company's rate base differs from RUCO's recommended rate base, an adjustment was required. RUCO's adjustment decreases interest synchronization by $8,923, as shown is RUCO Schedule JMM-25.

Operating Income Adjustment No. 13 – Income Tax Expense

Q. Has RUCO adjusted income taxes as a result of its adjustments, mentioned above?

A. Yes. RUCO applied the statutory state and federal income tax rates to RUCO's taxable income. As a result, RUCO has increased income tax expenses for the adjusted test year by $3,690,212, as shown in RUCO schedule JMM-26.

VI. OTHER ISSUES

Continuation of Energy Efficiency Enabling Provision ("EEP")

Q. Has the Company asked to continue its EEP?

A. Yes. The EEP is described in the direct testimony of Company witness Edward Gieseking on page 14, line 6 and is reproduced below:

"The EEP, authorized in the Company's last general rate case, is a mechanism that effectively decouples the recovery of the authorized delivery system revenue requirement from the amount of gas that is consumed. This is accomplished through a two part mechanism that includes a monthly weather normalization adjustment to customer bills during the winter months when the actual weather is warmer or colder than normal, and an annual true-up 13 calculation that limits the amount recovered from customers to the authorized margin per customer established by the Commission in the general rate case.

The annual true-up is accomplished through a per therm surcharge or credit. Each quarter, the Company provides the Commission a status report on the customer impacts associated with the EEP. Additionally, the Company makes an annual filing to establish the annual true-up rate, which includes additional details on the mechanism."

Q. In the past RUCO had legal concerns regarding the EEP and the definition of "Fair Value", and opposed the EEP on that basis, is this still a concern to RUCO?

A. No.

Q. Does RUCO support the continuation of the EEP?

A. No, not at this time. RUCO, believes if the Commission is inclined to continue the EEP, there should be additional benefits that accrue to ratepayers, and at a minimum should include a reduction in the return on equity, and contain a stay-out provision.

<u>Creation of more Adjustors</u>

Q. Has the Company asked for the creation of new adjustors in this case?

A. Yes, the Company has asked for the following adjustor mechanisms in this case, a Property Tax True-up Mechanism and a Gas Infrastructure Modernization Mechanism.

<u>Company proposed Property Tax True-up Mechanism</u>

Q. Company witness Byron C. Williams[5] cites to two Commission decisions that have allowed for some type of Property Tax True-up?

A. Yes.

[5] See Direct Testimony of Company witness Byron C. Williams, page 6, line 8.

Q. Are these decisions similar to what the Company is proposing here?

A. No.

Q. Please explain.

A. In the APS case as a result of a settlement between the parties, APS reduced its return on equity by 100 basis points. In addition, APS agreed to a stay out for four years.

As Staff stated in its opening brief in which they cited APS witness Guldner, "APS is concerned that its property tax rate and related expenses could increase significantly during the course of the proposed 4 year stay-out, as it has over the past few years."[6]

Q. Is the property tax deferral approved by the Commission in Decision No. 73183 the same as what the Company is proposing here?

A. No. The only similarity is they are both requests for property tax deferrals. As was stated in Decision No. 73183, referring to Section XII. Cost Deferral Related to Changes in Arizona Property Tax Rate – "This Section allows APS to defer without interest for future recovery: 25 percent of the prorated property tax rate increase in 2012, 50 percent in 2013, and 75 percent each year thereafter, and 100 percent of all property tax rate decreases; recovery will begin after the next general rate case with recovery of a positive balance

[6] See Staff Opening Brief in Docket No. E-01345A-11-0224 (dated February 29, 2012).

spread over 10 years and a negative balance over three years; and the signatories may review the deferrals for reasonableness and prudence."[7]

Clearly, the provisions in the APS property tax deferral were more palatable to ratepayers, then what the Company has proposed in this case.

Q. Has the Company stated that it is willing to reduce its Cost of Equity or has it agreed to a four year stay-out provision?

A. No.

Q. What about the UNS case?

A. As with the APS case the UNS case had components that benefited ratepayers related to the Gila River Challenge on the property tax assessment.

Q. Is there anything in this case that is beneficial to ratepayers?

A. No. In fact this is worse because the Company wants an annual true-up mechanism not a deferral. In addition, the Company proposes to increase not only any changes in the property tax that result from 1) changes in the property tax rate, but ***more importantly*** 2) the increase in the assessment value that results from the Company placing plant into service between rate cases which is in the Company's control.

[7] See page 15, line 20 of Decision No. 73183.

Q. What is RUCO's recommendation?

A. Absent some type of clear and meaningful benefit to ratepayers RUCO recommends denial of the Company's proposed Property Tax True-up Mechanism.

Company proposed Gas Infrastructure Modernization ("GIM") Mechanism

Q. What is the GIM Mechanism?

A. The GIM Mechanism will consist of two components the current Customer Owned Yard Line ("COYL") program and the Pre-1970 Vintage Steel Pipe Replacement and other aging infrastructure program.

Q. Does RUCO take any exceptions to the current COYL program?

A. No.

Q. Does RUCO take any exceptions to the other component of the GIM Mechanism?

A. Yes. As with most Companies once an adjustor mechanism is authorized by the Commission the utilities try to expand the adjustor mechanisms far beyond the original intent. For instance, in the recent Tucson Electric Power case, the Company asked for the Lost Fixed Cost Recovery Mechanism be expanded to recover generation costs. Now, the Company in this case not only wants recovery of the COYL program, but wants to recover costs for pre-1970 vintage steel pipe and other aging infrastructure.

Q. Is there a safety issue with current pre-1970 vintage steel pipe?

A. No, according to the Company's response to RUCO data request 2.02.

Q. Has the Company stated that if the Commission does not approve a GIM mechanism they would go ahead and start the program themselves?

A. No. To the contrary the Company stated that if they did not get prepayment from its ratepayers they would not proceed with the program.

Q. Has the Company indicated the total costs of replacing all of the pre-1970's steel vintage pipe and other aging infrastructure and over what period of time this would be accomplished?

A. No. However, the Company has indicated that if the Commission approves its replacement program ratepayers will prepay the following estimates by year, according to Staff data request 4.39:

2017	$ 33,000,000
2018	$115,000,000
2019	$121,000,000
2020	$140,000,000
2021	$140,000,000

Q. Is the COYLs program comparable in costs to the pre-1970's steel pipe and other aging infrastructure program?

A. No. Based on RUCO data request 2.01 a rough estimate of the average cost of a COYL replacement is $2,700. The Company estimates 86,205 COYLs still need replacing which will cost ratepayers approximately $232,753,500.

Based on RUCO data request 2.02 a rough estimate of the average cost of a Steel Pipe replacement is $105 per foot. The Company estimates 1,019,040 feet of transmission pipe need replaced and 30,312,480 of distribution pipe need replaced which will cost ratepayers approximately $3,289,809,600 (i.e. (1,019,040+30,312,480)x105), which is approximately 14 times larger than the COYLs program. Stated another way, the cost of the Pre-1970's vintage steel pipe and other ageing infrastructure replacement program is larger than the current gross plant in service amount of $3,211,402,249 in this case.

Q. Are there still questions about the total costs and what pre-1970's vintage steel pipe and other ageing infrastructure needs to replaced first?

A. Yes.

Q. Has the Company identified pre-1970's steel pipe and other aging infrastructure that needs to be replaced?

A. No. According to RUCO data request 6.06 the Company stated the following:

"As provided in the response to Staff 5.14 and 6.32, the Company plans to prioritize pre-1970's vintage steel pipe replacement based on a number of factors. These factors include the age of the pipe, class location, percent of the specified minimum yield strength based on operating pressure, availability of original as-built documentation, leak history, cathodic protection history, scheduled municipal work, considerations for additional operations and maintenance activities, and any available pipe condition data gathered through O&M activities. This prioritization process will occur for both distribution and transmission pre-1970's vintage steel pipe replacement.

The Company is currently preparing an initial list of projects that would be considered for replacement under the Company's proposal and will supplement this response accordingly. In contrast to a request for authorization to replace specific gas facilities, the GIM mechanism is a procedure that would allow for the timely recovery of the revenue requirement associated with investments in non-revenue producing infrastructure improvements, including the accelerated replacement of pre-1970's vintage steel pipe. As a part of that procedure, the Company *anticipates that it would annually prepare assessments of the most likely pipe replacement candidates and results of the replacement activity."*

Q. Are there any federal or state mandates that require the Company to remove and replace any of its pre-1970's vintage steel pipe or other aging infrastructure?

A. In response to RUCO data request 2.02 (b), the Company stated: *"Southwest Gas is not aware of any specific Federal or State regulatory mandates that require the removal of pre-1970's vintage steel."*

Q. Can you please summarize RUCO's concerns?

A. First, RUCO is concerned that just because plant infrastructure is old does not necessarily mean that it has to be dug-up and replaced, absent any safety issues or federal or state mandates.

Second, the Company has not shown why extraordinary ratemaking is necessary - if the Company truly is concerned about the pre-1970's vintage steel pipe and other aging infrastructure it should take the lead and start the project themselves using the traditional ratemaking approach of building the infrastructure and then ask for recovery of the projects in a rate case where a prudency review can be done.

Q. What is RUCO's recommendation?

A. RUCO recommends denial of the pre-1970's vintage steel pipe and other aging infrastructure program at this time.

Q. Does this conclude your direct testimony?

A. Yes.

ATTACHMENT A

ARIZONA COMMERCE AUTHORITY

BUSINESS FIRST JOIN US

BUSINESS FIRST: SIMPLIFIED TAX SYSTEM

A simplified tax system lowers your cost of doing business. Arizona's pro-business environment has resulted in corporate and individual income tax rates that are among the lowest in the nation. By 2017, corporate income tax will decline by 30% for a final rate of just 4.9%. In addition, the state has created a variety of tax programs that benefit companies located within Arizona.

Tax-Friendly Programs

There's no franchise tax, no business inventory tax, and no estate tax. In fact, the state recently reduced long-term capital gains tax by as much as 25% for property acquired after 2011. Businesses with multi-state operations will appreciate the transition to a 100% sales factor income appointment formula, which will be completely phased-in by 2017.

NO FRANCHISE TAX,
NO BUSINESS INVENTORY TAX
AND NO ESTATE TAX.

Continuing a 10-year trend of property tax reduction, business property taxes have been reduced by up to 10% and an enhanced accelerated depreciation program for real and personal property of businesses can dramatically reduce operating costs. The Arizona Competitiveness package enhances the state's additional depreciation allowance for property tax, and substantially reduces liability for most personal property devoted to commercial, industrial, and agricultural uses during its first five years of use.

Manufacturing, R&D and Investment

For taxpayers expanding or locating a qualified manufacturing facility -- which includes manufacturing-related research & development or headquarters facilities -- in Arizona, the state legislature established the Qualified Facility Tax Credit Program.

The pro-business environment also led to the Angel Investment Program, which provides tax credits to investors who make capital investment in small businesses certified by the Arizona Commerce Authority. For a qualified bioscience or rural company, an investor's income tax credit may total up to 35% of the investment amount over three years; for any other qualified business, the three-year total is 30%. Any unused tax credit amount may be carried forward for up to three taxable years.

Jobs and Training Credits

The Quality Jobs Tax Credit program encourages business investment and the creation of high-quality employment opportunities in Arizona by providing tax credits to employers creating a minimum number of net new quality jobs and making a minimum capital investment in the state.

In addition, the Quality Jobs tax credit -- earned over a three-year period for each new employee trained -- provides income tax credits of up to $9,000 for each new quality job created.

R&D and Computer Benefits

Companies focused on improving their research and computer equipment can take advantage of the Research and Development Tax Credit program, which provides an Arizona income tax credit for increased in-state R&D activities. That includes research conducted at a state university and research funded by the company.

House Engrossed

State of Arizona
House of Representatives
Fiftieth Legislature
Second Special Session
2011

HOUSE BILL 2001

AN ACT

AMENDING SECTIONS 5-504, 5-505, 5-522, 5-554, 5-555 AND 5-572, ARIZONA REVISED STATUTES; AMENDING SECTION 15-213.01, ARIZONA REVISED STATUTES, AS AMENDED BY LAWS 2009, CHAPTER 101, SECTION 1; AMENDING SECTION 15-972, ARIZONA REVISED STATUTES, AS AMENDED BY LAWS 2010, SEVENTH SPECIAL SESSION, CHAPTER 8, SECTION 5; AMENDING SECTION 15-1628.03, ARIZONA REVISED STATUTES; AMENDING TITLE 20, CHAPTER 2, ARTICLE 1, ARIZONA REVISED STATUTES, BY ADDING SECTION 20-224.03; AMENDING SECTIONS 20-224.04, 28-2416, 28-7282, 28-7284, 28-7286, 34-451, 36-274 AND 40-360.01, ARIZONA REVISED STATUTES; TRANSFERRING AND RENUMBERING SECTIONS 41-1509, 41-1510 AND 41-1515.01, ARIZONA REVISED STATUTES, FOR PLACEMENT IN TITLE 41, CHAPTER 1, ARTICLE 1, ARIZONA REVISED STATUTES, AS SECTIONS 41-110, 41-111 AND 41-112, ARIZONA REVISED STATUTES, RESPECTIVELY; AMENDING SECTIONS 41-110, 41-111 AND 41-112, ARIZONA REVISED STATUTES, AS TRANSFERRED AND RENUMBERED BY THIS ACT; AMENDING SECTIONS 41-191.09, 41-192, 41-724, 41-803 AND 41-1005, ARIZONA REVISED STATUTES; CHANGING THE DESIGNATION OF TITLE 41, CHAPTER 10, ARIZONA REVISED STATUTES, TO "ARIZONA COMMERCE AUTHORITY"; REPEALING SECTIONS 41-1501, 41-1502, 41-1503, 41-1504, 41-1504.01, 41-1504.02, 41-1505.01, 41-1505.02, 41-1505.03, 41-1505.04, 41-1505.05, 41-1505.06, 41-1505.07, 41-1505.08, 41-1505.10 AND 41-1506, ARIZONA REVISED STATUTES; AMENDING TITLE 41, CHAPTER 10, ARTICLE 1, ARIZONA REVISED STATUTES, BY ADDING NEW SECTIONS 41-1501, 41-1502, 41-1503, 41-1504, 41-1505 AND 41-1506; RENUMBERING SECTION 41-1505.09, ARIZONA REVISED STATUTES, AS SECTION 41-1506.01; AMENDING SECTION 41-1506.01, ARIZONA REVISED STATUTES, AS RENUMBERED BY THIS ACT; AMENDING SECTIONS 41-1507, 41-1508, 41-1510.01 AND 41-1511, ARIZONA REVISED STATUTES; REPEALING SECTIONS 41-1513, 41-1514 AND 41-1514.01, ARIZONA REVISED STATUTES; AMENDING SECTION

H. A taxpayer who claims a credit under section 43-1074, 43-1077 or 43-1079 may not claim a credit under this section with respect to the same full-time employment positions.

I. The department of revenue shall adopt rules and prescribe forms and procedures as necessary for the purposes of this section. The department of revenue and the ~~department of commerce~~ ARIZONA COMMERCE AUTHORITY shall collaborate in adopting rules as necessary to avoid duplication and contradictory requirements while accomplishing the intent and purposes of this section.

J. For the purposes of this section, renewable energy operations are limited to manufacturers of, and headquarters for, systems and components that are used or useful in manufacturing renewable energy equipment for the generation, storage, testing and research and development, transmission or distribution of electricity from renewable resources, including specialized crates necessary to package the renewable energy equipment manufactured at the facility.

Sec. 104. Repeal

Section 43-1088.01, Arizona Revised Statutes, is repealed.

Sec. 105. Section 43-1111, Arizona Revised Statutes, is amended to read:

43-1111. Tax rates for corporations

There shall be levied, collected and paid for each taxable year upon the entire Arizona taxable income of every corporation, unless exempt under section 43-1126 or 43-1201 or as otherwise provided in this title or by law, taxes in an amount of ~~6.968 per cent of net income or fifty dollars, whichever is greater.~~ THE GREATER OF FIFTY DOLLARS OR:

1. FOR TAXABLE YEARS BEGINNING THROUGH DECEMBER 31, 2013, 6.968 PER CENT OF NET INCOME.

2. FOR TAXABLE YEARS BEGINNING FROM AND AFTER DECEMBER 31, 2013 THROUGH DECEMBER 31, 2014, 6.5 PER CENT OF NET INCOME.

3. FOR TAXABLE YEARS BEGINNING FROM AND AFTER DECEMBER 31, 2014 THROUGH DECEMBER 31, 2015, 6.0 PER CENT OF NET INCOME.

4. FOR TAXABLE YEARS BEGINNING FROM AND AFTER DECEMBER 31, 2015 THROUGH DECEMBER 31, 2016, 5.5 PER CENT OF NET INCOME.

5. FOR TAXABLE YEARS BEGINNING FROM AND AFTER DECEMBER 31, 2016, 4.9 PER CENT OF NET INCOME.

Sec. 106. Section 43-1139, Arizona Revised Statutes, is amended to read:

43-1139. Allocation of business income

A. Except as provided in subsection B of this section, the taxpayer shall elect to apportion all business income to this state for taxable years beginning from and after:

1. December 31, 2006 through December 31, 2007 by either:

ATTACHMENT B

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107
ARIZONA GENERAL RATE CASE
****
ACC
ACC STAFF
STAFF 2
(STAFF 2-001 THROUGH STAFF 2-064)

DOCKET NO: G-01551A-16-0107
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: 06/24/2016

REQUEST NO: Staff 2-004

Did the Company make any pro forma adjustment to Accumulated Depreciation related to its Adjustment for Depreciation Expense?

a. If so, please identify the related adjustment to Accumulated Depreciation.
b. If not, explain fully why not.

RESPONDENT: Regulation

RESPONSE:

a. The Company did not make any pro forma adjustment to Accumulated Depreciation related to its Adjustment for Depreciation Expense.
b. New depreciation rates won't be used to calculate depreciation expense until the month after rates from this proceeding become effective. As such, there is no change to test year accumulated depreciation as a result of the proposed depreciation rate changes.

At the end of the test year, the accumulated depreciation associated with any post-test year plant adjustments is $0.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107
ARIZONA GENERAL RATE CASE
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ACC
ACC STAFF
STAFF 2
(STAFF 2-001 THROUGH STAFF 2-064)

DOCKET NO:	G-01551A-16-0107
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	06/24/2016

REQUEST NO: Staff 2-028

Employee Benefits. For each of the following benefits indicate whether the Company or any of its affiliates that charge cost to the Company offers such benefit; the annual cost of such benefit in the test year; and the amount and account charged. This response should also include such costs allocated from affiliated companies:

a. Company-provided automobiles;
b. Spousal travel;
c. Country or athletic club membership and expenses;
d. Personal travel on Company-owned or leased aircraft or watercraft;
e. Tax and/or estate planning;
f. Company-paid legal counsel for personal matters;
g. Company-provided housing.

RESPONDENT: Regulation

RESPONSE:

a. Company provided automobiles

An adjustment was made in Schedule C-2, Adj. No. 6, which removed $62,108 of employees' personal use of Company vehicles from the rate case.

b. Spousal travel

Spousal travel identified in the test year expenses was removed and not requested for recovery in this rate case.

c. Country or athletic club membership and expenses

Country club and/or social club memberships are recorded below-the-line and not requested for recovery in this rate case.

d. Personal travel on Company-owned or leased aircraft

Personal travel on Company-owned or leased aircraft is not provided as an employee benefit.

e. Tax and/or estate planning

Officers are provided a $5,000 allowance once every three years to assist in financial and estate planning. There was $13,530 included in account 926 during the test year on a total-Company basis. Account 926 is allocated to all accounts, based on charged labor, during the labor loading process. The portion that is requested for recovery from Arizona customers will be approximately half of this amount.

f. Company-paid legal counsel for personal matters

Company-paid legal counsel for personal matters is not provided as an employee benefit.

g. Company-provided housing

Company-paid housing is not provided as an employee benefit.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107
ARIZONA GENERAL RATE CASE
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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 2
(RUCO 2-001 THROUGH RUCO 2-011)

DOCKET NO:	G-01551A-16-0107
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	06/27/2016

REQUEST NO: RUCO 2-001

Customer Owned Yard Line ("COYL") – Please answer the following questions as they relate to the COYL program:

a. What is the number of COYL's left to replace in Arizona's jurisdiction?

b. What is the cost per unit to replace a COYL?

c. How are the COYLs accounted for on the Company's books? Please provide a brief summary to include at a minimum the following account categories along with the FERC numbers (inventory, cash/accounts, payables, plant, accumulated depreciation, depreciation expense and the depreciation rates utilized)?

d. How are the retired COYL's accounted for on the Company's books?

e. Are any of the COYL's sold for scrap, if so, how much has the Company received for the last five calendar years starting in calendar year 2015 and working backwards.

f. What were the average original expected lives of the COYL's?

g. What is average life of the COYL's being retired?

h. Are the COYL's that are being replaced fully depreciated? If no, then what is the average accumulated cost per COYL compared to the average original cost per COYL?

i. Is there federal funding in the form of grants or other means to address the COYL replacements?

j. How does the COYL adjustor mechanism currently work?

k. How is the COYL adjustor mechanism different from the System Improvement Benefit ("SIB")?

l. Does the Company assume liability for the new COYL's or is it the customer's responsibility?

<u>RESPONDENT</u>: Engineering Services/Regulation

<u>RESPONSE</u>:

a. As provided in the Direct Testimony of Kevin Lang (Q&A #11, Lines 13-14), the Company estimates that approximately 86,205 COYLs remain as of December 31, 2015 in the Company's Arizona jurisdiction.

b. As reported in the 2016 application to reset the COYL Cost Recovery Mechanism, the cumulative capital costs associated with the Company's COYL replacements since the program's inception averaged approximately $2,700 per COYL.

c. COYLs are accounted for in the following manner:

Inventory is issued to COYL work order:
DR 107 Account – Construction Work in Progress
CR 154 Account – Plant Materials

Contractors performing the COYL work invoice the Company for work performed. Most of this work is for Construction activity to install the new pipe, but part of the work performed by the contractor is for the removal of the customer owned yard line. The cost of removal includes costs such as cut, cap, and purge of the customer owned yard line.
DR 107 Account – Construction Work in Progress
DR 108 Account – Cost of Removal
CR 232 Account – Accounts Payable Liability

Contractor Invoice is paid:
DR 232 Account – Accounts Payable Liability
CR 131 Account - Cash

Month End process for COYL WOs moving CWIP charges to Gas Plant:
DR 106 Account - Completed Construction Not Classified
CR 107 Account – Construction Work in Progress
DR 101 Account – Gas Plant
CR 106 Account – Completed Construction Not Classified

Depreciation Calculation for COYL and all other Plant Account Assets use the current approved depreciation rates. The COYL assets are in account 381, Services. The approved depreciation rate for the Arizona Rate Jurisdiction for account 381 is the rate used to calculate depreciation expense for the COYL assets.
DR 403 Account – Depreciation Expense
CR 108 Account – Accumulated Depreciation

d. The customer owns the COYL assets so there are no assets on the Company's books to retire. There is some cost of removal, such as cut cap and purge that are charged to the 108 Account, but there are no assets to retire since the customer owns the assets.

e. COYLs are natural gas facilities owned and maintained by the customer. When a COYL meets the requirements of the Company's existing, Commission approved program, including customer acceptance, the Company disconnects service to the COYL, installs new piping and relocates the meter set assembly from the property line up to and adjacent to the customer's residence. The COYLs are not sold for scrap and the customer typically chooses to have the COYL abandoned in place.

f. COYLs are owned and maintained by the customer. Southwest Gas does not have information regarding the average original expected life of a Customer Owned Yard Line.

g. COYLs are natural gas facilities owned and maintained by the customer, Southwest Gas does not collect or maintain data regarding the installation date of COYLs retired within its Arizona jurisdiction to be able to determine the average life of a Customer Owned Yard Line.

h. The COYLs that are being replaced are not Southwest Gas' assets; therefore, the Company does not have information on original cost of installation, and the COYLs were not depreciated on Southwest Gas' books.

i. Southwest Gas is not aware of any federal funding in the form of grants or other means to address the replacement of Customer Owned Yard Lines.

j. The revenue requirement related to the COYL facilities that were replaced with Southwest Gas facilities is recovered through a surcharge. The calculation is performed using data at the end of each calendar year, and the new rate is effective the following June. The revenue requirement is calculated based on a revenue requirement formula approved in the Company's last general rate case which includes the sum of return on rate base, income taxes, and depreciation expense. The revenue requirement is calculated separately for Phase I and Phase II of the COYL program. The total revenue requirement is divided by the full margin therms to determine the surcharge rate.

k. Southwest Gas has not been a party to a Commission proceeding involving a SIB and may not be able to fully distinguish the SIB and the COYL mechanism absent having more detailed information on the SIB. Unlike the SIB mechanism, the COYL mechanism was designed to enhance public and customer safety by removing customer owned infrastructure that was found to be prevalent to enhanced safety concerns. The COYL mechanism replaces non-revenue producing facilities with new facilities, thus the COYL program is narrowly tailored to recover only the revenue requirement associated with replacing the customer owned and maintained facilities with new utility owned and operated facilities. Absent the COYL cost recovery mechanism there would be no revenue stream to cover these costs, and no reason for the utility to undertake these replacement activities since they are customer owned. The current COYL rate adjustments are limited to $0.01 per therm per year and all rate adjustments are reviewed and approved annually by the Commission. As mentioned above, the COYL program enhances public and customer safety while minimizing the bill impact to customers as the currently approved COYL rate is a $0.006 per therm or approximately $0.15 per month.

l. Under the COYL program, the COYL (generally defined as the line from the meter to the house) is replaced with a Southwest Gas-owned service line, and meter is relocated from the alley or property line to the side of the house. The COYL is not replaced with a new COYL. Since the new facilities up to the newly-relocated meter are owned by Southwest Gas, the Company assumes liability for those facilities.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107
ARIZONA GENERAL RATE CASE
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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 2
(RUCO 2-001 THROUGH RUCO 2-011)

DOCKET NO: G-01551A-16-0107
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: 06/27/2016

REQUEST NO: RUCO 2-002

Please answer the following questions as they relate to Pre-1970's Vintage Steel Pipe:

a. Are there any safety issues with pre-1970's Vintage Steel Pipe?
b. Are there any Federal or State mandates to remove pre-1970's vintage steel pipe?
c. How many feet of pre-1970's Vintage Steel Pipe need to be replaced in Arizona's jurisdiction?
d. What is the cost per unit to replace a foot of pre-1970's Vintage Steel Pipe?
e. Please explain how the Pre-1970's Vintage Steel Pipe will be combined along with the COYL into the new GIM adjustor mechanism?
f. Please provide a brief narrative of how the Company proposed GIM adjustor mechanism will work from an accounting perspective (see 2.01 c).
g. How are the retired pre-1970's Vintage Steel Pipes accounted for on the Company's books?
h. Are any of the pre-1970's Vintage Steel Pipe sold for scrap, if so, how much has the Company received for the last five calendar years starting in calendar year 2015 and working backwards?
i. What was the average original expected life of the pre-1970's Vintage Steel Pipes?
j. What is average life of the pre-1970's Vintage Steel Pipes being retired?
k. Are the pre-1970's Vintage Steel Pipes that are being replaced fully depreciated? If no, then what is the average accumulated cost per pre-1970's Vintage Steel Pipes compared to the original average cost per pre-1970's Vintage Steel Pipes?
l. How is the current COYL adjustor mechanism different than the proposed GIM?
m. How is the Company proposed GIM adjustor mechanism different from the SIB?
n. Is there federal funding in the form of grants or other means to address the pre-1970's Vintage Steel Pipe replacements?

RESPONDENT: Engineering Services

RESPONSE:

a. The pre-1970s vintage steel distribution and transmission pipe in the Company's Arizona system does not present an immediate safety concern. However, prior to 1970, federal and state pipeline safety code requirements had not been formally established for pipeline construction practices, material selection, material and pipeline testing, cathodic protection requirements, recordkeeping requirements, and other key elements of modern pipeline construction requirements. As such, older pipelines do not have all of the safety features associated with modern pipelines such as improved coatings, enhancements to steel pipe quality and performance standards, more comprehensive welding procedures, and enhanced testing requirements. These safety features are discussed in greater detail in the prepared direct testimony of Company witness Kevin Lang.

The Company's proposal to accelerate replacement of pre-1970's vintage steel pipe will proactively and cost-effectively address these factors by allowing the Company to bring all of its steel system up to modern construction and recordkeeping standards. This is consistent with the industry's response to several high profile natural gas incidents that have occurred since the Company's last Arizona general rate case. The industry has placed heightened focus on replacing aging infrastructure to enhance pipeline safety efforts. Several of these efforts consist of modernizing pipeline systems to ensure natural gas operators meet modern requirements for record keeping and documentation regarding pipeline construction practices, material selection, material and pipeline testing, and other key elements of modern pipeline construction requirements, as reflected in the recent Notice of Proposed Rulemaking (NPRM) issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA). The NPRM proposes numerous provisions, including but not limited to requirements that operators identify and remediate vintage steel transmission lines that were not constructed or tested to current standards. It also proposes verification of pipeline materials where an operator's data may not be complete, requirements to verify Maximum Allowable Operating Pressure (MAOP) through several proposed methods in the event MAOP was established utilizing the grandfather clause, and other key improvements and enhancements to the federal pipeline safety code – all of which will require operators to make significant investments in their systems to ensure compliance.

b. Southwest Gas is not aware of any specific Federal or State regulatory mandates that require the removal of pre-1970's vintage steel.

c. Southwest Gas approximates an inventory of 1,019,040 feet (193 miles) of transmission pipe and 30,312,480 feet (5,741 miles) of distribution pipe within its Arizona jurisdiction that is pre-1970's vintage steel pipe.

d. Based on the Company's Arizona steel replacement activity from 2013-2015 (including pre-1970 distribution steel, pre-1970 HP distribution steel and pre-1970 transmission steel), the average cost for steel pipe replacement is $105/foot.

e. The GIM mechanism will compute the revenue requirement in the same manner that the revenue requirement is currently calculated for the various phases of the COYL infrastructure investment. The costs for each GIM project will be tracked discreetly for management and audit purposes, then consolidated for the purposes of the revenue requirement calculation.

f. The accounting for projects replaced under the GIM mechanism is similar to the accounting for COYL mechanism as discussed in response to RUCO 2-001(c). The only difference is that the COYL mechanism only addresses investments in services. As discussed above, the GIM mechanism will consolidate all approved GIM projects for the purpose of calculating the revenue requirement and, as such, the GIM mechanism allows for investment in mains (in this case, as applicable to the proposed pre-1970's vintage steel replacement project). Costs for mains replaced under the GIM will be booked to the Mains account 376 and be subject to the authorized depreciation rate for mains.

g. There are typically some costs of removal incurred to retire pipe that include cut cap and purge. These costs are charged as a debit to the 108 Account. The original average cost of the vintage year of pipe being retired is used to record the retirement on the Company's books. The entry is a debit to the 108 Account and a credit to the 101 Account.

h. Southwest Gas does not actively engage in the practice of selling abandoned pipe for scrap as the pipe is typically abandoned pipe in situ due to the negative impacts of removing the physical pipe from the ground following abandonment.

i. The Company uses Group Depreciation for mass assets. The pre-1970's vintage steel pipe is depreciated through the Group Depreciation method. The pre-1970's vintage steel pipe is included in the 376 Mains Account. The average life of the account is determined as part of a Depreciation Study. As proposed in the Depreciation Study as part of this case, the average life for the 376 Mains account is 53 years. This average life is for all assets included in the 376 Mains Account regardless of the vintage or type of pipe that is included in the 376 Mains Account.

j. The current average life of the existing pre-1970's vintage steel pipeline facilities in the Company's Arizona jurisdiction is 58.9 years. Of the 5,934 miles of pre-1970's vintage steel pipeline facilities, approximately 65.6%, or approximately 3,800 miles, was put into service prior to January 1, 1960.

k. The Company uses Group Depreciation which groups all assets by account and rate jurisdiction and depreciates these assets as a group. The approved depreciation rate is applied to the original cost of the pipe and the depreciation calculation continues until the pipe is retired from the Company's books. On a calculated basis [dollars times rate times years in service], all pre-1970's vintage steel pipe is fully depreciated. As noted above and in compliance with the FERC Uniform System of Accounts, all assets in the group are depreciated until retired.

When the pipe is retired, the original average cost of the pipe vintage year that was installed is removed from the 101 Account and 108 Account. The 108 Account is debited and the 101 Account is credited to remove the asset from the Company's books.

l. The GIM mechanism is simply a rebranding of the Company's existing COYL Cost Recovery Mechanism which allows for the recovery of specifically defined costs associated with non-revenue producing investments in gas infrastructure. Such a mechanism embodies the necessary regulatory support to facilitate these types of initiatives that go above and beyond the normal course of business. The mechanism also protects consumers by limiting the rate impact and by narrowly tailoring the recovery of only those costs that are attributable to the specifically defined replacement activity, which ensures an appropriate matching of costs and revenues. The intent of rebranding this mechanism is to facilitate the inclusion of other non-revenue producing investment activity. Mechanically, the GIM mechanism is the same as the Commission approved COYL Cost Recovery Mechanism. Please refer to the response to RUCO 2-001(j).

m. Please refer to the response to RUCO 2-001(k).

n. Southwest Gas is not aware of any federal funding in the form of grants or other means to address the pre-1970's vintage steel pipe replacement.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107
ARIZONA GENERAL RATE CASE
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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 4
(RUCO 4-001 THROUGH RUCO 4-013)

DOCKET NO:	G-01551A-16-0107
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	08/30/2016

REQUEST NO: RUCO 4-007

4.07 Accumulated Deferred Income Taxes ("ADIT") – Please answer the questions as they relate to ADIT:

a. To clarify the Company did not make an adjustment to ADIT to account for the bonus depreciation related to the post test-year plant?

b. If yes to a. please provide the amount of bonus depreciation related to each project that the Company has claimed or will be claiming in its tax return for Post Test-Year plant (e.g. project 0034W1952265,
SI-BHC- ALTA VISTA LN & ALTA V, FERC No. 376, $221,825).

RESPONDENT: Regulation

RESPONSE:

a. The Company did not adjust ADIT to account for bonus depreciation related to post-test year plant. There is also no ADIT adjustment related to post-test year plant. There was no accumulated depreciation as of the end of the test year on post-test year plant; therefore, there are no book-tax differences at that point.

b. N/A

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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 4
(RUCO 4-001 THROUGH RUCO 4-013)

DOCKET NO: G-01551A-16-0107
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: 08/30/2016

REQUEST NO: RUCO 4-008

Post Test-Year Accumulated Depreciation – Please answer the questions as they relate to Post Test-Year Accumulated Depreciation:

a. To clarify the Company has not made an adjustment to post test-year accumulated depreciation?

b. What depreciation methodology does the Company use to depreciate its assets that have been recently placed in service during the year (e.g. monthly convention, half-year convention, etc.)?

RESPONDENT: Regulation

RESPONSE:

a. There were no adjustments made to accumulated depreciation recorded at the end of the test year.

b. The Company annualized depreciation expense so that a full year's worth of depreciation expense is reflected based on adjusted ending plant balances in the cost of service. Please refer to Adjustment No. 13.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107
ARIZONA GENERAL RATE CASE
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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 5
(RUCO 5-001 THROUGH RUCO 5-019)

DOCKET NO:	G-01551A-16-0107
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	09/26/2016

REQUEST NO: RUCO 5-010

American Gas Association ("AGA") dues – Please answer the following questions as they relate to AGA dues:

a. Provide a break-out of the amounts and percentages of AGA costs that relate to the following functions:

i. Legislative Advocacy
ii. Legislative Policy Advocacy
iii. Regulatory Advocacy
iv. Regulatory Policy Research
v. Advertising
vi. Marketing
vii. Utility Engineering and Operations
viii. Finance, Legal Planning, and Customer Service
ix. Public Relations

b. If AGA provides separate categories of expenses other than those provided in a. please provide those categories along with the amounts and percentages of those expense categories.

c. Provide all the invoices for the AGA dues that the Company is requesting to be recovered in this rate case.

RESPONDENT: Regulation

RESPONSE:

a./b. The American Gas Association (AGA) provided Southwest Gas with the program costs and percentage of total funding for each of the programs funded by AGA member dues for calendar year 2015. These amounts are shown in the following table.

Programs Funded by Dues		
Communications	$3,007,579	8.71%
Corporate Affairs	$3,707,984	10.74%
General & Administrative	$6,542,602	18.95%
General Counsel	$1,450,754	4.20%
Government Relations: Federal	$2,289,860	6.63%
Government Relations: State	$1,678,605	4.86%
Industry Finance & Administrative Programs	$1,785,133	5.17%
Operations & Engineering	$7,475,797	21.66%
Policy, Planning & Regulatory Affairs	$4,743,963	13.74%
Policy Strategy & Demand Growth	$1,837,845	5.32%
Total Expense as of 12/31/2015	$34,520,122	100.00%

c. The invoice for test year AGA dues was provided in Staff-2.25_Attachment 1.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107
ARIZONA GENERAL RATE CASE
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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 5
(RUCO 5-001 THROUGH RUCO 5-019)

DOCKET NO: G-01551A-16-0107
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: 09/26/2016

REQUEST NO: RUCO 5-016

Accumulated Deferred Income Taxes ("ADIT") – This is a follow-up to RUCO data request 4.07, based on the Company's response to this data request the Company does not intend to use bonus tax depreciation for tax purposes on its post-test year plant, correct? If so, why would the Company not take advantage of bonus tax depreciation when it files its corporate tax return?

RESPONDENT: Regulation

RESPONSE:

In its response to RUCO 4.07, the Company explained that since no book depreciation had been recorded on the post-test year plant as of the end of the test year, there was no book-tax depreciation difference related to that post-test year plant at November 2015 (the end of the test year). As a result, there is no adjustment to the deferred tax balance for post-test year plant. The Company did deduct bonus depreciation on all eligible plant additions in its 2015 federal income tax return. Likewise, the Company will deduct all allowable bonus depreciation in its 2016 federal income tax return.

SOUTHWEST GAS CORPORATION
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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 6
(RUCO 6-001 THROUGH RUCO 6-017)

DOCKET NO: G-01551A-16-0107
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: 10/03/2016

REQUEST NO: RUCO 6-001

Management Incentive Program ("MIP") – Please answer the following questions as they relate to MIP:

a. Provide the amount of MIP expense the Company is seeking recovery of in this rate case along with FERC number, account description, and line item(s)/schedule(s) where the MIP is summarized. In addition, please include the amount on a Company-wide basis and the amount that has been allocated to Arizona.

b. If any of the amount is related to payroll tax, provide this amount and the payroll tax percentage.

c. If any of the MIP is capitalized, briefly describe what percentage is allocated, and what plant accounts the allocations are made to, along with the percentage allocated to the plant accounts. In addition, briefly describe how the plant allocation was derived, and has the Company always used this methodology?

d. Are union employees and employees of the Company's wholly owned subsidiaries eligible for the MIP, or any other employee who does not work directly for the parent Company (i.e. Southwest Gas)? If so, please list the number of employees who do not work directly for the parent Company (Southwest Gas) that have received a MIP and the amount payed-out by annualized test year (i.e. December through November) for the prior four years.

e. What are the eligibility requirements for the MIP program (e.g. one year of service, etc.)?

f. Please provide the number of employees and total number of employees who work directly for the Company that were given MIP awards during the annualized test year and prior four years?

I. Further, please brake these awards out by Company position (e.g. CEO, Executive Officers, Senior Officers, Officers, Non-Officers, etc.) (last four years).

II. Please provide the amount paid to each of the Company's employees categorized by positions in I. (last four years).

III. In addition, please break out the amount provided in II, by cash and by stock and by Company position (last four years).

For example:

	2015		2014		2013		2012		2011	
	Cash	Stock	Cash	Stock	Cash	Stock	Cash	Stock	Cash	Stock
CEO	$XXX,XXX	$XXX,XXX	$XXX,XXX	$XXX,XXX	$XXX,XXX	$XXX,XXX	$XXX,XXX	$XXX,XXX	$XXX,XXX	$XXX,XXX

g. Somewhere in the discussion provide the amount of MIP that was allocated to the Arizona jurisdiction or the percentage used for the allocation for each of the last four years.

h. Has the Company every not paid-out an MIP award? If so, please explain.

RESPONDENT: Regulation

RESPONSE:

a. The Company is requesting the following amounts for MIP expense in this proceeding: Account 920: $9,067,243 total Company, and $4,873,906 allocated to Arizona. MIP is not summarized on any schedule, this amount is embedded in the total amount requested for Account 920 A&G Salaries on "C-1 A&G Recorded".

b. Since all employees who receive MIP have a base salary that exceeds the maximum taxable earnings for social security, the Company calculates its annualized payroll taxes on base salary only.

c. MIP is not capitalized.

d. Only Southwest Gas employees are eligible for MIP. The Company does not have union employees, and employees of subsidiaries are not eligible for MIP.

e. The eligibility requirements for MIP are as follows: (a) In determining the Key Employees that will be Participants and the Incentive Award Opportunity for each Participant, the Committee shall take into account the duties of the respective Participant, their present and potential contributions to the success of the Company, and such other factors as the Committee shall deem relevant in connection with accomplishing the purpose of the Plan, and (b) No Incentive Award Opportunity will be available to any person who, at the beginning of the applicable Performance Period, is a member of the Committee responsible for the administration of the Plan.

f. The MIP amounts by Company position are readily available on a calendar year basis. Please refer to RUCO 6.01_Attachment 1 for 2011-2015.

g. The amounts allocated to Arizona are included in the attachment referred to in part f.

h. No.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107
ARIZONA GENERAL RATE CASE
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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 6
(RUCO 6-001 THROUGH RUCO 6-017)

DOCKET NO:	G-01551A-16-0107
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	10/03/2016
REQUEST NO:	RUCO 6-002

Restricted Stock/Unit Plan ("RSUP") – Please answer the following questions as they relate to RSUP:

a. Provide the amount of RSUP expense the Company is seeking recovery of in this rate case along with FERC number, account description, and line item(s)/schedule(s) where the RSUP is summarized. In addition, please include the amount on a Company-wide basis and the amount that has been allocated to Arizona.

b. If any of the amount is related to payroll tax, provide this amount and the payroll tax percentage.

c. If any of the RSUP is capitalized, briefly describe what percentage is allocated, and what plant accounts the allocations are made to, along with the percentage allocated to the plant accounts. In addition, briefly describe how the plant allocation was derived, and has the Company always used this methodology?

d. Are union employees and employees of the Company's wholly owned subsidiaries eligible for the RSUP, or any other employee who does not work directly for the parent Company (i.e. Southwest Gas)? If so, please list the number of employees who do not work directly for the parent Company (Southwest Gas) that have received a RSUP and the amount payed-out by annualized test year (i.e. December through November) for the prior four years?

e. Provide the total RSUP amounts paid-out by annualized test year for the prior four years for employees who work directly for the Company. In addition, please include the amount on a Company-wide basis and the amount that has been allocated to Arizona.

f. What are the eligibility requirements for the RSUP program (e.g. limited to executive employees only, etc.)?

g. Has the Company ever not paid-out an RSUP award? If so, please explain.

RESPONDENT: Regulation

RESPONSE:

a. The Company is requesting the following amounts for RSUP expense in this proceeding:

   Account 920: $2,336,604 total Company, $1,255,992 allocated to Arizona;
   Account 930.2: $1,808,244 total Company, $971,984 allocated to Arizona.

   RSUP is not summarized on any schedule. These amounts are embedded in the total amounts requested for Accounts 920 A&G Salaries and 930.2 Miscellaneous General on "C-1 A&G Recorded".

b. Since all employees who receive RSUP have a base salary that exceeds the maximum taxable earnings for social security, the Company calculates its annualized payroll taxes on base salary only.

c. RSUP is not capitalized.

d. No.

e. RSUP expense for the 12-months ended November of each year from 2011-2015 are as follows:

	Total RSUP	**AZ Alloc**
2011	$ 3,016,275	$ 1,621,335
2012	4,949,499	2,660,499
2013	4,716,195	2,535,092
2014	2,595,489	1,395,151
2015	4,144,848	2,227,976

f. Eligibility for the RSUP is as follows: Awards may be granted to Employees and Directors. An Employee or Director who has been granted an Award may, if otherwise eligible, be granted additional Awards.

g. RSUP was introduced in 2006, and an award has been paid every year since its inception. RSUP replaced the Company's Stock Options program.

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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 6
(RUCO 6-001 THROUGH RUCO 6-017)

DOCKET NO:	G-01551A-16-0107
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	10/03/2016

REQUEST NO: RUCO 6-003

Supplemental Executive Retirement Plan (SERP) – Please answer the following questions as they relate to SERP:

a. Provide the amount of SERP expense the Company is seeking recovery of in this rate case along with FERC number, account description, and line item(s)/schedule(s) where the SERP is summarized. In addition, please include the amount on a Company-wide basis and the amount that has been allocated to Arizona.

b. If any of the amount is related to payroll tax, provide this amount and the payroll tax percentage.

c. If any of the SERP is capitalized, briefly describe what percentage is allocated, and what plant accounts the allocations are made to, along with the percentage allocated to the plant accounts. In addition, briefly describe how the plant allocation was derived, and has the Company always used this methodology?

d. Are union employees and employees of the Company's wholly owned subsidiaries eligible for the SERP, or any other employee who does not work directly for the parent Company (i.e. Southwest Gas)? If so, please list the number of employees who do not work directly for the parent Company (Southwest Gas) that have received a SERP and the amount payed-out by annualized test year (i.e. December through November) for the prior four years?

e. Provide the total SERP amounts paid-out by annualized test year for the prior four years for employees who work directly for the Company. In addition, please include the amount on a Company-wide basis and the amount that has been allocated to Arizona.

f. What are the eligibility requirements for the SERP program (e.g. limited to executive employees only, etc.)?

g. Has the Company ever not paid SERP expenses? If so, please explain.

RESPONDENT: Regulation

RESPONSE:

a. SERP is recorded to Account 926, and annualized as part of the Labor and Loading Annualization in Adjustment No. 3. The amount requested for SERP on a Total Company basis is $3,573,379 based on the 2016 SERP actuarial study, and is located in the "AZ 2016 Labor Annualization.xlsx" file on the "926" tab on line 7. The amount allocated to Arizona is derived from the amounts on the "Benefits Summary" page. The sum of $1,285,966 to Arizona, $211,395 corporate direct charges to Arizona, and the allocation of System Allocable amount (929,879*(1-4.13%)*56.07% results in a total SERP charge to Arizona of $1,997,198. Of this amount, only the O&M portion of $1,627,202 is annualized and this is the amount the Company has requested to be recovered through its operating expenses.

b. SERP is a retirement benefit, and is not subject to payroll taxes.

c. SERP is a component of the Company's total labor loading costs, and for each dollar of labor charged to an account, an additional percentage is charged as a labor loading to cover the Company's various benefits, paid time off, and payroll taxes. The labor loading percentage is determined annually, and is generally adjusted starting in October of each year so that by December the total costs that comprise the labor loading are cleared out. The percentages as for the test year are only calculated during a general rate case when a Labor and Loading Annualization analysis is performed, and are not available for prior periods. These calculations for the test year are done in the file "AZ 2016 Labor Annualization.xlsx". During the test year, 23.17% of Arizona direct labor was charged to capital, and a negligible amount of corporate labor was capitalized directly. A percentage of corporate labor is eventually capitalized through an A&G allocation, those credits to A&G appear in Account 922 and the debits appear in capital accounts that received an A&G overhead allocation. The Company has used this methodology to allocate SERP for at least the last two decades.

d. No.

e. SERP expense on a total Company basis is based on the results of an annual actuarial study for SERP. The actuarial amounts for the last 4 years are as follows:
2015: $3,308,493
2014: $2,820,335
2013: $2,879,033
2012: $2,586,399

Due to the complexity of the labor loading process, it is not possible to determine exactly how much SERP was allocated to Arizona during prior years. However, it is reasonable to use the percentages described above to determine an approximate amount of SERP that was charged to Arizona during those years.

f. Eligibility requirements for SERP are as follows:

2.1 Selection of Participants - Executives
An Executive shall become a Participant in the Plan as of the effective date of his election by the Board of Directors as an officer of the Company (unless the Board of Directors determines, at that time, that such Executive will not be eligible to participate in the Plan).

2.2 Selection of Participants - Employees
Any Employee who is a participant in the Executive Deferral Plan shall also be a Participant in this Plan as of the effective date of his selection to participate in the Executive Deferral Plan.

2.3 Normal Retirement - Any Participant
A Participant with 20 or more years of Continuous Service will be eligible to Retire and receive benefits under the Plan upon and after attaining age 55.

2.4 Senior Officers - Less Than 20 Years of Service
A Senior Officer with ten or more years of Continuous Service will be eligible to Retire and receive benefits under the Plan upon and after attaining age 65.

2.5 Limited Benefit -
A Participant who is vested under the Basic Plan, but who fails to satisfy the requirements of Articles 2.3 or 2.4, is eligible to receive benefits only under the provisions of Article 3.3 of the Plan.

g. The Company has always met its obligations to pay SERP beneficiaries and to fund the SERP.

SOUTHWEST GAS CORPORATION
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ARIZONA GENERAL RATE CASE
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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 6
(RUCO 6-001 THROUGH RUCO 6-017)

DOCKET NO: G-01551A-16-0107
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: 10/03/2016

REQUEST NO: RUCO 6-005

Severance Pay Expense – Please answer the following questions as they relate to Severance Pay:

a. Provide the amount of Severance pay expense the Company is seeking recovery of in this rate case along with FERC number, account description, and line item(s)/schedule(s) where the severance pay is summarized. In addition, please include the amount on a Company-wide basis and the amount that has been allocated to Arizona.

b. If any of the amount is related to payroll tax, provide this amount and the payroll tax percentage.

c. If any of the Severance pay is capitalized, briefly describe what percentage is allocated, and what plant accounts the allocations are made to, along with the percentage allocated to the plant accounts. In addition, briefly describe how the plant allocation was derived, and has the Company always used this methodology?

d. Are union employees and employees of the Company's wholly owned subsidiaries eligible for the Severance pay, or any other employee who does not work directly for the parent Company (i.e. Southwest Gas)? If so, please list the number of employees who do not work directly for the parent Company (Southwest Gas) that have received severance pay and the amount payed-out by annualized test year (i.e. December through November) for prior four years?

e. Provide the total severance pay amounts paid-out by annualized test year for the prior four years for employees who work directly for the Company. In addition, please include the amount on a Company-wide basis and the amount that has been allocated to Arizona.

f. Has the Company ever not paid severance expenses? If so, please explain.

g. Please provide the names and positions of the employees who are entitled to severance pay, and do they all work for the parent company (Southwest Gas)?

h. Was severance pay included in the Company's last two rate cases? If no, please explain why?

i. Please provide categories that would be included in the individual's severance pay package (i.e. stock options, medical benefits, etc.).

j. Is any severance pay expense based on Company financials or other performance measures? If so, please explain.

k. What percentage of severance pay expense was related to each of the following categories:

I. Firing

II. Layoff's

III. Resignations

IV. Retirements

RESPONDENT: Regulation

RESPONSE:

a. The amount of severance pay in the test year that Southwest Gas is requesting recovery for in this proceeding is as follows:
Account 920: $217,500 or $116,913 after allocation to Arizona
Account 908: $30,500 or $16,294 after allocation to Arizona.

b. None. The annualization of payroll taxes in the Labor and Loading Annualization adjustment does not take severance pay into account.

c. Severance pay is not capitalized.

d. No.

e. Please refer to RUCO 6.05_Attachment 1.

f. No.

g. All employees of the Company could be eligible for severance pay.

h. Yes, to the extent that there were payments.

i. Other than cash payment, Southwest Gas does not provide other severance pay benefits.

j. No.

k. The approximate percentages are as follows: Firing – 0%; Layoffs – 0%; Resignations – 25%; Retirements – 75%

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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 6
(RUCO 6-001 THROUGH RUCO 6-017)

DOCKET NO: G-01551A-16-0107
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: 10/03/2016

REQUEST NO: RUCO 6-006

Pre-1970's Vintage Steel Pipe – Please answer the following questions as they relate to Pre-1970's Vintage Steel Pipe:

a. How does the Company evaluate whether the pre-1970's vintage steel pipe needs replaced (e.g. Does the Company run a smart pig through the pipeline using magnetic flux and computer mapping to look at possible structure failures or corrosion in the pipe)?

b. If no to a. How does the Company evaluate the Pre-1970's Vintage Steel Pipe (Hydrostatic Pressure Testing), and why the Company cannot use a smart pig in the evaluation?

c. If an abnormality is detected how does the Company score the pipeline anomaly (e.g. 1-10, good – bad, etc.)?

d. How does the Company prioritize its projects (e.g. needs immediate attention, needs attention at a later date, etc.)?

e. Please provide a replacement schedule of the projects, what section of the system needs to be replaced, along with a scheduled time period based on the prioritization of the Company's projects.

f. In your discussion of e., please provide the estimated cost for each phase of the pipeline replacement.

g. How often does the Company test its pre-1970's vintage pipe via vie a smart pipe, hydrostatic testing or some other means (e.g. once every two years, once a year etc.)?

h. If abnormalities and structural defects are found in the pre-1970's vintage steel pipe, is it still the Company's position that it will not start replacing the pre-1970's vintage pipe unless the Commission approves the replacement program in this rate case?

RESPONDENT: Engineering Services

RESPONSE:

As indicated in Mr. Kevin Lang's prepared direct testimony, any unsafe pipe is replaced immediately in accordance with the Company's Operations Manual. The Company's distribution and transmission integrity management programs identify those pipelines that may represent a safety concern and may address those concerns with additional risk reduction measures.

a. Although the Company does utilize instrumented inline inspection tools or "smart pigs" and hydrostatic pressure testing as possible assessment methodologies in its transmission integrity management program, these assessment tools have not been utilized to prioritize proposed pre-1970's vintage steel transmission pipe replacement due to system constraints and other factors such as flow conditions, the existence of non-piggable fittings, inability to effectively remove water from a post-hydrostatically tested pipeline, and other related factors.

b. Please refer to the response to 6.06(a).

c. Southwest Gas does not utilize the term "abnormality" in regards to its pipeline facilities. The Company's Operations Manual sets forth policies and procedures for the evaluation and remediation of "defects" or "conditions" discovered on transmission pipelines. A "defect" is any damage to the transmission pipeline that meets the criteria for immediate repair, scheduled repair or monitoring. A "condition" is a potential threat to the integrity of all pipelines that could result in a transmission pipeline defect or damage that affects the serviceability of a distribution pipeline.

d. As provided in the response to Staff 5.14 and 6.32, the Company plans to prioritize pre-1970's vintage steel pipe replacement based on a number of factors. These factors include the age of the pipe, class location, percent of the specified minimum yield strength based on operating pressure, availability of original as-built documentation, leak history, cathodic protection history, scheduled municipal work, considerations for additional operations and maintenance activities, and any available pipe condition data gathered through O&M activities. This prioritization process will occur for both distribution and transmission pre-1970's vintage steel pipe replacement.

e. The Company is currently preparing an initial list of projects that would be considered for replacement under the Company's proposal and will supplement this response accordingly. In contrast to a request for authorization to replace specific gas facilities, the GIM mechanism is a procedure that would allow for the timely recovery of the revenue requirement associated with investments in non-revenue producing infrastructure improvements, including the accelerated replacement of pre-1970's vintage steel pipe. As a part of that procedure, the Company anticipates that it would annually prepare assessments of the most likely pipe replacement candidates and results of the replacement activity.

f. See refer to the response to 6.06(e).

g. Please refer to the response to 6.06(a). The Company does not currently perform other tests such as inline inspection ("smart pigging"), hydrostatic testing, or other tests on a regular interval on pre-1970's vintage steel pipe. As described in Mr. Kevin Lang's prepared direct testimony, the Company's distribution and transmission integrity management programs work to evaluate and mitigate risks.

h. As stated in Mr. Kevin Lang's prepared direct testimony, the Company immediately replaces any pipe or facilities that represent a safety concern. The Company's policies and procedures evaluate any anomalies discovered on its pipelines and addresses them accordingly.

SOUTHWEST GAS CORPORATION
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ARIZONA GENERAL RATE CASE
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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 8
(RUCO 8-001 THROUGH RUCO 8-007)

DOCKET NO: G-01551A-16-0107
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: 10/18/2016

REQUEST NO: RUCO 8-004

Western Energy Institute ("WEI") dues – Please answer the following questions as they relate to WEI dues:

a. Provide a break-out of the amounts and percentages of WEI costs that relate to the following functions:

I. Legislative Advocacy

II. Legislative Policy Advocacy

III. Regulatory Advocacy

IV. Regulatory Policy Research

V. Advertising

VI. Marketing

VII. Utility Engineering and Operations

VIII. Finance, Legal Planning, and Customer Service

IX. Public Relations

b. If WEI provides separate categories of expenses other than those provided in a. please provide those categories along with the amounts and percentages of those expense categories.

c. Provide all the invoices for the WEI dues that the Company is requesting to be recovered in this rate case.

RESPONDENT: Regulation

RESPONSE:

WEI does not categorize or account for its expenses by these functions. WEI has general and administrative expenses and meetings expenses. As stated in response to Staff 2-024, WEI does not engage in marketing or lobbying activities. A payment of $31,722 was made to WEI during the test year and was recorded to Account 930.2. The amount allocated to Arizona is $17,051. Please refer to RUCO 8.04_Attachment 1 for the invoice supporting the amount the Company is requesting to be recovered in this proceeding.

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ACC
RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO)
RUCO 8
(RUCO 8-001 THROUGH RUCO 8-007)

DOCKET NO: G-01551A-16-0107
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: 10/18/2016

REQUEST NO: RUCO 8-007

Bonus Depreciation related to Post-Test Year Plant – Please answer the questions as they relate to Bonus Depreciation related to Post-Test Year Plant:

a. Identify the Projects that the Company intends to take bonus depreciation on in its 2016 tax return.

b. Provide the estimated dollar amounts from the projects a. that the Company intends to take on its 2016 tax return.

RESPONDENT: Regulation

RESPONSE:

The Company is basing this response on the costs it is requesting for recovery in the Post-test year (PTY) plant adjustment, as updated in response to Staff 8.01.

a. All projects in the PTY plant adjustment are eligible for 50% bonus depreciation. The Company takes bonus depreciation on all eligible plant additions.

b. There may be trailing charges after August 31, 2016 that will impact the final cost of each project, but will not be requested for recovery in this proceeding. The amount related to bonus depreciation is 50% of each amount on the schedules provided, as follows:
   WP B-2 PTY Dir: $12,407,289
   WP B-2 Sys 303: $11,644,662
   WP B-2 Sys Gen: $1,325,263

ATTACHMENT C

DEF 14A

SOUTHWEST GAS CORP filed this Form DEF 14A on 03/31/2016

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Eligibility

Participants in the RSUP include directors, managerial employees and officers, including the Company's CEO and the other executives named in the Summary Compensation Table. As of March 8, 2016, 11 directors and 58 managerial employees and officers were eligible to be RSUP participants, and 12 directors and 57 managerial employees and officers were RSUP participants for 2015. Mr. Shaw's participation in the RSUP ended with the 2015 plan year.

Terms and Conditions of Awards

The RSUP provides for the grant of restricted stock and restricted stock units (collectively referred to as "awards"). Awards may be granted to officers, directors, and employees of the Company and its related entities. Each award granted under the RSUP is designated in an award agreement.

Subject to applicable laws, the Administrator has the authority, in its discretion, to select officers, directors and employees to whom awards may be granted from time to time, to determine whether and to what extent, awards are granted, to determine the number of shares of Common Stock, or the amount of other consideration to be covered by each award (subject to the limitations set forth under the above sub-section of this Proposal 2 titled "Shares Reserved for Issuance under the RSUP"), to approve award agreements for use under the RSUP, to determine the terms and conditions of any award (including the vesting schedule applicable to the award), to amend the terms of any outstanding award granted under the Plan, to construe and interpret the terms of the RSUP and awards granted, and to take such other action not inconsistent with the terms of the RSUP, as the Administrator deems appropriate.

The RSUP includes the following performance criteria that may be considered by the Administrator when granting awards intended to qualify as performance-based awards: (i) increase in share price, (ii) earnings per share, (iii) total shareholder return, (iv) operating margin, (v) operating costs, (vi) gross margin, (vii) return on equity, (viii) return on assets, (ix) return on investment, (x) operating income, (xi) net operating income, (xii) pre-tax profit, (xiii) cash flow, (xiv) revenue, (xv) expenses, (xvi) earnings before interest, taxes and depreciation, (xvii) economic value added, (xviii) market share, (xix) gas segment return on equity, (xx) customer to employee ratio, (xxi) customer service satisfaction, (xxii) performance of the Company relative to a peer group of companies and/or indexes, (xxiii) individual performance, (xxiv) safety goals and (xxv) financial performance of subsidiaries or individual business segments and/or operating regions. The performance criteria may be applicable to the Company, entities related to the Company, and/or any individual business units of the Company or any related entity.

Procedures for Calculating and Paying Actual Awards

The performance goal currently used by the Administrator to determine whether awards are earned by participants is the average MIP payout percentage for the three years immediately preceding the award determination date. The target is set at an average MIP payout percentage of 100%; however, no award will be earned unless the average MIP payout percentage is at or above 90%. If an award is earned, it can range from 50% to 150% of the incentive opportunity. The incentive opportunity for each of the Company's employees participating under the RSUP is based on the percentage of base salary as set forth in Appendix A of the RSUP. Non-employee directors also receive an award based on the Company's three-year performance under the MIP criteria, with the target award being 1,000 restricted stock units. Non-employee directors also receive an annual grant of 800 shares of restricted stock or restricted stock units under the RSUP as a portion of their annual compensation.

The RSUP provides that any amendment that would adversely affect the grantee's rights under outstanding awards shall not be made without the grantee's written consent. The Administrator may issue awards under the RSUP in settlement, assumption, or substitution for, outstanding awards or obligations to grant future awards in connection with the Company acquiring another entity in a merger or some other form of transaction.

Vesting of Awards

With respect to awards made to officers and employees, unless otherwise set forth in an individual award agreement or in an amendment to Appendix A to the RSUP (which sets forth the vesting schedule of awards), the shares or units subject to an award made to any employee of the Company will vest and be paid out in shares of Common Stock over a three year period as follows: 40% of the shares or units subject to the award will vest on the 4th of January following the grant date of the award and 30% of the shares or units subject to the award will vest on each of the second and third anniversaries of the vesting commencement date.

Awards made to directors will vest on the date of grant. Awards of restricted stock units, however, will not be converted into shares of Common Stock until the director's continuous service terminates or upon a Change in Control Event (as described below in the sub-section of this Proposal 2 titled "Change in Control Event").

SCHEDULES

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-16-0107
Test Year Ended November 30, 2016

TABLE OF CONTENTS TO RUCO's DIRECT SCHEDULES

REVENUE REQUIREMENT
ACC JURISDICTIONAL

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 1,336,049,260	$ 2,288,780,073	$ 1,812,414,666	$ 1,319,548,633	$ 2,270,794,885	$ 1,795,171,759
2							
3	Adjusted Operating Income (Loss)	89,293,036	89,293,036	89,293,036	95,275,783	95,275,783	95,275,783
4							
5	Current Rate Of Return (Line 3 / Line 1)	6.68%	3.90%	4.93%	7.22%	4.20%	5.31%
6							
7	Required Operating Income (Line 13 X Line 1)	$ 108,844,799	$ 108,844,799	$ 108,844,799	$ 101,811,452	$ 101,811,452	$ 101,811,452
8							
9	Weighted Average Cost of Capital	7.82%	7.82%	7.82%	7.34%	7.34%	7.34%
10							
11	Fair Value Adjustment	0.33%	-3.06%	-1.81%	0.38%	-2.85%	-1.67%
12							
13	Required Rate of Return	8.15%	4.76%	6.01%	7.72%	4.48%	5.67%
14							
15	Operating Income Deficiency (Line 7 - Line 3)	$ 19,551,764	$ 19,551,764	$ 19,551,764	6,535,669	6,535,669	6,535,669
16							
17	Gross Revenue Conversion Factor (Schedule JMM-2)	1.6329	1.6329	1.6329	1.6226	1.6226	1.6226
18							
19	Increase In Gross Revenue Requirement (Line 15 X Line 17)	$ 31,926,895	$ 31,926,895	$ 31,926,895	$ 10,604,948	$ 10,604,948	$ 10,604,948
20							
21	Adjusted Test Year Revenue	$ 481,681,406	$ 481,681,406	$ 481,681,406	$ 481,681,406	$ 481,681,406	$ 481,681,406
22							
23	Proposed Annual Revenue Requirement (Line 19 + Line 21)	$ 513,608,301	$ 513,608,301	$ 513,608,301	$ 492,286,354	$ 492,286,354	$ 492,286,354
24							
25	Required Percentage Increase In Revenue (Line 19 / Line 21)	6.63%	6.63%	6.63%	2.20%	2.20%	2.20%
26							
27	Rate Of Return On Common Equity	10.25%	10.25%	10.25%	9.39%	9.39%	9.39%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 and D-1
Column (D): Schedules JMM-3, JMM-9, and JMM-28
Column (E): Schedule JMM-3, Company Column (F)
Column (F): Average of Column (D) + Column (E) / 2

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-16-0107
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Schedule JMM-2

GROSS REVENUE CONVERSION FACTOR, INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A] Company Proposed	[B] RUCO Recommended
1	Gross Revenue	100.00%	100.00%
2			
3	Less: Uncollectible Revenue	0.30%	0.30%
4			
5	Taxable Income as a Percent	99.70%	99.70%
6			
7	Less: Federal and State Income Taxes	38.46%	38.07%
8			
9	Changes in Net Operating Income	61.24%	61.63%
10			
11	Gross Revenue Conversion Factor	1.6329	1.6226

References:
Column [A]: Company as Filed
Column [B]: RUCO Recommended

RATE BASE (OCRB, RCND and FVRB)
ACC JURISDICTIONAL

LINE NO.	Description	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant in Service							
2	Direct	$ 3,037,836,019	$ 4,996,152,529	$ 4,016,994,274	164.46%	$ 3,003,917,682	$ 4,952,760,891	$ 3,978,339,287
3	System Allocation	173,566,230	183,692,131	178,629,180	105.83%	172,814,945	177,458,131	175,136,538
4	Total Utility Plant in Service	$ 3,211,402,249	$ 5,179,844,660	$ 4,195,623,454		$ 3,176,732,627	$ 5,130,219,022	$ 4,153,475,825
5								
6	Accumulated Depreciation							
6	Direct	$ (1,285,149,725)	$ (2,145,382,255)	$ (1,715,265,990)	166.94%	$ (1,263,642,774)	$ (2,108,702,555)	$ (1,686,172,665)
7	System Allocation	(99,705,173)	(103,103,563)	(101,404,368)	103.41%	(97,940,856)	(101,279,109)	(99,609,982)
8	Total Accumulated Depreciation	$ (1,384,854,898)	$ (2,248,485,818)	$ (1,816,670,358)		$ (1,361,583,630)	$ (2,209,981,664)	$ (1,785,782,647)
9								
10	Total Net Utility Plant in Service	$ 1,826,547,350	$ 2,931,358,843	$ 2,378,953,096		$ 1,815,148,997	$ 2,920,237,358	$ 2,367,693,178
10								
11	Allowance for Working Capital							
12	Cash Working Capital	$ (4,113,676)	$ (4,113,676)	$ (4,113,676)	100.00%	$ (4,083,736)	$ (4,083,736)	$ (4,083,736)
13	Materials and Supplies	15,364,326	15,364,326	15,364,326	100.00%	15,364,326	15,364,326	15,364,326
14	Prepayments	6,885,291	6,885,291	6,885,291	100.00%	6,739,964	6,739,964	6,739,964
14	Total Allowance for Working Capital	$ 18,135,941	$ 18,135,941	$ 18,135,941		$ 18,020,554	$ 18,020,554	$ 18,020,554
15								
16	Customer Deposits	$ (39,253,787)	$ (39,253,787)	$ (39,253,787)	100.00%	$ (39,253,787)	$ (39,253,787)	$ (39,253,787)
17								
18	Customer Advances for Construction	(38,815,661)	(38,815,661)	(38,815,661)	100.00%	(38,815,661)	(38,815,661)	(38,815,661)
18								
19	Deferred Taxes	(430,564,584)	(582,645,263)	(506,604,924)	135.32%	(435,551,470)	(589,393,579)	(512,472,525)
20								
21	Total Original Cost Rate Base	$ 1,336,049,260	$ 2,288,780,073	$ 1,812,414,666		$ 1,319,548,633	$ 2,270,794,885	$ 1,795,171,759

References:
Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): Schedule JMM-4, Column (C)
Column (F): Column (D) X Column (E)
Column (G): Average Of Column (E) + Column (F) / 2

SOUTHWEST GAS CORPORATION
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Schedule JMM-4

ORIGINAL COST RATE BASE - ACC JURISDICTIONAL

LINE NO.	Description	(A) COMPANY AS FILED OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB
1	Gross Utility Plant in Service			
2	Direct	$ 3,037,836,019	$ (33,918,337)	$ 3,003,917,682
3	System Allocation	173,566,230	(751,285)	172,814,945
4	Total Utility Plant in Service	$ 3,211,402,249	$ (34,669,622)	$ 3,176,732,627
5				
6	Accumulated Depreciation			
7	Direct	$ (1,285,149,725)	$ 21,506,951	$ (1,263,642,774)
8	System Allocation	(99,705,173)	1,764,318	(97,940,856)
9	Total Accumulated Depreciation	$ (1,384,854,898)	$ 23,271,269	$ (1,361,583,630)
10				
11	Total Net Utility Plant in Service	$ 1,826,547,350	$ (11,398,353)	$ 1,815,148,997
12				
13	Allowance for Working Capital			
14	Cash Working Capital	$ (4,113,676)	$ 29,939	$ (4,083,736)
15	Materials and Supplies	15,364,326	-	15,364,326
16	Prepayments	6,885,291	(145,327)	6,739,964
17	Total Allowance for Working Capital	$ 18,135,941	$ (115,387)	$ 18,020,554
18				
19	Customer Deposits	$ (39,253,787)	$ -	$ (39,253,787)
20				
21	Customer Advances for Construction	(38,815,661)	-	(38,815,661)
22				
23	Deferred Taxes	(430,564,584)	(4,986,886)	(435,551,470)
24				
25	Total Original Cost Rate Base	$ 1,336,049,260	$ (16,500,627)	$ 1,319,548,633
26				
27			Reconciliation to RCND	
28		OCRB	RCND Ratio	RCND
29	Company OCRB and RCND as Filed	$ 1,336,049,260		$ 2,288,780,073
30	RUCO Adjustment #1			-
31	Plant	(6,111,843)	1.0000	(6,111,843)
32	Accumulated Depreciation	(1,160,472)	1.0000	(1,160,472)
33	RUCO Adjustment #2			
34	Direct Plant	(22,667,423)	1.6446	(37,279,795)
35	System Allocable	(751,285)	1.0583	(795,115)
36	Accumulated Depreciation:			
37	Direct Plant	22,667,423	1.6694	37,840,172
38	System Allocable	751,285	1.0341	776,892
39	RUCO Adjustment #3			
40	System Allocable	(5,139,070)	1.0583	(5,438,885)
41	Accumulated Depreciation	1,013,033	1.0341	1,047,561
42	ADIT	1,475,972	1.3532	1,997,304
43	RUCO Adjustment #4			
44	Cash Working Allowance	29,939	1.0000	29,939
45	RUCO Adjustment #5			
46	Prepayments - D&O Insurance	(145,327)	1.0000	(145,327)
47	RUCO Adjustment #6			
48	ADIT	(6,462,859)	1.3532	(8,745,619)
49	RUCO as Adjusted OCRB and RCND	$ 1,319,548,633		$ 2,270,794,885

References:
Column [A]: Company as Filed
Column [B]: RUCO Schedule 5
Column (C): Column (A) + Column (B)

SOUTHWEST GAS CORPORATION
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Schedule JMM-5

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

ACC Jurisdiction

Line No.	DESCRIPTION	(A) Company Adjusted OCRB As Filed	(B) Rate Base Adjustment No. 1 Post-Test Year Plant and Accumulated Depreciation	(C) Rate Base Adjustment No. 2 Retirement of Post-Test Plant and Accumulated Depreciation	(D) Rate Base Adjustment No. 3 Company Owned Aircraft, Aircraft Hanger, and Equipment	(E) Rate Base Adjustment No. 4 Cash Working Capital	(F) Rate Base Adjustment No. 5 Prepayments-Directors and Officers Insurance	(G) Rate Base Adjustment No. 6 ADIT related to Post-Test Year Plant	(H) RUCO Adjusted OCRB Recommended Balances
1	Gross Utility Plant in Service								
2	Direct	$ 3,037,836,019	$ (6,111,843)	$ (22,667,423)	$ (5,139,070)	$ -	$ -	$ -	$ 3,003,917,682
3	System Allocation	173,566,230	-	(751,285)		-	-	-	172,814,945
4	Total Utility Plant in Service	$ 3,211,402,249	$ (6,111,843)	$ (23,418,708)	$ (5,139,070)	$ -	$ -	$ -	$ 3,176,732,627
5									
6	Accumulated Depreciation								
7	Direct	$ (1,285,149,725)	$ (1,160,472)	$ 22,667,423	$ -	$ -	$ -	$ -	$ (1,263,642,774)
8	System Allocation	(99,705,173)	-	751,285	1,013,033	-	-	-	(97,940,856)
9	Total Accumulated Depreciation	$ (1,384,854,898)	$ (1,160,472)	$ 23,418,708	$ 1,013,033	$ -	$ -	$ -	$ (1,361,583,630)
10									
11	Total Net Utility Plant in Service	$ 1,826,547,350	$ (7,272,315)	$ -	$ (4,126,038)	$ -	$ -	$ -	$ 1,815,148,997
12									
13	Allowance for Working Capital								
14	Cash Working Capital	$ (4,113,676)	$ -	$ -	$ -	$ 29,939	$ -	$ -	$ (4,083,736)
15	Materials and Supplies	15,364,326	-	-	-	-	-	-	15,364,326
16	Prepayments	6,885,291	-	-	-	-	(145,327)	-	6,739,964
17	Total Allowance for Working Capital	$ 18,135,941	$ -	$ -	$ -	$ 29,939	$ (145,327)	$ -	$ 18,020,554
18									
19	Customer Deposits	$ (39,253,787)	$ -	$ -	$ -	$ -	$ -	$ -	$ (39,253,787)
20									
21	Customer Advances for Construction	(38,815,661)	-	-	-	-	-	-	(38,815,661)
22									
23	Deferred Taxes	(430,564,584)	-	-	1,475,972	-	-	(6,462,859)	(435,551,470)
24									
25	Total Original Cost Rate Base	$ 1,336,049,260	$ (7,272,315)	$ -	$ (2,650,065)	$ 29,939	$ (145,327)	$ (6,462,859)	$ 1,319,548,633

REFERENCES:
Column (A) Company Schedule B-1
Column (B) See JMM-6
Column (C) See JMM-7
Column (D) See JMM-8
Column (E) See JMM-9
Column (F) See JMM-10
Column (G) See JMM-11
Column (H) See Column (B) through (G)

SOUTHWEST GAS CORPORATION
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Schedule JMM-6

RATE BASE ADJUSTMENT NO. 1
POST-TEST YEAR PLANT AND ACCUMULATED DEPRECIATION

Line No.	DESCRIPTION	(A) Company Proposed	(B) RUCO Adjustment	(C) RUCO As Adjusted
1	Gross Utility Plant in Service	$ 3,037,836,019,000	$ (6,111,843)	$ 3,037,829,907,157
2	Accumulated Depreciation	(1,285,149,725,080)	(1,160,472)	(1,285,150,885,552)
3	Total Net Utility Plant in Service	$ 1,752,686,293,920	$ (7,272,315)	$ 1,752,679,021,605
4				
5	RUCO's Calculation:			
6	Post Test Year Plant			
7	Direct Post-Test Year Plant	$ 22,620,591	$ (3,905,569)	$ 18,715,022
8	System Allocable Post -Test Year Plant 303	15,277,047	(2,174,887)	13,102,160
9	System Allocable Post -Test Year Plant	1,520,252	(31,387)	1,488,865
10	Total Post-Test Year Plant	39,417,890	(6,111,843)	33,306,047
11				
12	Post Test Year Accumulated Depreciation			
13	Accumulated Depreciation	$ -	$ 1,160,472	$ 1,160,472
14				

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

SOUTHWEST GAS CORPORATION
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Schedule JMM-7

RATE BASE ADJUSTMENT NO. 2
POST-TEST YEAR PLANT RETIREMENTS

		(A)[1]	(B)	(C)
Line No.	DESCRIPTION	Company Proposed	RUCO Adjustment	RUCO As Adjusted
1	Gross Utility Plant in Service	$ 3,037,836,019,000	$ (23,418,708)	$ 3,037,812,600,292
2	Accumulated Depreciation	(1,285,149,725,080)	23,418,708	(1,285,126,306,372)
3	Total Net Utility Plant in Service	$ 1,752,686,293,920	$ -	$ 1,752,686,293,920
4				
5	RUCO's Calculation:			
6	Direct Plant Retired	$ 22,667,423		
7	System Allocable Plant Retired	751,285		
8		$ 23,418,708		

Note 1: Does not include prior adjustments

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) RUCO as Adjusted

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Schedule JMM-8

RATE BASE ADJUSTMENT NO. 3
COMPANY-OWNED AIRCRAFT, AIRCRAFT HANGAR, AND EQUIPMENT

		(A)[1]	(B)	(C)
Line No.	**DESCRIPTION**	**Company Proposed**	**RUCO Adjustment**	**RUCO As Adjusted**
1	Gross Utility Plant in Service	$ 3,037,836,019,000	$ (5,139,070)	$ 3,037,830,879,930
2	Accumulated Depreciation	(1,285,149,725,080)	1,013,033	(1,285,148,712,047)
3	Total Net Utility Plant in Service	$ 1,752,686,293,920	$ (4,126,038)	$ 1,752,682,167,882
4				
5	Deferred Taxes	$ (430,564,584)	$ 1,475,972	$ (429,088,612)
6				
7	RUCO's Calculation:			
8	Account 392.11 Aircraft			
9	Gas Plant	$ 4,609,628		
10	Accumulated Provision	(812,998)		
11	Deferred Taxes	(1,458,035)		
12	Rate Base	$ 2,338,595		
13				
14	Account 390.1 Aircraft Hangar and Equipment			
15	Gas Plant	$ 529,442		
16	Accumulated Provision	(200,035)		
17	Deferred Taxes	(17,938)		
18	Rate Base	$ 311,470		

Note 1: Does not include prior adjustments

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) RUCO as Adjusted

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Schedule JMM-9

RATE BASE ADJUSTMENT NO. 4
CASH WORKING CAPITAL

Line No.	Description [A]	Cost [B]	Adj No.	RUCO Adjustments [C]	RUCO as Adjusted [D]	Lag Days [E]	Dollar Days [F] = [D]*[E]
1	Cost of Gas [1]	$ 256,651,324		$ -	$ 256,651,324	42.43	$ 10,889,715,682
2	Labor and Labor Loading	134,338,717	4,5,6,7,8	(7,296,670)	127,042,047	10.90	1,384,758,316
3	Provision for Uncollected Accounts	2,369,037		-	2,369,037	120.00	284,284,429
4	Other O&M Expense	96,289,296	1,2,3.9	(866,878)	95,422,418	2.03	193,707,508
5	Total O&M Expense	$ 489,648,374		$ (8,163,548)	$ 481,484,826	26.21	12,752,465,936
6							
7	Interest	$ 33,627,705	12	$ 23,368	33,651,073	91.00	$ 3,062,247,649
8	Taxes Other than Income Taxes	41,628,621		-	41,628,621	174.28	7,255,036,052
9	Income Taxes - Current	46,530,675	13	3,690,212	50,220,887	37.00	1,858,172,813
10	Total Operating Expenses	$ 611,435,375		$ (4,449,968)	$ 606,985,407	40.68	$ 24,927,922,450
11							
12	Number of Days in Test Period				365.00		
13							
14	Average Daily Operating Expense				$ 1,662,974		
15							
16	Lag in Receipt of Revenue					38.22	
17							
18	Net Difference Revenue - Expense Lag				(2.46)		
19							
20	Cash Working Capital				$ (4,083,737)		
21							
22	Cash Working Capital Company				$ (4,113,676)		
23							
24	Adjustment				$ 29,939		
25							
26	[1] Gas Costs adjusted for present volumes and rates.						

References:
Column (A) Description
Column (B) Company Filing
Column (C) Testimony JMM
Column (D) = Column (B) - Column (C)
Column (E) Lag Days
Column (F) = Column (D) * Column (E)

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Schedule JMM-10

RATE BASE ADJUSTMENT NO. 5
PREPAYMENTS - DIRECTORS AND OFFICERS INSURANCE

Line No.	DESCRIPTION	(A) Company Proposed	(B) RUCO Adjustment	(C) RUCO As Adjusted
1	Prepayments	$ 6,885,291	$ (145,327)	$ 6,739,964
2				
3	RUCO's Calculation:			
4	Company Proposed	$ 290,653		
5	Split between Ratepayers and Shareholder	50%		
6	RUCO Adjustment - Total Company	$ 145,327		

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-11

RATE BASE ADJUSTMENT NO. 6
ACCUMULATED DEFERRED INCOME TAXES ("ADIT") RELATED TO POST-TEST YEAR PLANT BONUS DEPRECIAITON

Line No.	DESCRIPTION	(A) Company Proposed	(B) RUCO Adjustment	(C) RUCO As Adjusted
1	Deferred Taxes	$ (430,564,584)	$ (6,462,859)	$ (437,027,443)
2				
3	RUCO's Calcualton of ADIT on Post Test Year Plant:			
4	Direct Post-Test Year Plant	$ -	$ 3,512,941	$ 3,512,941
7	System Allocable Post -Test Year Plant 303	-	2,659,660	2,659,660
8	System Allocable Post -Test Year Plant	-	290,257	290,257
9	Total Post-Test Year Plant	$ -	$ 6,462,859	$ 6,462,859
10				
11		Direct PTYP	SAP 303	SAP
12	Post-Test Year Plant used and useful with six months	$ 18,715,022	$ 23,367,955	$ 2,655,420
13	Imputed Accumulated Depreciation	(315,434)	(1,477,166)	(56,011)
14	Allocation	N/A	56.07%	56.07%
15	Book Value	18,399,588	13,930,391	1,520,270
16	50 percent Bonus Depreciation for 2016	9,199,794	6,965,195	760,135
17	Effective Federal Tax rate	33.2850%	33.2850%	33.2850%
18	State Rate of 4.9 percent	4.9000%	4.9000%	4.9000%
19	Total Federal and State Effective Tax Rate	38.1850%	38.1850%	38.1850%
20	Increase to Deferred Taxes	$ 3,512,941	$ 2,659,660	$ 290,257
21				

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-12

SUMMARY OF OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO

LINE NO.	Description	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJMENTS	(C) RUCO TEST YEAR AS ADJUSTED
1	Operating Revenue	$ 481,681,406	$ -	$ 481,681,406
2	Gas Cost	-	-	-
3	Operating Margin	$ 481,681,406	$ -	481,681,406
4				
5	Operating Expenses			-
6	Other Gas Costs	$ 1,345,425	$ -	$ 1,345,425
7	Storage	-	-	-
8	Distribution	111,226,774	(138,294)	111,088,480
9	Customer Accounts	27,827,100	-	27,827,100
10	Customer Service & Info.	872,491	-	872,491
11	Sales	-	-	-
12	Administrative & General	-	-	-
13	Direct	6,052,009	(1,067,573)	4,984,436
14	System Allocable	70,960,598	(7,634,013)	63,326,585
15	Depreciation & Amortization	-	-	-
16	Direct	83,124,568	(200,250)	82,924,318
17	System Allocable	12,796,366	(623,906)	12,172,460
18	Regulatory Amortizations	(52,943)	-	(52,943)
19	Taxes Other Than Income	41,628,621	-	41,628,621
20	Interest on Customer Deposits	2,355,227	-	2,355,227
21	Income Taxes	34,252,135	3,681,289	37,933,424
22	Total Operating Expenses	$ 392,388,370	$ (5,982,747)	$ 386,405,623
23	Net Operating Income	$ 89,293,036	$ 5,982,747	$ 95,275,783

References:
Column [A]: Company as Filed
Column [B]: RUCO Schedule 13
Column (C): Column (A) + Column (B)

OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

LINE NO.	Description	(A) COMPANY AS FILED	(B) Adj. 1 Investor Relation Expense JMM-14	(C) Adj. 2 Benefit Expense JMM-15	(D) Adj. 3 Directors & Officers Ins. JMM-16	(E) Adj. 4 MIP Expense JMM-17	(F) Adj. 5 SERP Expense JMM-18	(G) Adj. 6 EDP Expense JMM-19
1	Operating Revenue	$ 481,681,406	$ -	$ -	$ -	$ -	$ -	$ -
2	Gas Cost	-	-	-	-	-	-	-
3	Operating Margin	$ 481,681,406	$ -	$ -	$ -	$ -	$ -	$ -
4								
5	Operating Expenses							
6	Other Gas Costs	$ 1,345,425	$ -	$ -	$ -	$ -	$ -	$ -
7	Storage	-	-	-	-	-	-	-
8	Distribution	111,226,774	-	(138,294)	-	-	-	-
9	Customer Accounts	27,827,100	-	-	-	-	-	-
10	Customer Service & Info.	872,491	-	-	-	-	-	-
11	Sales	-	-	-	-	-	-	-
12	Administrative & General		-	-	-	-	-	-
13	Direct	6,052,009	-	-	-	-	-	(1,067,573)
14	System Allocable	70,960,598	(217,870)	(24,678)	(333,962)	(2,436,953)	(1,627,202)	(442,981)
15	Depreciation & Amortization							
16	Direct	83,124,568	-	-	-	-	-	-
17	System Allocable	12,796,366	-	-	-	-	-	-
18	Regulatory Amortizations	(52,943)	-	-	-	-	-	-
19	Taxes Other Than Income	41,628,621	-	-	-	-	-	-
20	Interest on Customer Deposits	2,355,227	-	-	-	-	-	-
21	Income Taxes	34,252,135	-	-	-	-	-	-
22	Total Operating Expenses	$ 392,388,370	$ (217,870)	$ (162,972)	$ (333,962)	$ (2,436,953)	$ (1,627,202)	$ (1,510,554)
23	Net Operating Income	$ 89,293,036	$ 217,870	$ 162,972	$ 333,962	$ 2,436,953	$ 1,627,202	$ 1,510,554

SOUTHWEST GAS CORPORATION
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OPERATING OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS IME STATEMENT - ACC

LINE NO.	Description	(H) Adj. 7 RSUP Expense JMM-20	(I) Adj. 8 Severance Pay JMM-21	(J) Adj. 9 AGA Dues JMM-22	(k) Adj. 10 Rate Case Expense JMM-23	(L) Adj. 11 Depreciation Expense JMM-24	(M) Adj. 12 Interest Synchronization JMM-25	(N) Adj. 13 Income Tax JMM-26	(O) RUCO as Adjusted
1	Operating Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 481,681,406
2	Gas Cost	-	-	-	-	-	-	-	-
3	Operating Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 481,681,406
4									-
5	Operating Expenses								
6	Other Gas Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,345,425
7	Storage	-	-	-	-	-	-	-	-
8	Distribution	-	-	-	-	-	-	-	111,088,480
9	Customer Accounts	-	-	-	-	-	-	-	27,827,100
10	Customer Service & Info.	-	-	-	-	-	-	-	872,491
11	Sales	-	-	-	-	-	-	-	-
12	Administrative & General	-	-	-	-	-	-	-	-
13	Direct	-	-	-	-	-	-	-	4,984,436
14	System Allocable	(2,227,976)	(133,207)	(145,184)	(44,000)	-	-	-	63,326,585
15	Depreciation & Amortization	-	-	-	-	-	-	-	-
16	Direct	-	-	-	-	(200,250)	-	-	82,924,318
17	System Allocable	-	-	-	-	(623,906)	-	-	12,172,460
18	Regulatory Amortizations	-	-	-	-	-	-	-	(52,943)
19	Taxes Other Than Income	-	-	-	-	-	-	-	41,628,621
20	Interest on Customer Deposits	-	-	-	-	-	-	-	2,355,227
21	Income Taxes	-	-	-	-	-	(8,923)	3,690,212	37,933,424
22	Total Operating Expenses	$ (2,227,976)	$ (133,207)	$ (145,184)	$ (44,000)	$ (824,156)	$ (8,923)	$ 3,690,212	$ 386,405,623
23	Net Operating Income	$ 2,227,976	$ 133,207	$ 145,184	$ 44,000	$ 824,156	$ 8,923	$ (3,690,212)	$ 95,275,783

SOUTHWEST GAS CORPORATION
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Test Year Ended November 30, 2016

Schedule JMM-14

OPERATING INCOME ADJUSTMENT NO. 1
INVESTOR RELATIONS EXPENSES

Line No.	FERC Nos.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	921, 930	Investor Relations Expenses	$ 217,870	$ (217,870)	$ -
2					

Line No.	FERC	DESCRIPTION		PERIOD	DOLLARS
3	RUCO's Calculation				
4	FERC	DESCRIPTION		PERIOD	DOLLARS
5	9210	Employee Expense Report	Lodging	42095	$ 553
6	9210	Employee Expense Report	Lodging	42125	1,958
7	9210	Employee Expense Report	Meals	41974	129
8	9210	Employee Expense Report	Car Rental	42125	666
9	9210	Employee Expense Report	Car Rental	41974	124
10	9210	CORPORATE TRANSPORTATIO	Car Service	42309	1,707
11	9210	CORPORATE TRANSPORTATIO	Car Service	42278	213
12	9210	Employee Expense Report	Meals	42095	315
13	9210	Employee Expense Report	Meals	42125	1,536
14	9210	NATIONAL INVESTOR RELAT	Dues - Professional	42036	720
15	9210	STANDARD & POORS	Subscriptions/Publications	42036	6,175
16	9210	STANDARD & POORS	Subscriptions/Publications	42125	22,050
17	9210	CASH JOURNAL - 000	Subscriptions/Publications Refund	42186	(10,500)
18	9210	CASH JOURNAL - 000	Subscriptions/Publications Refund	42309	(11,025)
19	9210	Employee Expense Report	Other Business Expenses	42125	123
20	9302	POWER PROMOTIONS LLC	Office Supplies & Stationery	42036	3,888
21	9302	POWER PROMOTIONS LLC	Office Supplies & Stationery	42036	243
22	9302	CLEARING COMPANY PLANE	Air Travel	41974	1,560
23	9302	CLEARING COMPANY PLANE	Air Travel	42064	6,600
24	9302	CLEARING COMPANY PLANE	Air Travel	42095	7,920
25	9302	CLEARING COMPANY PLANE	Air Travel	42156	10,080
26	9302	CUISTOT - DEPOSIT FOR	Meals	42064	500
27	9302	CARDIFF LIMOUSINE - M	Meals/Minicoach Van	42186	880
28	9302	JETFINITY - DINNER FO	Meals	42095	335
29	9302	CUISTOT RESTAURANT	Meals	42125	8,171
30	9302	CASH JOURNAL - 000	Meals	42156	(642)
31	9302	SKY TOP VENDING INC	Meals	42217	4
32	9302	MONSTER FRAMING AND ART	Other Business Expenses	42036	289
33	9302	STUDIO WEST PHOTOGRAPHY	Other Business Expenses	42036	100
34	9302	STUDIO WEST PHOTOGRAPHY	Other Business Expenses	42036	910
35	9302	Employee Expense Report	Other Business Expenses	42064	126
36	9302	PAPER DIRECT - PLACE	Other Business Expenses	42125	70
37	9302	RR DONNELLEY	Outside Services - Printing Annual Report, Edgar-HTML, etc.	42125	106,966
38	9302	RR DONNELLEY	Outside Services - Printing Notice of Shareholder Meeting/Proxy, ε	42125	29,435
39	9302	COMPANY FORMS & SUPPLIE	Outside Services - Mail Carrier	42036	1
40	9302	FEDEX	Outside Services - Mail Carrier	42095	199
41	9302	FEDEX	Outside Services - Mail Carrier	42217	30
42	9302	NASDAQ OMX CORPORATE SO	Outside Services - Other Teleconferencing Services	41974	1,072
43	9302	STOYAN DESIGN INC	Outside Services - Other Annual Report	42005	26,780
44	9302	STUDIO WEST PHOTOGRAPHY	Outside Services - Other Annual Report	42036	5,270
45	9302	NASDAQ OMX CORPORATE SO	Outside Services - Other Teleconferencing Services	42064	665
46	9302	MORROW & CO LLC	Outside Services - Other Corporate Governance Consulting	42064	16,024
47	9302	MONSTER FRAMING AND ART	Outside Services - Other	42064	14
48	9302	STOYAN DESIGN INC	Outside Services - Other Annual Report	42064	27,780
49	9302	STOYAN DESIGN INC	Outside Services - Other Statistical and Quarterly Reports	42095	3,980
50	9302	NASDAQ OMX CORPORATE SO	Outside Services - Other Teleconferencing Services	42095	217
51	9302	MORROW & CO LLC	Outside Services - Other Proxy Services, etc.	42095	97
52	9302	MORROW & CO LLC	Outside Services - Other Proxy Services, etc.	42125	788
53	9302	MORROW & CO LLC	Outside Services - Other Proxy Services, etc.	42125	39,026
54	9302	MORROW & CO LLC	Outside Services - Other Proxy Services, etc.	42156	1,236
55	9302	NASDAQ OMX CORPORATE SO	Outside Services - Other Teleconferencing Services	42156	933
56	9302	MORROW & CO LLC	Outside Services - Other Proxy Services, etc.	42156	221
57	9302	MORROW & CO LLC	Outside Services - Other Proxy Services, etc.	42156	87
58	9302	NASDAQ OMX CORPORATE SO	Outside Services - Other Teleconferencing Services	42278	984
59	9302	MORROW & CO LLC	Outside Services - Other Corporate Governance Consulting	42278	16,024
60	9302	NASDAQ OMX CORPORATE SO	Other Fees Investor Relations Website and Webcasting	41974	13,920
61	9302	NASDAQ OMX CORPORATE SO	Other Fees IR One Subscription	42248	13,500
62	9302	ALM MEDIA LLC	Advertising - Magazine Investor Communications Program	42156	9,000
63	9302	ALM MEDIA LLC	Advertising - Magazine Investor Communications Program	42309	18,550
64					$ 388,576
65					
66				AZ Allocation Factor	56.07%
67					
68				Allocated to Arizona	$ 217,870

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

SOUTHWEST GAS CORPORATION
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Schedule JMM-15

OPERATING INCOME ADJUSTMENT NO. 2
BENEFIT EXPENSES

Line No.	FERC No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	926	Officers Tax and Estate Planning	$ 7,586	$ (7,586)	$ -
2	870	Vehicle Compensation	138,294	(138,294)	-
3	920	Vehicle Compensation	17,092	(17,092)	-
4		Total Expenses	$ 162,972	$ (162,972)	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-16

OPERATING INCOME ADJUSTMENT NO. 3
DIRECTORS AND OFFICERS (D&O) INSURANCE EXPENSE

			(A)	(B)	(C)
Line No.	**FERC No.**	**DESCRIPTION**	**COMPANY PROPOSED**	**RUCO ADJUSTMENT**	**RUCO AS ADJUSTED**
1	925	Directors and Officers Liability Insurance	$ 667,923	$ (333,962)	$ 333,962
2					
3		RUCO's Calculation:			
4		Company Proposed	$ 667,923		
5		Split between Ratepayers and Shareholder	50%		
6		RUCO Adjustment - Total Company	$ 333,962		

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

SOUTHWEST GAS CORPORATION
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Schedule JMM-17

OPERATING INCOME ADJUSTMENT NO. 4
MANAGEMENT INCENTIVE PROGRAM ("MIP") EXPENSE

			(A)	(B)	(C)
Line No.	**FERC No.**	**DESCRIPTION**	**COMPANY PROPOSED**	**RUCO ADJUSTMENT**	**RUCO AS ADJUSTED**
1	920	MIP Expense	$ 4,873,906	$ (2,436,953)	$ 2,436,953

RUCO's Calculation:		
Company Proposed	$	4,873,906
Split between Ratepayers and Shareholder		50%
RUCO Adjustment - Total Company	$	2,436,953

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-18

OPERATING INCOME ADJUSTMENT NO. 5
SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP")

Line No.	FERC No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	926	Supplemental Executive Retirement Plan	$ 1,627,202	$ (1,627,202)	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

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Schedule JMM-19

OPERATING INCOME ADJUSTMENT NO. 6
EXECUTIVE DEFERRAL PLAN

Line No.	FERC No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	926	Executive Deferral Plan AZ	$ 871,332	$ (871,332)	$ -
2	926	Executive Deferral Plan AZ Corp Dir	196,241	(196,241)	-
3	926	Executive Deferral Plan Sys Alloc	442,981	(442,981)	-
			$ 1,510,554	$ (1,510,554)	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

SOUTHWEST GAS CORPORATION
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Schedule JMM-20

OPERATING INCOME ADJUSTMENT NO. 7
RESTRICTED STOCK/UNIT PLAN ("RSUP")

Line No.	FERC No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	920	Restricted Stock/Unit Plant ("RSUP")	$ 1,255,992	$ (1,255,992)	$ -
2	930.2	Restricted Stock/Unit Plant ("RSUP")	971,984	(971,984)	-
3			$ 2,227,976	$ (2,227,976)	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

SOUTHWEST GAS CORPORATION
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Schedule JMM-21

OPERATING INCOME ADJUSTMENT NO. 8
SEVERANCE PAY

Line No.	FERC Nos.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	920, 908	Severance Pay	$ 133,207	$ (133,207)	$ -

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

SOUTHWEST GAS CORPORATION
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Schedule JMM-22

OPERATING INCOME ADJUSTMENT NO. 9
AMERICAN GAS ASSOCIATION ("AGA") AND WESTERN ENERGY INSTITUTE ("WEI") DUES

		(A)	(B)	(C)	(D)	(E)
Line No.	DESCRIPTION	TEST YEAR AMOUNT	COMPANY ADJUSTMENT	COMPANY PROPOSED	RUCO ADJUSTMENT	RUCO AS ADJUSTED
1	AGA Membership Dues	$ 300,348	$ (13,516)	$ 286,832	$ (136,658)	$ 150,174
2	WEI Membership Dues	17,051	-	17,051	(8,526)	8,526
6	Total Dues Expense	$ 317,399	$ (13,516)	$ 303,883	$ (145,184)	$ 158,700

Note: Test Year Amount After Allocation of 56.07 Percent

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)
Column (D) = Column (A)/2 + Column (B)
Column (E) = Column (A) + Column (B) + Column (D)

SOUTHWEST GAS CORPORATION
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OPERATING INCOME ADJUSTMENT NO. 10
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense	$ 576,000	$ (176,000)	$ 400,000
2	Normalization Years	4	4	4
3	Rate Case Expense	$ 144,000	$ (44,000)	$ 100,000

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

SOUTHWEST GAS CORPORATION
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Schedule JMM-24

OPERATING INCOME ADJUSTMENT NO. 11
POST-TEST YEAR DEPRECIATION EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Post-Test Year Depreciation Expense Direct Plant	$ 733,757	$ (102,888)	$ 630,868
2	Post-Test Year Depreciation Expense Sys 303	2,040,786	(419,686)	1,621,100
3	Post-Test Year Direct Plant Retirements Depreciation Expense	97,362	(97,362)	-
4	Post-Test Year System Allocable Retirements Depreciation Expense	7,658	(7,658)	-
5	Corporate Aircraft	184,385	(184,385)	-
6	Corporate Aircraft Hanger & Equipment	12,177	(12,177)	-
7	Total Post-Test Year Depreciation Expense	$ 3,076,125	$ (824,156)	$ 2,251,968

Note: Already adjusted Post Test Year Plant for ACC Jurisdictional Ratio

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

SOUTHWEST GAS CORPORATION
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Schedule JMM-25

Operating Adjustment No. 12
Interest Synchronization

Line No.	Description	Tax Rate	(A) Company Proposed	(B) RUCO Recommended
1	Adjusted Rate Base		$ 1,336,049,260	$ 1,319,548,633
2	Weighted Cost of Debt		2.52%	2.55%
3	Synchronized Interest Deduction		$ 33,627,705	$ 33,651,073
4	Increase (Decrease) in Deductible Interest			$ 23,368
5	State Income Taxes	4.90%		$ (1,145)
6	Federal Taxable Income			$ 22,223
7	Federal Income Taxes	35.00%		$ (7,778)
8	Increase (Decrease) to Income Tax Expense			$ (8,923)

References:
Column (A) Per Company Filing
Column (B) Testimony JMM

SOUTHWEST GAS CORPORATION
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Schedule JMM-26

OPERATING INCOME ADJUSTMENT NO. 13
INCOME TAX EXPENSE

Line No.	RUCO Income Tax Calculation on RUCO Adjustments (Thousands of Dollars)		
1	Operating Revenue	$	-
2	Gas Cost		-
3	Operating Margin		-
4			
5	Operating Expenses		
6	Other Gas Costs	$	-
7	Storage		-
8	Distribution		(138,294)
9	Customer Accounts		-
10	Customer Service & Info.		-
11	Sales		-
12	Administrative & General		
13	Direct		(1,067,573)
14	System Allocable		(7,634,013)
15	Depreciation & Amortization		
16	Direct		(200,250)
17	System Allocable		(623,906)
18	Regulatory Amortizations		-
19	Taxes Other Than Income		-
20	Interest on Customer Deposits		-
21	Pre -Tax Operating Expenses	$	(9,664,036)
22	Pre -Tax Operating Income	$	9,664,036
23	Income Taxes	$	3,690,212
24			
25	Combined Effective Tax Rate		38.1850%

Note: Includes State tax rate of 4.9 percent

References:
Testimony JMM

SOUTHWEST GAS CORPORATION
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Schedule JMM-27

COST OF CAPITAL - ORIGINAL COST RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Long-term Debt	$ 1,343,228,715	$ 38,612,400	1,381,841,115	49.02%	5.20%	2.55%
2							
3	Common Equity	1,437,158,401	-	1,437,158,401	50.98%	9.39%	4.79%
4							
5	TOTAL CAPITAL	$ 2,780,387,116	$ 38,612,400	$ 2,818,999,516	100.00%		
6							
7	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						7.34%
8							
9							

COST OF CAPITAL - FAIR VAUE RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
10							
11							
12-15	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
16							
17	Long-term Debt	1,343,228,715	$ 38,612,400	$ 1,381,841,115	49.02%	5.20%	2.55%
18							
19	Common Equity	1,437,158,401	-	1,437,158,401	50.98%	9.39%	4.79%
20							
21	TOTAL CAPITAL	$ 2,780,387,116	$ 38,612,400	$ 2,818,999,516	100.00%		
22							
23	WEIGHTED COST OF CAPITAL (Sum Lines 1 Thru 5)						7.34%
24							
25							
26					Fair Value Increment		-1.67%

References:
- Column (A): Company Schedule D-1
- Column (B): Testimony, JAC
- Column (C): Column (A) + Column (B)
- Column (D): Column (C), Line Item / Total Capital
- Column (E): Testimony, JAC
- Column (F): Column (D) X Column (E)

EXHIBIT
RUCO-4
ADMITTED

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-16-0107

DIRECT TESTIMONY

OF

JOHN CASSIDY

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 30, 2016

TABLE OF CONTENTS

EXHIBITS

JAC-A	FEDERAL RESERVE BANK OF CLEVELAND – EXPECTED INFLATION RATE (10-YEAR)
JAC-B	BLUE CHIP ECONOMIC INDICATORS – FORECASTS OF 10-YEAR TREASURY RATES

EXECUTIVE SUMMARY

RUCO recommends that the Commission adopt a 7.34 percent overall rate of return for Southwest Gas Corporation ("SWG," or "Company"), based upon (i) RUCO's proposed capital structure consisting of 49.02 percent long-term debt and 50.98 percent common equity, (ii) an embedded 5.20 percent cost of long-term debt, and (iii) RUCO's recommended 9.39 percent cost of common equity, as shown below:

	Weight	Cost	Weighted Cost
Long-Term Debt	49.02 %	5.20 %	2.55 %
Common Equity	50.98 %	9.39 %	4.79 %
Overall Rate of Return			7.34 %

RUCO's 9.39 percent cost of equity is derived from estimates obtained from three cost of equity estimation models, with the results obtained from the Discounted Cash Flow and Comparable Earnings Models assigned a weighting of 40 percent, and the results obtained from the Capital Asset Pricing Model assigned a weighting of 20 percent, as follows:

	Cost Estimate	Weight Factor	Weighted Average Cost Estimate
Discounted Cash Flow	9.27 %	40 %	3.71 %
Capital Asset Pricing Model	7.48 %	20 %	1.50 %
Comparable Earnings	10.46 %	40 %	4.18 %
Average Cost of Equity	9.07 %		
Weighted Average Cost of Equity			**9.39 %**

RUCO recommends that the Commission adopt a Fair Value Rate of Return ("FVROR") of 5.67 percent for Southwest Gas. RUCO's recommended FVROR assigns a 1.04 percent cost rate to the fair value increment of the Company's FVRB.

I will also demonstrate that the 10.25 percent cost of equity recommendation put forth by Southwest Gas witness, Mr. Robert B. Hevert, significantly over-states the Company's actual cost of equity.

I. INTRODUCTION

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

A. My name is John A. Cassidy. I am a Public Utilities Analyst V with the Residential Utility Consumers Office ("RUCO"). My business address is 1110 W. Washington Street, Suite 220, Phoenix, AZ.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Arts degree in History from Arizona State University, a Master of Library Science degree from the University of Arizona, and a Master of Business Administration degree with an emphasis in Finance from Arizona State University. I have been awarded the professional designation Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA") based upon experience and the successful completion of a written examination. I have eight years of professional regulatory work experience as a Public Utilities Analyst, both with RUCO and the Arizona Corporation Commission ("ACC") Staff, and have testified in numerous rate proceedings as a cost of capital witness before this Commission. Additionally, I have attended utility related seminars sponsored by both SURFA and the National Association of Regulatory Utility Commissioners (NARUC). Attachment 1 contains a summary of my prior regulatory work experience.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations for the establishment of a fair value rate of return. For purposes of establishing a fair value rate of return on its invested capital in this proceeding, the Company has elected to use the average of its original cost rate base (OCRB) and its reconstruction cost new depreciation (RCND) as its fair value rate base (FVRB).

Q. Will RUCO provide direct testimony on the rate base, operating income and rate design issues in this proceeding?

A. Yes. RUCO witness, Mr. Jeffrey Michlik, will also file direct testimony in this proceeding. Mr. Michlik's testimony will address the rate base and operating income issues associated with the case, as well as RUCO's proposed rate design.

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into twelve (12) different sections as identified in my "Table of Contents." In summary, I have derived cost of equity estimates obtained from both the Discounted Cash Flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"). The DCF and CAPM are market-based cost of equity estimation models, and both have consistently been employed by RUCO and ACC Staff in prior rate proceedings. Additionally, the DCF and CAPM are methodologies which the ACC has traditionally given the most weight when establishing authorized rates of return for utilities operating within its Arizona jurisdiction. In addition to the DCF and CAPM models, I have also prepared a Comparable Earnings ("CE") analysis. For purposes of RUCO's recommended cost of equity in this proceeding, I have assigned a 40 percent weight to the cost of equity results obtained from the DCF and CE models, and a 20 percent weight to the cost of equity results obtained from the CAPM. The Company's witness, Mr. Robert V. Hevert obtains cost of equity estimates from two DCF models (constant growth DCF and multi-stage

DCF), the CAPM, and a Bond Yield plus Risk Premium Approach. My testimony will conclude with a discussion of Mr. Hevert's cost of equity estimation methodology, and I will demonstrate that his analyses significantly over-states the Company's actual cost of equity.

Q. Please explain the rationale for RUCO assigning a weighting of 40 percent to the cost of equity estimation results obtained from both its constant growth DCF and CE models and a 20 percent weighting to the cost of equity estimates obtained from the CAPM.

A. As noted in testimony filed by Staff cost of capital witness, Mr. David Parcell, in the recent Arizona Water Company ("AWC") rate docket,[1] cost of equity estimates derived from the CAPM are lower than estimates obtained from the DCF and CE models for two reasons: (i) risk premiums are currently lower than they have been over the past several years, and (ii) yields on U.S. Treasury bonds (i.e., the risk-free rate) have also been lower in recent years. Although Mr. Parcell elected not to incorporate estimates derived from the CAPM into his analysis for purposes of his recommended cost of equity, he nevertheless maintains that results obtained from the CAPM should be considered as a factor in determining the cost of equity. RUCO agrees with this assessment. Therefore, rather than relying upon the arithmetic mean cost of equity estimate derived from its DCF, CE and CAPM models as it has traditionally done, RUCO has elected to assign a 40 percent weight to the results obtained from both its DCF and CE models, and a 20 percent weight to the cost of equity results from the CAPM. RUCO believes this modification to its cost

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[1] *See* Docket No. W-01445A-15-0277, Direct Testimony of David C. Parcell, dated March 11, 2016, pp. 30-31.

of equity methodology to be both reasonable and equitable, as it gives recognition to cost of equity estimates derived from the CAPM while providing for an incremental increase to RUCO's overall recommended cost of equity estimate.

Q. Please summarize the cost of capital recommendations to be addressed in your testimony.

A. Based upon the results of my analysis, I make the following recommendations:

I recommend that the Commission adopt a 7.34 percent overall rate of return for the Company, based upon (i) a capital structure consisting of 49.02 percent long-term debt and common equity of 50.98 percent, (ii) a cost of debt of 5.20 percent, and (iii) a cost of common equity of 9.39 percent. The components included in my cost of capital calculation are as follows:[2]

	Weight	Cost	Weighted Cost
Long-Term Debt	49.02 %	5.20 %	2.55 %
Common Equity	50.98 %	9.39 %	4.79 %
Overall Rate of Return			7.34 %

The cost of equity estimates included in my calculations are derived from the following three cost of equity models, with the results obtained from the DCF and CE models assigned a weight of 40 percent, and the results obtained from the CAPM assigned a weight of 20 percent:[3]

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[2] *See* JAC Schedule 1.
[3] *See* JAC Schedule 2.

	Cost Estimate	Weight Factor	Weighted Average Cost Estimate
Discounted Cash Flow	9.27 %	40 %	3.71 %
Capital Asset Pricing Model	7.48 %	20 %	1.50 %
Comparable Earnings	10.46 %	40 %	4.18 %
Average Cost of Equity	9.07 %		
Weighted Average Cost of Equity			**9.39 %**

III. ECONOMIC PRINCIPLES APPLICABLE TO ARIZONA

Q. What are the basic economic principles which apply in the determination of a fair rate of return for regulated public utilities in Arizona?

A. For regulated public utilities in Arizona, rates are established in a manner designed to allow for recovery of the utility's costs, including capital costs. This is traditionally referred to as "cost of service" ratemaking. Rates are established using the "rate base – rate of return" concept, wherein utilities are allowed to recover specific operating expenses, taxes and depreciation, and granted an opportunity to earn a fair value rate of return on the assets utilized (i.e., fair value rate base) in providing service to ratepayers. Rate base is derived from the asset side of the utility's balance sheet, while rate of return is developed from the liability/stockholders' equity side of the balance sheet. The revenue impact of the cost of capital in rates is determined by multiplying rate base by rate of return. In the instant docket, RUCO is recommending an overall rate of return for SWG of 7.34 percent.

Q. Is SWG proposing that its original cost rate base also be used as its fair value rate base?

A. No. The Company proposes that the average of its OCRB and RCND rate bases be used as its fair value rate base (FVRB).

Q. What is the meaning of a "fair rate of return" when analyzing a rate case application?

A. From an economic standpoint, a "fair rate of return" is one which allows an efficient and economically well managed utility the ability to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts. From a technical perspective, a "fair rate of return" is an <u>ex post</u> (i.e., after the fact) earned return on an asset base. Conversely, the cost of capital is an <u>ex ante</u> (i.e., before the fact) expected, or required, return on a capital base. In regulatory proceedings, the two terms are often used interchangeably.

Q. As regulated entities granted natural monopoly status, are public utilities guaranteed to earn their authorized rate of return?

A. No. Public utilities are afforded an opportunity to earn their authorized rate of return; there is no guarantee that they will actually earn the rate of return authorized in a rate case. Many factors are involved in determining a rate of return. However, investments in new plant assets made subsequent to a rate case and/or increases to operating expenses between rate cases can have a negative impact on a utility's realized rate of return. Conversely, an increase in revenues and/or a decrease in operating expenses can have a positive impact on the earned rate of return. In the former scenario, a public utility will generally file for a rate increase. In the latter scenario, should a public utility earn a rate of return in excess of that approved by a utility commission, then the commission may instruct the utility to file a rate application in order that new rates be established to provide rate relief to ratepayers.

IV. GENERAL ECONOMIC CONDITIONS

Q. Why are economic and financial conditions important in the determination of the cost of capital for a regulated public utility such as SWG?

A. Economic and financial conditions are important because the cost of capital, both fixed-cost debt as well as common equity, is largely determined by current and future economic and financial conditions. At any given time, the cost of capital is influenced by each of the following: (i) the level of economic activity (i.e., economic growth); (ii) the stage of the business cycle; (iii) the rate of inflation; and (iv) expectations of future economic conditions. That current and future economic and financial conditions largely determine the cost of equity is consistent with the Court's ruling in the *Bluefield* decision, which held that

> "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." Bluefield, 262 U.S. at 679.[4]

Measures of general economic indicators influencing the cost of capital are presented in Schedule JAC-6 (Pages 1-7).

Q. Briefly describe the recent trends in economic conditions and their impact on capital costs over the past thirty years?

A. From the early 1980's through the end of 2007, the United States economy experienced an extended period of relative stability; one characterized by longer economic expansions, periodic short contractions, low and declining inflation, and declining interest rates and

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[4] *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia* (262 U.S. 679), as cited in Parcell, David C., *The Cost of Capital: A Practitioner's Guide*, prepared for the Society of Utility and Regulatory Financial Analysts (SURFA): 2010 Edition (p.26).

other capital costs. In 2008 and 2009, however, the economy experienced a significant decline as a result of the sub-prime mortgage lending crisis, with the negative impact affecting financial and capital markets both in the U.S. and internationally. This economic decline has been described as the worst financial crisis since the Great Depression, and is often referred to as, the "Great Recession." As a consequence, central banks in the U.S. (i.e., Federal Reserve Bank, or "the Fed") and other foreign countries initiated accommodative monetary policies designed to stimulate economic growth and reduce unemployment in an effort to recover from this worldwide recession.

Q. Please describe how the economic and financial indicators were examined and how they relate generally to the cost of capital.

A. Schedule JAC-6 (Pages 1 and 2) identifies relevant economic data such as Real Gross Domestic Product ("GDP") Growth, Industrial Production Growth, Unemployment, Consumer Price Index ("CPI"), and Producer Price Index. As can be seen, 2007 marked the sixth year of economic expansion, but beginning in 2008 the economy entered into a significant decline, as indicated by negative real GDP and industrial production growth as well as an increase in the unemployment rate. The recession bottomed out in June 2009, and while the economy has expanded since that time it has done so at the slowest pace of any recovery since World War II.[5] Fortunately, the national unemployment rate has been cut in half from a high of 10.0 percent in the fourth quarter of 2009 to 4.9 percent in the third quarter of 2016. However, the Producer Price Index has remained negative in

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[5] Long, Heather, and Luhby, Tami, "Yes, This is the Slowest U.S. Recovery since WWII," CNNMoney.com (October 5, 2016). http://money.cnn.com/2016/10/05/news/economy/us-recovery-slowest-since-wwii/

each of the last two years, while in 2015 industrial production growth fell to its lowest level since 2003, and has remained negative through the first three quarters of 2016. It should be noted that at the State level, Arizona's unemployment rate -- 5.9 percent in the third quarter of 2016 -- continues to lag that of the nation.[6]

Since 2008, inflation as measured by the CPI has been 3.0 percent or lower, and in each of the last two years has remained below 1.0 percent; the annual inflation rate being 0.8 percent in 2014 and 0.7 percent in 2015. The annual rate of inflation has generally been declining over the past several business cycles and continues to do so as evidenced by the low annual inflation rates of the last four years, 2012-2015. Through the first three quarters of 2016, inflation continues to be low with the average rate being 1.1 percent.

Q. Is inflation expected to remain at relatively low levels over the next decade?

A. Yes. As shown in Exhibit JAC-A, the Federal Reserve Bank of Cleveland estimates expected inflation to average 1.69 percent over the next 10-years,[7] a figure well below the Fed's 2.0 percent targeted rate of inflation.

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[6] United States Department of Labor, Bureau of Labor Statistics, Arizona Unemployment Rate http://www.bls.gov/eag/eag.az.htm

[7] Federal Reserve Board of Cleveland, "Inflation Expectations," (News Release dated October 18, 2016). https://www.clevelandfed.org/our-research/indicators-and-data/inflation-expectations.aspx
The inflation expectations model employed by the Cleveland Fed uses Treasury yields, inflation data, inflation swaps, and survey-based measures of inflation expectations to calculate the expected inflation rate (CPI) over the next 30 years. The Cleveland Fed updates its 10-year expected inflation estimate on a monthly basis.

Q. How does this 10-year (i.e., 2016-2025) projected 1.69 percent annual rate of inflation compare to 10-year historical average annual rates of inflation over the 40-year period (i.e., 1976-2015)?

A. Based on the annual rates of inflation as presented in Schedule JAC-6 (Page 1), the average 10-year inflation rate[8] measured over four different 10-year periods going back to 1976 are as follows:

Historical CPI inflation (1976-1985)	7.05 %
Historical CPI inflation (1986-1995)	3.45 %
Historical CPI inflation (1996-2005)	2.53 %
Historical CPI inflation (2006-2015)	1.86 %
Projected CPI inflation (2016-2025)	1.69 %

As can be seen, historical average annual inflation has fallen in each of the last four decades, and this trend is expected to continue as evidenced by projected average annual inflation during the 10-year period, 2016-2025, being 17 basis points lower than that of the prior 10-year period, 2006-2015 (1.86% - 1.69% = 0.17%).

Q. Holding all other factors constant, is a projected average annual inflation rate of 1.69 percent over the next 10-year period suggestive that the current low interest rate environment will continue into the future?

A. Yes, it is.

[8] The historical annual inflation rates presented are computed as an arithmetic mean (i.e., simple average) over each 10-year period.

Q. Since the election of Donald Trump as President, the bond market has experienced a sharp sell-off, with the yield on the benchmark 10-year Treasury Note rising by 51 basis points (from 1.83 percent to 2.34 percent), while the yield on the 30-year Treasury Bond has risen by 41 basis points (from 2.60 percent to 3.01 percent) over the 8-day trading period, November 7-18, 2016. What caused this sharp rise in yield, and is it an indication that inflation expectations have changed?

A. The sell-off in the bond markets is attributable to the pledge made by President-elect Trump to initiate a fiscal stimulus plan to rebuild the nation's infrastructure,[9] and yes, it is suggestive that inflation expectations have changed, as bond investors are concerned that such infrastructure spending "will fuel growth and spur inflation."[10] It should be noted, however, that President-elect Trump won't take office until January 2017, and the details of his administration's fiscal stimulus infrastructure spending programs have yet to be worked out.

Q. Are the Trump administration's planned infrastructure spending programs expected to increase growth within the U.S. economy?

A. According to Mr. James Bullard, president of the Federal Reserve Bank of St. Louis, "there's a chance the U.S. economy could get a medium-term boost" from President-elect Trump's planned infrastructure spending and tax reforms. However, Mr. Bullard believes that it is "still too soon to say how the economy may be affected by the election and he

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[9] Wallace, Karen, "How Trump has Changed Inflation Expectations," *Morningstar.com* (November 16, 2016). http://news.morningstar.com/articlenet/article.aspx?id=780914

[10] Van der Walt, Eddie, "Sell-off in Bonds, Emerging-Market Assets Deepen as Dollar Gains," *Bloomberg.com* (November 13, 2016). http://www.bloomberg.com/news/articles/2016-11-13/asian-futures-outside-japan-tip-stock-losses-as-quake-hits-kiwi

hasn't changed his near-term outlook for growth or monetary policy." Bullard anticipates that a "single policy-rate increase" (i.e., a ¼ percent hike in the Fed funds rate) in December 2016 will be sufficient "to move monetary policy to a neutral setting," and is on record as advocating that the Fed then "keep them on hold for an extended period of time."[11]

Q. Given the above noted rise in yield on the 10-year Treasury Note, as of the close of market trading on Friday, November 18, 2016, is there any way of knowing what investors currently expect average inflation to be over the next 10-years?

A. Yes. The 10-year breakeven inflation rate represents a current measure of what investors expect average inflation to be over the next 10-year period, and is calculated as the difference between the current nominal yield on the 10-year Treasury Note (2.34 percent) and the current rate on the 10-Year Treasury Inflation-Indexed Constant Maturity Securities, or TIPS, (0.44 percent). Thus, as of the close of market trading on November 18, 2016, the current 10-year breakeven inflation rate is <u>1.90 percent</u> (2.34% - 0.44% = 1.90%).[12]

Q. What has been the trend in interest rates over the forty-year period, 1975-2015?

A. As shown in Schedule JAC-6 (Pages 3 – 4), interest rates rose sharply to record levels during the period, 1975-1981, when inflation was high and generally rising. Interest rates

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[11] Ward, Jim and Meakin, Lucy, "Fed's Bullard Sees Medium-Term Boost from Trump Spending," *Bloomberg.com* (November 16, 2016). https://www.bloomberg.com/news/articles/2016-11-16/fed-s-bullard-sees-medium-term-boost-from-trump-economic-policy

[12] The 10-year nominal rate and the 10-year TIPS rate are available from the U.S. Department of the Treasury. https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/default.aspx

declined substantially, as did inflation, during the remainder of the 1980s and throughout the 1990s. Interest rates declined even further during the period, 2000-2005, and after trending slightly upward in years 2006-2008, have since continued on a downward path reaching levels in years 2009-2016 not previously seen since the early 1960s. In 2008, the Federal Reserve (the "Fed") initiated an accommodative monetary by lowering the federal funds ("Fed Funds") rate (the rate the Fed charges banks for overnight transfers of funds), and in an effort to promote increased lending and liquidity, eventually initiated a policy of quantitative easing, an unconventional monetary policy used when short-term interest rates are at or approaching zero. As a consequence, in years 2012-2016, both U.S. and corporate bond yields declined to their lowest levels in more than 40 years, with the yield on the benchmark 10-year Treasury Note falling to an all-time low earlier this year.[13]

Q. Is the decline in long-term interest rates which has taken place since the mid-1980s something which the financial markets and professional forecasters saw coming and accurately predicted?

A. No, it is not. As reported in a recent study prepared by the Council of Economic Advisors,[14] "forecasters largely missed the ***secular decline*** of the last three decades" because "past forecasts of long-term nominal interest rates have tended to err on the side of ***mean reversion***."[15] (emphasis added) As evidence of such mean reversion, the

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[13] On July 8, 2016, the 10-year Treasury Note traded at an all-time low of 1.361 percent. http://www.wsj.com/articles/government-bond-yields-in-u-s-europe-hit-historic-lows-1467731411

[14] Executive Office of the President, Council of Economic Advisors, "Long-Term Interest Rates: A Survey," (July 2015). https://www.whitehouse.gov/sites/default/files/docs/interest_rate_report_final.pdf

[15] *Ibid*., p. 12.

authors of the study prepared a graphic presentation (10-Year Treasury Rates and Historical Economist Forecasts) showing that forecasts made by a group of more than 50 private-sector economists of the benchmark 10-year Treasury rate, as reported by Blue Chip Economic Indicators ("Blue Chip"), had systematically been overstated. This graphic presentation is provided as RUCO Exhibit JAC-B. As shown, Blue Chip forecasts have consistently exceeded the actual path (shown in blue) of nominal 10-year Treasury rates since 1995, and supports a conclusion that forecasters mistakenly believed the yield on the 10-year Treasury Note would—during the period(s) under study—revert back to a perceived historical mean. In the study, the authors further note the following:

> "Although economists' forecasts steadily declined after 1995, <u>their pace of decline has lagged well behind the realized drop-off in interest rates</u>. Indeed, since 1996, long-range private sector forecasts have exhibited a root mean square error of 2.7 percentage points relative to the nominal Treasury rate realized 10 years later."[16] (emphasis added)

Q. What conclusions do the authors of the study to which you cite above draw regarding the decline in long-term interest rates?

A. As noted in the Executive Summary of the report, the authors state the following:

> This report surveys the recent thinking on the many drivers of long-term interest rates in recent decades and going forward. **<u>It concludes</u>**:
>
> - **The decline in long-term interest rates over the past thirty years was real, global, and unexpected.** While lower inflation explains some of the decline in nominal interest rates, the downtrend is evident even when adjusting nominal interest rates for the rate of inflation. The decline has also been evident across a wide range of countries, reflecting the increasing integration of the global economy. <u>Financial markets and professional forecasters alike consistently failed</u>

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[16] *<u>Ibid</u>*., p. 10. In a footnote, the authors describe the "root mean square error" as follows: "The root mean square error is a commonly used measure of the deviation between predicted and actual values. The difference between the two values is squared and then summed over time. The square root of that number is typically reported as a summary statistic, with large values indicating large prediction errors."

to predict the secular shift, focusing too much on cyclical factors and missing the long-term trend.

- **The decline is consistent with several theoretical frameworks economists have used to analyze interest rates.** The interest rate settles at the level that equates the supply of saving with the demand for investment, and innumerable factors affect both sides of the equation. Many frameworks suggest that long-term interest rates are closely related to productivity growth. Other factors such as the rate of population growth and technological advance, as well as aggregate demand and the stance of fiscal and monetary policy, also play a role.

- **A number of factors, both transitory and longer-lived, have contributed to the decline—with many of these factors suggesting that long-run equilibrium interest rates have fallen.** Transitory factors include global fiscal and monetary policies, shifts in the term premium and inflation risk, and post-crisis private-sector deleveraging. More persistent factors include lower potential output and productivity growth, shifting demographics, and the global "saving glut."

Ultimately, interest rates reflect underlying macroeconomic conditions; there is no "optimal" long-term rate of interest. Rather, policy should support long-run growth, maintain price stability, and support a stable financial system.[17] (emphasis added)

Q. Has the secular decline in long-term interest rates which has taken place over the last 30 years proven beneficial to equity investors in the United States?

A. Yes, it has. In a recent report published by McKinsey & Company,[18] the 30-year period, 1985-2014, was characterized as the "golden era for investment returns," as real (i.e., inflation adjusted) total returns on equities averaged 7.9 percent in the United States over this period, a figure 140 basis points higher than the 6.5 percent 100 year average, and 220 basis points higher than the 5.7 percent 50 year average (emphasis added).[19] As noted in the report, the underpinnings of these above average equity returns were made possible by the confluence of the following four exceptional factors:

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[17] *Ibid*., Executive Summary, p. 4.
[18] McKinsey Global Institute, "Diminishing Returns: Why Investors May Need to Lower their Expectations," May 2016. www.mckinsey.com/industries/.../why-investors-may-need-to-lower-their-sights
[19] *Ibid*., p. 2. As noted in the report, over this same 30-year period Western European investors also achieved real total returns on equity of 7.9 percent, a figure 300 basis points higher than the 4.9 percent 100 year average.

(i) A sharp decline in inflation from the unusually high levels of the late 1970s and early 1980s;
(ii) The resultant decline in nominal long-term interest rates,
(iii) Strong global GDP growth, lifted by positive demographics, productivity gains, and rapid growth in China; and
(iv) Even stronger corporate profit growth, reflecting revenue growth from new markets, declining corporate taxes, and advances in automation and global supply chains that contained costs.[20]

Q. Over this same 1985-2014 time period, did bond investors also achieve higher real returns on fixed-income investments?

A. Yes. As measured by returns on 10-year U.S. Treasury Bonds, fixed income investors achieved total real returns of 5.0 percent over the 30-year period, 1985-2014, a figure 330 basis points higher than the 1.7 percent 100 year average, and 250 basis points higher than the 2.5 percent 50 year average.[21]

Q. Going forward, does the McKinsey report anticipate this 'golden era' for investment returns to continue?

A. No, it does not. In fact, the purpose of the report is to place investors on notice that on a going-forward basis they should begin to lower their expectations regarding investment returns on both equity and debt securities, as "[t]his era is coming to an end."[22] Based upon its analysis, the McKinsey report lays out two scenarios as to what investors might expect over the 20-year period, 2016-2035; Scenario 1 being a <u>*slow growth*</u> scenario, and Scenario 2 being a <u>*growth recovery*</u> scenario. In the report, McKinsey points out that in

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[20] <u>*Ibid*</u>., pp. 10-16.
[21] <u>*Ibid*</u>., pp. 2-3. As further noted in the report (p. 11), of this 5.0 percent real total return for U.S. bond investors capital gains accounted for fully 1.9 percent (190 basis points) due to nominal interest rates falling from 9 percent to 2 percent.
[22] <u>*Ibid*</u>., p. 3.

both its *slow growth* and *growth recovery* scenarios, "U.S. and Western European equity and bond returns fail to match those of the past 30 years and could be lower than the 50- and 100-year averages (emphasis added)."[23] Furthermore, under Scenario 1 "slow growth could reduce total U.S. equity returns by more than 250 basis points and bond returns[24] by 400 basis points or more below the 1985-2014 period (emphasis added);"[25] under Scenario 2, "in a growth-recovery scenario, U.S. equity and bond returns would be 140-240 and 300-400 basis points, respectively, below the average of the 1985-2014 period (emphasis added)."[26] As presented in the McKinsey report, the following is a summary of both historical real total investment returns on equities and 10-year U.S. Treasury Bonds over the 100-year period, 1915-2014, the 50-year period, 1965-2014, and the 30-year period, 1985-2014, as contrasted with the expected investment returns over the 20-year period, 2016-2035, under each of the above noted scenarios:[27]

Historical and Projected Investment Returns on U.S. Equities and 10-Year Treasury Bonds

	Historical Returns			Prospective Returns (2016-2035)	
Investment	1915-2014	1965-2014	1985-2014	Slow Growth	Growth Recovery
U.S. Equities	6.5%	5.7%	7.9%	4.0-5.0%	5.5-6.5%
10-Year Treasuries	1.7%	2.5%	5.0%	0-1.0%	1.0-2.0%

[23] *Ibid*., p. 21.
[24] For purposes of its analysis, investment returns on bonds are measured by the return on 10-year U.S. Treasury Bonds.
[25] *Ibid*.
[26] *Ibid*., p. 22.
[27] *Ibid*., p. 2, Exhibit 1.

Q. Briefly discuss the reasons cited in the McKinsey report for the expected decline in investment returns on equity and debt securities over the 20-year period, 2016-2035.

A. As noted earlier, the McKinsey report attributed the on-set of the so-called 'golden era' of investment returns to the confluence of four exceptional factors. The authors now view the fundamental economic and business conditions which contributed to above-average returns over the past 30 years to "have run out of steam, and in some cases are in the process of reversing."[28] Specifically, the report cites to the following three contributing factors as reasons for the expected decline in investment returns going forward:

- the steep decline in interest rates over the past 30 years is unlikely to be repeated
- expected slower GDP growth, due to (i) an aging population and (ii) declining productivity growth, and
- lower profit margins for businesses facing greater competition from (i) emerging markets, (ii) technology and tech-enabled firms, and (iii) small and medium-sized enterprises.[29]

Q. The findings of the McKinsey report relate to non-regulated firms subject to market competition rather than regulated public utilities granted natural monopoly status. On a going-forward basis, does an expected decline in equity investment returns for non-regulated firms suggest that equity investment returns for regulated public utilities might also be expected to decline?

A. Yes.

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[28] *Ibid*., p. 17.
[29] *Ibid*., pp. 17-19.

Q. On December 16, 2015, the Fed raised the Federal funds rate from a level of 0 to ¼ percent to ¼ - ½ percent. In doing so, did the action taken by the Fed signal a change in monetary policy by the U.S. central bank?

A. No, it did not. While the increase to the Fed Funds rate marked the first time the Fed had increased the rate it charged banks for overnight transfers of funds since mid-2006,[30] in a press release issued on December 16, 2015, the Fed made the following statement: "The stance of monetary policy remains accommodative after this increase, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation."[31]

Q. After raising the Fed Funds rate in December 2015, was the Fed expected to continue to take steps to raise the Fed funds rate in 2016?

A. Yes. In keeping with its plan to "normalize" interest rates, it was generally believed that the Fed would raise the Fed funds rate four more times by ¼ percent (25 basis points) in 2016, an annual increase of 1.0 percent (100 basis points).[32]

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[30] The Fed last raised the Fed Funds rate on June 29, 2006. http://www.federalreserve.gov/monetarypolicy/openmarket.htm

[31] Federal Reserve Board, Federal Open Market Committee, *Press Release* (December 16, 2015). http://www.federalreserve.gov/newsevents/press/monetary/20151216a.htm

[32] Blue Chip Financial Forecasts (December 1, 2015), p.1.

Q. To date, the Fed has yet to hike the Fed funds rate in 2016. Do we know the reason(s) why the Fed held off from following through on those planned rate increases?

A. I believe the reasons can be found in statements made by the Chairwoman of the Federal Reserve, Ms. Janet Yellen. When testifying before the Joint Congressional Economic Committee ("Committee") in early December 2015 (i.e., prior to the hike in the Fed Funds rate), Ms. Yellen downplayed the possibility of a recession in the U.S. economy but specifically acknowledged the risk of a global economic recession, stating that a hike in the Fed Funds rate would give the Fed "the flexibility to lower it if those risks cause the economy to falter in the future."[33] However, when testifying before the Committee on February 11, 2016, Ms. Yellen "conceded that there's a 'chance' of a downturn ahead," and even indicated that the Fed was "studying whether negative interest rates would help should conditions worsen."[34] In further testimony before the Committee, Ms. Yellen acknowledged that Fed officials had been "caught off guard" by (i) the degree to which "[m]arkets have been tumbling as oil prices plunge, with traders now pricing in the chance that the Fed's next move could be a rate cut rather than hike;" and (ii) the persistent strength of the greenback, as the dollar movement is "not something we anticipated."[35] (emphasis added)

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[33] Puzzanghera, Jim, "Downplaying Risk of Recession, Yellen Indicates an Interest Rate Hike is Coming this Month," *Los Angeles Times* (December 3, 2015). http://www.latimes.com/business/la-fi-yellen-congress-20151203-story.html

[34] Cox, Jeff, "Yellen on Negative Rates: 'We Wouldn't Take those off the Table,'" (February 11, 2016). http://www.cnbc.com/2016/02/11/fed-chair-yellen-theres-always-some-chance-of-recession.html

[35] *Ibid.*

Q. Since testifying before Congress in February 2016, has Fed Chair Yellen made additional public comments relating to the outlook for the U.S. economy and monetary policy?

A. Yes. In a speech delivered to the Economic Club of New York,[36] Ms. Yellen laid out the view that the Federal Open Market Committee ("FOMC") continues to expect

1) Moderate economic growth over the medium term; and
2) Further labor market improvement and a return of inflation to the Fed's 2.0 percent objective over the next two or three years.

However, Ms. Yellen frequently qualified her remarks by acknowledging that "<u>global developments pose ongoing risks</u>," pointing out that "<u>manufacturing and net exports continue to be hard hit</u> by slow global growth and the <u>significant appreciation of the dollar</u> since 2014." Furthermore, while it is her judgment that "inflation expectations are well anchored," Chairperson Yellen acknowledged that "the decline in some indicators has heightened the risk that this <u>judgment could be wrong</u>," and if so, <u>a return to the Fed's desired 2 percent rate of inflation could take longer than expected</u> and "require a more accommodative stance of monetary policy." As a consequence, Ms. Yellen stated that only "**<u>gradual increases in the federal funds rate are likely to be warranted in coming years</u>**." (emphasis added)

Q. From a monetary policy perspective, please explain why strength in the U.S. dollar is a concern to the Fed.

A. A strong dollar *vis-à-vis* other currencies places U.S. exports at a competitive disadvantage in foreign markets as they become more expensive. For U.S. exporters,

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[36] Yellen, Janet, "The Outlook, Uncertainty, and Monetary Policy," a speech delivered to the Economic Club of New York, March 29, 2016. https://www.federalreserve.gov/newsevents/speech/yellen20160329a.htm

this has the effect of reducing revenues and lowering profits. However, from a monetary policy perspective "increases in the federal funds rate also result in a strengthening of the U.S. dollar."[37] (emphasis added) Consequently, should the Fed hike short-term interest rates at a time when the dollar is already strong it places U.S. exporters at a further competitive disadvantage and increases the prospect that the U.S. economy might slip into recession.

Q. Relative to other currencies, is the strength of the U.S. dollar currently high by historical standards?

A. Yes, it is. The ICE U.S. Dollar Index[38] measures the strength of the U.S. Dollar relative to a basket of six other foreign currencies,[39] and in market trading on Friday, November 18, 2016, the index "reached its highest level in more than 13 years."[40]

Q. Was the strength of the U.S. dollar seen as a concern prior to the time the Fed first raised the fed funds rate in mid-December 2015?

A. Yes. As noted by Blue Chip, "the Fed will begin normalizing rates at a time when most other central banks remain extremely accommodative, thus risking further increases in the foreign exchange value of an already strong U.S. dollar."[41] (emphasis added)

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[37] Tarver, Evan, "How the Fed Fund Rate Hikes Affect the U.S. Dollar," Investopedia.com (October 12, 2015). http://www.investopedia.com/articles/investing/101215/how-fed-fund-rate-hikes-affect-us-dollar.asp

[38] The ICE U.S. Dollar Index (USDX) futures contract is a leading benchmark for the international value of the US dollar and the world's most widely-recognized traded currency index. ICE is short for Intercontinental Exchange. https://www.theice.com/products/194/US-Dollar-Index-Futures

[39] The six foreign currencies are: the Euro, Japanese yen, British pound, Canadian dollar, Swedish krona and Swiss franc.

[40] Dulaney, Chelsey, and Eisen, Ben, "Dollar's Rapid Gain Triggers Angst in Emerging Markets," *WSJ.com*, November 18, 2016. http://www.wsj.com/articles/strong-dollar-could-be-rallys-weak-link-1479474002

[41] Blue Chip Financial Forecasts (December 1, 2015), p.1.

Q. As noted earlier, the report issued by the Council of Economic Advisors found that long-term interest rates are closely related to productivity growth. What is productivity growth, and why is it important?

A. Productivity growth – more output for the same volume of inputs – is economic growth which cannot be explained by changes in the other key factor inputs, capital and labor. Rising output per hour is seen as the most common definition of improving productivity, and a benchmark for how efficiently the economy is performing. Gains in productivity typically stem from innovation, new ideas and technological progress.[42] As to its importance, Warren Buffet has described productivity growth as, "the 'secret sauce' of America's remarkable gains in living standards since the nation's founding in 1776," and the link to our nation's "prosperity,"[43] while economist Paul Krugman is noted for having observed that, "[p]roductivity isn't everything, but in the long run it is almost everything."[44]

Q. As a measure of overall economic health, is productivity growth in the U.S. rising, or falling?

A. Productivity is a key ingredient in determining future growth in wages, prices and overall economic output, and at present the U.S. economy is experiencing the "longest slide in worker productivity since the late 1970s," and Fed Chair Yellen recently described "the

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[42] Lambert, John, "Prodictivity is Everything," *GAM.com* https://www.gam.com/en/insights-content/2016/macroeconomics/productivity-is-everything/

[43] Buffet, Warren, "Letter to the Shareholders of Berkshire Hathaway, Inc.," Berkshire Hathaway 2015 Annual Report, p. 21. http://www.berkshirehathaway.com/letters/2015ltr.pdf

[44] Krugman, Paul, The Age of Diminishing Expectations, 1994, as quoted in Lambert, John, "Prodictivity is Everything," GAM.com https://www.gam.com/en/insights-content/2016/macroeconomics/productivity-is-everything/

outlook for productivity growth as a 'key uncertainty for the U.S. economy.'"[45] Over time, it is believed that "persistently weak productivity would weigh on American living standards," and be "a force that could prompt Federal Reserve officials to keep interest rates low for years to come."[46]

Q. Many have used the expression, "new normal," when describing the current state of the economy. Given the current downward trend in productivity growth, what is the estimated 'new normal' for real (i.e., inflation adjusted) GDP growth going forward?

A. In a newly issued *Economic Letter* published by the Federal Reserve Bank of San Francisco, the new normal pace of real GDP growth is estimated to fall in the range of 1½ to 1¾ percent.[47] As noted in the *Letter*, this estimate is based on "trends in demographics, education, and productivity," and assumes that

(i) the aging and retirement of the baby boom generation is expected to hold down employment growth relative to population growth,
(ii) educational attainment has plateaued, reducing the contribution of labor quality to productivity growth, and
(iii) the slower forecast for overall GDP growth reflects the pace of productivity growth as measured over the period, 1973-2015.

As presented in the *Economic Letter*,[48] productivity growth grew at an average rate of approximately 2.75 percent during the period, 1948-1973, fell to a level of approximately

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[45] Leubsdorf, Ben, "Productivity Slump Threatens Economy's Long-Term Growth," *WSJ.com*, August 9, 2016. http://www.wsj.com/articles/u-s-productivity-dropped-at-0-5-pace-in-the-second-quarter-1470746092
[46] *Ibid*.
[47] Fernald, John, "What is the New Normal for U.S. Growth?," *Economic Letter 2016-30*, Federal Reserve Bank of San Francisco (October 11, 2016), p.1. http://www.frbsf.org/economic-research/publications/economic-letter/2016/october/new-normal-for-gdp-growth/
[48] *Ibid*., Figure 2: *Variation in productivity growth by trend period* (p. 2).

1.25 percent during the period, 1973-1995, rose to a level of approximately 2.50 percent during the period, 1995-2004, and has since fallen to an average level of approximately 1.00 percent during the period, 2004-2015. However, over the most recent 5-year period, 2010-2015, average productivity growth has fallen to a level of approximately 0.3 percent.

Q. Among the factors taken into consideration by the author when estimating the new normal for real GDP growth, which factor causes the greatest uncertainty?

A. As noted by the author, the major source of uncertainty about the future is productivity growth. While the author acknowledges that changes in trend productivity growth have historically been "unpredictable and large," and that a new wave of "IT revolution from machine learning and robots" might boost productivity growth, until such a development occurs "the most likely outcome is a continuation of slow productivity growth."[49]

Q. What conclusions does the author draw concerning real GDP growth going forward?

A. The author states that once the U.S. economy fully recovers from the Great Recession, real GDP growth "is likely to be well below historical norms, plausibly in the range of 1½ to 1¾ percent per annum." The author further notes that this slower pace of growth will lead to (i) <u>slower growth in average wages and living standards for workers</u>, (ii) relatively <u>modest growth in sales for businesses</u>, and from a monetary policy perspective (iii) a <u>low 'speed limit' for the economy</u>. Citing to another recent *Economic Letter* published by the

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[49] <u>*Ibid*</u>., p. 4.

Federal Reserve Bank of San Francisco,[50] the author concludes by saying that this slower pace of growth also suggests "a lower equilibrium or neutral rate of interest."[51] (emphasis added)

Q. As discussed in the *Economic Letter* cited to above, what is the equilibrium, or neutral rate of interest?

A. In the article, the equilibrium, or neutral rate of interest is referred to as the "natural real rate of interest," "r*," or "r-star," and defined by the author as the "short-term real (inflation-adjusted) rate that balances monetary policy so that it is neither accommodative nor contractionary in terms of growth and inflation."[52] (emphasis added)

Q. Is the natural real rate of interest (r-star), synonymous with (i.e., same thing as) the Fed funds rate?

A. No, it is not. The Fed funds rate is the rate the Fed charges banks for overnight transfers of funds, while the natural real rate of interest is a conceptual interest rate which cannot be observed but must instead be estimated. In fact, when making public statements regarding monetary policy and the Fed funds rate, Fed Chairwoman Janet Yellen often cites to what she refers to as the "neutral rate" (i.e., r-star), contrasting its level to that of the Fed funds rate.[53]

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[50] Williams, John C., "Monetary Policy in a Low R-star World," *Economic Letter 2016-23*, Federal Reserve Bank of San Francisco (August 15, 2016). http://www.frbsf.org/economic-research/publications/economic-letter/2016/august/monetary-policy-and-low-r-star-natural-rate-of-interest/

[51] *Ibid*.

[52] *Ibid*., pp. 1-2.

[53] Coy, Peter, "The Search for the Elusive Natural Interest Rate," *Bloomberg.com*, (July 22, 2016). http://www.bloomberg.com/news/articles/2016-07-22/the-search-for-the-elusive-natural-interest-rate

Q. Has the natural real rate of interest (r-star), experienced a significant decline over the last 25 years?

A. Yes, as a variety of economic factors have "pushed natural interest rates very low."[54] As noted by the author, in 1990 the inflation-adjusted natural rate of interest (r-star) was estimated to be between 2½ to 3½ percent in the United States, Canada, the euro area, and the United Kingdom. On the eve of the global financial crisis, by 2007 these rates had declined to between 2 and 2½ percent. By 2015, they had declined even further, with the inflation-adjusted natural rate being "nearly zero for the United States, and below zero for the euro area."[55]

Q. What is the key takeaway from the trend in lower global natural real rates of interest (r-star) which has taken place over the past quarter century?

A. As noted by the author, the key takeaway from this global trend is that

> "interest rates are going to <u>stay lower</u> than we've come to expect in the past. This does not mean they will be zero, but when juxtaposed with pre-recession normal short-term interest rates of, say, 4 to 4½%, it may be jarring to see the underlying r-star guiding us towards a <u>new normal</u> of <u>3 to 3½%—or even lower</u>. Importantly, <u>this future low level of interest rates is not due to easy monetary policy</u>; instead, <u>it is the rate expected to prevail when the **economy is at full strength and the stance of monetary policy is neutral**</u>."[56] (emphasis added)

Q. At present, is it appropriate to think of the U.S. economy as being at, 'full strength?'

A. No, it is not. Furthermore, as noted earlier the stance of monetary policy remains accommodative.

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[54] Williams (2016), p. 2.
[55] <u>*Ibid*</u>., p.2, and as presented in Figure 1: *Estimated inflation-adjusted natural rates of interest* (p. 2).
[56] <u>*Ibid*</u>.

Q. To your knowledge, is the natural real rate of interest (r-star) for the United States higher, or lower, than the current Fed funds target range of ¼ to ½ percent?

A. As evidenced by statements made by Fed Chair Janet Yellen when testifying before the Joint Economic Committee, United States Congress, on November 17, 2016, the natural real rate of interest (r-star) is currently estimated to be <u>slightly higher</u> than the fed funds rate. Specifically, Ms. Yellen noted that "[w]ith the federal funds rate currently only <u>somewhat below estimates of the neutral rate [i.e., r-star]</u>, the stance of monetary policy is likely <u>moderately accommodative</u>, which is appropriate to foster further progress toward the FOMC's objectives."[57] (emphasis added) In this regard, Ms. Yellen indicated that "[t]he FOMC continues to expect the <u>evolution of the economy</u> will warrant only <u>gradual increases in the federal funds rate over time</u> to achieve and maintain maximum employment and price stability."[58] (emphasis added)

Q. When testifying before the Congressional Joint Economic Committee, did Fed Chair Yellen make additional references to the natural real rate of interest (r-star)?

A. Yes. Referring to the natural real rate of interest (r-star) as, "the neutral federal funds rate," Ms. Yellen characterized it as "<u>neither expansionary nor contractionary</u>" and a rate which "<u>keeps the economy on an even keel</u>."[59] (emphasis added)

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[57] Yellen, Janet L., "*The Economic Outlook*," Testimony before the Joint Economic Committee, U.S. Congress, Washington, DC (November 17, 2016).
https://www.federalreserve.gov/newsevents/testimony/yellen20161117a.htm

[58] *Ibid*.

[59] *Ibid*.

Q. The election of Donald Trump as President and the consequent sell-off which took place in the bond markets due to concerns of higher inflation preceded the appearance of Fed Chair Yellen before Congress on November 17, 2016. With regard to the economic outlook, does Ms. Yellen anticipate a sudden rise in inflation?

A. No, she does not, as evidenced by the following statement: "With regard to the outlook, I expect economic growth to continue at a moderate pace sufficient to generate some further strengthening in labor market conditions and a return of inflation to the Committee's 2 percent objective over the next couple of years."[60] (emphasis added)

Q. You point out that Fed Chairwoman Yellen and the FOMC continue to anticipate a return of inflation to the Fed's 2.0 percent objective over the next two to three years. Prior to the recent sell-off in the bond market, did the market agree with the Fed on this point?

A. No. As expressed by one market pundit earlier this year,

> "[t]he market and the Federal Reserve have very different views on where inflation will go from here. The Fed sees it moving pretty quickly from today's lows back to the Fed's two percent target. The market, on the other hand, doesn't see inflation rising near the Fed's goals anytime in the next decade."[61]

Q. What trends do the economic indicators suggest for common share prices?

A. As shown in Schedule JAC-6 (Pages 5 and 6), stock prices were stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. In 1983,

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[60] *Ibid*.
[61] Matthews, Chris, "The Market Doesn't Believe Janet Yellen," *Fortune*, March 30, 2016. http://fortune.com/2016/03/30/janet-yellen-fed-interest-rates/

however, equity prices began to rise steadily, particularly as measured by the Dow Jones Industrial Average ("DJIA"), before peaking in 2007. With the onset of the Great Recession in 2008, equity prices declined sharply from their highs of 2007, reaching a low in the first quarter of 2009. Beginning in the third quarter of 2009, equity prices again began to rise, eventually recovering the losses sustained as a consequence of the "crash" in 2008 and, as evidenced by the performance of the DJIA, the S&P 500 Composite Index ("S&P 500"), and the NASDAQ Composite Index ("NASDAQ"), went on to reach new all-time highs in the fourth quarter of 2015. Following the action taken by the Fed to raise the Fed Funds rate in December 2015, the equity markets experienced a sell-off, but all three major stock indices have since risen to establish new highs in the third quarter of 2016. It should be noted that on the night of the election, the Dow Jones futures contracts were down at one point by over 900 points on news that Donald Trump had been elected President. At the market open the following day, most of those losses had been recovered, and the equity markets finished higher not only on that day, but have since continued to rise, with the DJIA breaking through 19,000 for the first time ever.[62]

Q. We are now in the seventh year of recovery from the Great Recession. Is the U.S. economy at significant risk of falling back into recession?

A. Yes, there is significant risk that the U.S. economy could fall into recession sometime within the next four years, as periods of economic expansion have lasted, on average,

[62] Holm, Eric, "Dow Hits 19,000 for First Time," *WSJ.com* (November 22, 2016). http://blogs.wsj.com/moneybeat/2016/11/22/dow-hits-19000-for-first-time/

only about five years going back to the end of World War II.[63] Recession is defined as two consecutive quarters of shrinking economic growth.

Q. In setting monetary policy, what is the Fed's stated long-term objective?

A. Consistent with its statutory mandate, when setting monetary policy the long-term objective of the Fed's Federal Open Market Committee ("FOMC") is two-fold: (i) maximum employment, and (ii) price stability (i.e., inflation of 2.0 percent).[64]

Q. In the event the U.S. economy were to slip into recession and the unemployment rate were to rise, is it possible that the Fed might once again have to take steps to stimulate economic growth in order to achieve full employment?

A. Yes, in keeping with its statutory mandate to achieve full employment, the Fed might well have to do that.

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[63] Isidore, Chris, "Will Donald Trump get Hit with a Recession?," *CNN Money On-line*, November 9, 2016. http://money.cnn.com/2016/11/09/news/economy/president-elect-donald-trump-recession/

[64] Federal Reserve Board, Federal Open Market Committee, *Press Release* (April 27, 2016). http://www.federalreserve.gov/newsevents/press/monetary/20160427a.htm

Q. If inflation were to remain below two percent for the next decade, would it be difficult for the Fed to justify raising short-term rates over such an extended period of time?

A. Yes, because when setting monetary policy the Fed is 'data dependent,' and in the event inflation were to remain below the Fed's 2.0 percent targeted rate, justifying a raise in short-term interest rates would be made difficult.[65]

Q. Are there other reasons to expect that yields on long-term Treasury securities will remain low?

A. Yes, there are four reasons which have been identified.[66] First, U.S. Government backed Treasury securities are viewed as "haven assets," and as such analysts expect there to be a continued global flight-to-quality into U.S. Treasuries, particularly the 10-year note. Second, following Fed Chairman Yellen's speech to the Economic Club of New York, investors began to view the Fed as being more "dovish," as she stressed the need for a cautious approach to raising short-term interest rates, citing the risks associated from a slowdown in global growth. Third, yields on long-term Treasury securities are mostly influenced by projections of growth and inflation within the U.S. economy, and not by actions taken by the Fed to control the front-end of the yield curve. Lastly, analysts anticipate that due to the low, and in some cases negative, yields on sovereign debt

[65] Sharf, Samantha, "Even the Fed Can't Decide what 'Data Dependent' Really Means,"*Forbes.com*, February 18, 2015. http://www.forbes.com/sites/samanthasharf/2015/02/18/even-the-fed-doesnt-know-what-data-dependent-really-means/#1fe98f3de0b9

[66] Ismailidou, Ellie, "Four Reasons Why Treasury Yields are Hurtling Lower," *MarketWatch* (April 6, 2016). http://www.marketwatch.com/story/4-reasons-why-treasury-yields-are-hurtling-lower-2016-04-06

issued in Europe and Japan, investor demand for U.S. Treasury securities will continue to be strong, further keeping downward pressure on yields.

Q. What is the current consensus opinion regarding how many times the Fed is expected to raise short-term interest rates next year?

A. As evidenced by the most recent quarterly median estimate submitted by Fed policy makers, the Fed is projected to increase the federal funds rate two times in 2017, with each increase expected to be ¼ percent.[67]

Q. What conclusions can be drawn from the above discussion of economic and financial conditions as they relate to the cost of capital?

A. Despite expectations that the Fed may raise the federal funds rate in December 2016, and perhaps two additional times in 2017, I believe the probability of continued rate hikes going forward to be low. As discussed previously in my direct testimony, long-term interest rates have experienced a secular decline over the last 35-40 year period, and inflation has fallen to levels not seen since the early 1960s. Given this back drop, there is ample evidence to suggest that on a going-forward basis, both long-term interest rates and inflation will continue to remain low, and that investment returns on equities and fixed-income debt securities are expected to decline over the course of the next 20 years. As previously discussed, the so-called 'natural real rate of interest' (i.e., r-star) which allows the economy 'to remain on an even keel' is expected to be lower going forward than it has

[67] Ward, Jim and Meakin, Lucy, "Fed's Bullard Sees Medium-Term Boost from Trump Spending," *Bloomberg.com* (November 16, 2016). https://www.bloomberg.com/news/articles/2016-11-16/fed-s-bullard-sees-medium-term-boost-from-trump-economic-policy

been in the past, and this trend is indicative of a decline in the costs of capital relative to levels seen in the past. Although the U.S. economy continues its slow recovery from the Great Recession, future GDP growth is expected to decline from levels experienced in the past, thanks in part to a decline in productivity growth. While it is true that the economy may experience higher growth and increased inflation in the near-term as a consequence of President-elect Trump's planned infrastructure spending, there is a danger that the U.S. economy could slip back into recession, and this is particularly true should the strength of the U.S. dollar continue to rise. In the event of recession, the unemployment rate would be expected to rise, and in keeping with its mandate to maintain full employment the Fed would almost certainly be forced to once again cut short-term interest rates in an effort to stimulate economic growth. Thus, while the economy may briefly experience a short-term rise in GDP growth and inflation from planned fiscal stimulus spending, the propensity of the evidence suggests that over the medium- and longer-term, the U.S. economy will continue to experience real GDP growth and inflation of less than 2.0 percent annually, and keep both long-term interest rates and the cost of equity at or near current levels for an extended period of time.

V. CAPITAL STRUCTURE AND COST OF DEBT

Q. What capital structure does SWG propose in this proceeding?

A. As shown in Schedule D-1 (Sheet 1), the Company proposes a capital structure consisting of 48.31 percent long-term debt and 51.69 percent common equity. It should be noted that the Company's proposed capital structure excludes certain tax-free, industrial development revenue bonds ("IDRBs") issued in Nevada and California.

Q. What capital structure does RUCO recommend in this proceeding?

A. RUCO recommends a capital structure consisting of 49.02 percent long-term debt and 50.98 percent common equity.

Q. Please explain why RUCO's recommended capital structure is different from that proposed by SWG.

A. In essence, the difference arises because SWG has proposed a capital structure whose debt component consists of the net proceeds received from its long-term debt issuances, rather than the Company's actual balance of outstanding long-term debt. RUCO's recommended capital structure reflects the Company's outstanding principal balance of long-term debt as of the November 30, 2015 test-year end.

Q. Is the Company's long-term debt amortizing, or non-amortizing, debt?

A. Without exception, each series (i.e., debentures, medium-term notes, and tax-exempt debt) of SWG's long-term debt is non-amortizing. As such, annual debt service is confined to periodic interest payments only, as the entire principal balance for each series of long-term debt is due and payable upon maturity. RUCO's recommended capital structure gives recognition to this fact, whereas the capital structure proposed by the Company does not.

Q. In percentage terms, the equity component of RUCO's recommended capital structure (i.e., 50.98 percent) is lower than the equity component (i.e., 51.69 percent) proposed by the Company. Is the reduction to the equity component in RUCO's recommended capital structure attributable solely to the above noted change to the debt component of RUCO's recommended capital structure?

A. Yes, it is. As shown in Schedule JAC-1, RUCO's recommended capital structure increases both the dollar value of (i) long-term debt, and (ii) total capitalization (i.e., long-term debt plus common equity) by <u>$38,612,400</u> over and above that proposed by the company. As a consequence, the relative size of the debt component in RUCO's recommended capital structure <u>increases to 49.02 percent</u>, while the relative size of the equity component <u>decreases to 50.98 percent</u>. RUCO's recommended capital structure makes no adjustment to the dollar value of the Company's proposed common equity.

Q. What is the Company's proposed cost of debt in this proceeding?

A. As shown in Schedule D-1 (Sheet 1), the Company proposes a cost of debt of 5.21 percent.

Q. What is RUCO's recommended cost of debt in this proceeding?

A. As shown in Schedule JAC-1, RUCO recommends a cost of debt of 5.20 percent.

Q. Please explain why RUCO's recommended cost of debt is fractionally lower than the cost of debt proposed by Company.

A. The difference is attributable to the fact that RUCO's cost of debt is calculated using the outstanding principal balance to compute interest expense, whereas the Company's cost of debt is computed using the net proceeds of long-term debt to compute interest expense.

Q. Does RUCO adopt the Company's proposed cost of debt for each of the individual series of SWG long-term debt?

A. Yes. As presented in Schedule D-2 (Sheet 4), RUCO adopts the individual effective (i.e., yield-to-maturity) cost rates shown in Column (m), lines 1-10, for each series of debentures and medium-term notes. Additionally, as presented in Schedule D-2 (Sheet 2), RUCO gives recognition to the $171,862 ($14,321.81 x 12 months) annual effective cost associated with amortizing the loss on reacquired debt, as shown in Column (f), line 12. Finally, as presented in Schedule D-2 (Sheet 3), RUCO adopts the Company's proposed 1.10 percent variable cost rate for its term facility, as shown in Column (e), line 1.

VI. SELECTION OF PROXY GROUP

Q. Was RUCO able to directly estimate the cost of common equity for the Company?

A. Because the common stock of SWG is publicly-traded on the New York Stock Exchange, it is possible to directly estimate the cost of the Company's common equity utilizing available market data. However, rather than directly estimating the Company's cost of equity, RUCO elected to estimate the Company's cost of equity by employing a proxy group of publicly-traded natural gas distribution companies to indirectly estimate the

Company's cost of equity utilizing financial market data available for each sample company.

Q. What publicly-traded natural gas distribution companies has RUCO selected for inclusion in its proxy group?

A. RUCO's proxy group consists of the following eight publicly-traded natural gas companies: Atmos Energy Corp., Chesapeake Utilities, New Jersey Resources, Northwest Natural Gas, South Jersey Industries, Spire, Inc. (formerly, Laclede Group), UGI Corp., and WGL Holdings, Inc. These eight natural gas distribution companies have been selected because they (i) are followed by *The Value Line Investment Survey*, (ii) receive at least 60 percent of operating revenues from regulated natural gas utility operations, (iii) have a consistent track record of paying quarterly dividends, and (iv) are not presently known to be a party to a merger. Attachment 2 contains the most recent *Value Line* quarterly update for each of RUCO's eight proxy companies.

Q. For purposes of his analysis, does the Company's cost of capital witness, Mr. Robert Hevert, employ the same proxy group as that of RUCO?

A. No. Mr. Hevert, employs a proxy group consisting of six sample companies, all of which are included in RUCO's proxy. Mr. Hevert excludes both Chesapeake Utilities and UGI Corp. from his proxy group of sample companies.

VII. DCF ANALYSIS

Q. What is the theory and methodological basis of the DCF model?

A. The DCF model is one of the oldest and most commonly used models for estimating the COE for public utilities, and the only one which intrinsically takes into consideration the price investors are willing to pay for a given unit of return. The DCF is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate and the following formula will generate the cost of capital.

$$K = \frac{D}{P} + g$$

Where: K = cost of equity
P = current price
D = current dividend rate
K = discount rate (cost of capital)
g = constant rate of expected growth

This formula essentially recognizes that the return expected, or required, by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how RUCO employed the DCF model.

A. For purposes of its analysis, RUCO employed the constant growth DCF model. In doing so, RUCO combined the current dividend yield for each proxy group utility stock with several indicators of expected dividend growth.

Q. How did RUCO derive the dividend yield component of the DCF equation?

A. Several different methods can be used to compute the dividend yield component in the constant growth DCF model. However, for purposes of its analysis RUCO utilized the Gordon quarterly compounding method to compute the dividend yield component, as it gives recognition to the timing of dividend payments and dividend increases. The Gordon quarterly compounding method is expressed as follows:

$$Yield = \frac{D_0(1 + 0.5g)}{P_0}$$

The current (P_o) stock price in my yield calculation represents the average closing stock price for each proxy company for the most recent three month period (August – October, 2016). The current (D_o) dividend is the current annualized dividend rate for each proxy company.

Q. How does RUCO estimate the dividend growth (g) component of the DCF equation?

A. In estimating the dividend growth rate in its DCF analysis, RUCO gives consideration to the following five indicators of growth:

1. Five-year average (2011-2015) earnings retention (i.e., fundamental) growth, as reported by *Value Line*;
2. Five-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS), as reported by *Value Line*;
3. Years 2016, 2017 and 2019-2021 projections of earnings retention growth, as reported by *Value Line*;
4. Years 2013-2015 to 2019-2021 projections of EPS, DPS, and BVPS, as reported by *Value Line*; and,

5. Five - year projections of EPS growth, as reported by Yahoo Finance.

RUCO believes this combination of growth indicators to be a representative and appropriate set with which to estimate investor expectations of dividend growth for its proxy group of sample companies, as each is a determinant of dividend growth. Additionally, these growth indicators are reflective of the types of information that investors normally take into consideration when making an investment decision.

Q. Please describe RUCO's DCF calculations.

A. RUCO's DCF analysis is presented in Schedule JAC-3, Pages 1 through 4. Page 1 presents RUCO's overall DCF cost of equity estimation results for its proxy group of sample companies. As can be seen, "raw" DCF calculations are presented on several bases: mean, median, and high values. Page 2 presents the calculation of the dividend yield for each proxy company prior to adjustment for growth. Pages 3 and 4 present RUCO's historical and projected growth rate calculations for its proxy group of companies.

Q. What does RUCO conclude from its DCF cost of equity estimation analyses?

A. The DCF cost of equity rates obtained for RUCO's proxy group fall into a range between 7.95 percent and 9.27 percent. The highest DCF estimate is 9.27 percent. RUCO concludes that 9.27 percent represents the current DCF-derived cost of equity for the proxy group. Accordingly, RUCO adopts a DCF-derived cost of equity of 9.27 percent for the Company, which is based on the high end of the DCF range. For purposes of its overall recommended cost of equity in this proceeding, RUCO assigns a weighting factor of 40 percent to this 9.27 percent DCF cost of equity estimate.

VIII. CAPM ANALYSIS

Q. Please describe the theory and methodological basis of the CAPM.

A. Developed in the 1960s and 1970s as an extension of modern portfolio theory, the CAPM describes the relationship between a security's investment risk and its market rate of return.[68] This relationship identifies the rate of return which investors expect a security to earn so that its market return is comparable with the market returns earned by other securities that have similar risk. The relationship is specified by the Security Market Line (SLM) that indicates the relationship between each security or portfolio's "beta" and its resulting return. Beta is a measure of relative risk (i.e., volatility) between a given equity security and the market as a whole.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta\,(R_m - R_f)$$

Where: K = *cost of equity*

R_f = *risk free rate*

R_m = *return on market*

β = *beta*

$R_m - R_f$ = *market risk premium*

[68] The CAPM makes the following assumptions: 1) single holding period; 2) perfect and competitive securities market; 3) no transaction costs; 4) no restrictions on short selling or borrowing; 5) the existence of a risk-free rate; and 6) homogeneous expectations.

Q. Can you please identify the strengths of using the CAPM model in your analysis?

A. The CAPM is cited as having the following strengths (1) it is based on the concept of risk and return; (2) it is company specific as it relates to the specific beta's within the industry; (3) it has widespread use as it recognizes that investors can and do diversify; (4) it's highly structured and easy to apply when using the assumptions of the model; (5) the model is formulistic and the data used in the computations is readily available; (6) it is a forward looking concept; and (7) it is a method for converting changes in interest rates to the cost of equity.

Q. What risk-free (R_f) rate does RUCO use in its CAPM analysis?

A. For purposes of its CAPM analysis, RUCO uses a risk-free rate of 2.37 percent. RUCO's risk-free rate represents a composite 3-month average yield on the 30-year long-term U.S. Treasury Bond, measured over the 3-month period, August - October 2016. The calculation of RUCO's risk-free rate is presented in Schedule JAC-4, Page 1.

Q. Is it customary to use the yield on U.S. Treasury securities as the risk-free (R_f) rate in the CAPM?

A. Yes, because debt securities issued by the United States Department of the Treasury are considered to be free of default risk. Two general types of U.S. Treasury securities are most often used as the risk free *(R_f)* component, short-term U.S. Treasury bills and long-term U.S. Treasury bonds. For purposes of its analysis, RUCO elected to use the yield on 30-year U.S. Treasury bonds as a proxy for the risk-free rate because yields on long-term Treasury bonds more closely match the useful life of the plant assets to be funded by the Company's common equity capital.

Q. Did RUCO consider use of a forecasted long-term Treasury bond rate as the risk-free rate to be used in its CAPM analysis?

A. No. The appropriate interest rate to be used in the CAPM is the current rate borne by investors in the market place. Use of a forecasted risk-free rate overstates cost of equity estimates derived from the CAPM. Use of a current long-term Treasury rate is reflective of investor's current expectations, and as such is the appropriate risk-free rate to be used in the CAPM.

Q. What beta coefficients does RUCO employ in its CAPM analysis?

A. RUCO employs the most recent *Value Line* beta reported for each company in its proxy group. Once again, beta[69] is a measure of the relative risk, or volatility, of a particular stock in relation to the market as a whole. The overall market is assumed to have a beta of 1.0. Stocks having beta coefficients less than 1.0 are considered to be less risky than the market, whereas stocks having betas greater than 1.0 are considered to be more risky than the market. As regulated entities which have been granted natural monopoly status, public utilities are considered less risky than the market and typically have betas less than 1.0.

Q. How does RUCO estimate the market risk premium (R_m-R_f) component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks above that of the risk-free rate, or government bonds. For purposes of its analysis, RUCO estimated the market risk premium by comparing annual realized

[69] See Attachment 2 – Individual proxy companies beta's identified

returns on equity for the S&P 500 group with annual yields on 20-year long-term Treasury bonds over the period, 1978-2015. As shown in Schedule JAC-4, Page 2, the market risk premium component used in RUCO's CAPM represents the average of differential returns on equity for the S&P 500 group and the annual yields on 20-year U.S. Treasury bonds over this 1978-2015 period of time. RUCO determined the average ROE on the S&P 500 to be 13.70 percent, and the average 20-year U.S. Treasury bond yield to be 6.83 percent. Thus, based upon these returns RUCO concluded the market risk premium (R_m-R_f) component in its CAPM to be 6.87 percent.

Q. What did RUCO conclude the overall CAPM COE to be?

A. As shown in Schedule JAC-4, Page 1, RUCO determined the CAPM derived cost of equity to be 7.48 percent for its proxy group of sample companies. For purposes of its overall recommended cost of equity in this proceeding, RUCO assigns a weighting factor of 20 percent to this 7.48 percent CAPM estimated cost of equity.

IX. CE ANALYSIS

Q. Please describe the basis of the Comparable Earnings (CE) methodology.

A. The CE method is designed to measure returns expected to be earned on the original cost book value of similar risk business enterprises, in this case RUCO's proxy group of companies. Thus, it provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests, and provides additional support that the Company will be allowed the opportunity to earn a fair rate of return.

Q. How did RUCO apply the CE methodology?

A. RUCO applied the CE methodology by examining realized returns on equity for its proxy group of sample companies over the 10-year period, 2006-2015, as well as projected returns on equity for 2016 and 2017, and 2019-2021.

Q. What cost of equity results were obtained from RUCO's CE analysis?

A. As shown in Schedule 5, RUCO calculated historical returns on equity for its sample companies over both a 5- and 10-year period, and projected returns on equity over the 5-year period, 2016-2020. Based upon its analysis, RUCO generated mean, median, and average of mean and median CE cost of equity estimates ranging from a low of 10.46 percent to a high of 11.29 percent. The results of RUCO's CE cost of equity analysis based on returns on equity for the proxy group can be summarized as follows:

	Historic ROE's	Projected ROE's
Mean	10.64 % - 11.29 %	10.46 %
Median	10.81 % - 11.09 %	10.92 %
Average of Mean and Median	10.87 % - 11.05 %	10.69 %

For purposes of its analysis, RUCO adopts the 10.46 percent projected mean cost of equity estimate as its CE-derived cost of equity estimate for the Company. RUCO selects this lower estimate largely because SWG, in its prior rate case, was authorized full revenue decoupling by the Commission. For purposes of its overall recommended cost of equity in this proceeding, RUCO assigns a weighting factor of 40 percent to this 10.46 percent CE estimated cost of equity.

X. RUCO RESPONSE TO COMPANY'S COST OF CAPITAL WITNESS MR. ROBERT B. HEVERT

Q. Have you reviewed the cost of capital testimony of SWG witness, Mr. Robert Hevert?

A. Yes, I have.

Q. Briefly summarize Mr. Hevert's cost of equity recommendations.

A. Mr. Hevert recommends a cost of equity for SWG of 10.25 percent, based on estimates derived from several sets of DCF, CAPM and Risk Premium models, using a proxy group of six publicly-traded natural gas distribution companies. The results obtained from Mr. Hevert's DCF analyses are shown in Table 1a, on page 4 of his direct testimony, while the results obtained from his various Risk Premium models appear in Table 1b, on page 5 of his direct testimony, and are summarized below:

Discounted Cash Flow Results

	Low	Mean	High
Constant Growth DCF			
30-Day Average	8.39%	9.52%	11.30%
90-Day Average	8.50%	9.64%	11.41%
180-Day Average	8.66%	9.79%	11.57%
Multi-Stage DCF			
30-Day Average	9.03%	9.33%	9.82%
90-Day Average	9.16%	9.47%	9.97%
180-Day Average	9.32%	9.65%	10.18%

Risk Premium Results

	Bloomberg MRP	Value Line MRP
CAPM - Average Bloomberg Beta		
Current 30-Year Treasury (2.79%)	9.69%	9.26%
Projected 30-Year Treasury (3.35%)	10.25%	9.83%
CAPM - Average Value Line Beta		
Current 30-Year Treasury (2.79%)	10.78%	10.28%
Projected 30-Year Treasury (3.35%)	11.34%	10.85%

Bond Yield plus Risk Premium Approach	
Current 30-Year Treasury (2.79%)	9.98%
Near-Term Projected 30-Year Treasury (3.35%)	10.02%
Long-Term Projected 30-Year Treasury (4.65%)	10.39%

As noted in his testimony, Mr. Hevert determined the cost of equity for his sample group falls within the range of 10.0 percent to 10.5 percent, and based on his "quantitative and qualitative analyses concludes that an ROE of 10.25 percent is reasonable and appropriate."[70] Mr. Hevert further states that the "key consideration in determining the Cost of Equity is to ensure that the methodologies employed reasonably reflect investors' view of the financial markets in general, and the subject company (in the context of the proxy group) in particular."[71]

Q. In light of the above, is Mr. Hevert's recommended 10.25 percent cost of equity supported by his analysis?

A. No, it is not. As reproduced above, Mr. Hevert's recommended 10.25 percent cost of equity can be rationalized only by use of estimates obtained from the 'High' 30-, 90- and 180-day average Constant Growth DCF model, and the 'Average Value Line Beta' CAPM. As shown, both the results of Mr. Hevert's 'Mean' Constant Growth DCF (9.52 percent to 9.79 percent) and 'Mean' Multi-stage DCF estimates (9.33 percent to 9.65 percent) are well below 10.0 percent, while the results of his overall Multi-stage DCF analysis indicate a range of 9.03 percent to 10.18 percent. The results of Mr. Hevert's 'Average Bloomberg Beta" CAPM indicate a range of 9.26 percent to 10.25 percent (midpoint 9.75 percent), while his 'Bond Yield plus Risk Premium Approach' indicates a range of 9.98 percent to

[70] *See* Hevert Direct, p. 2, lines 15-18.
[71] Ibid., p.14, lines 20-23.

10.39 percent (midpoint 10.19 percent). Therefore, as regards SWG's market cost of equity Mr. Hevert's recommended 10.25 percent ROE is <u>overstated</u>, as it fails to '*reasonably reflect investors' view of the financial markets in general, and the subject company (in the context of the proxy group) in particular.*' The following discussion will shed additional light as to the reasons why this is the case.

Q. Briefly explain Mr. Hevert's Constant Growth DCF methodology?

A. For purposes of his Constant Growth DCF analysis, Mr. Hevert's methodology employs (i) average stock prices measured over 30-day, 90-day and 180-day periods ending February 12, 2016, (ii) annualized dividends per share measured as of that same date, and (iii) dividend growth (g) rates computed as the average of Value Line, First Call, and Zack's EPS projections and projected retention (BR + SV) growth rates. Utilizing these inputs, Mr. Hevert then obtains 'Low,' 'Mean,' and 'High' DCF cost of equity estimates for each of his six sample companies based on 30-, 90- and 180-day average stock prices.

The results of Mr. Hevert's Constant Growth DCF analyses are presented in Exhibit RBH-1. As shown, for each proxy company his 'Low ROE' estimate represents the sum of the expected dividend yield and the <u>*lowest*</u> of the four earnings growth rates he considers; his 'Mean ROE' estimate represents the sum of the expected dividend yield and the <u>*sample average*</u> earnings growth rate; and his 'High ROE' estimate represents the sum of the expected dividend yield and the <u>*highest*</u> individual earnings growth rate. Thus, for purposes of his 'High ROE' estimate, Mr. Hevert's Constant Growth DCF analysis is predicated on the assumption that when making investment decisions investors consider *only* the most optimistic growth rate, as his 'High ROE' estimate ignores three of the four individual earnings growth estimates obtained for each sample company.

Q. Among the cost of equity estimates obtained from the various models employed by Mr. Hevert in his analyses, are those derived from his 'High ROE' Constant Growth DCF the highest estimates?

A. Yes, for as shown the 'High ROE' Constant Growth DCF estimates obtained from use of 30-day, 90-day, and 180-day average stock prices lie within the range, 11.30 percent to 11.57 percent.

Q. When estimating the cost of equity from a proxy group of sample companies, is it appropriate to focus only on the highest growth estimate obtained for each sample company?

A. No. It is neither realistic nor proper to focus on a single growth rate in a DCF context, and this is particularly the case when one "cherry picks" the highest earnings growth rate for each sample company, as Mr. Hevert has done for purposes of his 'High ROE' Constant Growth DCF analyses.

Q. In your judgement, when making an investment decision would a so-called "rational investor" be expected to consider only the highest growth estimate?

A. No. I believe that before making an investment decision a rational investor would want to consider a range of growth estimates – both historical as well as projected – and ideally among a variety of different growth parameters (i.e., EPS, BVPS, and retention growth).

Doing so would allow such an investor the opportunity to gain a more realistic expectation of investment outcomes, thereby leading to a more reasoned investment decision.

Q. For purposes of estimating the dividend growth (g) rate in his Constant Growth DCF analyses, does Mr. Hevert incorporate historical measures of EPS, BVPS or retention growth?

A. No, he does not. As noted earlier, the dividend growth (g) rate in Mr. Hevert's Constant Growth DCF analyses is computed as the average of EPS projections obtained from Value Line, First Call, and Zack's, as well as projected retention growth (BR + SV) rates for each of his sample companies. Thus, Mr. Hevert's Constant Growth DCF analysis neither gives consideration to historical measures of growth, nor to growth in BVPS.

Q. Does this mean that Mr. Hevert's Constant Growth DCF analysis relies exclusively on analysts' forecasts of EPS to estimate the dividend growth (g) rate?

A. Essentially, yes, as three (i.e., Value Line, First Call, and Zack's) of the four growth rates Mr. Hevert relies upon directly use analysts' forecasts of EPS growth, while the fourth growth rate (BR + SV) utilizes EPS forecasts as a component.

Q. Is it improper to rely exclusively on analysts' forecasts of EPS growth in a DCF analysis?

A. Yes, because investors have an abundance of available information to assist them in evaluating stocks, and it is not realistic to believe that they would rely exclusively on a single factor, such as analysts' forecasts of EPS growth. As evidence of this fact, Value Line – a source Mr. Hevert relies upon for EPS forecasts – makes available a wide variety of historical and projected growth data relating to the individual companies which they follow, and this information is presumably made available for consideration by investors who subscribe to the service. Nevertheless, for purposes of his DCF analysis Mr. Hevert gives consideration only to analysts' forecasts of EPS growth.

Q. Is there evidence to suggest that analysts' forecasts of EPS growth tend to be overly optimistic?

A. Yes.[72] As discussed in the academic study cited to, the author concluded that "[a]nalysts' forecasts of EPS and growth in EPS tend to be overly optimistic," based upon a finding that analysts' forecasts of EPS had been more than twice the actual growth rate.

Q. How do you respond to Mr. Hevert's Multi-stage DCF analyses?

A. The results of Mr. Hevert's Multi-stage DCF analyses are presented in Exhibit RBH-3, and I have three comments regarding his Multi-stage DCF methodology, all of which pertain to the 5.31 percent long-term projected GDP growth rate used in the terminal stage of his analysis. As noted in his direct testimony (p. 26, lines 16-20), this 5.31 percent figure represents the sum of (i) a 3.24 percent real (i.e., inflation adjusted) compound rate of growth in GDP as measured over the period, 1929-2015, and (ii) a projected 2.01 percent long-term expected rate of inflation.

[72] *See*, Chopra, Vijay Kumer, "Why So Much Error In Analysts' Earnings Forecasts?," *Financial Analysts Journal*, Vol. 54, No. 6 (Nov.-Dec. 1998), pp. 35-42.

First, as presented in Exhibit RBH-3 there is a mathematical computation error in Mr. Hevert's 5.31 percent long-term GDP growth rate, for based upon the above inputs (i.e., 3.24 percent real GDP and 2.01 percent projected inflation), Mr. Hevert's long-term GDP growth rate should be 5.25 percent (3.24% + 2.01% = 5.25%), and not 5.31 percent.

Second, as noted earlier Mr. Hevert steadfastly refused to incorporate historical measures of growth in his Constant Growth DCF analyses, yet for purposes of his Multi-stage DCF analyses he relies *exclusively* on historic real GDP growth. This is not only an inconsistency in his testimony, but suggests that Mr. Hevert's cost of equity estimation methodology is focused on obtaining only the highest growth rates. As discussed earlier in my direct testimony, there is ample evidence to suggest that on a going-forward basis, real GDP growth will be less than that experienced over the historical period 1929-2015. Accordingly, Mr. Hevert's use of historical measures of real GDP growth serve to overstate his Multi-stage DCF cost of equity estimates, as they are not representative of expected future long-term GDP growth.

Third, the 2.01 percent long-term inflation rate employed in Mr. Hevert's Multi-stage DCF analysis represents the average of a 1.82 percent 'TIPS spread' and a 2.20 percent projected Blue Chip estimate for CPI inflation over the period, 2022-2026. Again, as discussed earlier in my direct testimony, there is ample evidence that the long-term rate of inflation is also in decline, which suggests that the 2.01 percent long-term inflation rate used to compute the corrected 5.25 percent GDP growth rate in Mr. Hevert's Multi-stage DCF analysis has, likewise, been overstated.

Q. Briefly discuss Mr. Hevert's CAPM cost of equity estimation methodology?

A. The results of Mr. Hevert's CAPM analyses are summarized in Table 7, page 31, of his direct testimony, and the analysis is presented in Exhibits RBH-4, RBH-5 and RBH-6. As shown in Exhibit RBH-4 (Page 1 of 14), utilizing market data from Bloomberg Mr. Hevert obtains a market risk premium ("MRP") of <u>10.65 percent</u>, and as shown in Exhibit RBH-4 (Page 8 of 14), utilizing market data from Value Line he obtains a MRP of <u>9.99 percent</u>. As shown in Exhibit RBH-5, Mr. Hevert utilizes two different beta coefficients; a 0.648 sample average beta obtained from Bloomberg, and a 0.75 sample average beta obtained from Value Line. Finally, for purposes of his analysis Mr. Hevert utilizes two different risk-free rates; a 2.79 percent 'Current 30-Year Treasury' rate, and a 3.35 percent 'Near-Term Projected 30-Year Treasury' rate. As shown in Exhibit RBH-6, by applying each of the two (i) MRPs, (ii) beta coefficients, and (iii) risk-free (R_f) rates into the CAPM formula, Mr. Hevert then obtains the eight different CAPM cost of equity estimates presented in Table 7. As shown, the highest CAPM cost of equity estimates are those obtained from use of (a) the Bloomberg derived MRP and (b) the average Value Line beta coefficient (i.e., 10.78 percent and 11.34 percent), while the lowest are those obtained using (c) the Value Line derived MRP and (d) the average Bloomberg beta coefficient (i.e., 9.26 percent and 9.83 percent).

Q. Do you agree with the two MRP components (i.e., 10.65 percent and 9.99 percent) which Mr. Hevert uses in his CAPM analyses?

A. No. Both the 10.65 percent MRP which Mr. Hevert obtains from Bloomberg data and the 9.99 percent MRP he obtains from Value Line data <u>greatly exceed</u> the long-term market investment return differential between common stocks and government bonds over the period, 1929 to the present. Furthermore, as discussed earlier in my testimony the McKinsey report anticipates future investment returns on both common stocks and government bonds to decline over the next 20-year period. Based upon these two considerations, there is every reason to believe that the two MRP components utilized in Mr. Hevert's CAPM analyses serve to <u>overstate</u> the various cost of equity estimates derived therefrom.

Q. Briefly describe Mr. Hevert's Bond Yield plus Risk Premium Approach methodology.

A The results of Mr. Hevert's Bond Yield plus Risk Premium approach are shown in Table 1b, page 5, of his direct testimony, and the analysis is presented in Exhibit RBH-7. As discussed in his direct testimony (pp. 31-34), Mr. Hevert's Bond Yield plus Risk Premium approach compares authorized ROEs for natural gas distribution utilities to long-term 30-Year U.S. Treasury Bond yields over the period, January 1980 - February 12, 2016. Mr. Hevert models the relationship between interest rates and the Equity Risk Premium by performing a regression analysis in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. Mr. Hevert's regression results are presented in Chart 1, page 33, of his direct testimony, and based upon the regression coefficients presented in Chart 1, he obtains an implied ROE range of 9.98 percent to 10.39 percent. As shown in Exhibit RBH-7 (Page 1 of 20), in obtaining this range of estimates Mr. Hevert applies this regression result to a 2.79 percent 'Current' 30-year

Treasury yield, a 3.35 percent 'Near-Term Projected' 30-year Treasury yield, and a 4.65 percent 'Long-Term Projected' 30-year Treasury yield.

Q. Is the 9.98 percent to 10.39 percent implied range of ROE estimates obtained from Mr. Hevert's Bond Yield plus Risk Premium Approach supported by the authorized returns he utilizes as inputs in his regression analysis?

A. No, they are not, for as presented in Exhibit RBH-6 (Pages 19-20 of 20) of Mr. Hevert's direct testimony, over the last six quarters (i.e., Q4 2014 – Q1 2016) authorized ROEs for natural gas distribution utilities have averaged 9.68 percent, as shown below:

Period	Authorized ROE
2014 Q4	10.28%
2015 Q1	9.47%
2015 Q2	9.43%
2015 Q3	9.75%
2015 Q4	9.67%
2016 Q1	9.50%
Average ROE	9.68%

Thus, while Mr. Hevert's Equity Risk Premium results suggest an implied ROE range of 9.98 percent to 10.39 percent, the reality is that authorized ROEs for natural gas distribution utilities are currently well below that range, with the above recent average ROE being 57 basis points lower than the 10.25 percent cost of equity Mr. Hevert recommends for SWG in this proceeding (10.25% - 9.68% = 0.57%).

Q. For purposes of his analysis, Mr. Hevert also makes provision for an upward 3 basis point flotation cost adjustment. Does RUCO agree with the inclusion of flotation costs in establishing an authorized return on equity for SWG in this proceeding?

A. No. It is not proper to include a flotation cost adjustment in determining the cost of equity for Southwest Gas. While Mr. Hevert states in direct testimony (p. 3, lines 8-13) that he "did not make explicit adjustments" to his ROE estimates for flotation costs, he nevertheless "takes them into consideration," and in so doing makes an "implicit adjustment" for flotation costs.

Q. Does Mr. Hevert's direct testimony provide evidence that an upward adjustment was made to his recommended cost of equity in this proceeding?

A. Yes, as evidenced by the footnotes appearing beneath the following Tables in Mr. Hevert's direct testimony: Table 1a (p. 4); Table 3 (p. 22); Table 6 (p. 28); and Table 10a (p. 49).

XI. FAIR VALUE RATE OF RETURN

Q. What FVROR does SWG propose in this proceeding?

A. The Company proposes a FVROR of 6.01 percent.

Q. What FVROR for SWG does RUCO recommend in this proceeding?

A. As shown in Schedule JAC-1, RUCO recommends a FVROR for the Company of 5.67 percent.

Q. In arriving at its recommended 5.67 percent FVROR for the Company, does RUCO employ the same methodology as that used by SWG?

A. Yes, RUCO's methodology is essentially the same as that used by the Company. As shown in Schedule JAC-1a, based upon the OCRB (i.e., \$1,321,867,091) and RCND (i.e., \$2,272,474,052) values as determined by RUCO witness, Mr. Jeff Michlik, RUCO assigned a 1.04 percent cost rate to the fair value increment (i.e., \$475,303,481) of the Company's Arizona jurisdictional RCND capital structure. The 1.04 percent cost rate assigned by RUCO to the fair value increment is computed using the following inputs: (i) a nominal risk free rate of 3.00 percent (i.e., closing spot yield on the 30-year U.S. Treasury Bond as of the close of market on November 21, 2016), (ii) an inflation rate of 0.92 percent (i.e., closing spot yield on the 30-year U.S. Treasury Inflation Protected Securities (TIPs) as of the close of market on November 21, 2016); and (iii) a 50% factor to reduce inflation from the fair value cost rate. Utilizing these inputs, RUCO's recommended 1.04 percent fair value cost rate is computed as follows:

Nominal Risk-Free Rate	3.00 %
Less: Inflation Component	0.92%
Equals: Real Risk-Free Rate	2.08 %
Times: 50% Factor	0.50 %
Fair Value Cost Rate	**1.04 %**

As shown in Schedule JAC-1a, RUCO's recommended 5.67 percent FVROR is computed by assigning this 1.04 percent fair value cost rate to the fair value increment of RUCO's recommended RCND capital structure.

XII. CONCLUSION AND RECOMMENDATIONS

Q. Please summarize RUCO's cost of capital recommendations in this proceeding.

A. RUCO recommends that the Commission adopt the following:

1) A capital structure composed of 49.02 percent long-term debt and 50.98 percent common equity;
2) A cost of debt of 5.20 percent;
3) A cost of common equity of 9.39 percent;
4) An overall rate of return of 7.34 percent; and
5) A fair value rate of return of 5.67 percent.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ATTACHMENT 1

Attachment 1

John A. Cassidy, CRRA

EDUCATION

Arizona State University -- Master of Business Administration-Finance (May 1987)

University of Arizona -- Master of Library Science (August 1980)

Arizona State University -- B.A. History, Latin American Studies (May 1976)

EXPERIENCE

Public Utilities Analyst V – Residential Utility Consumer Office (RUCO), Phoenix, AZ (July 2015-Present)

Public Utilities Analyst III -- Arizona Corporation Commission, Phoenix, AZ (March 2013-July 2015)

Public Utilities Analyst II -- Arizona Corporation Commission, Phoenix, AZ (May 2012-March 2013)

Public Utility Consultant -- Arizona Corporation Commission, Phoenix, AZ (Jan. 2012-May 2012)

Regulatory Utility Consultant – Self-Employed, Tempe, AZ (2009-2010)

- Assisted in the preparation of testimony filed by the Residential Utility Consumer Office (RUCO) in the Litchfield Park W/WW rate case (Docket No. SW-01428A-09-0103, et al)

Regulatory Utility Consultant – Self-Employed, Tempe, AZ (2007-2008)

- Filed formal cost of capital testimony/schedules on behalf of intervener, Anthem Town Council, and testified at evidentiary hearing in the Arizona-American Water Co., Anthem Water and Anthem/Agua Fria WW rate case (Docket No. WS-01303A-06-0403)

Utilities Auditor II -- Arizona Corporation Commission, Phoenix, AZ (Aug. 1993-Nov. 1997)

PROFESSIONAL DEVELOPMENT

Certified Rate of Return Analyst (CRRA) (May 2016)

Annual Regulatory Studies Program ("Camp NARUC"), Institute of Public Utilities, Michigan State University, East Lansing, MI (August 4-15, 2014)

45th and 48th Financial Forums, Society of Utility and Regulatory Financial Analysts (SURFA), Indianapolis, IN (April 17-19, 2013 and April 28-29, 2016)

NARUC Utility Rate School, San Diego, CA (May 13-17, 2013)

HONORS

CPA Candidate - Passed the CPA exam (1997), but opted not to pursue certification

Beta Gamma Sigma - National Honor Society in Business Administration

Rate Dockets Testified - Cost of Capital:

Southwest Gas Corporation	Docket Nos. G-01551A-16-0107
Liberty Utilities (Bella Vista W / Rio Rico W/WW)	Docket Nos. W-02465A-15-0367, et al.
Arizona Water Company	Docket No. W-01445A-15-0277
Liberty Utilities (Black Mountain Sewer)	Docket Nos. SW-02361A-15-0206, et al.
Quail Creek Water Company	Docket No. W-02514A-14-0343
EPCOR Water Arizona	Docket No. WS-01303A-14-0010
Utility Source, L.L.C.	Docket No. WS-04235A-13-0331
Verde Santa Fe Wastewater Company	Docket No. SW-03437A-13-0292
Chaparral City Water Company	Docket No. W-02113A-13-0118
Payson Water Company	Docket No. W-03514A-13-0111
Lago Del Oro Water Company	Docket No. W-01944A-13-0215
Las Quintas Serenas Water Company	Docket No. W-01583A-13-0117
Litchfield Park Service Company	Docket Nos. SW-01428A-13-0042, et al.
Adaman Mutual Water Company	Docket No. W-01997A-12-0501
Global Water Utilities	Docket Nos. W-01212A-12-0309, et al.
New River Utility Company	Docket No. W-01737A-12-0478
Arizona Water Company	Docket No. W-01445A-12-0348
Far West Water & Sewer, Inc.	Docket No. WS-03478A-12-0307
Cordes Lakes Water Company	Docket No. W-02060A-12-0356
Rio Rico Utilities, Inc.	Docket No. WS-02676A-12-0196
Ray Water Company	Docket No. W-01380A-12-0254
Vail Water Company	Docket No. W-01651B-12-0339
Valley Water Company	Docket No. W-01412A-12-0195
Arizona Water Company	Docket No. W-01445A-11-0310
Pima Utility Company	Docket Nos. W-02199A-11-0329, et al.

Rate Dockets Testified - Revenue Requirement/Rate Design:

Arizona Water Company	Docket No. W-01445A-15-0277
Quail Creek Water Company	Docket No. W-02514A-14-0343

Beaver Dam Water Company	Docket No. W-03067A-12-0232
Eden Water Company	Docket No. W-02068A-11-0471
Great Prairie Oasis, dba Sunland Water Co.	Docket No. W-04015A-12-0051

Financing Dockets - Responsible for ACC Staff Report:

Arizona Public Service Company	Docket No. E-01345A-11-0423
Tucson Electric Power Company	Docket No. E-01933A-12-0176
Chaparral City Water Company	Docket No. W-02113A-13-0047
Payson Water Company	Docket No. W-03514A-13-0142
Lago Del Oro Water Company	Docket No. W-01944A-13-0242
Duncan Valley Electric Cooperative, Inc.	Docket No. E-01703A-13-0272
Sulphur Springs Valley Electric Cooperative, Inc.	Docket No. E-01575A-12-0457
Trico Electric Cooperative, Inc.	Docket No. E-01461A-12-0056
Great Prairie Oasis, dba Sunland Water Co.	Docket No. W-04015A-12-0050
Columbus Electric Cooperative, Inc.	Docket No. E-01851A-11-0415
Pima Utility Company	Docket Nos. W-02199A-11-0403, et al.

ATTACHMENT 2

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE	74.90	P/E RATIO	21.4 (Trailing: 22.7 / Median: 15.0)	RELATIVE P/E RATIO	1.12	DIV'D YLD	2.4%	VALUE LINE

TIMELINESS 2 Lowered 6/17/16

SAFETY 1 Raised 6/6/14

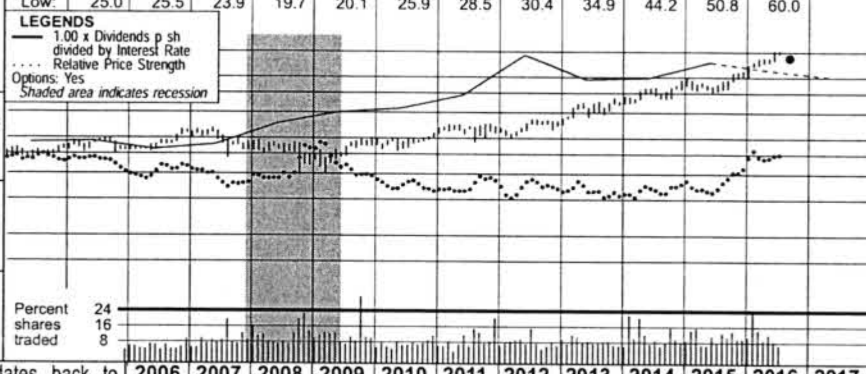
TECHNICAL 1 Raised 8/19/16

BETA .75 (1.00 = Market)

High:	30.0	33.1	33.5	29.3	30.3	32.0	35.6	37.3	47.4	58.2	64.8	82.0
Low:	25.0	25.5	23.9	19.7	20.1	25.9	28.5	30.4	34.9	44.2	50.8	60.0

Target Price Range
2019 | 2020 | 2021

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+45%)	12%
Low	90	(+20%)	7%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	2	7	0	2	0	0	2	6	0
to Sell	0	0	1	0	0	0	0	1	0

Institutional Decisions

	3Q2015	4Q2015	1Q2016
to Buy	130	159	212
to Sell	137	133	142
Hld's(000)	69743	70628	71888

% TOT. RETURN 7/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	48.0	4.8
3 yr.	96.7	25.2
5 yr.	181.7	69.0

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.

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
75.27	66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	*30.70*	*32.75*	Revenues per sh A	*45.85*
4.26	4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	*6.05*	*6.30*	"Cash Flow" per sh	*7.25*
2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	*3.35*	*3.55*	Earnings per sh A B	*4.20*
1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	*1.68*	*1.80*	Div'ds Decl'd per sh C■	*2.15*
5.20	4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	*9.90*	*10.10*	Cap'l Spending per sh	*10.60*
20.16	22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	*31.95*	*31.15*	Book Value per sh	*36.65*
81.74	89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	*107.00*	*110.00*	Common Shs Outst'g D	*120.00*
13.5	15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	*Bold figures are*		Avg Ann'l P/E Ratio	*24.0*
.73	.84	.82	.83	.84	.90	1.01	.89	.85	.89	*Value Line*		Relative P/E Ratio	*1.50*
4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*2.2%*
6152.4	5898.4	7221.3	4969.1	4789.7	4347.6	3438.5	3886.3	4940.9	4142.1	*3285*	*3600*	Revenues ($mill) A	*5500*
162.3	170.5	180.3	179.7	201.2	199.3	192.2	230.7	289.8	315.1	*360*	*390*	Net Profit ($mill)	*500*
37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	33.8%	38.2%	39.2%	38.3%	*36.5%*	*37.0%*	Income Tax Rate	*40.0%*
2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	5.6%	5.9%	5.9%	7.6%	*11.0%*	*10.8%*	Net Profit Margin	*9.1%*
57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	45.3%	48.8%	44.3%	43.5%	*40.0%*	*43.0%*	Long-Term Debt Ratio	*45.0%*
43.0%	48.0%	49.2%	50.1%	54.6%	50.6%	54.7%	51.2%	55.7%	56.5%	*60.0%*	*57.0%*	Common Equity Ratio	*55.0%*
3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	4315.5	5036.1	5542.2	5650.2	*5700*	*6000*	Total Capital ($mill)	*8000*
3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	5475.6	6030.7	6725.9	7430.6	*8100*	*8560*	Net Plant ($mill)	*10200*
6.1%	5.9%	5.9%	5.9%	6.9%	6.1%	6.1%	5.9%	6.4%	6.6%	*7.5%*	*8.0%*	Return on Total Cap'l	*7.5%*
9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	*10.5%*	*11.5%*	Return on Shr. Equity	*11.5%*
9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	*10.5%*	*11.5%*	Return on Com Equity	*11.5%*
3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	2.8%	4.0%	4.7%	4.9%	*5.5%*	*5.5%*	Retained to Com Eq	*5.5%*
63%	65%	65%	68%	62%	62%	65%	56%	50%	51%	*50%*	*51%*	All Div'ds to Net Prof	*52%*

CAPITAL STRUCTURE as of 6/30/16
Total Debt $3126.1 mill. **Due in 5 Yrs** $1157.9 mill.
LT Debt $2205.6 mill. **LT Interest** $135.0 mill.
(LT interest earned: 5.4x; total interest coverage: 5.4x)
Leases, Uncapitalized Annual rentals $16.5 mill.
Pfd Stock None
Pension Assets-9/15 $450.9 mill.
Oblig. $508.6 mill.
Common Stock 103,847,858 shs.
as of 7/29/16
MARKET CAP: $7.8 billion (Large Cap)

CURRENT POSITION ($MILL.)	2014	2015	6/30/16
Cash Assets	42.3	28.7	66.2
Other	733.5	602.3	582.7
Current Assets	775.8	631.0	648.9
Accts Payable	311.6	238.9	198.9
Debt Due	196.7	457.9	920.5
Other	402.4	458.0	410.4
Current Liab.	910.7	1154.8	1529.8
Fix. Chg. Cov.	637%	743%	750%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-2.0%	-6.5%	*.5%*
"Cash Flow"	5.0%	4.5%	*5.0%*
Earnings	5.5%	7.0%	*6.5%*
Dividends	2.0%	2.5%	*6.5%*
Book Value	5.0%	5.0%	*3.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	1034.2	1309.0	857.9	685.2	3886.3
2014	1255.1	1964.3	942.7	778.8	4940.9
2015	1258.8	1540.1	686.4	656.8	4142.1
2016	906.2	1132.3	632.9	*613.6*	*3285*
2017	*930*	*1280*	*710*	*680*	*3600*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	.85	1.23	.36	.08	2.50
2014	.95	1.38	.45	.23	2.96
2015	.96	1.35	.55	.23	3.09
2016	1.00	1.38	.69	*.28*	*3.35*
2017	*1.06*	*1.47*	*.68*	*.34*	*3.55*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.345	.345	.345	.35	1.39
2013	.35	.35	.35	.37	1.42
2014	.37	.37	.37	.39	1.50
2015	.39	.39	.39	.42	1.59
2016	.42	.42	.42		

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to roughly three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2015: 66%, residential; 29%, commercial; 3%, industrial; and 2% other. The company has around 4,760 employees. Officers and directors own approximately 1.5% of common stock (12/15 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy is about to close the books on a solid fiscal 2016 (concludes September 30th). The core natural gas distribution unit has benefited nicely from rate adjustments in the Mid-Tex, Mississippi, and West Texas divisions. Meanwhile, the performance of the regulated pipeline business was aided by higher revenue from the Gas Reliability Infrastructure Program (GRIP) filings approved in fiscal 2015 and 2016. In all, we look for full-year share net to grow about 8% versus the fiscal 2015 total. The bottom line next year stands to advance at a similar percentage rate, assuming that operating margins expand further.

Activity has been brisk on the rate-filing front. Through the first nine months of fiscal 2016, Atmos was able to finish 15 rate-case proceedings, resulting in a $63.7 million rise in annual operating income. What's more, a few ratemaking efforts are in progress seeking $24.5 million of annual operating income. But there are no guarantees that the company will receive everything it wants.

***Value Line* is constructive about Atmos' prospects out to 2019-2021.** It is one of the nation's largest natural gas-only distributors, presently with around three million customers spread across several states, including Texas, Louisiana, and Mississippi. Also, the other units, particularly pipelines, seem to have solid overall growth potential. Lastly, we believe management will eventually resume its successful strategy of acquiring less efficient utilities and shoring up their profitability via cost-reduction initiatives, rate relief, and aggressive marketing efforts. (The last big deal happened in October, 2004, when Atmos bought TXU Gas Company.)

The stock touched its highest price point over the past few months. It appears that move can be traced partly to the energy firm's decent earnings in fiscal 2016. Consequently, these shares possess a 2 (Above Average) rank for Timeliness. Other positives include the healthy level of current dividend income (plus prospects of additional hikes in the well-covered payout), the 1 (Highest) Safety rank, and excellent score for Price Stability. In all, a broad range of investors ought to find something to like here.

Frederick L. Harris, III September 2, 2016

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '06, d18¢; '07, d2¢; '09, 12¢; '10, 5¢; '11, (1¢). Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢. Next egs. rpt. due early Nov.
(C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	90

CHESAPEAKE UTIL. NYSE-CPK

RECENT PRICE **65.55** | P/E RATIO **20.9** (Trailing: 23.9 / Median: 15.0) | RELATIVE P/E RATIO **1.10** | DIV'D YLD **1.9%** | **VALUE LINE**

TIMELINESS 3 Lowered 5/20/16
SAFETY 2 New 6/5/15
TECHNICAL 2 Raised 8/12/16
BETA .60 (1.00 = Market)

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+35%)	10%
Low	70	(+5%)	4%

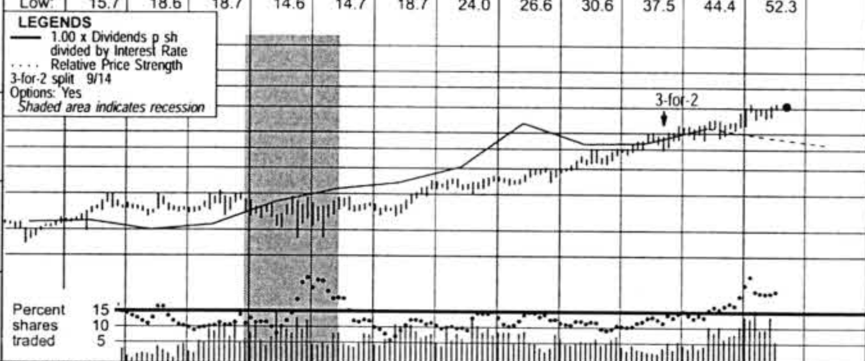
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	5	0	0	9	0
to Sell	0	1	2	0	0	1	0	0	1

Institutional Decisions

	3Q2015	4Q2015	1Q2016
to Buy	65	62	86
to Sell	55	72	66
Hld's(000)	8224	8284	8673

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	23.9	23.8	24.8	23.2	23.3	28.1	29.7	32.6	40.8	52.7	61.1	67.9
Low:	15.7	18.6	18.7	14.6	14.7	18.7	24.0	26.6	30.6	37.5	44.4	52.3



Target Price Range
2019 | 2020 | 2021
128
96
80
64
48
40
32
24
16
12

% TOT. RETURN 7/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.3	4.8
3 yr.	73.9	25.2
5 yr.	184.7	69.0

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
42.21	40.82	17.12	19.11	20.70	26.02	23.05	25.41	28.46	19.07	29.93	29.13	27.26	30.73	34.19	30.07	*29.40*	*30.60*	Revenues per sh	*37.50*
1.95	1.95	1.93	2.42	2.26	2.35	2.18	2.52	2.50	2.15	3.50	3.69	3.95	4.35	4.73	5.05	*5.35*	*5.55*	"Cash Flow" per sh	*7.00*
.93	.83	.69	1.17	1.09	1.18	1.15	1.29	1.39	1.43	1.82	1.91	1.99	2.26	2.47	2.68	*3.00*	*3.20*	Earnings per sh A	*4.00*
.71	.73	.73	.73	.75	.76	.77	.78	.81	.83	.87	.91	.96	1.01	1.07	1.12	*1.19*	*1.26*	Div'ds Decl'd per sh B■	*1.50*
2.75	3.61	1.77	1.39	2.07	3.74	4.87	3.08	3.00	1.89	3.18	3.28	5.00	6.72	6.66	9.47	*11.20*	*11.30*	Cap'l Spending per sh	*11.60*
8.05	8.26	8.03	8.59	9.07	9.60	11.08	11.76	12.02	14.89	15.84	16.78	17.82	19.28	20.59	23.45	*25.50*	*26.75*	Book Value per sh	*30.45*
7.95	8.09	8.31	8.49	8.60	8.82	10.03	10.17	10.24	14.09	14.29	14.35	14.40	14.46	14.59	15.27	*16.00*	*17.00*	Common Shs Outst'g C	*20.00*
12.6	15.0	18.6	12.7	15.0	16.8	17.9	16.7	14.2	14.2	12.2	14.2	14.8	15.6	17.7	19.1	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
.82	.77	1.02	.72	.79	.89	.97	.89	.85	.95	.78	.89	.94	.88	.93	.96	*Value Line*		Relative P/E Ratio	*1.25*
6.1%	5.8%	5.7%	4.9%	4.6%	3.8%	3.8%	3.6%	4.1%	4.1%	3.9%	3.4%	3.3%	2.9%	2.4%	2.2%	*estimates*		Avg Ann'l Div'd Yield	*1.9%*
						231.2	258.3	291.4	268.8	427.5	418.0	392.5	444.3	498.8	459.2	*470*	*520*	Revenues ($mill)	*750*
						10.5	13.2	14.4	15.9	26.1	27.6	28.9	32.8	36.1	40.2	*48.0*	*54.0*	Net Profit ($mill)	*80.0*
						39.4%	39.4%	39.1%	41.8%	39.7%	39.4%	40.1%	40.2%	39.9%	39.5%	*40.0%*	*40.0%*	Income Tax Rate	*41.0%*
						4.5%	5.1%	4.9%	5.9%	6.1%	6.6%	7.4%	7.4%	7.2%	8.8%	*10.2%*	*10.4%*	Net Profit Margin	*10.7%*
						39.0%	34.6%	41.3%	32.0%	28.4%	31.4%	28.4%	29.7%	34.5%	29.4%	*29.0%*	*29.0%*	Long-Term Debt Ratio	*30.0%*
						61.0%	65.4%	58.7%	68.0%	71.6%	68.6%	71.6%	70.3%	65.5%	70.6%	*71.0%*	*71.0%*	Common Equity Ratio	*70.0%*
						182.2	182.8	209.5	308.6	315.9	351.1	358.5	396.4	458.8	507.5	*575*	*640*	Total Capital ($mill)	*870*
						240.8	260.4	280.7	436.4	462.8	487.7	541.8	631.2	689.8	855.0	*950*	*1050*	Net Plant ($mill)	*1430*
						7.1%	8.4%	7.9%	6.1%	9.1%	8.9%	8.8%	8.8%	8.5%	8.9%	*9.0%*	*9.5%*	Return on Total Cap'l	*10.0%*
						9.5%	11.1%	11.7%	7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	*12.0%*	*12.0%*	Return on Shr. Equity	*13.0%*
						9.5%	11.1%	11.7%	7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	*12.0%*	*12.0%*	Return on Com Equity	*13.0%*
						4.1%	5.2%	5.2%	3.8%	6.6%	6.6%	6.4%	7.1%	7.4%	6.8%	*7.0%*	*7.0%*	Retained to Com Eq	*8.0%*
						57%	53%	55%	50%	42%	42%	43%	40%	38%	40%	*40%*	*40%*	All Div'ds to Net Prof	*38%*

CAPITAL STRUCTURE as of 6/30/16
Total Debt $336.0 mill. **Due in 5 Yrs** $230.0 mill.
LT Debt $143.9 mill. **LT Interest** $9.0 mill.
(LT interest earned: 7.7x; total interest coverage: 7.7x) (28% of Cap'l)
Leases, Uncapitalized Annual rentals $1.3 mill.
Pfd Stock None
Pension Assets-12/15 $51.0 mill. **Oblig.** $75.9 mill.
Common Stock 15,323,102 shs. **as of 7/31/16**

MARKET CAP: $1.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2014	2015	6/30/16
Cash Assets	4.6	2.9	3.3
Other	117.8	109.6	83.6
Current Assets	122.4	112.5	86.9
Accts Payable	44.6	39.3	35.5
Debt Due	97.3	182.5	192.1
Other	52.3	57.8	56.3
Current Liab.	194.2	279.6	283.9
Fix. Chg. Cov.	865%	898%	890%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	3.5%	4.0%	*3.0%*
"Cash Flow"	7.0%	11.5%	*7.0%*
Earnings	8.0%	10.0%	*8.5%*
Dividends	3.5%	5.0%	*6.0%*
Book Value	9.0%	8.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	140.7	94.1	86.6	122.9	444.3
2014	186.3	100.5	91.6	120.4	498.8
2015	170.1	92.7	91.9	104.5	459.2
2016	146.3	102.3	*96.7*	*124.7*	*470*
2017	*184*	*105*	*100*	*131*	*520*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	1.02	.30	.27	.67	2.26
2014	1.21	.35	.22	.69	2.47
2015	1.44	.35	.33	.56	2.68
2016	1.33	.52	*.45*	*.70*	*3.00*
2017	*1.46*	*.50*	*.50*	*.74*	*3.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.23	.23	.243	.243	.95
2013	.243	.243	.257	.257	1.00
2014	.257	.257	.27	.27	1.05
2015	.27	.27	.288	.288	1.12
2016	.288	.288	.305		

BUSINESS: Chesapeake Utilities Corporation consists of two units: Regulated Energy and Unregulated Energy. The Regulated Energy segment (65% of 2015 revenues) distributes natural gas in Delaware, Maryland, and Florida; distributes electricity in Florida; and transmits natural gas on the Delmarva Peninsula and in Florida. The Unregulated Energy operation (35% of 2015 revenues) wholesales and distributes propane; markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Officers and directors own 5.4% of common stock; T. Rowe Price, 8.3; BlackRock, 5.8% (3/16 Proxy). CEO: Michael P. McMasters. Inc.: Delaware. Address: 909 Silver Lake Boulevard, Dover, DE 19904. Tel.: (302) 734-6799. Internet: www.chpk.com.

Following a tough first quarter of 2016, Chesapeake Utilities' earnings came roaring back in the June interim. Indeed, share net stood at $0.52, close to 50% higher than the prior-year total of $0.35. One contributor was the Regulated Energy division, aided partially by natural gas transmission line expansions that were completed in 2015 and 2016. Benefits of additional Gas Reliability Infrastructure Program (GRIP) investments in the Florida natural gas distribution operations also helped here. Meanwhile, results of the Unregulated Energy segment were lifted by Aspire Energy (acquired in April, 2015) plus a decent performance from PESCO, the natural gas marketing subsidiary.

Finances are sufficient. Through the first six months, cash on hand amounted to $3.3 million and cash flows were decent. Meanwhile, long-term debt was just 28% of total capital, and short-term obligations did not appear to present a major obstacle. Too, the company possessed four unsecured bank credit facilities totaling $170 million. Moreover, it is capable of issuing more equity and debt, if necessary. All told, we think that Chesapeake is positioned to satisfy, for the time being, its capital requirements, which include investments in new plants and equipment and dividends.

***Value Line* expects a continuation of generally favorable trends during the second half.** Consequently, the bottom line stands to climb about 12%, to $3.00 a share, for the entire year. Looking at 2017, an advance of around 7%, to $3.20, seems plausible, assuming that operating margins expand further.

The stock has recovered some since our last full-page review in June. It appears that price movement reflects the company's good second-quarter profits. Note, also, the 2 (Above Average) rating for Safety, below-market Beta coefficient, and relatively high Price Stability grade of 85 (out of 100).

Steady dividend growth is probable out to the dawn of the next decade. Too, our projections indicate that the payout ratio over that span will be in the 35% to 40% range, which is quite manageable. For now, these shares are an Average selection for Timeliness.

Frederick L. Harris, III September 2, 2016

(A) Diluted shrs. Excludes nonrecurring items: '02, d23¢; '08, d7¢; '15, 6¢. Excludes discontinued operations: '03, d9¢; '04, d1¢. Next earnings report due early Nov.
(B) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available.
(C) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	90
Earnings Predictability	95

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 34.27 | P/E RATIO 20.2 (Trailing: 22.0 / Median: 16.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 2 Raised 6/10/16

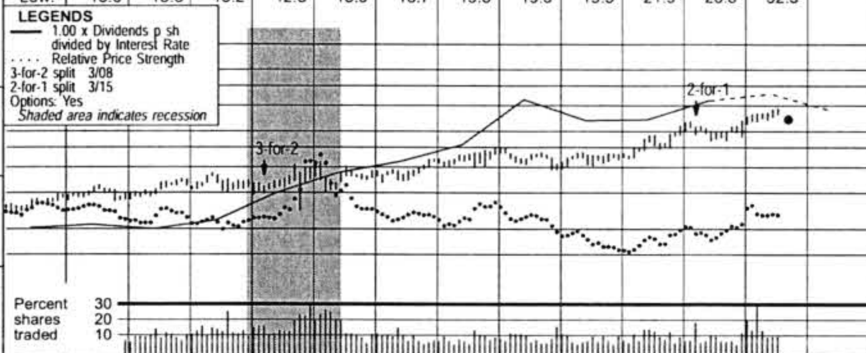
SAFETY 1 Raised 9/15/06

TECHNICAL 1 Raised 8/19/16

BETA .80 (1.00 = Market)

High:	16.4	17.7	18.8	20.6	21.2	22.0	25.2	25.1	23.8	32.1	34.1	38.9		Target Price Range 2019 / 2020 / 2021
Low:	13.6	13.8	15.2	12.3	15.0	16.7	19.8	19.3	19.5	21.9	26.8	32.3		

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/08
2-for-1 split 3/15
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(-10%)	*Nil*
Low	25	(-25%)	*-4%*

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	7	6	7	6	0	0	0	0	0
to Sell	0	0	0	0	0	4	0	1	0

Institutional Decisions

	3Q2015	4Q2015	1Q2016
to Buy	105	117	114
to Sell	103	94	114
Hld's(000)	49793	49713	51216

% TOT. RETURN 7/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	32.9	4.8
3 yr.	83.6	25.2
5 yr.	102.0	69.0

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
14.71	25.61	22.06	31.14	30.44	38.10	39.81	36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	*20.95*	*26.15*	Revenues per sh A	*28.60*
1.00	1.06	1.07	1.19	1.25	1.31	1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	*2.35*	*2.55*	"Cash Flow" per sh	*2.65*
.60	.65	.70	.79	.85	.88	.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	*1.60*	*1.80*	Earnings per sh B	*1.85*
.38	.39	.40	.41	.43	.45	.48	.51	.56	.62	.68	.72	.77	.81	.86	.93	*.96*	*.98*	Div'ds Decl'd per sh C■	*1.02*
.62	.55	.51	.57	.72	.64	.64	.73	.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	*1.70*	*1.75*	Cap'l Spending per sh	*1.80*
4.14	4.40	4.35	5.13	5.62	5.30	7.50	7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	*13.80*	*14.65*	Book Value per sh D	*17.15*
79.17	79.99	83.00	81.70	83.22	82.64	82.88	83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	*86.00*	*86.00*	Common Shs Outst'g E	*86.00*
14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.96	.73	.80	.80	.81	.89	.87	1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	*Value Line*		Relative P/E Ratio	*.90*
4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 6/30/16
Total Debt $1223.8 mill. Due in 5 Yrs $321.9 mill.
LT Debt $967.8 mill. LT Interest $25.4 mill.
Incl. $53.2 mill. capitalized leases.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Pension Assets-9/15 $256.4 mill. Oblig. $394.4 mill.

Pfd Stock None

Common Stock 86,150,280 shs. as of 8/1/16
MARKET CAP: $3.0 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
3299.6	3021.8	3816.2	2592.5	2639.3	3009.2	2248.9	3198.1	3738.1	2734.0	*1800*	*2250*	Revenues ($mill) A	*2460*
78.5	65.3	113.9	101.0	101.8	106.5	112.4	113.7	176.9	153.7	*140*	*155*	Net Profit ($mill)	*160*
38.9%	38.8%	37.8%	27.1%	41.4%	30.2%	7.1%	25.4%	30.2%	26.3%	*32.0%*	*32.0%*	Income Tax Rate	*32.0%*
2.4%	2.2%	3.0%	3.9%	3.9%	3.5%	5.0%	3.6%	4.7%	5.6%	*7.7%*	*6.9%*	Net Profit Margin	*6.5%*
34.8%	37.3%	38.5%	39.8%	37.2%	35.5%	39.2%	36.6%	38.2%	43.2%	*43.0%*	*43.0%*	Long-Term Debt Ratio	*40.5%*
65.2%	62.7%	61.5%	60.2%	62.8%	64.5%	60.8%	63.4%	61.8%	56.8%	*57.0%*	*57.0%*	Common Equity Ratio	*59.5%*
954.0	1028.0	1182.1	1144.8	1154.4	1203.1	1339.0	1400.3	1564.4	1950.6	*2090*	*2210*	Total Capital ($mill)	*2475*
934.9	970.9	1017.3	1064.4	1135.7	1295.9	1484.9	1643.1	1884.1	2128.3	*2170*	*2215*	Net Plant ($mill)	*2350*
9.6%	7.7%	10.7%	9.7%	9.7%	9.7%	9.2%	9.0%	12.1%	8.6%	*7.5%*	*8.0%*	Return on Total Cap'l	*7.5%*
12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	13.9%	*11.5%*	*12.5%*	Return on Shr. Equity	*11.0%*
12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	13.9%	*11.5%*	*12.5%*	Return on Com Equity	*11.0%*
6.3%	3.6%	9.5%	7.2%	6.7%	6.2%	6.2%	5.2%	11.0%	6.8%	*4.5%*	*5.5%*	Retained to Com Eq	*4.5%*
50%	64%	40%	50%	52%	55%	55%	59%	40%	50%	*60%*	*54%*	All Div'ds to Net Prof	*55%*

CURRENT POSITION ($MILL.)	2014	2015	6/30/16
Cash Assets	2.2	4.9	94.8
Other	680.5	539.6	509.9
Current Assets	682.7	544.5	604.7
Accts Payable	330.3	273.2	216.0
Debt Due	335.5	77.5	256.0
Other	125.3	85.4	129.5
Current Liab.	791.1	436.1	601.5
Fix. Chg. Cov.	1007%	750%	750%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	1.5%	1.0%	*-5.0%*
"Cash Flow"	6.5%	7.5%	*1.5%*
Earnings	7.5%	6.5%	*1.0%*
Dividends	7.0%	7.0%	*3.0%*
Book Value	8.0%	6.5%	*6.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	736.0	960.9	767.5	733.7	3198.1
2014	878.4	1579.6	688.3	591.9	3738.2
2015	824.1	1013.1	458.5	438.3	2734.0
2016	444.3	574.2	393.2	*388.3*	*1800*
2017	*550*	*690*	*510*	*500*	*2250*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	.43	.82	.12	d.01	1.37
2014	.47	1.79	.05	d.23	2.08
2015	.65	1.16	.03	d.06	1.78
2016	.58	.91	.13	*d.02*	*1.60*
2017	*.63*	*.96*	*.20*	*.01*	*1.80*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.19	.19	.19	.40	.97
2013	--	.20	.20	.20	.60
2014	.21	.21	.21	.23	.86
2015	.23	.23	.23	.24	.93
2016	.24	.24	.24		

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 512,300 customers at 9/30/15 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2015 volume: 341 bill. cu. ft. (14% interruptible, 21% residential and commercial and electric utility, 65% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2015 dep. rate: 2.5%. Has 991 empls. Off./dir. own about 1.4% of common (12/15 Proxy). Chrmn., CEO & Pres.: Laurence M. Downes. Inc.: NJ Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources posted mixed financial results for the June quarter. Revenues declined 14.2% on a year-over-year basis. This reflected a 19.9% downturn in non-utility volumes, partially offset by a 2.5% rise in utility volumes. The New Jersey Natural Gas (NJNG) regulated utility segment added 5,289 new customers during the first nine months of the year. Despite this increase in active customer meters, the downturn in natural gas prices resulted in that segment posting reduced top-line contributions. Meanwhile, on the profitability front, total operating expenses increased 520 basis points as a percentage of revenues. On the upside, other income and an income tax benefit helped to boost the bottom line. After excluding unrealized losses on derivatives NJR's third-quarter earnings rose more than threefold, to $0.13 a share. This was modestly below our earlier call of $0.15, but still represented a healthy improvement over 2015's easy comparison.

That said, we have left our 2016 and 2017 earnings estimates unchanged at $1.60 and $1.80, respectively. The NJNG regulated utility division is anticipated to add approximately 8,150 new customers this year. Assuming that business develops as planned, this should equate to roughly 24,000-28,000 additional active meters over the period from 2016-2018. However, the reduction in natural gas prices will likely be a primary detractor for this year's bottom line. Over the longer time frame, an active capital growth project program will likely take some time to bear fruit.

These shares have improved one notch in Timeliness, to 2 (Above Average). This suggests NJR will outpace the broader market averages in the coming year and may appeal to momentum accounts. However, the stock's quotation is trading above our Target Price Range, making it an unsuitable choice for the long term. From a fundamental standpoint, it is also trading at a somewhat rich price-to-earnings multiple, especially for a utility. Finally, when compared to other stocks in this industry, New Jersey Resources' dividend yield is a bit light. As a result, we think these shares are best-suited for short-term investors.

Bryan J. Fong *September 2, 2016*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late Oct.
(C) Dividends historically paid in early Jan., April, July, and October. 1Q '13 div'd paid in 4Q '12. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2015: $410.2 million, $4.82/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	55
Earnings Predictability	60

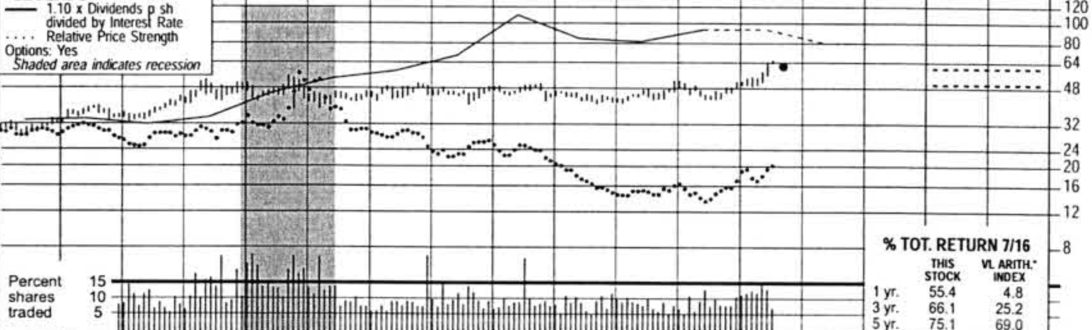
N.W. NAT'L GAS NYSE-NWN

RECENT PRICE **61.52** | P/E RATIO **27.7** (Trailing: 27.5 / Median: 18.0) | RELATIVE P/E RATIO **1.45** | DIV'D YLD **3.0%** | VALUE LINE

TIMELINESS 3 Lowered 8/12/16
SAFETY 1 Raised 3/18/05
TECHNICAL 1 Raised 8/26/16
BETA .65 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	39.6	43.7	52.8	55.2	46.5	50.9	49.0	50.8	46.6	52.6	52.3	66.2
Low:	32.4	32.8	39.8	37.7	37.7	41.1	39.6	41.0	40.0	40.1	42.0	48.9

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2019 | 2020 | 2021

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(Nil)	3%
Low	50	(-20%)	-1%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	3	0	4	12	3	0	4	6
to Sell	0	4	1	0	0	4	0	2	7

Institutional Decisions

	3Q2015	4Q2015	1Q2016
to Buy	69	81	98
to Sell	74	65	65
Hld's(000)	16793	16813	15946

Percent shares traded 15 / 10 / 5

% TOT. RETURN 7/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	55.4	4.8
3 yr.	66.1	25.2
5 yr.	75.1	69.0

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	**25.23**	**26.80**	Revenues per sh	**31.80**
3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	**4.70**	**5.00**	"Cash Flow" per sh	**6.35**
1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	**2.20**	**2.35**	Earnings per sh A	**3.15**
1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	**1.87**	**1.88**	Div'ds Decl'd per sh B■	**2.05**
3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	**4.70**	**6.45**	Cap'l Spending per sh	**6.80**
17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	**28.70**	**29.55**	Book Value per sh D	**32.85**
25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	**27.75**	**28.00**	Common Shs Outst'g C	**28.00**
12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	*Bold figures are*		Avg Ann'l P/E Ratio	**17.0**
.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	*Value Line*		Relative P/E Ratio	**1.05**
5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	*estimates*		Avg Ann'l Div'd Yield	**3.7%**
						1013.2	1033.2	1037.9	1012.7	812.1	848.8	730.6	758.5	754.0	723.8	**700**	**750**	Revenues ($mill)	**890**
						65.2	74.5	68.5	75.1	72.7	63.9	59.9	60.5	58.7	53.7	**61.0**	**66.0**	Net Profit ($mill)	**88.0**
						36.3%	37.2%	36.9%	38.3%	40.5%	40.4%	42.4%	40.8%	41.5%	40.0%	**40.0%**	**39.0%**	Income Tax Rate	**39.0%**
						6.4%	7.2%	6.6%	7.4%	8.9%	7.5%	8.2%	8.0%	7.8%	7.4%	**8.7%**	**8.8%**	Net Profit Margin	**9.9%**
						46.3%	46.3%	44.9%	47.7%	46.1%	47.3%	48.5%	47.6%	44.8%	42.5%	**43.0%**	**43.0%**	Long-Term Debt Ratio	**43.0%**
						53.7%	53.7%	55.1%	52.3%	53.9%	52.7%	51.5%	52.4%	55.2%	57.5%	**57.0%**	**57.0%**	Common Equity Ratio	**57.0%**
						1116.5	1106.8	1140.4	1261.8	1284.8	1356.2	1424.7	1433.6	1389.0	1357.7	**1395**	**1445**	Total Capital ($mill)	**1605**
						1425.1	1495.9	1549.1	1670.1	1854.2	1893.9	1973.6	2062.9	2121.6	2182.7	**2270**	**2360**	Net Plant ($mill)	**2655**
						7.1%	8.5%	7.7%	7.3%	7.0%	6.2%	5.7%	5.8%	5.8%	5.5%	**5.5%**	**5.5%**	Return on Total Cap'l	**6.5%**
						10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	6.9%	**7.5%**	**8.0%**	Return on Shr. Equity	**9.5%**
						10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	6.9%	**7.5%**	**8.0%**	Return on Com Equity	**9.5%**
						4.5%	6.0%	4.5%	5.0%	4.0%	2.4%	1.6%	1.5%	1.1%	.6%	**1.0%**	**1.0%**	Retained to Com Eq	**3.5%**
						59%	52%	59%	56%	61%	73%	80%	81%	85%	92%	**85%**	**80%**	All Div'ds to Net Prof	**65%**

CAPITAL STRUCTURE as of 6/30/16
Total Debt $747.9 mill. **Due in 5 Yrs** $360.0 mill.
LT Debt $570.1 mill. **LT Interest** $45.0 mill.

(Total interest coverage: 3.5x)

Pension Assets-12/15 $249.4 mill. **Oblig.** $445.6 mill.

Pfd Stock None

Common Stock 27,550,206 shares as of 7/22/16

MARKET CAP $1.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2014	2015	6/30/16
Cash Assets	9.5	4.2	5.5
Other	353.1	327.9	196.6
Current Assets	362.6	332.1	202.1
Accts Payable	91.4	73.2	57.8
Debt Due	274.7	295.0	177.8
Other	103.3	109.5	78.0
Current Liab.	469.4	477.7	313.6
Fix. Chg. Cov.	321%	300%	352%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	--	-5.5%	2.5%
"Cash Flow"	2.0%	-1.0%	4.0%
Earnings	1.0%	-5.0%	7.0%
Dividends	3.5%	3.0%	2.0%
Book Value	3.0%	2.5%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	277.9	131.7	88.2	260.7	758.5
2014	293.4	133.1	87.2	240.3	754.0
2015	261.7	138.3	93.1	230.7	723.8
2016	255.5	99.2	**95.0**	**250.3**	**700**
2017	**260**	**135**	**90.0**	**265**	**750**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	1.40	.08	d.31	1.07	2.24
2014	1.40	.04	d.32	1.04	2.16
2015	1.04	.08	d.24	1.08	1.96
2016	1.33	.07	**d.30**	**1.10**	**2.20**
2017	**1.35**	**.10**	**d.25**	**1.15**	**2.35**

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.445	.445	.445	.455	1.79
2013	.455	.455	.455	.460	1.83
2014	.460	.460	.460	.465	1.85
2015	.465	.465	.465	.4675	1.86
2016	.4675	.4675	.4675		

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 704,000 customers, in Oregon (89% 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, 35%; commercial, 22%; industrial, gas transportation, and other, 43%. Employs 1,092. BlackRock Inc. owns 10.0% of shares; officers and directors, 2.1% (4/16 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Gas reported steady second-quarter results. Earnings per share were mostly flat at $0.07, as the company benefited from decent customer growth and better gas storage results. Indeed, storage income increased $1.5 million year over year. Still, these factors were more than offset by a 7% decrease in natural gas volumes, which was caused by 22% warmer temperatures year over year, though a weather normalization mechanism helped somewhat. As we think the company will have decent second-half results, we have raised our 2016 earnings-per-share estimate by a dime to $2.20 a share.

The near-term picture is benefiting from solid meter additions in Portland. Indeed, total customer growth was 1.5% during the quarter, and the company should continue to benefit from housing starts in the area, with permits up 21% year over year. This should allow for better volumes in the years ahead. In addition, the higher usage of natural gas to power appliances is boosting overall demand.

Meanwhile, the Mist storage expansion project continues to make progress. The company's plan to provide storage services to PGE generating plants has received approval from regulatory boards, and the company is now working with Portland General Electric to evaluate construction project bids. The ultimate goal is the creation of facilities to handle 2.5 billion cubic feet of ready-to-use natural gas storage and a new pipeline. These are expected to be put into service in the winter of 2018-2019. This should allow for much higher long-term volumes and better earnings, which we think can reach $3.15 a share by decade's end.

Shares of Northwest Natural Gas are not appealing at the recent quotation. The shares have run up in price over the past three months, which has led them to trade above our long-term Target Price Range. Too, this caused the dividend yield to become less compelling, and the stock's P/E ratio to reach an unusually high level. Also, the payout is expected to be raised at a low rate over the long haul. Income-seekers would be best served looking elsewhere.

John E. Seibert III *September 2, 2016*

(A) Diluted earnings per share. Excludes nonrecurring items: '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 6¢; May not sum due to rounding. Next earnings report due in early November.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2015: $370.7 million, $13.52/share.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	90

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE	30.52	P/E RATIO	23.1 (Trailing: 20.8; Median: 17.0)	RELATIVE P/E RATIO	1.21	DIV'D YLD	3.6%	VALUE LINE

TIMELINESS **1** Raised 8/26/16

SAFETY **2** Lowered 1/4/91

TECHNICAL **2** Lowered 9/2/16

BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	16.2	17.1	20.6	20.3	20.4	27.1	29.0	29.0	31.1	30.6	30.4	32.0
Low:	12.5	12.8	15.6	12.6	16.0	18.6	21.4	22.9	25.3	25.9	21.2	22.1

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+15%)	7%
Low	25	(-20%)	-1%

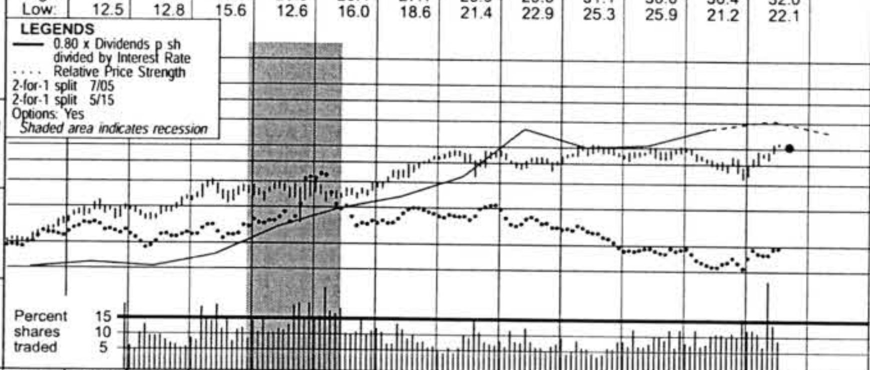
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	9	0	9	0	0	1
to Sell	0	0	0	0	0	1	1	0	0

Institutional Decisions

	3Q2015	4Q2015	1Q2016
to Buy	105	105	109
to Sell	59	72	77
Hld's(000)	42947	43333	46585

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
2-for-1 split 5/15
Options: Yes
Shaded area indicates recession



Target Price Range
2019 | 2020 | 2021

% TOT. RETURN 7/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	37.1	4.8
3 yr.	16.5	25.2
5 yr.	50.1	69.0

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
11.22	17.65	10.35	13.17	14.75	15.89	15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	*11.55*	*12.20*	Revenues per sh	*15.10*
.97	.95	1.06	1.12	1.22	1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.42	*2.30*	*2.45*	"Cash Flow" per sh	*2.95*
.54	.57	.61	.68	.79	.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.44	*1.32*	*1.40*	Earnings per sh A	*1.80*
.37	.37	.38	.39	.41	.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	*1.08*	*1.15*	Div'ds Decl'd per sh B ■	*1.40*
1.11	1.41	1.74	1.18	1.34	1.60	1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	4.87	*3.50*	*3.95*	Cap'l Spending per sh	*5.10*
3.62	3.91	4.84	5.63	6.20	6.75	7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	14.62	*16.90*	*18.30*	Book Value per sh C	*21.50*
46.00	47.44	48.83	52.92	55.52	57.96	58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.97	*80.00*	*82.00*	Common Shs Outst'g D	*86.00*
13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.9	**Bold figures are**		Avg Ann'l P/E Ratio	*16.0*
.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.90	**Value Line**		Relative P/E Ratio	*1.00*
5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.9%	**estimates**		Avg Ann'l Div'd Yield	*4.9%*

CAPITAL STRUCTURE as of 6/30/16
Total Debt $1221.1 mill. Due in 5 Yrs $1140 mill.
LT Debt $831.1 mill. LT Interest $25.0 mill.
(Total interest coverage: 5.1x)

Leases, Uncapitalized Annual rentals $.8 mill.
Pension Assets-12/15 $184.8 mill.
Oblig. $254.2 mill.

Pfd Stock None

Common Stock 79,477,822 shs.
as of 8/1/16

MARKET CAP: $2.4 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
931.4	956.4	962.0	845.4	925.1	828.6	706.3	731.4	887.0	959.6	*925*	*1000*	Revenues ($mill)	*1300*
72.0	61.8	67.7	71.3	81.0	87.0	93.3	97.1	104.0	99.0	*100*	*112*	Net Profit ($mill)	*150*
41.3%	41.9%	47.7%	23.0%	15.2%	22.4%	10.8%	--	10.8%	5.9%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
7.7%	6.5%	7.0%	8.4%	8.8%	10.5%	13.2%	13.3%	11.7%	10.3%	*10.8%*	*11.2%*	Net Profit Margin	*11.5%*
44.7%	42.7%	39.2%	36.5%	37.4%	40.5%	45.0%	45.1%	48.0%	49.2%	*41.5%*	*42.5%*	Long-Term Debt Ratio	*45.0%*
55.3%	57.3%	60.8%	63.5%	62.6%	59.5%	55.0%	54.9%	52.0%	50.8%	*58.5%*	*57.5%*	Common Equity Ratio	*55.0%*
801.1	839.0	848.0	856.4	910.1	1048.3	1337.6	1507.4	1791.9	2043.9	*2300*	*2600*	Total Capital ($mill)	*3350*
920.0	948.9	982.6	1073.1	1193.3	1352.4	1578.0	1859.1	2134.1	2448.1	*2550*	*2650*	Net Plant ($mill)	*2950*
10.1%	8.6%	8.9%	9.0%	9.5%	8.9%	7.4%	6.8%	6.4%	5.4%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	9.5%	*7.5%*	*7.5%*	Return on Shr. Equity	*8.0%*
16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	9.5%	*7.5%*	*7.5%*	Return on Com Equity	*8.0%*
10.2%	6.7%	6.7%	6.4%	7.1%	6.7%	5.8%	4.8%	4.3%	2.8%	*1.0%*	*1.0%*	Retained to Com Eq	*1.5%*
37%	48%	49%	51%	50%	52%	55%	59%	61%	71%	*86%*	*84%*	All Div'ds to Net Prof	*80%*

CURRENT POSITION ($MILL.)	2014	2015	6/30/16
Cash Assets	4.2	3.9	4.2
Other	562.5	427.4	371.6
Current Assets	566.7	431.3	375.8
Accts Payable	273.0	186.4	166.4
Debt Due	395.6	461.2	390.0
Other	181.6	184.9	202.0
Current Liab.	850.2	832.5	758.4
Fix. Chg. Cov.	432%	496%	475%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-1.5%	-4.0%	*3.0%*
"Cash Flow"	7.5%	6.0%	*2.5%*
Earnings	7.0%	4.0%	*3.0%*
Dividends	9.0%	9.5%	*6.5%*
Book Value	8.0%	8.5%	*8.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	255.6	122.6	128.8	224.4	731.4
2014	350.2	133.3	122.4	281.1	887.0
2015	383.0	177.7	141.1	257.8	959.6
2016	333.0	154.4	*150*	*287.6*	*925*
2017	*350*	*170*	*160*	*320*	*1000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.76	.16	d.02	.62	1.52
2014	1.01	.15	d.05	.47	1.57
2015	.86	.03	d.07	.62	1.44
2016	.80	.12	*d.10*	*.50*	*1.32*
2017	*.80*	*.10*	*d.06*	*.56*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	--	.202	.202	.423	.83
2013	--	.222	.222	.458	.90
2014	--	.237	.237	.488	.96
2015	--	.251	.251	.515	1.02
2016	--	.264	.264		

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 373,100 customers in New Jersey's southern counties. Gas revenue mix '15: residential, 45%; commercial, 22%; cogeneration and electric generation, 12%; industrial, 21%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 720 employees. Off./dir. own less than 1% of common shares; BlackRock, Inc., 10.5%; The Vanguard Group, Inc., 7.7% (3/16 proxy). Pres. & CEO: Michael J. Renna. Inc.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have come off an all-time high price lately. The company reported mixed results for the second quarter. The top line declined roughly 13%, on a year-over-year basis. The bottom-line picture was more favorable, with earnings per share of $0.12 advancing considerably from the prior-year period. This was largely due to improved operating performance at the energy production business, South Jersey Energy Services. Modest customer growth supported results at mainstay utility South Jersey Gas.

We expect unfavorable bottom-line comparisons in the third and fourth quarters, and lower earnings per share for the current year. A reduction in solar investments ought to produce a much lower contribution to earnings from investment tax credits going forward. On the bright side, we do envision healthy bottom-line improvement from 2017 onward. The addition of several fuel supply management contracts ought to benefit performance at the wholesale and retail commodity business, South Jersey Energy Group. The Energy Services division will likely perform well, too, and the company's interest in the PennEast pipeline should contribute to earnings growth. Elsewhere, prospects for the utility look fairly attractive. Natural gas remains the fuel of choice within its service territory. This business will probably continue to benefit from customer conversions to natural gas, considering its cost effectiveness compared with alternatives. Customer additions and significant infrastructure investment ought to drive earnings growth over the long haul.

This stock is ranked to outperform the broader market averages for the coming six to 12 months. Moreover, we envision healthy operating improvement for the company over the pull to late decade. However, the pluses look to be largely reflected in the recent quotation, and appreciation potential appears fairly limited for the pull to 2019-2021. Even so, income-seeking accounts may find the stock's healthy dividend yield attractive. Also, South Jersey earns high marks for Safety, Financial Strength, Price Stability, and Earnings Predictability.

Michael Napoli, CFA *September 2, 2016*

(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, $1.05; '08, $1.29; '09, $0.97; '10, $1.11; '11, $1.49; '12, $1.49; '13, $1.28; '14, $1.46; '15, $1.52. Excl. nonrecur. gain (loss): '01, $0.07; '08, $0.16; '09, ($0.22); '10, ($0.24); '11, $0.04; '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08. Egs. may not sum due to rounding. Next egs. report due early Nov. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2015: $521.0 mill., $7.34 per shr. (D) In mill., adj. for split.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	80

SPIRE INC. NYSE-SR

RECENT PRICE 66.63 | P/E RATIO 19.8 (Trailing: 20.8 Median: 14.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 8/12/16

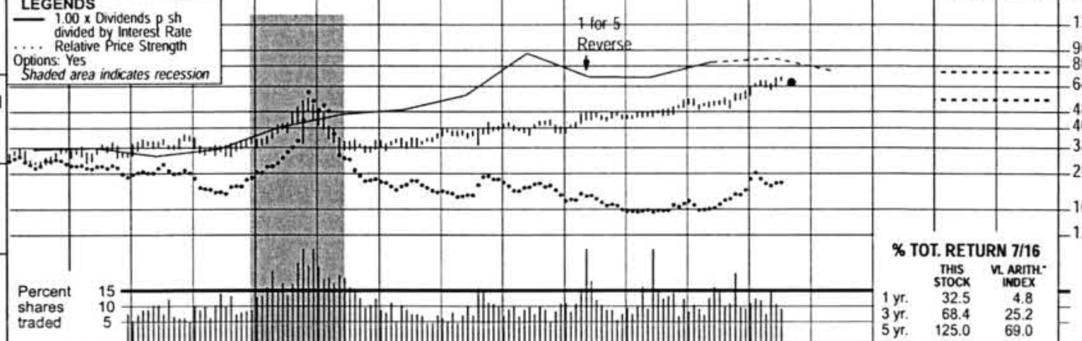
SAFETY 2 Raised 6/20/03

TECHNICAL 2 Lowered 9/2/16

BETA .70 (1.00 = Market)

High:	34.3	37.5	36.0	55.8	48.3	37.8	42.8	44.0	48.5	55.2	61.0	71.2		Target Price Range
Low:	26.9	29.1	28.8	31.9	29.3	30.8	32.9	36.5	37.4	44.0	49.1	57.1		2019 | 2020 | 2021

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+15%)	6%
Low	55	(-15%)	-1%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	6	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2015	4Q2015	1Q2016
to Buy	102	114	109
to Sell	95	86	104
Hld's(000)	35808	34753	35632

% TOT. RETURN 7/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	32.5	4.8
3 yr.	68.4	25.2
5 yr.	125.0	69.0

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	*35.85*	*40.45*	Revenues per sh A	*53.00*
2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	*6.10*	*6.55*	"Cash Flow" per sh	*7.40*
1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	*3.25*	*3.50*	Earnings per sh A B	*4.20*
1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	*1.93*	*1.97*	Div'ds Decl'd per sh C ■	*2.20*
2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	*6.85*	*6.90*	Cap'l Spending per sh	*7.10*
14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	*36.45*	*38.00*	Book Value per sh D	*42.70*
18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	*46.00*	*47.00*	Common Shs Outst'g E	*48.00*
14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.97	.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.84	*Value Line*		Relative P/E Ratio	*.95*
6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 6/30/16
Total Debt $1949.1 mill. Due in 5 Yrs $525.0 mill.
LT Debt $1851.5 mill. LT Interest $70.0 mill.
(Total interest coverage: 4.2x)

Leases, Uncapitalized Annual rentals $11.0 mill.
Pension Assets-9/15 $448.9 mill. Oblig. $652.3 mill.

Pfd Stock None
Common Stock 45,640,580 shs. as of 7/29/16

MARKET CAP: $3.0 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
1997.6	2021.6	2209.0	1895.2	1735.0	1603.3	1125.5	1017.0	1627.2	1976.4	*1650*	*1900*	Revenues ($mill) A	*2650*
50.5	49.8	57.6	64.3	54.0	63.8	62.6	52.8	84.6	136.9	*150*	*160*	Net Profit ($mill)	*210*
32.5%	33.4%	31.3%	33.6%	33.4%	31.4%	29.6%	25.0%	27.6%	31.2%	*28.0%*	*28.0%*	Income Tax Rate	*30.0%*
2.5%	2.5%	2.6%	3.4%	3.1%	4.0%	5.6%	5.2%	5.2%	6.9%	*9.1%*	*8.7%*	Net Profit Margin	*7.9%*
49.5%	45.3%	44.4%	42.9%	40.5%	38.9%	36.1%	46.6%	55.1%	53.0%	*52.5%*	*52.0%*	Long-Term Debt Ratio	*51.5%*
50.4%	54.6%	55.5%	57.1%	59.5%	61.1%	63.9%	53.4%	44.9%	47.0%	*47.5%*	*48.0%*	Common Equity Ratio	*48.5%*
798.9	784.5	876.1	906.3	899.9	937.7	941.0	1959.0	3359.4	3345.1	*3535*	*3735*	Total Capital ($mill)	*4395*
763.8	793.8	823.2	855.9	884.1	928.7	1019.3	1776.6	2759.7	2941.2	*3090*	*3245*	Net Plant ($mill)	*3755*
8.4%	8.5%	8.1%	8.7%	7.4%	8.1%	7.9%	3.3%	3.1%	5.1%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.0%*
12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	*9.0%*	*9.0%*	Return on Com Equity	*10.0%*
5.1%	4.3%	5.2%	5.9%	3.6%	4.9%	4.3%	1.0%	1.5%	3.7%	*3.5%*	*4.0%*	Retained to Com Eq	*5.0%*
59%	63%	56%	53%	64%	56%	59%	81%	73%	58%	*60%*	*57%*	All Div'ds to Net Prof	*50%*

CURRENT POSITION ($MILL.)	2014	2015	6/30/16
Cash Assets	16.1	13.8	4.9
Other	588.8	516.3	448.5
Current Assets	604.9	530.1	453.4
Accts Payable	176.7	146.5	135.8
Debt Due	287.1	418.0	97.6
Other	319.0	289.3	258.4
Current Liab.	782.8	853.8	491.8
Fix. Chg. Cov.	360%	365%	421%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-5.0%	-15.5%	*6.5%*
"Cash Flow"	4.0%	0.5%	*9.5%*
Earnings	3.0%	-1.0%	*9.0%*
Dividends	2.5%	3.0%	*3.5%*
Book Value	7.5%	8.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	307.0	397.6	165.3	147.1	1017.0
2014	468.6	694.5	241.8	222.3	1627.2
2015	619.6	877.4	275.2	204.2	1976.4
2016	399.4	609.3	249.3	*342*	*1650*
2017	*475*	*775*	*250*	*400*	*1900*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	1.14	1.34	.25	d.30	2.02
2014	1.09	1.59	.33	d.35	2.35
2015	1.09	2.18	.32	d.43	3.16
2016	1.08	2.31	.24	*d.38*	*3.25*
2017	*1.20*	*2.30*	*.30*	*d.30*	*3.50*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.415	.415	.415	.415	1.66
2013	.425	.425	.425	.425	1.70
2014	.44	.44	.44	.44	1.76
2015	.46	.46	.46	.46	1.84
2016	.49	.49	.49		

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City. Has roughly 1.6 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2015: 2.7 bill. Revenue mix for regulated operations: residential, 66%; commercial and industrial, 24%; transportation, 2%; other, 8%. Has around 3,078 employees. Officers and directors own 3.2% of common shares (1/16 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Spire Inc. reported lackluster fiscal third-quarter results (ended June 30). Revenues dipped to $249.3 million, hurt by lower commodity prices but partially offset by higher volumes. Too, gas and marketing income retreated year over year. This led earnings per share to fall to $0.24. As we expect a higher share count and depressed commodity costs to weigh on fiscal fourth-quarter results, we have trimmed our fiscal 2016 full-year earnings-per-share estimate by $0.15, to $3.25.

The regulatory environment is causing some near-term concerns. The Office of Public Council has questioned the return on equity and the impact of Spire's pending acquisition of two gas utilities (more below) on Missouri customers. A negative outcome could cause customer givebacks. Meantime, Spire will file new rate cases for its Missouri Gas and Laclede Gas subsidiaries in April of 2017. These efforts should impact profitability.

The acquisitions of Mobile Gas and Willmut Gas appear to be on track. Spire will pay $344 million in order to gain the customer bases in Alabama and Mississippi; the deal is set to close by calendar yearend. The company has firmed up financing, including the sale of 2.2 million shares, which raised $138 million. Too, it has debt commitments lined up for $165 million on the transaction's completion. This deal should be earnings accretive in fiscal 2018, with cost synergies driving further gains thereafter.

Infrastructure builds should improve long-term earnings. The company has made progress on its Spire STL pipeline, which ought to lower distribution costs of natural gas and have higher allowable returns on equity. Infrastructure expenditures are expected to be above $1.8 billion over the next five years. With infrastructure replacement surcharges built into service contracts, Spire should benefit from better reliability.

Shares of Spire offer decent current income. An Above-Average Safety rank (2) adds appeal. Yet, although the yield is better than the industry mean, total return potential is limited, given that the shares are trading within our long-term Target Price Range. Most investors would do best waiting for a dip in price.

John E. Seibert III *September 2, 2016*

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late October. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '14: $383.8 mill., $8.85/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	100
Price Growth Persistence	40
Earnings Predictability	85

UGI CORP. NYSE-UGI

RECENT PRICE 45.40 | P/E RATIO 20.8 (Trailing: 21.4 Median: 15.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 2.1% | VALUE LINE

TIMELINESS **2** Lowered 7/29/16

SAFETY **2** Raised 9/17/04

TECHNICAL **2** Raised 8/26/16

BETA .90 (1.00 = Market)

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(-25%)	-3%
Low	30	(-35%)	-7%

Insider Decisions

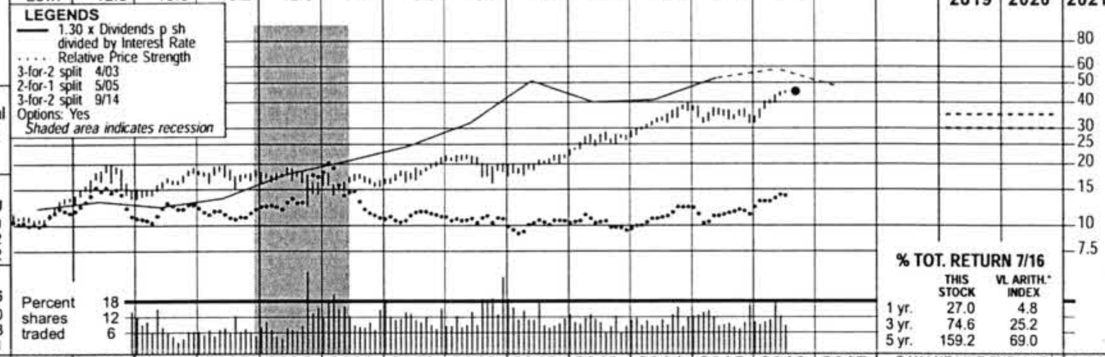
	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	1	7	4	1	0	3	2
to Sell	0	0	0	0	2	2	0	3	2

Institutional Decisions

	3Q2015	4Q2015	1Q2016
to Buy	141	170	170
to Sell	171	141	158
Hld's(000)	134852	133006	134051

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	20.0	19.3	19.8	19.2	18.3	21.7	22.4	22.4	28.8	39.7	38.6	46.5
Low:	12.8	13.5	15.2	12.5	14.1	15.9	16.0	17.3	21.9	26.8	31.5	31.6

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 4/03
2-for-1 split 5/05
3-for-2 split 9/14
Options: Yes
Shaded area indicates recession



% TOT. RETURN 7/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.0	4.8
3 yr.	74.6	25.2
5 yr.	159.2	69.0

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
14.50	20.09	17.76	23.62	24.63	31.10	33.01	34.24	41.27	35.25	34.01	36.31	38.56	42.10	47.92	38.65	*34.30*	*39.45*	Revenues per sh A	*45.65*
1.16	1.32	1.36	1.59	1.63	2.09	2.05	2.26	2.48	2.82	2.87	2.75	3.05	3.75	4.05	4.20	*4.40*	*4.65*	"Cash Flow" per sh	*5.20*
.35	.47	.60	.76	.81	1.15	1.10	1.18	1.33	1.57	1.59	1.37	1.17	1.59	1.92	2.01	*2.10*	*2.25*	Earnings per sh AB	*2.70*
.34	.35	.36	.38	.40	.43	.46	.48	.50	.52	.60	.68	.71	.74	.79	.89	*.94*	*.95*	Div'ds Decl'd per sh C ■	*1.04*
.58	.64	.76	.79	.87	1.01	1.21	1.39	1.44	1.85	2.11	2.15	2.01	2.84	2.64	2.83	*3.00*	*3.15*	Cap'l Spending per sh	*3.25*
2.04	2.08	2.55	4.45	5.43	6.35	6.95	8.26	8.80	9.78	11.10	11.79	13.21	14.59	15.39	15.55	*17.05*	*18.40*	Book Value per sh D	*22.30*
121.47	122.83	124.66	128.10	153.63	157.20	158.18	159.97	161.09	162.78	164.38	167.75	169.06	170.88	172.73	173.12	*170.00*	*175.00*	Common Shs Outst'g E	*170.00*
13.6	12.1	11.4	12.6	13.4	13.8	14.0	15.1	13.3	10.3	10.9	15.0	16.4	15.4	15.8	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*12.0*
.88	.62	.62	.72	.71	.73	.76	.80	.80	.69	.69	.94	1.04	.87	.83	.90	*Value Line*		Relative P/E Ratio	*.75*
7.0%	6.2%	5.3%	3.9%	3.7%	2.7%	3.0%	2.7%	2.9%	3.2%	3.5%	3.3%	3.7%	3.0%	2.6%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*
						5221.0	5476.9	6648.2	5737.8	5591.4	6091.3	6519.2	7194.7	8277.3	6691.1	*6000*	*6900*	Revenues ($mill) A	*7765*
						176.2	191.8	215.5	258.5	261.0	232.9	199.4	278.1	337.2	353.8	*380*	*405*	Net Profit ($mill)	*470*
						30.5%	23.8%	30.6%	29.4%	32.0%	29.8%	34.8%	27.6%	30.6%	30.0%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
						3.4%	3.5%	3.2%	4.5%	4.7%	3.8%	3.1%	3.9%	4.1%	5.3%	*6.3%*	*5.9%*	Net Profit Margin	*6.0%*
						64.1%	60.7%	58.4%	56.2%	44.0%	51.6%	60.0%	58.7%	56.4%	56.1%	*56.0%*	*54.0%*	Long-Term Debt Ratio	*50.0%*
						35.9%	39.3%	41.6%	43.8%	56.0%	48.4%	40.0%	41.3%	43.6%	43.9%	*44.0%*	*46.0%*	Common Equity Ratio	*50.0%*
						3064.6	3360.7	3405.0	3630.0	3256.7	4088.0	5580.7	6034.7	6092.7	6133.8	*6760*	*7000*	Total Capital ($mill)	*7585*
						2214.7	2397.4	2449.5	2903.6	3053.2	3204.5	4233.1	4480.2	4543.7	4994.1	*5490*	*6035*	Net Plant ($mill)	*8000*
						7.5%	7.4%	7.9%	8.9%	10.1%	7.4%	5.6%	6.6%	7.5%	7.7%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
						16.0%	14.5%	15.2%	16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	13.1%	*12.5%*	*12.5%*	Return on Shr. Equity	*12.5%*
						16.0%	14.5%	15.2%	16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	13.1%	*12.5%*	*12.5%*	Return on Com Equity	*12.5%*
						9.4%	8.7%	9.5%	10.9%	8.9%	6.0%	3.6%	6.1%	7.6%	7.4%	*7.5%*	*7.5%*	Retained to Com Eq	*7.5%*
						41%	40%	38%	33%	38%	49%	60%	45%	40%	43%	*43%*	*41%*	All Div'ds to Net Prof	*37%*

CAPITAL STRUCTURE as of 6/30/16
Total Debt $4300.9 mill. **Due in 5 Yrs** $2124 mill.
LT Debt $3774.7 mill. **LT Interest** $242 mill.
(Total interest coverage: 4.2x)

Leases, Uncapitalized Annual rentals $73.4 mill.
Pension Assets-9/15 $472 mill. **Oblig.** $466 mill.

Pfd Stock None

Common Stock 173,246,168 shares as of 7/31/16

MARKET CAP: $7.9 bill. (Mid. Cap)

CURRENT POSITION ($MILL.)	2014	2015	6/30/16
Cash Assets	419.5	369.7	909.2
Other	1243.5	1090.1	972.9
Current Assets	1663.0	1459.8	1882.1
Accts Payable	459.8	392.9	337.0
Debt Due	288.0	447.9	526.2
Other	683.1	838.1	726.1
Current Liab.	1430.9	1678.9	1589.3
Fix. Chg. Cov.	338%	338%	340%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	5.0%	3.0%	*1.0%*
"Cash Flow"	8.5%	8.0%	*4.5%*
Earnings	7.5%	4.0%	*4.0%*
Dividends	7.0%	8.5%	*4.0%*
Book Value	11.0%	9.0%	*6.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	2018	2542	1374	1259	7194.7
2014	2316	3163	1486	1311	8277.3
2015	2005	2456	1148	1082	6691.1
2016	1607	1972	1131	*1289*	*6000*
2017	*1830*	*2195*	*1355*	*1520*	*6900*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	.60	.99	.09	d.09	1.59
2014	.70	1.23	.10	d.11	1.92
2015	.66	1.23	.03	.01	2.01
2016	.64	1.24	.23	*d.01*	*2.10*
2017	*.68*	*1.28*	*.27*	*.02*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.175	.175	.18	.18	.71
2013	.18	.18	.19	.19	.74
2014	.19	.19	.20	.22	.80
2015	.22	.22	.23	.23	.90
2016	.23	.238	.238		

BUSINESS: UGI Corp. operates six business segments: AmeriGas Propane (accounted for 21.7% of net income in 2015), UGI International (18.8%), Gas Utility (41.2%), Midstream & Marketing (38.8%), and Corp. & Other -21%. UGI Utilities distributes natural gas and electricity to over 617,000 customers mainly in Pennsylvania; 27%-owned AmeriGas Partners is the largest U.S. propane marketer, serving about 1.3 million users in 50 states. Acquired remaining 80% interest in Antargaz (3/04); Energy Transfer Partners (1/12). Wellington Management Co. holds 9.6% of stock; officers/dir., about 3% (12/15 proxy). Has 8,500 empls. CEO: John L. Walsh. Inc.: PA. Address: 460 N. Gulph Rd., King of Prussia, PA 19406. Telephone: 610-337-1000. Internet: www.ugicorp.com.

UGI Corp. registered somewhat mixed financial results for the June period. Indeed, the company's revenues declined 1.5% on a year-over-year basis, to roughly $1.131 billion. This reflected reduced contributions from the AmeriGas Propane, UGI Utilities, and Midstream & Marketing divisions, partially offset by higher volumes at the UGI International segment. We view this largely as a technicality owing to the sharp downturn in commodity prices when compared to last year's figures. On the profitability front, total expenses declined 890 basis points as a percentage of the top line. All told, these factors equated to an almost sevenfold advance in the bottom line, to $0.23 a share. This handily beat our earlier call of $0.11.

Consequently, we have raised our fiscal 2016 (ends September 30th) earnings estimate by a nickel, to $2.10 a share. This would represent an annual earnings increase of approximately 4.5%. This uptick in profits is in direct contrast to our top-line forecast, which calls for a dip of more than 10%. That said, the bulk of the diminished revenues can be attributed to the weak commodity prices. Although this trend hurts revenues, however, it also benefits UGI from reduced cost of goods sold. Additional gains should come from the six bolt-on acquisitions at the AmeriGas segment, which should boost throughput by about 10 million gallons annually.

Growth projects augur well for the company's prospects. The $160 million Sunbury Pipeline project has been fully approved by FERC and should be in service by next summer. The PennEast project is progressing along nicely and could be in service by the second half of 2018. Finally, the LNG liquification unit in Manning, PA could be on line by January, 2017. This would add much-needed capacity. Meantime, the pending rate case with the Pennsylvania Public Utility Commission would allow UGI to recoup about $27 million annually. Those new rates may go into effect as early as mid-October.

These shares are timely. However, the dividend yield is light, and with the stock trading above our Target Price Range, those seeking total return potential would do well to take a pass.

Bryan J. Fong *September 2, 2016*

(A) Fiscal year ends Sept. 30. Quarterly sales and earnings may not sum to total due to rounding and/or change in share count. (B) Diluted earnings. Excludes nonrecur. items: '99, 13¢; '01, d1¢; '03, 22¢; '04, d6¢; '05, 3¢; '06, 5¢; '07, 12¢. Next egs. report due late Oct. (C) Dividends historically paid in early Jan., April, July, and Oct. ■ Div. reinvest. plan available. (D) Incl. intang. At 9/15: $3,564 mill., $20.61/sh. (E) In mill., adjusted for stock splits.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	85
Earnings Predictability	75

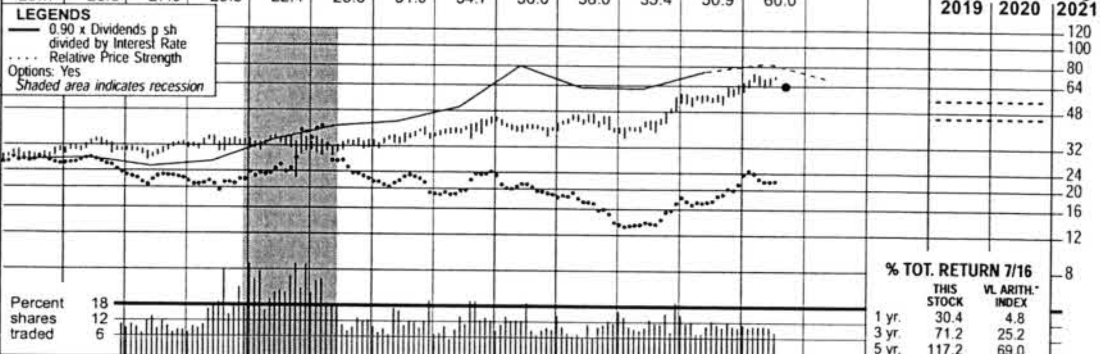
WGL HOLDINGS NYSE-WGL

RECENT PRICE 64.09 | P/E RATIO 20.0 (Trailing: 20.9, Median: 15.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 2 Raised 8/12/16
SAFETY 1 Raised 4/2/93
TECHNICAL 1 Raised 8/19/16
BETA .75 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	34.8	33.6	35.9	37.1	35.5	40.0	45.0	45.0	47.0	56.8	65.6	74.1
Low:	28.8	27.0	29.8	22.4	28.6	31.0	34.7	36.0	38.0	35.4	50.9	60.0

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2019 | 2020 | 2021

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(-15%)	Nil
Low	45	(-30%)	-4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	13	0	0	9	0	0	0	0	0
to Sell	1	0	0	0	1	2	0	1	0

Institutional Decisions

	3Q2015	4Q2015	1Q2016
to Buy	109	123	126
to Sell	113	106	121
Hld's(000)	32753	33248	34219

Percent shares traded 18 / 12 / 6

% TOT. RETURN 7/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	30.4	4.8
3 yr.	71.2	25.2
5 yr.	117.2	69.0

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	53.98	53.60	53.75	47.07	47.70	53.73	53.43	*46.55*	*51.90*	Revenues per sh A	*53.65*
3.20	3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	4.01	4.53	4.29	4.80	5.60	*5.50*	*5.70*	"Cash Flow" per sh	*6.00*
1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	2.25	2.68	2.31	2.68	3.16	*3.10*	*3.30*	Earnings per sh B	*3.30*
1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.47	1.50	1.55	1.59	1.66	1.72	1.83	*1.93*	*1.99*	Div'ds Decl'd per sh C ■	*2.05*
2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	2.77	2.57	3.94	4.87	6.04	7.63	9.33	*16.35*	*17.30*	Cap'l Spending per sh	*19.10*
15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	21.89	22.82	23.49	24.64	24.65	24.08	24.97	*27.00*	*29.00*	Book Value per sh D	*34.60*
46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.14	50.54	51.20	51.52	51.70	51.76	49.78	*51.00*	*52.00*	Common Shs Outst'g E	*55.00*
14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	12.6	15.1	17.0	15.3	18.2	15.2	17.0	Bold figures are		Avg Ann'l P/E Ratio	*15.0*
.95	.75	1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	.97	1.02	.80	.86	Value Line		Relative P/E Ratio	*.95*
4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	4.6%	4.4%	4.1%	3.9%	3.9%	4.2%	3.4%	estimates		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 6/30/16
Total Debt $1552.6 mill. Due in 5 Yrs $329.3 mill.
LT Debt $1194.3 mill. LT Interest $50.5 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x) (45% of Total Capital)
Pension Assets-9/15 $1,218.7 mill. Oblig. $1,218.7 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 51,059,773 shs. as of 7/31/16

MARKET CAP: $3.3 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
2637.9	2646.0	2628.2	2706.9	2708.9	2751.5	2425.3	2466.1	2780.9	2659.8	*2375*	*2700*	Revenues ($mill) A	*2950*
96.0	102.9	122.9	128.7	115.0	115.5	138.4	119.7	139.0	158.2	*155*	*170*	Net Profit ($mill)	*185*
39.0%	39.1%	37.1%	39.1%	38.7%	42.4%	40.1%	30.2%	29.0%	39.9%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
3.6%	3.9%	4.7%	4.8%	4.2%	4.2%	5.7%	4.9%	5.0%	5.9%	*6.6%*	*6.1%*	Net Profit Margin	*6.2%*
37.8%	37.9%	35.9%	33.3%	33.4%	32.3%	31.2%	28.7%	34.8%	42.6%	*41.5%*	*41.5%*	Long-Term Debt Ratio	*43.5%*
60.4%	60.3%	62.4%	65.0%	65.0%	66.2%	67.3%	69.8%	63.8%	56.1%	*57.5%*	*57.0%*	Common Equity Ratio	*55.5%*
1526.1	1625.4	1679.5	1687.7	1774.4	1818.1	1886.9	1826.8	1954.0	2215.6	*2405*	*2635*	Total Capital ($mill)	*3430*
2067.9	2150.4	2208.3	2269.1	2346.2	2489.9	2667.4	2907.5	3314.4	3672.7	*4070*	*4510*	Net Plant ($mill)	*6135*
7.6%	7.6%	8.5%	8.8%	7.6%	7.5%	8.3%	7.5%	8.1%	8.3%	*8.0%*	*7.5%*	Return on Total Cap'l	*7.0%*
10.1%	10.2%	11.4%	11.4%	9.7%	9.4%	10.7%	9.2%	10.9%	12.4%	*11.5%*	*11.0%*	Return on Shr. Equity	*9.5%*
10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	10.8%	9.3%	11.0%	12.6%	*11.5%*	*11.0%*	Return on Com Equity	*9.5%*
3.2%	3.5%	5.0%	5.0%	3.3%	3.4%	4.8%	2.6%	4.3%	5.4%	*4.0%*	*4.5%*	Retained to Com Eq	*3.5%*
69%	66%	57%	57%	67%	64%	56%	72%	62%	58%	*63%*	*61%*	All Div'ds to Net Prof	*62%*

CURRENT POSITION ($MILL.)	2014	2015	6/30/16
Cash Assets	8.8	6.7	16.5
Other	826.7	774.7	804.1
Current Assets	835.5	781.4	820.6
Accts Payable	313.2	325.1	333.2
Debt Due	473.5	357.0	358.3
Other	233.6	300.8	303.4
Current Liab.	1020.3	982.9	994.9
Fix. Chg. Cov.	535%	535%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	1.5%	-.5%	0.5%
"Cash Flow"	2.0%	2.5%	3.5%
Earnings	2.5%	2.5%	3.5%
Dividends	3.0%	3.5%	2.5%
Book Value	4.0%	2.5%	6.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	686.7	891.4	478.1	409.9	2466.1
2014	680.5	1174.0	467.5	458.9	2780.9
2015	749.2	1001.7	441.2	467.7	2659.8
2016	613.4	835.7	440.6	*485.3*	*2375*
2017	*695*	*915*	*520*	*570*	*2700*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2013	1.14	1.75	d.03	d.55	2.31
2014	.99	1.84	.02	d.17	2.68
2015	1.16	2.02	.22	d.23	3.16
2016	1.18	1.78	.33	*d.19*	*3.10*
2017	*1.23*	*1.83*	*.38*	*d.14*	*3.30*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.39	.40	.40	.40	1.59
2013	.40	.42	.42	.42	1.66
2014	.42	.44	.44	.44	1.74
2015	.44	.463	.463	.463	
2016	.463	.488	.488		

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 (1,129,865 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. BlackRock, Inc. owns 8.7% of common stock; Off./dir. less than 1% (1/16 proxy). Chrmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings logged mixed financial results for the June quarter. Revenues receded modestly. This reflected an almost 2% drop in utility volumes, partially offset by a 1.2% rise in the nonutility business. However, we view the apparent weakness in the regulated utility business as more of a technicality, owing to the year-over-year decline in natural gas prices. On the margin front, operating expenses fell 710 basis points as a percentage of the top line. After accounting for rising earnings from unconsolidated affiliates and reduced interest costs, the bottom line increased 50%, to $0.33 a share. This handily beat our earlier call of $0.21.

Consequently, we have raised our fiscal 2016 and 2017 (ends September 30th) share-net estimates by a dime each, to $3.10 and $3.30, respectively. In the current year, this would still represent a moderate earnings shortfall of almost 2%. The top line is anticipated to decline more than 10% this year due to sustained pressure on natural gas prices as well as a general slowdown in natural gas consumption patterns in WGL's primary service territory. On the upside, the company continues to add new customer accounts. Over the past 12 months, the regulated utility division added about 12,100 active meters. The Commercial Energy Systems and Midstream Energy Services units have been nicely complementary this year. Finally, recently filed rate cases in Virginia and the District of Columbia augur well for recouping costs associated with WGL's infrastructure program.

The Constitution Pipeline has been delayed. Management believes the venture could be in service in the second half of 2018. WGL has a 10% stake in that pipeline. Unfortunately, the decision by the NY State Department of Environmental Conservation to deny the water quality certificate is adding uncertainty here.

The balance sheet is in good shape. Although long-term debt advanced a bit more than 25%, it still represents a pretty standard percentage of total capital for a utility. Finances are solid enough to support the decent dividend.

These shares are timely. But the run-up in price over the past two years places WGL above our Target Price Range.

Bryan J. Fong — *September 2, 2016*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late Oct. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '15: $705.8 million, $14.18/sh.
(E) In millions.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	75

ATTACHMENT 3

(•) US Markets are closed

S&P 500	Dow 30	Nasdaq	Crude Oil
2,204.66	19,121.60	5,379.92	45.23
2.94 (0.13 %)	23.70 (0.12 %)	11.11 (0.21 %)	-1.85 (-3.93%)

Atmos Energy Corporation (ATO)

☆ Add to watchlist

NYSE - NYSE Real Time Price. Currency in USD

Quote Lookup

74.15 +1.45 (+1.99%)

At close: 4:02 PM EST

People also watch:
WGL PNY NWN VVC NJR

Summary Conversations Statistics Profile Financials Options Holders Historical Data Analysts

Currency in USD

Earnings Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	7	N/A	11	10
Avg. Estimate	1.03	N/A	3.53	3.77
Low Estimate	1.01	N/A	3.45	3.63
High Estimate	1.1	N/A	3.58	3.87
Year Ago EPS	0.93	1.4	3.37	3.53

Revenue Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	4	2	6	6
Avg. Estimate	899.94M	1.04B	3.46B	3.58B
Low Estimate	679.23M	901.94M	2.47B	2.73B
High Estimate	1.04B	1.18B	3.87B	4B
Year Ago Sales	906.22M	1.13B	3.35B	3.46B
Sales Growth (year/est)	-0.70%	-8.10%	3.30%	3.50%

Earnings History	12/30/2015	3/30/2016	6/29/2016	9/29/2016
EPS Est.	1.01	1.4	0.59	0.32
EPS Actual	0.93	1.4	0.67	0.39
Difference	-0.08	N/A	0.08	0.07
Surprise %	-7.90%	N/A	13.60%	21.90%

EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
Current Estimate	1.03	N/A	3.53	3.77
7 Days Ago	1.03	1.44	3.53	3.76

EPS Trend	Current Qtr.	Next Qtr	Current Year	Next Year
30 Days Ago	1.01	1.44	3.52	3.76
60 Days Ago	1.01	1.44	3.52	3.76
90 Days Ago	1.03	1.43	3.53	3.78

EPS Revisions	Current Qtr.	Next Qtr	Current Year	Next Year
Up Last 7 Days	N/A	N/A	1	N/A
Up Last 30 Days	N/A	N/A	2	N/A
Down Last 30 Days	N/A	N/A	N/A	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Estimates	ATO	Industry	Sector	S&P 500
Current Qtr.	10.80%	0.22		
Next Qtr.	N/A	0.43		
Current Year	4.70%	0.13		
Next Year	6.80%	0.03		
Next 5 Years (per annum)	7.30%	0.05		
Past 5 Years (per annum)	38.26%	N/A		

Recommendation Trends ›

Recommendation Rating ›

2.4

1 Strong Buy | 2 Buy | 3 Hold | 4 Under-perform | 5 Sell

Analyst Price Targets (7) ›

Average 75.14

Low 67.00 | Current 74.15 | High 83.00

Chesapeake Utilities Corporation (CPK)

NYSE - NYSE Real Time Price. Currency in USD

Add to watchlist

Quote Lookup

67.30 +0.05 (+0.07%)

At close: 4:02 PM EST

People also watch: DGAS SJI RGCO NJR SWX

Summary Conversations Statistics Profile Financials Options Holders Historical Data **Analysts**

Currency in USD.

Earnings Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	3	1	3	3
Avg. Estimate	0.7	1.56	2.87	3.22
Low Estimate	0.65	1.56	2.79	3.11
High Estimate	0.77	1.56	2.91	3.41
Year Ago EPS	0.73	1.33	2.9	2.87

Revenue Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	1	1	1	1
Avg. Estimate	116.6M	159.9M	465.8M	512.4M
Low Estimate	116.6M	159.9M	465.8M	512.4M
High Estimate	116.6M	159.9M	465.8M	512.4M
Year Ago Sales	104.57M	146.3M	459.24M	465.8M
Sales Growth (year/est)	11.50%	9.30%	1.40%	10.00%

Earnings History	12/30/2015	3/30/2016	6/29/2016	9/29/2016
EPS Est.	0.71	1.5	0.49	0.4
EPS Actual	0.73	1.33	0.52	0.29
Difference	0.02	-0.17	0.03	-0.11
Surprise %	2.80%	-11.30%	6.10%	-27.50%

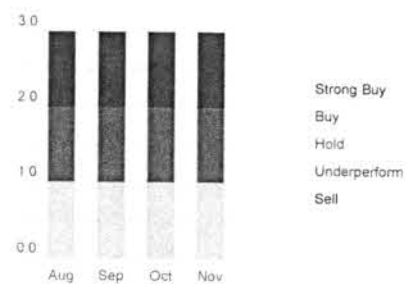
EPS Trend	Current Qtr.	Next Qtr	Current Year	Next Year
Current Estimate	0.7	1.56	2.87	3.22
7 Days Ago	0.7	1.56	2.87	3.22

EPS Trend	Current Qtr	Next Qtr	Current Year	Next Year
30 Days Ago	0.71	1.54	2.95	3.29
60 Days Ago	0.71	1.54	2.95	3.29
90 Days Ago	0.72	1.64	3.1	3.42

EPS Revisions	Current Qtr.	Next Qtr.	Current Year	Next Year
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	1	1	1	1
Down Last 30 Days	N/A	N/A	N/A	N/A
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Estimates	CPK	Industry	Sector	S&P 500
Current Qtr.	-4.10%	0.22		
Next Qtr.	17.30%	0.43		
Current Year	-1.00%	0.13		
Next Year	12.20%	0.03		
Next 5 Years (per annum)	3.00%	0.05		
Past 5 Years (per annum)	19.86%	N/A		

Recommendation Trends ›



Recommendation Rating ›

2

1	2	3	4	5
Strong Buy	Buy	Hold	Under-perform	Sell

Analyst Price Targets (3) ›

Average 70.00

Low 62.00 — Current 67.30 — High 75.00

US Markets are closed

S&P 500	Dow 30	Nasdaq
2,204.66	19,121.60	5,379.92
2.94 (0.13 %)	23.70 (0.12 %)	11.11 (0.21 %)

New Jersey Resources Corporation (NJR)

Add to watchlist

NYSE - NYSE Real Time Price. Currency in USD

Quote Lookup

35.30 +0.30 (+0.86 %) **35.23** -0.10 (-0.28%)

At close: 4:02 PM EST After hours: 4:11 PM EST

People also watch: SJI NWN WGL PNY SWX

Summary Conversations Statistics Profile Financials Options Holders Historical Data **Analysts**

Currency in USD

Earnings Estimate	Current Qtr	Next Qtr.	Current Year	Next Year
No. of Analysts	2	2	9	6
Avg. Estimate	0.61	0.94	1.79	1.89
Low Estimate	0.6	0.87	1.7	1.81
High Estimate	0.61	1.01	1.94	2.08
Year Ago EPS	0.57	0.91	1.61	1.79

Revenue Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	2	2	6	4
Avg. Estimate	505M	656.5M	2.42B	2.76B
Low Estimate	466M	595M	1.89B	2.37B
High Estimate	544M	718M	3.19B	3.46B
Year Ago Sales	444.26M	574.19M	1.88B	2.42B
Sales Growth (year/est)	13.70%	14.30%	28.80%	13.70%

Earnings History	12/30/2015	3/30/2016	6/29/2016	9/29/2016
EPS Est.	0.56	0.91	0.14	0.01
EPS Actual	0.57	0.91	0.13	-0.02
Difference	0.01	N/A	-0.01	-0.03
Surprise %	1.80%	N/A	-7.10%	-300.00%

EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
Current Estimate	0.61	0.94	1.79	1.89
7 Days Ago	0.61	0.94	1.79	1.89

EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
30 Days Ago	0.6	1.01	1.79	1.88
60 Days Ago	0.6	1.01	1.75	1.9
90 Days Ago	0.6	1.01	1.77	1.9

EPS Revisions	Current Qtr.	Next Qtr	Current Year	Next Year
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	N/A	N/A	2	N/A
Down Last 30 Days	N/A	N/A	N/A	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Estimates	NJR	Industry	Sector	S&P 500
Current Qtr.	7.00%	0.22		
Next Qtr.	3.30%	0.43		
Current Year	11.20%	0.13		
Next Year	5.60%	0.03		
Next 5 Years (per annum)	6.00%	0.05		
Past 5 Years (per annum)	23.75%	N/A		

Recommendation Trends ›

Recommendation Rating ›

2.6

1 Strong Buy | 2 Buy | 3 Hold | 4 Under-perform | 5 Sell

Analyst Price Targets (5) ›

Average 34.80

Low 32.00 | Current 35.30 | High 39.00

Upgrades & Downgrades ›

	BB&T Capital Mkts: Hold	3/30/2016
	Ladenburg Thalmann: Neutral	1/13/2016
	Wells Fargo: Market Perform	1/6/2016
↑ Upgrade	Argus: Hold to Buy	7/16/2015
↓ Downgrade	Brean Capital: Buy to Hold	5/29/2014

(•) US Markets are closed

S&P 500	Dow 30	Nasdaq	Crude Oil
2,204.66	19,121.60	5,379.92	45.23
2.94 (0.13 %)	23.70 (0.12 %)	11.11 (0.21 %)	-1.85 (-3.93%)

Northwest Natural Gas Company (NWN)

☆ Add to watchlist

NYSE - NYSE Real Time Price. Currency in USD

Quote Lookup

59.65 +0.75 (+1.27 %) **59.65** 0.00 (0.00%)

At close: 4:02 PM EST After hours: 4:02 PM EST

People also watch:
PNY WGL VVC NJR SJI

Summary Conversations Statistics Profile Financials Options Holders Historical Data Analysts

Currency in USD

Earnings Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	N/A	N/A	N/A	N/A
Avg. Estimate	N/A	N/A	N/A	N/A
Low Estimate	N/A	N/A	N/A	N/A
High Estimate	N/A	N/A	N/A	N/A
Year Ago EPS	1.16	1.4	N/A	N/A

Revenue Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	2	2	2	2
Avg. Estimate	288.5M	269.45M	735.15M	787.95M
Low Estimate	284M	265M	733.3M	764M
High Estimate	293M	273.9M	737M	811.9M
Year Ago Sales	230.72M	255.53M	723.79M	735.15M
Sales Growth (year/est)	25.00%	5.40%	1.60%	7.20%

Earnings History	12/30/2015	3/30/2016	6/29/2016	9/29/2016
EPS Est.	1.03	1.25	0.06	-0.34
EPS Actual	1.16	1.4	0.07	-0.29
Difference	0.13	0.15	0.01	0.05
Surprise %	12.60%	12.00%	16.70%	14.70%

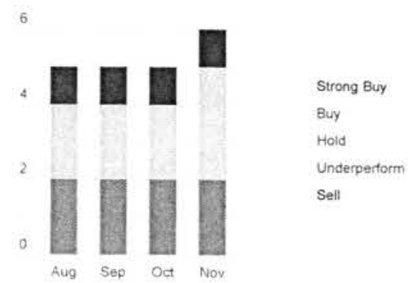
EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
Current Estimate	N/A	N/A	N/A	N/A
7 Days Ago	1.05	1.57	2.23	2.34

EPS Trend	Current Qtr	Next Qtr	Current Year	Next Year
30 Days Ago	1.1	1.61	2.08	2.33
60 Days Ago	1.1	1.61	2.08	2.33
90 Days Ago	1.1	1.61	2.08	2.33

EPS Revisions	Current Qtr	Next Qtr	Current Year	Next Year
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	N/A	N/A	N/A	1
Down Last 30 Days	N/A	N/A	N/A	N/A
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Estimates	NWN	Industry	Sector	S&P 500
Current Qtr.	N/A	0.22		
Next Qtr.	N/A	0.43		
Current Year	N/A	0.13		
Next Year	N/A	0.03		
Next 5 Years (per annum)	4.00%	0.05		
Past 5 Years (per annum)	-3.27%	N/A		

Recommendation Trends ›



Recommendation Rating ›

3

1	2	3	4	5
Strong Buy	Buy	Hold	Under-perform	Sell

Analyst Price Targets (5) ›

Average 55.40

Low 48.00 — Current 59.65 — High 75.00

Upgrades & Downgrades ›

↓ Downgrade	Hilliard Lyons: Neutral to Underperform	5/26/2016
	Sidoti: Buy	4/25/2016
↓ Downgrade	McAdams Wright Ragen: Buy to Hold	6/10/2014
↑ Upgrade	Brean Capital: Sell to Hold	5/3/2013
↓ Downgrade	Brean Capital: Buy to Sell	10/31/2012

US Markets are closed

S&P 500	Dow 30	Nasdaq	Crude Oil
2,204.66	19,121.60	5,379.92	45.23
2.94 (0.13 %)	23.70 (0.12 %)	11.11 (0.21 %)	-1.85 (-3.93%)

South Jersey Industries, Inc. (SJI) Add to watchlist

NYSE - NYSE Real Time Price. Currency in USD

Quote Lookup

33.85 +0.24 (+0.71%) **33.83** -0.03 (-0.10%)

At close: 4:02 PM EST After hours: 4:11 PM EST

People also watch: NJR SWX WGL NWN PNY

Summary Conversations Statistics Profile Financials Options Holders Historical Data Analysts

Currency in USD

Earnings Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	6	N/A	N/A	7
Avg. Estimate	0.43	N/A	N/A	1.36
Low Estimate	0.37	N/A	N/A	1.17
High Estimate	0.52	N/A	N/A	1.5
Year Ago EPS	0.62	0.8	N/A	N/A

Revenue Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	2	2	3	3
Avg. Estimate	269.1M	402.05M	935.1M	1.02B
Low Estimate	262M	396.1M	903M	979.77M
High Estimate	276.2M	408M	982.7M	1.08B
Year Ago Sales	257.84M	333.04M	959.57M	935.1M
Sales Growth (year/est)	4.40%	20.70%	-2.50%	9.10%

Earnings History	12/30/2015	3/30/2016	6/29/2016	9/29/2016
EPS Est.	0.67	0.8	0.14	-0.1
EPS Actual	0.62	0.8	0.12	0.05
Difference	-0.05	N/A	-0.02	0.15
Surprise %	-7.50%	N/A	-14.30%	150.00%

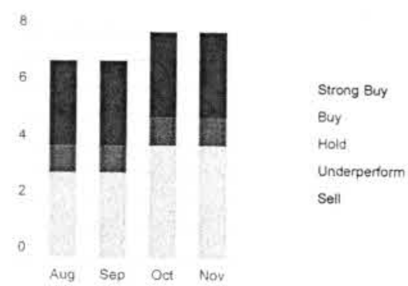
EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
Current Estimate	0.43	N/A	N/A	1.36
7 Days Ago	0.43	0.76	1.33	1.36

EPS Trend	Current Qtr	Next Qtr.	Current Year	Next Year
30 Days Ago	0.51	0.76	1.3	1.34
60 Days Ago	0.51	0.76	1.3	1.33
90 Days Ago	0.49	0.71	1.31	1.38

EPS Revisions	Current Qtr.	Next Qtr	Current Year	Next Year
Up Last 7 Days	N/A	N/A	2	1
Up Last 30 Days	N/A	N/A	3	4
Down Last 30 Days	1	N/A	N/A	N/A
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Estimates	SJI	Industry	Sector	S&P 500
Current Qtr.	-30.60%	0.22		
Next Qtr.	N/A	0.43		
Current Year	N/A	0.13		
Next Year	N/A	0.03		
Next 5 Years (per annum)	6.00%	0.05		
Past 5 Years (per annum)	26.56%	N/A		

Recommendation Trends ›



Recommendation Rating ›

2.1

1	2	3	4	5
Strong Buy	Buy	Hold	Under-perform	Sell

Analyst Price Targets (6) ›

Average 34.17

Low 31.00
Current 33.85
High 42.00

Upgrades & Downgrades ›

↓ Downgrade	Williams Capital Group: Buy to Hold	11/23/2016
	Morgan Stanley: Equal-Weight	9/8/2016
	JP Morgan: Neutral	6/14/2016
	Guggenheim: Buy	5/16/2016
	Sidoti: Buy	3/30/2016

Spire Inc. (SR)
NYSE - NYSE Real Time Price. Currency in USD

☆ Add to watchlist

Quote Lookup

66.25 +0.30 (+0.45%)
At close: 4:04 PM EST

66.25 0.00 (0.00%)
After hours: 4:27 PM EST

People also watch:
SRT SXI EBF SMP STL

Summary Conversations Statistics Profile Financials Options Holders Historical Data Analysts

Currency in USD

Earnings Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	3	3	5	9
Avg. Estimate	1.09	2.36	3.55	3.67
Low Estimate	1.08	2.3	3.52	3.52
High Estimate	1.12	2.46	3.58	3.82
Year Ago EPS	1.04	2.37	3.42	3.55

Revenue Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	3	3	4	6
Avg. Estimate	449.54M	679.23M	1.79B	1.79B
Low Estimate	432.4M	650.94M	1.7B	1.59B
High Estimate	463.22M	697.74M	2.04B	2.07B
Year Ago Sales	399.4M	609.3M	1.54B	1.79B
Sales Growth (year/est)	12.60%	11.50%	16.40%	N/A

Earnings History	12/30/2015	3/30/2016	6/29/2016	9/29/2016
EPS Est.	1.11	2.28	0.27	-0.32
EPS Actual	1.04	2.37	0.33	-0.32
Difference	-0.07	0.09	0.06	N/A
Surprise %	-6.30%	3.90%	22.20%	N/A

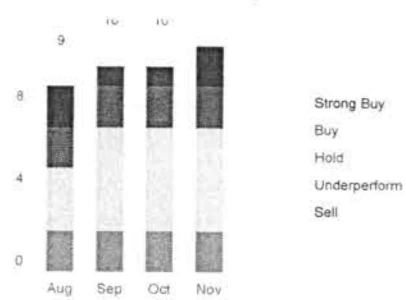
EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
Current Estimate	1.09	2.36	3.55	3.67
7 Days Ago	1.07	2.32	3.54	3.67

EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
30 Days Ago	1.09	2.32	3.54	3.65
60 Days Ago	1.11	2.36	3.55	3.63
90 Days Ago	1.12	2.34	3.55	3.64

EPS Revisions	Current Qtr	Next Qtr.	Current Year	Next Year
Up Last 7 Days	N/A	N/A	N/A	2
Up Last 30 Days	N/A	N/A	2	2
Down Last 30 Days	N/A	N/A	1	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Estimates	SR	Industry	Sector	S&P 500
Current Qtr.	4.80%	0.22		
Next Qtr.	-0.40%	0.43		
Current Year	3.80%	0.13		
Next Year	3.40%	0.03		
Next 5 Years (per annum)	4.23%	0.05		
Past 5 Years (per annum)	-0.43%	N/A		

Recommendation Trends ›



Recommendation Rating ›

2.6

1 Strong Buy | 2 Buy | 3 Hold | 4 Under-perform | 5 Sell

Analyst Price Targets (8) ›

Average 67.88

Low 59.00 | Current 66.25 | High 77.00

(•) US Markets are closed

S&P 500	Dow 30	Nasdaq	Crude Oil
2,204.66	19,121.60	5,379.92	45.23
2.94 (0.13 %)	23.70 (0.12 %)	11.11 (0.21 %)	-1.85 (-3.93%)

UGI Corporation (UGI)

Add to watchlist

NYSE - NYSE Real Time Price. Currency in USD

Quote Lookup

46.34 +0.54 (+1.18%)

At close: 4:02 PM EST

People also watch: WGL VVC ATO PNY NJR

Summary Conversations Statistics Profile Financials Options Holders Historical Data Analysts

Currency in USD.

Earnings Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	4	4	5	4
Avg. Estimate	0.75	1.39	2.33	2.4
Low Estimate	0.72	1.34	2.12	2.19
High Estimate	0.83	1.46	2.43	2.48
Year Ago EPS	0.64	1.24	2.05	2.33

Revenue Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	3	3	3	2
Avg. Estimate	1.82B	2.26B	6.56B	6.87B
Low Estimate	1.81B	2.19B	6.35B	6.51B
High Estimate	1.84B	2.3B	6.91B	7.24B
Year Ago Sales	1.61B	1.97B	5.69B	6.56B
Sales Growth (year/est)	13.30%	14.40%	15.40%	4.70%

Earnings History	12/30/2015	3/30/2016	6/29/2016	9/29/2016
EPS Est.	0.7	1.25	0.07	-0.06
EPS Actual	0.64	1.24	0.23	-0.05
Difference	-0.06	-0.01	0.16	0.01
Surprise %	-8.60%	-0.80%	228.60%	16.70%

EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
Current Estimate	0.75	1.39	2.33	2.4
7 Days Ago	0.75	1.39	2.33	2.4

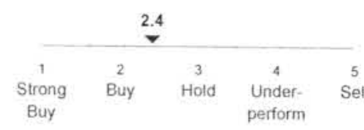
EPS Trend	Current Qtr	Next Qtr	Current Year	Next Year
30 Days Ago	0.75	1.36	2.33	2.39
60 Days Ago	0.77	1.32	2.34	2.4
90 Days Ago	0.8	1.3	2.26	2.4

EPS Revisions	Current Qtr	Next Qtr.	Current Year	Next Year
Up Last 7 Days	N/A	1	1	1
Up Last 30 Days	N/A	1	1	1
Down Last 30 Days	N/A	N/A	N/A	N/A
Down Last 90 Days	N/A	N/A	N/A	N/A

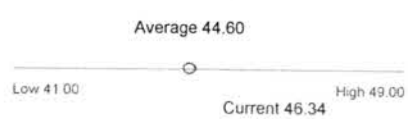
Growth Estimates	UGI	Industry	Sector	S&P 500
Current Qtr.	17.20%	0.22		
Next Qtr.	12.10%	0.43		
Current Year	13.70%	0.13		
Next Year	3.00%	0.03		
Next 5 Years (per annum)	7.60%	0.05		
Past 5 Years (per annum)	-22.89%	N/A		

Recommendation Trends >

Recommendation Rating >



Analyst Price Targets (5) >



(·) US Markets are closed

S&P 500	Dow 30	Nasdaq
2,204.66	19,121.60	5,379.92
2.94 (0.13 %)	23.70 (0.12 %)	11.11 (0.21 %)

WGL Holdings, Inc. (WGL) ☆ Add to watchlist

NYSE - NYSE Delayed Price. Currency in USD

Quote Lookup

75.21 +6.19 (+8.97 %) **73.00** -2.21 (-2.94%)

At close: 4:00 PM EST After hours: 5:10 PM EST

People also watch: VVC PNY NWN NJR ATO

Summary Conversations Statistics Profile Financials Options Holders Historical Data **Analysts**

Currency in USD

Earnings Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	N/A	N/A	N/A	N/A
Avg. Estimate	N/A	N/A	N/A	N/A
Low Estimate	N/A	N/A	N/A	N/A
High Estimate	N/A	N/A	N/A	N/A
Year Ago EPS	-0.23	1.18	N/A	N/A

Revenue Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	2	2	4	4
Avg. Estimate	489.07M	657.75M	2.53B	2.68B
Low Estimate	483M	639M	2.37B	2.48B
High Estimate	495.14M	676.49M	2.85B	3B
Year Ago Sales	467.69M	613.38M	2.66B	2.53B
Sales Growth (year/est)	4.60%	7.20%	-5.00%	6.10%

Earnings History	9/29/2015	12/30/2015	3/30/2016	6/29/2016
EPS Est.	-0.35	1.25	1.96	0.14
EPS Actual	-0.23	1.18	1.78	0.33
Difference	0.12	-0.07	-0.18	0.19
Surprise %	34.30%	-5.60%	-9.20%	135.70%

EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
Current Estimate	N/A	N/A	N/A	N/A
7 Days Ago	-0.12	1.18	3.17	3.25

EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
30 Days Ago	-0.12	1.18	3.17	3.25
60 Days Ago	-0.12	1.18	3.17	3.25
90 Days Ago	-0.12	1.18	3.15	3.24

EPS Revisions	Current Qtr.	Next Qtr.	Current Year	Next Year
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Estimates	WGL	Industry	Sector	S&P 500
Current Qtr.	N/A	0.22		
Next Qtr.	N/A	0.43		
Current Year	N/A	0.13		
Next Year	N/A	0.03		
Next 5 Years (per annum)	8.00%	0.05		
Past 5 Years (per annum)	-0.99%	N/A		

Recommendation Trends ›

Recommendation Rating ›

3.2

1 Strong Buy | 2 Buy | 3 Hold | 4 Under-perform | 5 Sell

Analyst Price Targets (3) ›

Average 64.67

Low 60.00 High 70.00 Current 75.21

Upgrades & Downgrades ›

	BB&T Capital Mkts: Hold	3/30/2016
	Wells Fargo: Market Perform	1/6/2016
↓ Downgrade	Brean Capital: Buy to Hold	10/31/2014
↑ Upgrade	Brean Capital: Hold to Buy	8/8/2014
↓ Downgrade	Brean Capital: Buy to Hold	11/14/2013

SCHEDULES

Southwest Gas Corporation
Test Year Ending November 30, 2015
Docket No. G-01551A-16-0107

WEIGHTED AVERAGE COST OF CAPITAL

Line No	Description	Capitalization Per Company	RUCO Adjustments	RUCO Adjusted Capitalization	Capital Ratio	Cost	Weighted Cost
1	Long Term Debt	$ 1,343,228,715	$ 38,612,400	$ 1,381,841,115	49.02%	5.20%	2.55%
2							
3	Common Equity	$ 1,437,158,401	$ -	$ 1,437,158,401	50.98%	9.39%	4.79%
4							
5	TOTAL CAPITALIZATION	$2,780,387,116	$38,612,400	$2,818,999,516	100.00%		**7.34%**

Southwest Gas Corporation
Test Year Ending November 30, 2015
Docket No. G-01551A-16-0107

Schedule JAC-1a

Cost of Capital Calculation
Fair Value Rate Base (FVRB),
Fair Value Rate of Return (FVROR) and
Cost Rate to be Assigned to the Fair Value Increment
RUCO Recommended

Calculation of RUCO Fair Value Rate Base (FVRB)

Line No.	Rate Base Estimate	Amount	Weighting	Weighted Amount
1	[1] Original Cost Rate Base (OCRB) - RUCO Recommended	$ 1,321,867,091	50%	$ 660,933,546
2	[2] RUCO Reconstruction Cost New (RCND) Rate Base	2,272,474,052	50%	1,136,237,026
3	**Fair Value Rate Base (FVRB)**			**$ 1,797,170,572**
4				
5	Appreciation above OCRB			$ 475,303,481
6	FV/OCRB Multiple	1.36		

Calculation of RUCO Fair Value Rate of Return (FVROR)

Line No.	Capital	Amount	Percent	Cost Rate	Weighted Cost
7	Long-Term Debt	$ 647,964,033	36.05%	5.20%	1.88%
8	Common Equity	673,903,058	37.50%	9.39%	3.52%
9	Capital Financing OCRB	$ 1,321,867,091			
10					
11	Fair Value Increment	$ 475,303,481	26.45%	1.04%	0.28%
12					
13	**Fair Value Rate of Return**	$ 1,797,170,572	100.00%		**5.67%**

Calculation of Cost Rate to be Assigned to the Fair Value Increment

Line No.	Cost Inputs		Cost Rate
14	[3] Current Nominal Risk-Free Rate		3.00%
15	[4] Less: Inflation Component		0.92%
16	Real Risk-Free Rate		2.08%
17			
18	Inflation Adjustment Factor	x	50.00%
19			
20	**Cost Rate - Fair Value Increment**		**1.04%**

Sources:

[1] Michlik Direct, Schedule JMM-1

[2] Michlik Direct, Schedule JMM-1

[3] Current nominal risk-free rate is the spot yield on the 30-year U.S. Treasury Bond at the close of market on November 21, 2016.
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2016

[4] Inflation component is the spot real yield on 30-year U.S. Treasury Inflation Protected Securities (TIPS) at the close of market on November 21, 2016.
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=realyieldYear&year=2016

Southwest Gas Corporation
Test Year Ending November 30, 2015
Docket No. G-01551A-16-0107

Cost of Capital -- Common Equity

Line No			[A] Cost Estimate	[B] Weighting Factor	[C] Weighted Average Cost
1	Discounted Cash Flow Model ("DCF")	Schedule JAC - 3	9.27%	40.00%	3.71%
2					
3	Capital Asset Pricing Model ("CAPM")	Schedule JAC - 4	7.48%	20.00%	1.50%
4					
5	Comparable Earnings Model ("CE")	Schedule JAC - 5	10.46%	40.00%	4.18%
6					
7	Cost of Common Equity		9.07%		**9.39%**

[A] : From Schedules JAC-3, JAC-4 and JAC-5
[B] : See Testimony
[C] : [A] * [B]

PROXY GROUP -- DCF ANALYSIS

Line No	Proxy Group Companies	(A) Current Dividend Yield (D_0/P_0)	(B) Historic Retention Growth	(C) Projected Retention Growth	(D) Five Year Historic Growth Rate	(E) Projected Per Share Growth Rates	(F) Projected EPS Growth	(G) Average Growth	(H) Expected Dividend Yield (D_1/P_0)	(I) DCF Rates
1	Atmos Energy Corp.	2.3%	3.9%	5.5%	4.8%	5.5%	7.30%	5.4%	2.3%	7.7%
2	Chesapeake Utilities	1.9%	6.9%	7.3%	7.7%	7.0%	3.00%	6.4%	2.0%	8.4%
3	New Jersey Resources	2.8%	7.1%	4.8%	6.7%	3.5%	6.50%	5.7%	2.9%	8.6%
4	Northwest Natural Gas	3.1%	1.4%	1.8%	2.8%	3.8%	4.00%	2.8%	3.1%	5.9%
5	South Jersey Industries	3.6%	4.9%	1.2%	7.3%	5.8%	6.00%	5.0%	3.7%	8.7%
6	Spire, Inc.	3.0%	3.1%	4.2%	5.5%	5.7%	4.52%	4.6%	3.1%	7.7%
7	UGI Corp.	2.1%	6.1%	7.5%	7.2%	4.8%	7.60%	6.6%	2.2%	8.8%
8	WGL Holdings, Inc.	3.1%	4.1%	4.0%	2.8%	4.0%	8.00%	4.6%	3.2%	7.7%
9										
10										
11	Mean	2.74%	4.69%	4.54%	5.59%	5.02%	5.87%	5.14%	2.81%	**7.95%**
12										
13										
14	Median	2.95%	4.49%	4.50%	6.08%	5.17%	6.25%	5.23%	3.02%	**8.06%**
15										
16										
17	Composite-Mean		7.50%	7.35%	8.40%	7.83%	**8.68%**	7.95%		
18										
19										
20	Composite-Median		7.51%	7.52%	9.11%	8.19%	**9.27%**	8.25%		
21										

Note: Negative values not used in calculations.

Sources:
Column (A) - Schedule JAC - 3, page 3 of 4
Column (B) - Schedule JAC - 3, page 4 of 4
Column (C) - Schedule JAC - 3, page 4 of 4
Column (D) and Column (E) - Schedule JAC - 3, page 2 of 4
Column (F) See Yahoo Finance, Analyst EPS Growth Estimates - Next 5 Years - Attachment 7
Column (G) - Average Columns (B) through (F)
Column (H) - Column (A) * [1 + Column (G)]
Column (I) - Column (G) + Column (H)

PROXY GROUP -- PER SHARE GROWTH RATES

Line		5-Year Historic Growth Rates				Est'd '12-'14 to '18-'20 Growth Rates			
No	Proxy Group Companies	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
1	Atmos Energy Corp.	7.0%	2.5%	5.0%	4.8%	6.5%	6.5%	3.5%	5.5%
2	Chesapeake Utilities	10.0%	5.0%	8.0%	7.7%	8.5%	6.0%	6.5%	7.0%
3	New Jersey Resources	6.5%	7.0%	6.5%	6.7%	1.0%	3.0%	6.5%	3.5%
4	Northwest Natural Gas	NMF	3.0%	2.5%	2.8%	7.0%	2.0%	2.5%	3.8%
5	South Jersey Industries	4.0%	9.5%	8.5%	7.3%	3.0%	6.5%	8.0%	5.8%
6	Spire, Inc.	NMF	3.0%	8.0%	5.5%	9.0%	3.5%	4.5%	5.7%
7	UGI Corp.	4.0%	8.5%	9.0%	7.2%	4.0%	4.0%	6.5%	4.8%
8	WGL Holdings, Inc.	2.5%	3.5%	2.5%	2.8%	3.5%	2.5%	6.0%	4.0%
9									
10	Average				5.6%				5.0%

Sources:

Value Line Investment Survey - September 2, 2016 (*See* Attachment 1)

PROXY GROUP -- DIVIDEND YIELD

Line No	Proxy Group Companies	(A) DPS	(B) August - October, 2016 High	(C) Low	(D) Average	(E) Yield
1	Atmos Energy Corp.	$1.68	$80.18	$68.93	$74.26	2.26%
2	Chesapeake Utilities	$1.22	$67.88	$57.63	$62.82	1.94%
3	New Jersey Resources	$0.96	$37.29	$30.46	$33.72	2.85%
4	Northwest Natural Gas	$1.87	$65.53	$56.10	$60.31	3.10%
5	South Jersey Industries	$1.06	$32.03	$27.51	$29.65	3.56%
6	Spire, Inc.	$1.96	$69.85	$59.54	$64.32	3.05%
7	UGI Corp.	$0.95	$48.13	$42.86	$45.47	2.09%
8	WGL Holdings, Inc.	$1.95	$70.99	$58.66	$63.23	3.09%
9						
10	Average					**2.74%**

Sources:

Column (A) - Value Line Investment Survey - Current Quarterly Dividend, Annualized
Columns (B), (C), and (D) - Yahoo Finance

PROXY GROUP -- GROWTH RATES - RETAINED TO COMMON EQUITY

Line No	Proxy Group Companies	(A) 2011	(B) 2012	(C) 2013	(D) 2014	(E) 2015	Average	2016	2017	2019-'21	Average
1	Atmos Energy Corp.	3.3%	2.8%	4.0%	4.7%	4.9%	3.9%	5.5%	5.5%	5.5%	5.5%
2	Chesapeake Utilities	6.6%	6.4%	7.1%	7.4%	6.8%	6.9%	7.0%	7.0%	8.0%	7.3%
3	New Jersey Resources	6.2%	6.2%	5.2%	11.0%	6.8%	7.1%	4.5%	5.5%	4.5%	4.8%
4	Northwest Natural Gas	2.4%	1.6%	1.5%	1.1%	0.6%	1.4%	1.0%	1.0%	3.5%	1.8%
5	South Jersey Industries	6.7%	5.8%	4.8%	4.3%	2.8%	4.9%	1.0%	1.0%	1.5%	1.2%
6	Spire, Inc.	4.9%	4.3%	1.0%	1.5%	3.7%	3.1%	3.5%	4.0%	5.0%	4.2%
7	UGI Corp.	6.0%	3.6%	6.1%	7.6%	7.4%	6.1%	7.5%	7.5%	7.5%	7.5%
8	WGL Holdings, Inc.	3.4%	4.8%	2.6%	4.3%	5.4%	4.1%	4.0%	4.5%	3.5%	4.0%
9											
10	Average						**4.69%**				**4.54%**

Source: Value Line Investment Survey (September 2, 2016)

CAPITAL ASSET PRICING MODEL -- HISTORICAL MARKET RISK PREMIUM

Line No	Proxy Group Companies	[A] Risk Free Rate	[B] Beta		[C] Risk Premium		[D] CAPM Rates	[E] CAPM Estimated Cost of Equity
1	Atmos Energy Corp.	2.37%	0.75	X	6.87%	=	5.15%	7.52%
2	Chesapeake Utilities	2.37%	0.60	X	6.87%	=	4.12%	6.49%
3	New Jersey Resources	2.37%	0.80	X	6.87%	=	5.49%	7.86%
4	Northwest Natural Gas	2.37%	0.65	X	6.87%	=	4.46%	6.83%
5	South Jersey Industries	2.37%	0.80	X	6.87%	=	5.49%	7.86%
6	Spire, Inc.	2.37%	0.70	X	6.87%	=	4.81%	7.18%
7	UGI Corp.	2.37%	0.90	X	6.87%	=	6.18%	8.55%
8	WGL Holdings, Inc.	2.37%	0.75	X	6.87%	=	5.15%	7.52%
9								
10								
11	Average							7.48%

Line No	20 year Treasury Bonds		30 year Treasury Bonds
16	August, 2016	1.89%	2.26%
17	September, 2016	2.02%	2.35%
18	October, 2016	2.17%	2.50%
19	Average	2.03%	2.37%

21 RUCO Risk-Free Rate 2.37%

24 **REFERENCES**

25 Column [A]: Federal Reserve Selected Interest Rates H.15 - Attachment 2

26 Column [B]: Value Line Investment Survey - September 2, 2016 - Attachment 1

27 Column [C]: JAC - 4, Page 2 of 2

28 Column [D]: [B] * [C]

Column [E]: [A] + [D]

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Line No.	Year	[A] EPS	[B] BVPS	[C] ROE	[D] 20-YEAR T-BOND	[E] RISK PREMIUM
1	1977		$79.07			
2	1978	$12.33	$85.35	15.00%	7.90%	7.10%
3	1979	$14.86	$94.27	16.55%	8.86%	7.69%
4	1980	$14.82	$102.48	15.06%	9.97%	5.09%
5	1981	$15.36	$109.43	14.50%	11.55%	2.95%
6	1982	$12.64	$112.46	11.39%	13.50%	-2.11%
7	1983	$14.03	$116.93	12.23%	10.38%	1.85%
8	1984	$16.64	$122.47	13.90%	11.74%	2.16%
9	1985	$14.61	$125.20	11.80%	11.25%	0.55%
10	1986	$14.48	$126.82	11.49%	8.98%	2.51%
11	1987	$17.50	$134.07	13.42%	7.92%	5.50%
12	1988	$23.75	$141.32	17.25%	8.97%	8.28%
13	1989	$22.87	$147.26	15.85%	8.81%	7.04%
14	1990	$21.73	$153.01	14.47%	8.19%	6.28%
15	1991	$16.29	$158.85	10.45%	8.22%	2.23%
16	1992	$18.86	$149.74	12.22%	7.29%	4.93%
17	1993	$21.89	$180.88	13.24%	7.17%	6.07%
18	1994	$30.60	$193.06	16.37%	6.59%	9.78%
19	1995	$33.96	$216.51	16.58%	7.60%	8.98%
20	1996	$38.73	$237.08	17.08%	6.83%	10.25%
21	1997	$39.72	$249.52	16.33%	6.69%	9.64%
22	1998	$37.71	$266.40	14.62%	5.72%	8.90%
23	1999	$48.17	$290.68	17.29%	6.20%	11.09%
24	2000	$50.00	$325.80	16.22%	6.23%	9.99%
25	2001	$24.70	$338.37	7.44%	5.63%	1.81%
26	2002	$27.59	$321.72	8.36%	5.43%	2.93%
27	2003	$48.73	$367.17	14.15%	4.96%	9.19%
28	2004	$58.55	$414.75	14.98%	5.04%	9.94%
29	2005	$69.93	$453.06	16.12%	4.64%	11.48%
30	2006	$81.51	$504.39	17.03%	5.00%	12.03%
31	2007	$66.18	$529.59	12.80%	4.91%	7.89%
32	2008	$14.88	$451.37	3.03%	4.36%	-1.33%
33	2009	$50.97	$513.58	10.56%	4.11%	6.45%
34	2010	$77.35	$579.14	14.16%	4.03%	10.13%
35	2011	$86.95	$613.14	14.59%	3.62%	10.97%
36	2012	$86.51	$666.97	13.52%	2.54%	10.98%
37	2013	$100.20	$715.84	14.49%	3.12%	11.37%
38	2014	$102.31	$726.96	14.18%	3.07%	11.11%
39	2015	$86.53	$737.54	11.82%	2.55%	9.27%
40	Average			**13.70%**	**6.83%**	**6.87%**

[A]: Diluted earnings per share on the S&P 500 Composite Index.
[B]: Book value per share on the S&P 500 Composite Index.
[C]: Average of current- and prior year [B] / current year [A].
[D]: Annual income returns on 20-year U.S. Treasury bonds.
[E]: [C] - [D]

Sources for [A] and [B]: Standard & Poor's 2015 Analysts' Handbook and
https://ycharts.com/indicators/reports/sp_500_earnings

Source for [D]: Morningstar 2015 Classic Yearbook (Table A-7) and
U.S. Department of the Treasury
https://www.treasury.gov/Pages/default.aspx

COMPARABLE EARNINGS ANALYSIS

RETURN ON COMMON EQUITY FOR RUCO'S PROXY GROUP OF COMPANIES

Company	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2019 - 2021	10-Year Historical Average 2006-2015	5-Year Historical Average 2011-2015	5-Year Projected Average 2016-2020
Atmos Energy Corp.	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	10.5%	11.5%	11.5%	9.0%	9.0%	11.2%
Chesapeake Utilities	9.5%	11.1%	11.7%	7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	12.0%	12.0%	13.0%	10.9%	11.5%	12.3%
New Jersey Resources	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	13.9%	11.5%	12.5%	11.0%	14.0%	14.5%	11.7%
Northwest Natural Gas	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	6.9%	7.5%	8.0%	9.5%	9.6%	7.9%	8.3%
South Jersey Industries	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	9.5%	7.5%	7.5%	8.0%	12.9%	11.8%	7.7%
Spire, Inc.	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	9.0%	9.0%	10.0%	9.9%	8.2%	9.3%
UGI Corp.	16.0%	14.5%	15.2%	16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	13.1%	12.5%	12.5%	12.5%	13.4%	11.5%	12.5%
WGL Holdings, Inc.	10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	10.8%	9.3%	11.0%	12.6%	11.5%	11.0%	9.5%	10.7%	10.6%	10.7%
Mean	12.2%	11.5%	12.4%	11.9%	11.7%	11.2%	10.5%	9.9%	11.0%	10.7%	10.3%	10.5%	10.6%	11.29%	10.64%	**10.46%**
Median	11.7%	11.4%	11.8%	12.0%	11.0%	11.3%	10.6%	10.3%	11.1%	10.6%	11.0%	11.3%	10.5%	10.81%	11.09%	10.92%
Average of Mean and Median														11.05%	10.87%	10.69%

Source: Value Line Investment Survey (September 2, 2016)

ECONOMIC INDICATORS

Line No	Year	Real GDP Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
1	1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
2	1976	5.4%	10.8%	7.7%	4.8%	3.7%
3	1977	5.5%	5.9%	7.0%	6.8%	6.9%
4	1978	5.0%	5.7%	6.0%	9.0%	9.2%
5	1979	2.8%	4.4%	5.8%	13.3%	12.8%
6	1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
7	1981	1.8%	1.9%	7.5%	8.9%	7.1%
8	1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
9	1983	4.0%	3.7%	9.5%	3.8%	0.6%
10	1984	6.8%	9.3%	7.5%	3.9%	1.7%
11	1985	3.7%	1.7%	7.2%	3.8%	1.8%
12	1986	3.1%	0.9%	7.0%	1.1%	-2.3%
13	1987	2.9%	4.9%	6.2%	4.4%	2.2%
14	1988	3.8%	4.5%	5.5%	4.4%	4.0%
15	1989	3.5%	1.8%	5.3%	4.6%	4.9%
16	1990	1.8%	-0.2%	5.6%	6.1%	5.7%
17	1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
18	1992	3.0%	3.1%	7.5%	2.9%	1.6%
19	1993	2.7%	3.4%	6.9%	2.7%	0.2%
20	1994	4.0%	5.5%	6.1%	2.7%	1.7%
21	1995	3.7%	4.8%	5.6%	2.5%	2.3%
22	1996	4.5%	4.3%	5.4%	3.3%	2.8%
23	1997	4.5%	7.3%	4.9%	1.7%	-1.2%
24	1998	4.2%	5.8%	4.5%	1.6%	0.0%
25	1999	3.7%	4.5%	4.2%	2.7%	2.9%
26	2000	4.1%	4.0%	4.0%	3.4%	3.6%
27	2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
28	2002	1.8%	0.2%	5.8%	2.4%	1.2%
29	2003	2.8%	1.2%	6.0%	1.9%	4.0%
30	2004	3.8%	2.3%	5.5%	3.3%	4.2%
31	2005	3.3%	3.2%	5.1%	3.4%	5.4%
32	2006	2.7%	2.2%	4.6%	2.5%	1.1%
33	2007	1.8%	2.5%	4.6%	4.1%	6.2%
34	2008	-0.3%	-3.6%	5.8%	0.1%	-0.9%
35	2009	-2.8%	-11.5%	9.3%	2.7%	4.3%
36	2010	2.5%	5.5%	9.6%	1.5%	4.7%
37	2011	1.6%	2.9%	8.9%	3.0%	4.7%
38	2012	2.2%	2.8%	8.1%	1.7%	1.4%
39	2013	1.7%	1.9%	7.4%	1.5%	0.8%
40	2014	2.4%	2.9%	6.2%	0.8%	-1.2%
41	2015	2.6%	0.3%	5.3%	0.7%	-3.8%

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Line No	Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
1	2003					
2	1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
3	2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
4	3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
5	4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
6	2004					
7	1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
8	2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
9	3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
10	4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
11	2005					
12	1st Qtr.	4.1%	3.8%	5.3%	4.4%	5.6%
13	2nd Qtr.	1.7%	3.0%	5.1%	1.6%	-0.4%
14	3rd Qtr.	3.1%	2.7%	5.0%	8.8%	14.0%
15	4th Qtr.	2.1%	2.9%	4.9%	-2.0%	4.0%
16	2006					
17	1st Qtr.	5.4%	3.4%	4.7%	4.8%	-0.2%
18	2nd Qtr.	1.4%	4.5%	4.6%	4.8%	5.6%
19	3rd Qtr.	0.1%	5.2%	4.7%	0.4%	-4.4%
20	4th Qtr.	3.0%	3.5%	4.5%	0.0%	3.6%
21	2007					
22	1st Qtr.	0.9%	2.5%	4.5%	4.8%	6.4%
23	2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
24	3rd Qtr.	2.3%	1.8%	4.6%	1.2%	1.2%
25	4th Qtr.	2.9%	1.7%	4.8%	0.6%	6.5%
26	2008					
27	1st Qtr.	-1.8%	1.9%	4.9%	2.8%	9.6%
28	2nd Qtr.	1.3%	0.2%	5.3%	7.6%	14.0%
29	3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%	-0.4%
30	4th Qtr.	-8.9%	6.0%	6.9%	-13.2%	-28.4%
31	2009					
32	1st Qtr.	-5.3%	-11.6%	8.1%	2.4%	-0.4%
33	2nd Qtr.	-0.3%	-12.9%	9.3%	3.2%	9.2%
34	3rd Qtr.	1.4%	-9.3%	9.6%	2.0%	-0.8%
35	4th Qtr.	4.0%	-4.5%	10.0%	2.5%	8.8%
36	2010					
37	1st Qtr.	1.6%	2.7%	9.7%	0.9%	6.5%
38	2nd Qtr.	3.9%	6.5%	9.7%	-1.2%	-2.4%
39	3rd Qtr.	2.8%	6.9%	9.6%	2.8%	4.0%
40	4th Qtr.	2.8%	6.2%	9.6%	2.8%	9.2%
41	2011					
42	1st Qtr.	-1.5%	5.4%	9.0%	4.8%	9.6%
43	2nd Qtr.	2.9%	3.6%	9.0%	3.2%	3.6%
44	3rd Qtr.	0.8%	3.3%	9.1%	2.4%	6.4%
45	4th Qtr.	4.6%	4.0%	8.7%	0.4%	-1.2%
46	2012					
47	1st Qtr.	2.3%	4.5%	8.3%	3.2%	2.0%
48	2nd Qtr.	1.6%	4.7%	8.2%	0.0%	-2.8%
49	3rd Qtr.	2.5%	3.4%	8.1%	4.0%	9.6%
50	4th Qtr.	0.1%	2.8%	7.8%	0.0%	-3.6%
51	2013					
52	1st Qtr.	1.9%	2.5%	7.7%	2.0%	1.2%
53	2nd Qtr.	1.1%	2.0%	7.6%	1.2%	2.4%
54	3rd Qtr.	3.0%	2.6%	7.3%	1.6%	0.0%
55	4th Qtr.	3.8%	3.3%	7.0%	1.2%	0.3%
56	2014					
57	1st Qtr.	-0.9%	3.2%	6.6%	1.6%	0.3%
58	2nd Qtr.	4.6%	4.2%	6.2%	3.6%	0.2%
59	3rd Qtr.	4.3%	4.7%	6.1%	0.0%	0.0%
60	4th Qtr.	2.1%	4.5%	5.7%	-2.8%	-0.8%
61	2015					
62	1st Qtr.	0.6%	3.5%	5.6%	-0.2%	-2.3%
63	2nd Qtr.	3.9%	1.5%	5.4%	0.6%	1.2%
64	3rd Qtr.	2.0%	1.1%	5.2%	0.0%	-1.8%
65	4th Qtr.	1.0%	-0.8%	5.0%	0.2%	-0.9%
66	2016					
67	1st Qtr.	0.80%	-1.6%	4.9%	1.10%	-0.4%
68	2nd Qtr.	1.40%	-1.1%	4.9%	1.03%	0.6%
69	3rd Qtr.	2.90% P	-1.0%	4.9%	1.13%	0.0%
70	4th Qtr.					

*GDP=Gross Domestic Product

P: Preliminary

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Line No	Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
2	1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
3	1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
4	1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
5	1979	12.67%	10.04%	9.43%	9.86%	10.22%	10.49%	10.96%
6	1980	15.27%	11.51%	11.43%	12.30%	13.00%	13.34%	13.95%
7	1981	18.89%	14.03%	13.92%	14.64%	15.30%	15.95%	16.60%
8	1982	14.86%	10.69%	13.01%	14.22%	14.79%	15.86%	16.45%
9	1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
10	1984	12.04%	9.58%	12.46%	12.72%	13.66%	14.03%	14.53%
11	1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
12	1986	8.33%	5.98%	7.67%	8.92%	9.30%	9.58%	10.00%
13	1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
14	1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
15	1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
16	1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
17	1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
18	1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
19	1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
20	1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
21	1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
22	1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
23	1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
24	1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
25	1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
26	2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
27	2001	6.91%	3.44%	5.02%	7.47%	7.59%	7.78%	8.02%
28	2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
29	2003	4.12%	1.01%	4.01%		6.40%	6.58%	6.84%
30	2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
31	2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
32	2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
33	2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
34	2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
35	2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
36	2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%
37	2011	3.25%	0.06%	2.78%		4.78%	5.04%	5.57%
38	2012	3.25%	0.09%	1.80%		3.83%	4.13%	4.86%
39	2013	3.25%	0.06%	2.35%		4.24%	4.47%	4.98%
40	2014	3.25%	0.03%	2.54%		4.19%	4.28%	4.80%
41	2015	3.27%	0.05%	2.14%		4.00%	4.12%	5.03%
42	2016	3.50%	0.29%	1.75%				

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

Note: Figures for 2016 are year-to-date averages (January - October, 2016)

Southwest Gas Corporation
Test Year Ending November 30, 2015
Docket No. G-01551A-16-0107

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INTEREST RATES

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	**2007**						
2	Jan	8.25%	4.96%	4.76%	5.78%	5.96%	6.16%
3	Feb	8.25%	5.02%	4.72%	5.73%	5.90%	6.10%
4	Mar	8.25%	4.97%	4.56%	5.66%	5.85%	6.10%
5	Apr	8.25%	4.88%	4.69%	5.83%	5.97%	6.24%
6	May	8.25%	4.77%	4.75%	5.86%	5.99%	6.23%
7	June	8.25%	4.63%	5.10%	6.18%	6.30%	6.54%
8	July	8.25%	4.84%	5.00%	6.11%	6.25%	6.49%
9	Aug	8.25%	4.34%	4.67%	6.11%	6.24%	6.51%
10	Sept	7.75%	4.01%	4.52%	6.10%	6.18%	6.45%
11	Oct	7.50%	3.97%	4.53%	6.04%	6.11%	6.36%
12	Nov	7.50%	3.49%	4.15%	5.87%	5.97%	6.27%
13	Dec	7.25%	3.08%	4.10%	6.03%	6.16%	6.51%
14	**2008**						
15	Jan	6.00%	2.86%	3.74%	5.87%	6.02%	6.35%
16	Feb	6.00%	2.21%	3.74%	6.04%	6.21%	6.60%
17	Mar	5.25%	1.38%	3.51%	5.99%	6.21%	6.68%
18	Apr	5.00%	1.32%	3.68%	5.99%	6.29%	6.82%
19	May	5.00%	1.71%	3.88%	6.07%	6.27%	6.79%
20	June	5.00%	1.90%	4.10%	6.19%	6.38%	6.93%
21	July	5.00%	1.72%	4.01%	6.13%	6.40%	6.97%
22	Aug	5.00%	1.79%	3.89%	6.09%	6.37%	6.98%
23	Sept	5.00%	1.46%	3.69%	6.13%	6.49%	7.15%
24	Oct	4.00%	0.84%	3.81%	6.95%	7.56%	8.58%
25	Nov	4.00%	0.30%	3.53%	6.83%	7.60%	8.98%
26	Dec	3.25%	0.04%	2.42%	5.93%	6.54%	8.13%
27	**2009**						
28	Jan	3.25%	0.12%	2.52%	6.01%	6.39%	7.90%
29	Feb	3.25%	0.31%	2.87%	6.11%	6.30%	7.74%
30	Mar	3.25%	0.25%	2.82%	6.14%	6.42%	8.00%
31	Apr	3.25%	0.17%	2.93%	6.20%	6.48%	8.03%
32	May	3.25%	0.15%	3.29%	6.23%	6.49%	7.76%
33	June	3.25%	0.17%	3.72%	6.13%	6.20%	7.30%
34	July	3.25%	0.19%	3.56%	5.63%	5.97%	6.87%
35	Aug	3.25%	0.18%	3.59%	5.33%	5.71%	6.36%
36	Sept	3.25%	0.13%	3.40%	5.15%	5.53%	6.12%
37	Oct	3.25%	0.08%	3.39%	5.23%	5.55%	6.14%
38	Nov	3.25%	0.05%	3.40%	5.33%	5.64%	6.18%
39	Dec	3.25%	0.07%	3.59%	5.52%	5.79%	6.26%
40	**2010**						
41	Jan	3.25%	0.06%	3.73%	5.55%	5.77%	6.16%
42	Feb	3.25%	0.10%	3.69%	5.69%	5.87%	6.25%
43	Mar	3.25%	0.15%	3.73%	5.64%	5.84%	6.22%
44	Apr	3.25%	0.15%	3.85%	5.62%	5.81%	6.19%
45	May	3.25%	0.16%	3.42%	5.29%	5.50%	5.97%
46	June	3.25%	0.12%	3.20%	5.22%	5.46%	6.18%
47	July	3.25%	0.16%	3.01%	4.99%	5.26%	5.98%
48	Aug	3.25%	0.15%	2.70%	4.75%	5.01%	5.55%
49	Sept	3.25%	0.15%	2.65%	4.74%	5.01%	5.53%
50	Oct	3.25%	0.13%	2.54%	4.89%	5.10%	5.62%
51	Nov	3.25%	0.13%	2.76%	5.12%	5.37%	5.85%
52	Dec	3.25%	0.15%	3.29%	5.32%	5.56%	6.04%

INTEREST RATES

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
53	**2011**						
54	Jan	3.25%	0.15%	3.39%	5.29%	5.57%	6.06%
55	Feb	3.25%	0.14%	3.58%	5.42%	5.68%	6.10%
56	Mar	3.25%	0.11%	3.41%	5.33%	5.56%	5.97%
57	Apr	3.25%	0.06%	3.46%	5.32%	5.55%	5.98%
58	May	3.25%	0.04%	3.17%	5.08%	5.32%	5.74%
59	June	3.25%	0.04%	3.00%	5.04%	5.26%	5.67%
60	July	3.25%	0.03%	3.00%	5.05%	5.27%	5.70%
61	Aug	3.25%	0.05%	2.30%	4.44%	4.69%	5.22%
62	Sept	3.25%	0.02%	1.98%	4.24%	4.48%	5.11%
63	Oct	3.25%	0.02%	2.15%	4.21%	4.52%	5.24%
64	Nov	3.25%	0.01%	2.01%	3.92%	4.25%	4.93%
65	Dec	3.25%	0.02%	1.98%	4.00%	4.33%	5.07%
66	**2012**						
67	Jan	3.25%	0.02%	1.97%	4.03%	4.34%	5.06%
68	Feb	3.25%	0.08%	1.97%	4.02%	4.36%	5.02%
69	Mar	3.25%	0.09%	2.17%	4.16%	4.48%	5.13%
70	Apr	3.25%	0.08%	2.05%	4.10%	4.40%	5.11%
71	May	3.25%	0.09%	1.80%	3.92%	4.20%	4.97%
72	June	3.25%	0.09%	1.62%	3.79%	4.08%	4.91%
73	July	3.25%	0.10%	1.53%	3.58%	3.93%	4.85%
74	Aug	3.25%	0.11%	1.68%	3.65%	4.00%	4.88%
75	Sept	3.25%	0.10%	1.72%	3.69%	4.02%	4.81%
76	Oct	3.25%	0.10%	1.75%	3.68%	3.91%	4.54%
77	Nov	3.25%	0.11%	1.65%	3.60%	3.84%	4.42%
78	Dec	3.25%	0.08%	1.72%	3.75%	4.00%	4.56%
79	**2013**						
80	Jan	3.25%	0.07%	1.91%	3.90%	4.15%	4.66%
81	Feb	3.25%	0.10%	1.98%	3.95%	4.18%	4.74%
82	Mar	3.25%	0.09%	1.96%	3.90%	4.15%	4.66%
83	Apr	3.25%	0.06%	1.76%	3.74%	4.00%	4.49%
84	May	3.25%	0.05%	1.93%	3.91%	4.17%	4.65%
85	June	3.25%	0.05%	2.30%	4.27%	4.53%	5.08%
86	July	3.25%	0.04%	2.58%	4.44%	4.68%	5.21%
87	Aug	3.25%	0.04%	2.74%	4.53%	4.73%	5.28%
88	Sept	3.25%	0.02%	2.81%	4.58%	4.80%	5.31%
89	Oct	3.25%	0.06%	2.62%	4.48%	4.70%	5.17%
90	Nov	3.25%	0.07%	2.72%	4.56%	4.77%	5.24%
91	Dec	3.25%	0.07%	2.90%	4.59%	4.81%	5.25%
92	**2014**						
93	Jan	3.25%	0.05%	2.86%	4.44%	4.63%	5.09%
94	Feb	3.25%	0.06%	2.71%	4.38%	4.53%	5.01%
95	Mar	3.25%	0.05%	2.72%	4.40%	4.51%	5.00%
96	Apr	3.25%	0.04%	2.71%	4.30%	4.41%	4.85%
97	May	3.25%	0.03%	2.56%	4.16%	4.26%	4.69%
98	June	3.25%	0.03%	2.60%	4.23%	4.29%	4.73%
99	July	3.25%	0.03%	2.54%	4.16%	4.23%	4.66%
100	Aug	3.25%	0.03%	2.42%	4.07%	4.13%	4.65%
101	Sept	3.25%	0.02%	2.53%	4.18%	4.24%	4.79%
102	Oct	3.25%	0.02%	2.30%	3.96%	4.06%	4.67%
103	Nov	3.25%	0.02%	2.33%	4.03%	4.09%	4.75%
104	Dec	3.25%	0.04%	2.21%	3.90%	3.95%	4.70%
105	**2015**						
106	Jan	3.25%	0.03%	1.88%	3.52%	3.58%	4.39%
107	Feb	3.25%	0.02%	1.98%	3.62%	3.67%	4.44%
108	Mar	3.25%	0.03%	2.04%	3.67%	3.74%	4.51%
109	Apr	3.25%	0.02%	1.94%	3.63%	3.75%	4.51%

Southwest Gas Corporation
Test Year Ending November 30, 2015
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INTEREST RATES

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
110	May	3.25%	0.02%	2.20%	4.05%	4.17%	4.91%
111	Jun	3.25%	0.02%	2.36%	4.29%	4.39%	5.13%
112	Jul	3.25%	0.03%	2.32%	4.27%	4.40%	5.22%
113	Aug	3.25%	0.07%	2.17%	4.13%	4.25%	5.23%
114	Sep	3.25%	0.02%	2.17%	4.25%	4.39%	5.42%
115	Oct	3.25%	0.02%	2.07%	4.13%	4.29%	5.47%
116	Nov	3.25%	0.13%	2.26%	4.22%	4.40%	5.57%
117	Dec	3.50%	0.23%	2.24%	4.16%	4.35%	5.55%
118	**2016**						
119	Jan	3.50%	0.26%	2.09%			
120	Feb	3.50%	0.31%	1.78%			
121	Mar	3.50%	0.30%	1.89%			
122	Apr	3.50%	0.23%	1.81%			
123	May	3.50%	0.28%	1.81%			
124	Jun	3.50%	0.27%	1.64%			
125	Jul	3.50%	0.30%	1.50%			
126	Aug	3.50%	0.30%	1.56%			
127	Sep	3.50%	0.29%	1.63%			
128	Oct	3.50%	0.33%	1.76%			
129	Nov						
130	Dec						

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Line No	Year	S&P Composite	NASDAQ Composite	DJIA	S&P Dividend/Price Ratio	S&P Earnings/Price Ratio
1	1975			802.49	4.31%	9.15%
2	1976			974.92	3.77%	8.90%
3	1977			894.63	4.62%	10.79%
4	1978			820.23	5.28%	12.03%
5	1979			844.40	5.47%	13.46%
6	1980			891.41	5.26%	12.66%
7	1981			932.92	5.20%	11.96%
8	1982			884.36	5.81%	11.60%
9	1983			1,190.34	4.40%	8.03%
10	1984			1,178.48	4.64%	10.02%
11	1985			1,328.23	4.25%	8.12%
12	1986			1,792.76	3.49%	6.09%
13	1987			2,275.99	3.08%	5.48%
14	1988			2,060.82	3.64%	8.01%
15	1989	322.84		2,508.91	3.45%	7.41%
16	1990	334.59		2,678.94	3.61%	6.47%
17	1991	376.18	491.69	2,929.33	3.24%	4.79%
18	1992	415.74	$599.26	3,284.29	2.99%	4.22%
19	1993	451.21	715.16	3,522.06	2.78%	4.46%
20	1994	460.42	751.65	3,793.77	2.82%	5.83%
21	1995	541.72	925.19	4,493.76	2.56%	6.09%
22	1996	670.50	1,164.96	5,742.89	2.19%	5.24%
23	1997	873.43	1,469.49	7,441.15	1.77%	4.57%
24	1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
25	1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
26	2000	1,427.22	2,783.67	10,734.90	1.15%	3.63%
27	2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
28	2002	993.94	1,539.73	9,226.43	1.61%	2.92%
29	2003	965.23	1,647.17	8,993.59	1.77%	3.84%
30	2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
31	2005	1,207.06	2,099.03	10,547.67	1.83%	5.36%
32	2006	1,310.67	2,265.17	11,408.67	1.87%	5.78%
33	2007	1,476.66	2,577.12	13,169.98	1.86%	5.29%
34	2008	1,220.89	2,162.46	11,252.61	2.37%	3.54%
35	2009	946.73	1,841.03	8,876.15	2.40%	1.86%
36	2010	1,139.31	2,347.70	10,662.80	1.98%	6.04%
37	2011	1,268.89	2,680.42	11,966.36	2.05%	6.77%
38	2012	1,379.56	2,965.77	12,967.08	2.24%	6.20%
39	2013	1,462.51	3,537.69	14,999.67	2.14%	5.57%
40	2014	1,930.67	4,374.31	16,773.99	2.04%	5.25%
41	2015	2,061.20	4,940.49	17,590.61	2.10%	4.59%

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

Line No		S&P Composite	NASDAQ Composite	DJIA	S&P Dividends/Price Ratio	S&P Earnings/Price Ratio
1	2004					
2	1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
3	2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
4	3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
5	4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
6						
7	2005					
8	1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
9	2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
10	3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
11	4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
12						
13	2006					
14	1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
15	2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
16	3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
17	4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
18						
19	2007					
20	1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
21	2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
22	3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
23	4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
24						
25	2008					
26	1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
27	2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
28	3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
29	4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
30						
31	2009					
32	1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
33	2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
34	3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
35	4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
36						
37	2010					
38	1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
39	2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
40	3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
41	4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
42						
43	2011					
44	1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
45	2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
46	3rd Qtr.	1,237.12	2,613.11	11,671.47	2.15%	7.69%
47	4th Qtr.	1,225.65	2,600.91	11,798.65	2.25%	6.91%
48						
49	2012					
50	1st Qtr.	1,347.44	2,902.90	12,839.80	2.12%	6.29%
51	2nd Qtr.	1,350.39	2,928.62	12,765.58	2.30%	6.45%
52	3rd Qtr.	1,402.21	3,029.86	13,118.72	2.27%	6.00%
53	4th Qtr.	1,418.21	3,001.69	13,142.91	2.28%	6.07%
54						
55	2013					
56	1st Qtr.	1,514.41	3,177.10	14,000.30	2.21%	5.59%
57	2nd Qtr.	1,609.77	3,369.49	14,961.28	2.15%	5.66%
58	3rd Qtr.	1,675.31	3,643.63	15,255.25	2.14%	5.65%
59	4th Qtr.	1,770.45	3,960.54	15,751.96	2.06%	5.42%
60						
61	2014					
62	1st Qtr.	1,834.30	4,210.05	16,170.26	2.04%	5.39%
63	2nd Qtr.	1,900.37	4,195.81	16,603.50	2.06%	5.26%
64	3rd Qtr.	1,975.95	4,483.51	16,953.85	2.02%	5.38%
65	4th Qtr.	2012.04	4607.88	17368.36	2.03%	4.97%
66						
67	2015					
68	1st Qtr.	2063.46	4821.99	17806.47	2.02%	4.80%
69	2nd Qtr.	2102.03	5017.47	18007.48	2.05%	4.60%
70	3rd Qtr.	2,026.14	4,921.81	17,065.52	2.16%	4.72%
71	4th Qtr.	2,053.17	5,000.70	17,482.97	2.16%	4.23%
72						
73	2016					
74	1st Qtr.	1948.32	4609.47	16,635.76	2.31%	4.20%
75	2nd Qtr.	2074.99	4845.55	17,763.85	2.19%	4.14%
76	3rd Qtr.	2161.36	5165.06	18,367.92	2.13%	4.13%
77	4th Qtr.					

Source: Council of Economic Advisors, Economic Indicators, various issues.

PROXY GROUP COMMON EQUITY RATIOS

	Company	2011	2012	2013	2014	2015	Estimated 2016
1	Atmos Energy Corp.	50.6%	54.7%	51.2%	55.7%	56.5%	60.0%
2	Chesapeake Utilities	68.6%	71.6%	70.3%	65.5%	70.6%	71.0%
3	New Jersey Resources	64.5%	60.8%	63.4%	61.8%	56.8%	57.0%
4	Northwest Natural Gas	52.7%	51.5%	52.4%	55.2%	57.5%	57.0%
5	South Jersey Industries	59.5%	55.0%	54.9%	52.0%	50.8%	58.5%
6	Spire, Inc.	61.1%	63.9%	53.4%	44.9%	47.0%	47.5%
7	UGI Corp.	48.4%	40.0%	41.3%	43.6%	43.9%	44.0%
8	WGL Holdings, Inc.	66.2%	67.3%	69.8%	63.8%	56.1%	57.5%
9							
10							
11	Average	59.0%	58.1%	57.1%	55.3%	54.9%	56.6%
12							
13	Southwest Gas	56.8%	50.8%	50.6%	47.6%	50.7%	53.0%

Source: Value Line Investment Survey (September 2, 2016)

EXHIBIT JAC-A

Inflation Expectations

10.18.16

The Federal Reserve Bank of Cleveland's inflation expectations model uses Treasury yields, inflation data, inflation swaps, and survey-based measures of inflation expectations to calculate the expected inflation rate (CPI) over the next 30 years. The Cleveland Fed model is run every month on the date of the CPI release.

Latest Inflation Expectations Model Release (October 18, 2016)

The Federal Reserve Bank of Cleveland reports that its latest estimate of 10-year expected inflation is 1.69 percent. In other words, the public currently expects the inflation rate to be less than 2 percent on average over the next decade.

Historical Data

- Excel : This spreadsheet contains the inflation expectations model's output from 1982 to the present. Output includes expected inflation for horizons from 1 year to 30 years, the real risk premium, the inflation risk premium, and the real interest rate.
- Archives: View previous releases of inflation expectations going back to January 2015.

How to Interpret the Data

We report 10-year expected inflation, which is the rate that inflation is expected to average over the next 10 years.

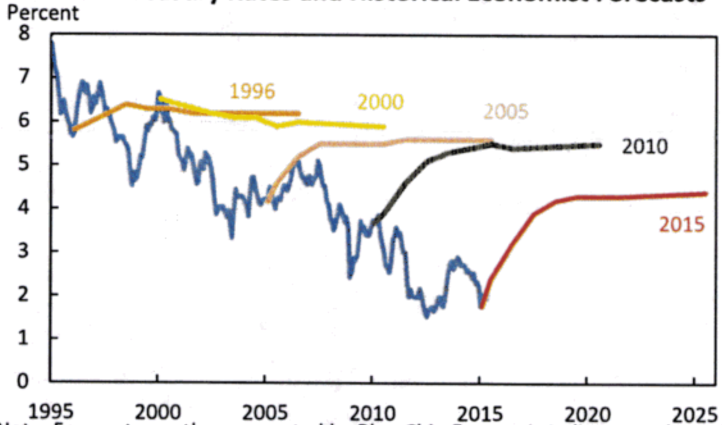
We also provide the model's estimates of the inflation risk premium, the real risk premium, and the real interest rate (see the charts below and the Excel file above). The **inflation risk premium** is a measure of the premium investors require for the possibility that inflation may rise or fall more than they expect over the period in which they hold a bond. Similarly, the **real risk premium** is a measure of the compensation investors require for holding real (inflation-protected) bonds over some period, given the fact that future short-term rates might be different from what they expect. Both the real risk premium and the inflation risk premium can be interpreted as investors' assessment of risk. In the case of the real risk premium, it is an assessment of the risk of unexpected changes in the real interest rate, and in the case of the inflation risk premium, it is an assessment of the risk of unexpected changes in inflation.

EXHIBIT JAC-B

have tended to be inaccurate. Between 1984 and 2012, CBO, private-sector forecasters, and the Administration all systematically overestimated the path of nominal interest rates just two years into the future (CBO 2015a).

Figure 5

10-Year Treasury Rates and Historical Economist Forecasts



Note: Forecasts are those reported by Blue Chip Economic Indicators released in March of the given calendar year, the median of over 50 private-sector economists. Source: Blue Chip Economic Indicators, Aspen Publishers.

A central question in forming a long-run forecast is whether interest rates are statistically stationary—i.e., whether they have a tendency to return to a definite long-run mean value or average. To the extent interest rates are mean-reverting, the historical average may contain the most useful information for projecting the long-run long-term interest rate. On the other hand, if changes in interest rates are permanent (or at least, highly persistent), recent data may contain more useful information about long-run interest rates than historical data. In general, econometric tests suggest that real and nominal interest rates revert to their mean very slowly, with close to unit root (non-stationary) [9] properties.[10] Tests for non-stationarity tend to be weak, however, in that distinguishing between a true unit root and mean reversion with very high persistence is difficult in a finite sample of data (Neely and Rapach 2008).

Economic theory strongly suggests that real interest rates are bounded, if not fully mean reverting (as discussed in more detail in section III).[11] A high return on investment should trigger a reallocation of resources from consumption toward capital accumulation, driving down the marginal product of capital and the real interest rate over time. Similarly, a low return on

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[9] A time series is said to contain a unit root if its random changes contain a permanent component. In this case it is statistically non-stationary.

[10] Hamilton et. al. (2015) reject the hypothesis that the real interest rate converges to a fixed constant. The difficulty in predicting the long-run real interest rate leads them to be skeptical of models, like the Ramsey model considered below, that place a strong emphasis on the link between output growth and the real interest rate.

[11] Even when interest rates are mean-reverting, and therefore stationary in the statistical sense, they can be "trend-stationary," reverting to means that evolve deterministically over time rather than being constants. Thus, stationarity of interest rates does not rule out the possibility that they trend upward or downward over long periods as a result of somewhat predictable, secular economic forces.