MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

REVENUE REQUIREMENT
COST OF SERVICE

SUMMIT NATURAL GAS OF MISSOURI, INC.

CASE NO. GR-2014-0086

Jefferson City, Missouri
May 30, 2014

** **Denotes Highly Confidential Information** **

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REVENUE REQUIREMENT

COST OF SERVICE REPORT OF

SUMMIT NATURAL GAS OF MISSOURI, INC.

CASE NO. GR-2014-0086

I. Executive Summary

Staff's Revenue Requirement Recommendation

Staff of the Missouri Public Service Commission ("Staff") has conducted a review in Case No. GR-2014-0086 of all cost of service components (capital structure and return on rate base, rate base, depreciation expense, revenues and operating expenses) which comprise Summit Natural Gas of Missouri, Inc.'s ("SNG" or "Company") revenue requirement. The ordered test year for this case is the twelve months ending September 30, 2013. The test year update period ordered for this case is December 31, 2013. The Commission has also ordered a true-up in this case based on June 30, 2014. The Staff's recommended revenue requirement for SNG, based upon updated results through December 31, is a range from $6.8 million to $7.8 million at the Staff's recommended rate of return range of 6.92 percent to 7.32 percent. Staff's recommendation for return on equity is between 9.80 percent to 10.80 percent with a mid-point of 10.30 percent. The capital structure recommendation is 40.00 percent common equity and 60.00 percent debt.

Impact of Staff's Revenue Requirement on Retail Rate Revenue

Staff's recommended revenue requirement of $7.28 million would represent an increase in SNG's total natural gas revenues based on existing rates. The increase relates only to SNG's margin revenues and does not include SNG's gas cost revenues. The impact of Staff's recommended revenue requirement for each of SNG's rate classes will be discussed in Staff's rate design and class cost of service report that is to be filed on June 13, 2014.

A. Major Issues

SNG filed its case based upon a test year ending September 30, 2013, but it did not update a majority of its case beyond that point. Because Staff updated the major components of the Company's revenue requirement through December 31, 2013, the difference in the timing of the case has resulted in some differences in Staff's and SNG's calculated revenue requirements. Along with these differences, there are other major differences in traditional revenue requirement that exist between Staff and SNG based on their respective direct filings. A brief description of each item is as follows:

Return on Equity (ROE) – Staff has recommended a 10.30 percent ROE at the mid-point. SNG is requesting a 12 percent ROE. This issue is addressed in Section V of this report.

Depreciation Reserve – SNG has been accruing depreciation rates for Gallatin and Warsaw districts based on depreciation rates set for the Lake of the Ozarks CCN GA-2012-0285 instead of the ordered rates for these districts from cases GO-2005-0120 and GA-2009-0264. The use of the wrong depreciation rates for Warsaw and Gallatin began at the time of the merger January 1, 2012 and has continued to the present. Positive and negative adjusts will need to be made to the depreciation reserves to reflect the use of the correct depreciation rates for the Gallatin and Warsaw districts/regions.

Staff Expert/Witness: Amanda C. McMellen

B. Conditions of Prior Stipulations and Agreements

In the course of this audit, Staff reviewed conditions placed on the Company set forth in prior orders and agreements. SNG has several approved stipulation and agreements, currently in effect, that require them to follow certain conditions. After reviewing these conditions, Staff became aware that SNG is not complying with a number of the conditions. Examples of some of the non-compliance issues are as follows:

Case No. GM-2011-0354 – 1) Condition 3E: "…submit to Staff and Public Counsel a highly confidential use of funds statement of funds statement identifying the portion of the new debt and equity attributed to each pre-merger entity. The use of funds statement shall be maintained and provided upon request at the time of the next rate case." The Company did not provide this information; 2) Condition 4: "Upon closing of this transaction, MGU shall provide surveillance reports for the combined companies to the Auditing Department of the Utility Services Division and the Public Counsel on a quarterly basis." These reports were not provided on a monthly basis as required. It wasn't until Staff requested these reports in this rate proceeding that SNG provided the information.

Case No. GR-2010-0347 – 1) Condition (2) a: The Company shall develop and maintain detailed vehicle logs for all Company owned vehicles. Staff requested these vehicle logs, which do not exist. The response to Staff Data Request (DR) No. 0041.4 in Case No. GR-2014-0086 was as follows:

> …Completing the daily logs was highly labor intensive. SMNG did have the administrative staff to maintain the records, however once the merger was complete the process of collecting the data was discontinued since many of the day to day administrative activities no longer resided in Missouri. There was no Corporate discussions regarding eliminating the activity, it just simply dropped through the cracks.

This condition was also reaffirmed in the merger case, Case No. GM-2011-0354 condition 10, requiring MGU to comply with conditions imposed from prior orders and agreements.

The conditions listed above are a few examples of conditions that SNG has not complied with from prior orders and agreements, this is a non-exhaustive list. Although SNG's non-compliance with these conditions does not have an effect on Staff's calculated revenue requirements in this case, Staff wanted to make the parties and the Commission aware of these issues. Staff recommends that the Commission re-order SNG to comply with these previous orders.

Staff Expert/Witness: Amanda C. McMellen

II. Background of Rate Case

On January 2, 2014, SNG filed tariffs for a proposed increase of $7.47 million, representing a 26.5 percent increase. The revenue increase recommended by SNG is based on a proposed ROE of 12.00 percent with a capital structure of 43.04 percent long-term debt and 56.96 percent common equity as follows:

SNG's Cost of Capital

Type of Capital	Ratio	Cost of Capital	Weighted Cost of Capital
Long-Term Debt	43.04%	3.21%	1.38%
Common Equity	56.96%	12.00%	6.83%
Total	100.00%		**8.22%**

Source: SNG work papers

Staff Expert/Witness: Amanda C. McMellen

III. Background of SNG

SNG is a local natural gas distribution utility serving approximately 200,000 customers and operates in 21 counties covering parts of northern, central and south central Missouri. The five districts (service territories) for SNG are Gallatin and Warsaw (former MGU divisions), Lake of the Ozarks ("LOO"), and Branson and Rogersville (former SMNG divisions). Due to a moratorium on rate increases ordered in the Case No. GA-2012-0285, the LOO district is not included in this rate proceeding.

SNG is the current name of the corporate entity formerly known as Missouri Gas Utility, Inc. (MGU). MGU is a wholly-owned subsidiary of Summit Utilities, Inc. (SUI or "Summit Utilities"). SUI was formerly known as CNG Holdings, Inc. (Holdings). SUI owns a number of regulated and unregulated subsidiaries. Its subsidiaries include the regulated gas utilities of Colorado Natural Gas (CNG) and Summit Natural Gas of Maine. Certain corporate costs incurred by SUI are directly assigned or allocated to SUI affiliates, including SNG.

SUI acquired the municipal gas systems of Gallatin, MO and Hamilton, MO under their previous corporate name of CNG Holdings, Inc. These are the systems that were originally known as MGU. MGU began operating these systems on January 1, 2005. The Commission approved the acquisition of these systems by MGU in December 2004 through its Order in Case No. GO-2005-0120. MGU last received authorization for a general rate increase from the Commission in Case No. GR-2008-0060 in an Order Approving Unanimous Stipulation and Agreement and Authorizing Tariff filing issued on March 20, 2008 with the rates effective on April 15, 2008. In its Order, the Commission approved the stipulated annual rate increase amount of $301,000.

In Case No. GA-94-127, Tartan Energy, doing business as Southern Missouri Gas Company, filed an application for a certificate of convenience and necessity ("CCN"). This is now referred to as the legacy system. Since the original CCN case discussed above, there have been various owners and multiple reorganizations. Within those years, Southern Missouri Gas Company began doing business as Southern Missouri Natural Gas (SMNG). SMNG last received authorization for a general rate increase from the Commission in Case No. GR-2010-0347 in an Order Approving Unanimous Small Company Rate Increase and

Approving Tariff issued on January 19, 2011 with the rates effective on February 1, 2011. In its Order, the Commission approved the stipulated annual rate increase amount of $1,300,000.

MGU merged with SMNG in Case No. GM-2011-0354, with MGU as the surviving entity. This merger was approved by the Commission on September 28, 2011 and effective October 8, 2011. At the time of the merger filing, MGU and SMNG's owners were the same, which was IIF CNG Investment LLC. More details regarding the corporate structure are included in Section V.D.

Staff Expert/Witness: Amanda C. McMellen

IV. True-Up Recommendation

A test year update period reflects material known and measurable changes to Staff's case through a date near the conclusion of Staff's audit. In contrast, true-ups are updates of major elements of a utility's revenue requirement beyond the end of an ordered test year and update period. True-ups are not required for every rate proceeding, and typically are only ordered when it can be demonstrated material changes to the revenue requirement will likely occur after the end of the ordered update period within a period close enough to the operation-of-law date in the case to allow for a review and verification of these known changes.

The Commission ordered a true-up in this case for the period ending June 30, 2014 to reflect known changes in this proceeding. The Commission's Order Correcting Modified Procedural Schedule issued March 21, 2014 allows for the results of the true-up to be filed as True-up Direct Testimony on September 5, 2014.

The true-up will include the following components of SNG's revenue requirement:

RATE BASE:

Plant in Service

Depreciation Reserve

Deferred Taxes

Gas inventory

CAPITAL STRUCTURE:

Rate of Return

Capital Structure

INCOME STATEMENT:

Revenues for customer growth

Payroll – employee levels and wage rates

Payroll related benefits and taxes

Rate Case Expense

Bad Debt Expense (uncollectibles)

Depreciation and Amortization Expense

Related income tax effects

Property Taxes

Staff Expert/Witness: Amanda C. McMellen

V. Rate of Return

A. Introduction

An essential ingredient of the cost-of-service ratemaking formula provided above is the rate of return (ROR), which is designed to provide a utility with a return of the costs required to secure debt and equity financing. This ROR is equal to the utility's weighted average cost of capital ("WACC"), which is calculated by multiplying each component ratio of the appropriate capital structure by its cost and then summing the results. While the proportion and cost of most components of the capital structure are a matter of record, the cost of common equity must be determined through expert analysis.

Staff's expert financial analyst, David Murray, has determined SNG's cost of common equity by applying a well-respected and widely-used methodology[1] to data derived from a carefully-assembled group of comparable companies. Staff then used that cost of common equity, together with other capital component information as of the updated test year date, December 31, 2013, to calculate SNG's fair rate of return, as follows:

[1] Staff relied primarily on its Discounted Cash Flow ("DCF") analysis of a group of comparable utilities, checking the reasonableness of its result with a Capital Asset Pricing Model ("CAPM") analysis as well as by other corroborating data.

TABLE ONE: SNG's Rate of Return:					
			Weighted Cost of Capital Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	**9.80%**	**10.30%**	**10.80%**
Common Stock Equity	40.00%	----	3.92%	4.12%	4.32%
Long-Term Debt	60.00%	5.00%	3.00%	3.00%	3.00%
	100.00%		**6.92%**	**7.12%**	**7.32%**

Source: Schedule 14

As contained in Table One, Staff recommends, based upon its expert analysis, a ROE range of 9.80 percent – 10.80 percent and an overall ROR range of 6.92 percent – 7.32 percent, with mid-point estimates of 10.30 percent and 7.12 percent, respectively. The details of Staff's analysis and recommendations are, presented in Appendix 2 and Schedules 1-14, attached to this report.

Staff's cost of equity estimate is primarily based on the constant-growth DCF model results. The major assumption made when the constant-growth DCF model is applied to mature companies, such as natural gas distribution companies, is that mature companies experience constant growth into perpetuity. The constant growth (perpetual growth) used in Staff's constant-growth DCF model is premised on Staff's assumption that Staff's set of comparable natural gas distribution companies (proxy group)[2] should not experience a compound annual perpetual growth rate much, if any higher than those actually achieved for the natural gas distribution industry over a prolonged time period. As Staff will explain in detail later in this Section of the Cost of Service Report, the constant-growth rate should not be any higher than 5 percent based on actual experience.

B. Analytical Parameters

The determination of a fair rate of return is guided by principles of economic and financial theory; and by certain minimum constitutional standards. Investor-owned public utilities such as SNG are private property that the state may not confiscate without appropriate compensation. The Constitution requires, therefore, that utility rates set by the

[2] Schedule 9-2.

government must allow a reasonable opportunity for the shareholders to earn a fair return on their investments. The United States Supreme Court has described the minimum characteristics of a Constitutionally-acceptable rate of return in two frequently-cited cases. In ***Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,*** the Court stated:[3]

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. 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.

Similarly, in the later of the two cases, ***Federal Power Commission v. Hope Natural Gas Co.,*** the Court stated:[4]

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

From these two decisions, Staff derives and applies the following principles to guide it in recommending a fair and reasonable ROR:

[3] 262 U.S. 679, 692-93, 43 S.Ct. 675, 679, 67 L.Ed. 1176, 1182-83 (1923).
[4] 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 333, 345 (1943).

1. A return consistent with returns of investments of comparable risk;

2. A return sufficient to assure confidence in the utility's financial integrity; and

3. A return that allows the utility to attract capital.

Embodied in these three principles is the economic theory of the opportunity cost of an investment. The opportunity cost of an investment is the return that investors forego in order to invest in similar risk investment opportunities, which will vary depending on market and business conditions.

The methodologies of financial analysis has advanced greatly since the ***Bluefield*** and ***Hope*** decisions. Additionally, today's utilities compete for capital in a global market rather than a local market.[5] Nonetheless, the parameters defined in those cases are readily met using current methods and theory. The principle of the commensurate return is based on the concept of risk. Financial theory holds that the return an investor may expect is reflective of the degree of risk inherent in the investment, risk being a measure of the likelihood that an investment will not perform as expected by that investor. Any line of business carries with it its own peculiar risks and it follows, therefore, that the return SNG may expect is equal to that required for comparable-risk utility companies.

Financial theory holds that the results of a company-specific DCF method satisfies the constitutional principles inherent in estimating a return consistent with those of companies of comparable risk;[6] however, Staff recognizes that there is also merit in analyzing a comparable group of companies as this approach allows for consideration of industry-wide data. Because Staff believes the cost of equity can be reliably estimated using a comparable group of companies and the Commission has expressed a preference for this approach, Staff relies primarily on its analysis of a comparable group of companies to estimate the cost of equity for SNG.

In this case, Staff has applied this comparable company approach through the use of both the DCF method and the Capital Asset Pricing Model ("CAPM"). Properly used and

[5] Neither the DCF nor the CAPM methods were in use when those decisions were issued.

[6] Because the DCF method uses stock prices to estimate the cost of equity, this theory not only compares the utility investment to other utilities, but it compares the utility investment to all available assets. Consequently, setting the allowed ROE based on a market-determined cost of equity is necessarily consistent with the principles of ***Hope*** and ***Bluefield***.

applied in appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate estimates of a utility's cost of equity. Because it is a well-accepted economic theory that a company that earns its cost of capital will be able to attract capital and maintain its financial integrity, Staff believes that authorizing an *allowed* return on common equity no lower than the *cost* of common equity is consistent with the principles set forth in ***Hope*** and ***Bluefield***.

C. Current Economic and Capital Market Conditions

Determining whether a cost of capital estimate is fair and reasonable requires a good understanding of the current economic and capital market conditions, with the former having a significant impact on the latter. With this in mind, Staff emphasizes that an estimate of a utility's cost of equity should pass the "common sense" test when considering the broader current economic and capital market conditions.

1. Economic Conditions

For the 2013 calendar year, the U.S. economy expanded in all four quarters. Real GDP increased 1.1 percent in the first quarter, 2.5 percent in the second quarter, 4.1 percent in the third quarter and 2.6 percent in the fourth quarter.[7] The Bureau of Economic Analysis attributes the deceleration in real GDP growth in the fourth quarter to a downturn in inventory investment, a larger decrease in federal government spending, and a downturn in housing investment. As of March 19, 2014, the Federal Reserve Bank ("Fed") projected the economy would grow between 2.8 percent and 3.0 percent this year and between 3.0 percent and 3.2 percent next year. Assuming the projected economic growth does not cause inflation rates to rise above the Fed's target inflation rate of 2 percent and the unemployment rate continues to trend toward 6.5 percent, the Fed's actions should be consistent with what it has communicated to markets.

Information released from the recently held Federal Open Market Committee ("FOMC") meeting held on March 19, 2014, share the FOMC's view that the data received since the last meeting in January indicate that growth in economic activity decelerated. Labor market indicators showed further improvement, but the unemployment rate remains elevated.

[7] Bureau of Economic Analysis, GDP Growth Slows in Fourth Quarter, March 27, 2014 and National Income and Product Accounts Gross Domestic Product, 4th quarter and annual 2013 (third estimate); Corporate Profits, 4th quarter and annual 2013.

The FOMC reduced its overall bond purchase program by another $10 billion per month beginning April 2014; and also indicated that it will continue to taper the bond purchase program if the incoming information and financial developments exhibit substantial improvement.

The FOMC updated its forward guidance based on the unemployment rate now nearing 6.5 percent. The following excerpt reflects the FOMC's current stance:

> To support continued progress toward maximum employment and price stability, the Committee today reaffirmed its view that a highly accommodative stance of monetary policy remains appropriate. In determining how long to maintain the current 0 to ¼ percent target range for the federal funds rate, the Committee will assess progress–both realized and expected—toward its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial developments. The Committee continues to anticipate, based on its assessment of these factors, that it likely will be appropriate to maintain the current target range for the federal funds rate for a considerable time after the asset purchase program ends, especially if projected inflation continues to run below the Committee's 2 percent longer-run goal, and provided that longer-term inflation expectations remain well anchored.
>
> When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent. The Committee currently anticipates that, even after employment and inflation are near mandate-consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels the Committee views as normal in the longer run.[8]

Some of Staff's proxy group companies' issuances of long-term debt offer evidence of the existence of the still-low long-term debt cost environment. On August 13, 2013, Laclede Gas Company issued $450 million of first mortgage bonds 3.34 percent (average) debt series ($100 million 5-year term 2.00 percent series debt, $250 million 10-year term 3.40 percent series debt and $100 million 30-year term 4.625 percent series debt) compared with Laclede Gas Company's 6.5 percent $25 million first mortgage bonds paid at maturity on October 15, 2012. On August 19, 2013, Northwest Natural Gas Company issued 3.542 percent

[8] Federal Reserve Press Release March 19, 2014.

$50 million first mortgage bonds with a 10-year maturity. Another example is AGL Resources issuance of $500 million in 30-year senior notes with a fixed interest rate of 4.4 percent on May 16, 2013.

2. Capital Market Conditions

a. Utility Debt Markets

Utility debt markets clearly indicate a lower cost-of-capital environment. If one were to assume that the risk premium[9] required for investing in utility stocks rather than utility bonds were constant, then the currently low utility debt yields clearly translate into a lower required return on equity. In other words, lower cost of debt is indicative of lower cost of capital, all else being equal.

Although long-term interest rates –as measured by 30-year Treasury Bonds ("T-Bonds") and utility bond yields–increased during the 2013 calendar year, they have decreased slightly during the first three months of 2014 and are still low when compared to long-term interest rates experienced prior to and immediately after the end of the most recent recession in June 2009 (*see* Schedules 4-2 and 4-3, and Schedules 4-1 and 4-3 respectively). As of March 2014, the average spread between 30-year T-bonds (3.62 percent) and average utility bond yields (4.74 percent)[10] was 112 basis points, which is 42 basis points below the average of such yields displayed in the period since 1980 (*see* Schedule 4-4). Utility bond yields over the last couple of years continue to remain at levels not experienced since the 1960s.[11]

b. Utility Equity Markets

Investors view regulated utility company stock investments as a close alternative to bond investments. Therefore, like bond investments, typically when long-term interest rates fall, regulated utility company stock prices rise. This is what largely triggered utility company stocks, specifically natural gas utility stocks, to outperform the broader markets

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[9] Risk Premium in this context is the excess required return to invest in a company's equity rather than its debt.
[10] The 4.74 percent yield is based on an average from data obtained from BondsOnline.com. For utility bond yields that Staff provides prior to September 2010, Staff used Mergent Bond Record. Staff has canceled its subscription to Mergent Bond Record and will rely on data it receives from BondsOnline pursuant to a subscription agreement.
[11] Because Staff does not have utility bond yield data dating back to the 1960s, this is based on Staff's review of general corporate bond yields that were available from the St. Louis Federal Reserve website. This data showed that the general level of bond yields was much lower in the 1960s.

until approximately May 2013. During the next few months, interest rates started to increase out of fear that the Fed would start tightening monetary policy in the near future, which caused returns on utility stocks to lag that of the S&P 500 by a fairly wide margin for the rest of the 2013 calendar year. The total return on the S&P 500 for 2013 was 32.39 percent compared to a total return of 21.08 percent for Staff's natural gas utility proxy group.

The broader markets have moderated a bit during the first quarter of 2014. This appears to be largely due to concerns about valuation levels of growth stocks as compared to prospects for future growth. This appears to have caused some movement back to utility stocks. During the first quarter of 2014, the S&P 500 had total return of 1.81 percent as compared to the total return on Staff's natural gas utility proxy group of 3.96 percent. For the twelve months ended March 31, 2014, the total return on the S&P 500 was 22.40 percent as compared to the total return on Staff's natural gas utility proxy group of 13.61 percent.

Because regulated utilities had been trading at a premium to the S&P 500 before the rally in the broader markets during the latter half of 2013, it appeared that investors were fairly risk averse and seeking yield through investment in utility stocks and other defensive sectors. However, investors became more willing to increase their risk exposure in the broader markets during the latter half of 2013. But this trend has not continued during the first quarter of 2014. Investors have shown that they continue to value dividend-paying stocks as compared to growth stocks. In a recent Wall Street Journal article, investors' favor of dividend stocks for the first part of 2014 was discussed:

> The shift from last year, when so-called growth stocks were in favor, reflects rising concern that corporate earnings are running out of gas and the economic recovery will be stuck in low gear. Few investors expect the market to deliver the gains seen last year, when the S&P 500 returned 32% including dividends…
>
> …An unexpected drop in interest rates this year has increased the appeal of dividend-paying stocks. Despite the Federal Reserve's staggered withdrawal of its rate-lowering stimulus measures, the yield on 10-year Treasury notes stands at 2.726%, down from 3% at the start of this year.[12]

It appears that investors have pulled back from growth stocks because of reduced expectations for growth in earnings for the broader markets. The appeal of some dividend-paying stocks,

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[12] Dan Strumpf, "Dividend Stocks Bear Fruit: *As Shares Get Pricey, More Investors Pick Steady Payouts Over Rapid Growth*," April 7, 2014, P. C1, Wall Street Journal.

such as Staff's natural gas distribution proxy group, is that they offer dividend yields that are higher than yields on Treasury Bonds and they offer a fairly predictable growth rate in the dividends assuming the natural gas distribution company does not expose itself to unpredictable non-regulated operations.

However, it is important to understand that while Staff's natural gas proxy group lagged behind the S&P 500 for the twelve months ended through March 31, 2014, the returns were still well above what can be explained by expected earnings growth. Because the valuation levels of the stocks of Staff's natural gas utility proxy group have increased since Staff last sponsored testimony in the Kansas City Power & Light Company (KCPL), Ameren Missouri and Empire rate cases, this supports Staff's position that investors are still not requiring a very high return to invest in gas utility companies. In fact, some investment analysts believe at current valuation levels utility stocks won't experience any capital appreciation in 2014.[13]

D. Summit Utilities, Inc.'s and Summit Natural Gas of Missouri's Corporate/Ownership Structure and Operations

SNG is a wholly-owned subsidiary of SUI which is a wholly-owned by one private equity investor, Infrastructure Investments Fund ("IIF"), through the investment entity IIF CNG Investment LLC. This private equity investor is advised by JP Morgan Asset Management. SNG (referred to as Missouri Gas Utility, Inc. or "MGU" before November 17, 2011)[14] acquired the assets of SMNG on January 3, 2012. Although MGU and SMNG were separate entities before January 3, 2012, IIF was the ultimate owner of both entities before MGU acquired SMNG and formed SNG. Consequently, the transaction did not involve a third party. IIF initially acquired majority interest in the MGU system in May 2007 by acquiring shares of Summit Utilities, Inc.'s (known as CNG Holdings at the time). Summit Utilities created MGU in October 2004 for purposes of acquiring and holding the municipal gas distribution systems in Gallatin and Hamilton. IIF became the sole shareholder in Summit Utilities in 2010. IIF initially acquired interests in the SMNG system in 2008 through IIF SMNG Investment LLC. IIF became the sole owner of the SMNG in 2011.

[13] Shahriar (Shah) Pourreza, Sophie K Karp, Ryan Levine and Mark Rudovic, "FY 2014 utility Sector Sneak Peak: Stock Pickers Market – Select Winners and Losers Exist in '14," January 2, 2014, Citi Research.
[14] Note 1 to Summit Natural Gas of Missouri Inc.'s Financial Statements and Independent Auditors' Report, December 31, 2012 and 2011.

As the owner of these systems, IIF has expended considerable capital expanding the systems in the Branson and Lake of the Ozarks areas. Staff estimates the amount of capital invested in the Lake of the Ozarks system at approximately ** __________ ** through December 31, 2013 and approximately $47 million in the Branson system based on its estimated rate base. Other than recapitalization of the Company, in which IIF refunded itself for ** __________ ** it had advanced to SMNG while it was a separate entity with multiple owners, IIF has not received a return on or a return of capital it has invested in Missouri.[15] It is rare that equity investors in a regulated gas distribution utility do not receive dividend distributions, but it is also rare to have a utility expending so much capital to build new gas distribution systems to communities that have never had the option to take natural gas.

Although IIF has shown a commitment to its investment in expanding its Missouri gas distribution operations, it has not been forthcoming in providing financial information that is relevant to determining a fair and reasonable rate of return in this case. This lack of transparency is a hinderance to evaluating and recommending a fair and reasonable rate of return for SNG's operations. As the Commission is aware (and in some cases as the Commission has ordered), subsidiaries rarely are financed as separate and distinct entities. At the very least, even if a subsidiary does perform its own financing functions, its credit rating is dependent or even driven by that of the parent company. Consequently, the Commission has ordered the use of a parent company consolidated capital structure and parent company consolidated cost of debt in determining the allowed rate of return for some Missouri utilities.[16] Although Staff believes each case should be judged on its own merits for purposes of deciding whether to recommend a subsidiary or a consolidated parent company capital structure,[17] Staff must be afforded the opportunity to perform this investigation to make its own independent determination. Instead, the Company is making this determination on its own. For example, SNG stated the following in response to Staff DR No. 0073, in which Staff requested Summit Utilities' consolidated cost of debt:

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[15] id.
[16] See Commission Report and Orders in Case Nos. GR-2009-0355 and ER-2012-0174 and ER-2012-0175.
[17] Staff recommendations and Commission Report and Orders in Ameren Missouri rate cases have adopted Ameren Missouri's capital structure and cost of debt because Ameren Missouri's capital structure and financing seemed to be managed at least to a higher degree of separation.

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Because the financing activities of the parent company and the other subsidiaries under the same parent company can influence the financial risk and consequently, the cost of capital to the regulated subsidiary, it is important for Staff to be able to independently evaluate financial information of the consolidated entity in order to decide whether it is appropriate to recommend SNG's allowed ROR to be based on Summit Utilities' consolidated cost of debt rather than a subsidiary-specific cost of debt. In fact, even in circumstances in which Staff has recommended the Commission not include another subsidiaries' cost of debt, the Commission determined in its report and order that this debt should be included in the company's allowed ROR.[18] In such situations, the company provided the details of the other subsidiaries' costs of debt so Staff could evaluate whether to recommend that this debt cost be included.

Although Staff believes its recommended capital structure and rate of return in this case should not include this debt, Staff was not able to review much of the financial information it typically would review for companies such as Ameren Missouri, KCPL, Laclede Gas, Missouri-American, etc. Being that these companies are owned by publicly-traded holding companies, it is much easier to analyze and understand how these companies manage their corporate financing activities simply by analyzing filings with the Securities and Exchange Commission in addition to the data provided in data request responses. Because SNG and Summit Utilities are owned by a private equity fund, IIF, Staff is wholly dependent on the Company's willingness to provide at least the financial information Staff requests through data requests. Because the Company objected to several of Staff's data requests for information about SNG's parent company, Summit Utilities, Staff's assessment of corporate financing activities performed for SNG at the Summit Utilities level was hindered.

[18] See Commission Report and Order in Case No. GR-2009-0355.

E. Summit Natural Gas of Missouri, Inc.'s and Summit Utilities, Inc.'s Credit Ratings

Neither SNG nor Summit Utilities, Inc. have been assigned a credit rating by any of the major rating agencies. In response to Staff DR No. 0140, SNG stated the following:

> Neither Summit Utilities, Inc. nor any of its subsidiaries (to include Summit Natural Gas of Missouri, Inc.) have pursued an independent credit rating or been apprised of a credit rating equivalent as assessed by an outside creditor or lender.

Although neither SNG nor Summit Utilities has a credit rating, both entities have been able to raise capital for their operations. Additionally, the cost of this capital has been fairly low, but this is due in part to the fact that the debt was issued at variable interest rates and shorter maturities. SNG raised $100 million of debt capital recently through a 3-year term loan. Although this debt currently only has an interest rate of 2.68 percent, this seems to be driven more by the characteristics of the loan rather than the credit quality of the borrower. SNG issued this short-term, variable rate loan in conjunction with its ongoing construction of the natural gas utility infrastructure in its newly formed Lake of the Ozarks Division. Based on discovery Staff performed in SNG's recent Application in Case No. GF-2013-0261, Staff determined that ** _______ ** of the proceeds would be directly used for establishing the new gas distribution system in the Lake of the Ozarks area and ** __________ ** of the proceeds would be used to refinance a bridge loan issued to effectuate the SMNG and MGU merger. Consequently, the $100 million term loan is for construction financing and a brief extension of a previous bridge loan, which SNG had originally intended to refinance with more permanent long-term debt.

Considering the restrictive covenants imposed on the $100 million term loan, which are not typical for a well-established, investment-grade natural gas distribution utility, it appears that the lenders are concerned about the willingness of the investors to support the loan and the ability of the investments to support the loan commitments. Because SNG's earnings before interest, taxes, depreciation and amortization ("EBITDA") before expansion into the Lake of the Ozarks was only about 50 percent of what it had expected, SNG's decision to take on additional business and financial risk with the large construction project in the Lake of the Ozarks most likely has only heightened concerns about whether actual performance will be consistent with the Company's projections. Considering that Staff had

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determined in Case No. GO-2012-0102 that under the scenario in which SMNG did not pursue the Lake of the Ozarks project the Company's projected financial ratios were already consistent with a non-investment grade entity, adding the business risk and the financial risk associated with the Lake of the Ozarks project has likely caused further uncertainty regarding SNG's ability to issue long-term permanent debt in the near future.

Although SNG's current financial condition implies that the current required return on debt and equity is likely higher due to the Lake of the Ozarks expansion, customers of the other systems should not be charged a higher return due to this increased risk. In fact, the Company and Staff specifically agreed to attempt to separate costs related to the Lake of the Ozarks expansion from the rest of SNG's systems when the Commission granted SNG a CCN for the Lake of the Ozarks area (*see* Case No. GA-2012-0285). Consequently, Staff believes its cost of capital recommendation in this case should be conservative, to ensure that customers of the established systems do not pay higher rates due to the increased risks caused by the Lake of the Ozarks project. Although this is admittedly a somewhat subjective process, because SNG at one time had suspended plans to expand into the Lake of the Ozarks, the Company provided Staff its financing plans as if it did not perform this expansion. The details of the SNG's previous financing plans were provided in Case No. GO-2012-0102, which Staff will discuss in more detail when it explains the rationale for its capital structure and cost of debt recommendation.

F. Cost of Capital

In order to arrive at Staff's recommended ROR, Staff specifically examined (1) an appropriate ratemaking capital structure, (2) the embedded cost of debt and finally (3) the cost of common equity.

1. Capital Structure

In most rate cases for established utilities, Staff recommends either the actual consolidated parent company capital structure or the actual subsidiary capital structure. Staff's decision on which to use depends on Staff's assessment of whether investors' view the subsidiary as being financially managed on a stand-alone basis and whether the credit quality of the subsidiary is assessed primarily on a stand-alone basis. Although Staff did review both Summit Utilities' consolidated capital structure and SNG's subsidiary capital structure in this rate case (*see* Schedules 6-1 and 6-2), because of the peculiarity of SNG's ongoing expansion and commitments it made to not include costs associated with the Lake of the Ozarks project in this rate case, Staff determined it was appropriate to impute a capital structure and cost of debt based on the assumption that SNG's existing divisions were capitalized and operated separate from the Lake of the Ozarks.

Often such situations are addressed by using an average capital structure and resulting cost of capital of a proxy group of companies as a starting point and then making any adjustments for the specific risk profile of the subject operations. The drawback of such an approach is that it is not based on a cost structure specific to the risk profile of the subject company's assets and how the company planned to finance those assets. Fortunately, at the time SNG filed its Application in Case No. GO-2012-0102, it had planned to operate without expanding into the Lake of the Ozarks. SNG had actually negotiated terms for the cost of the debt and the amount of debt it would issue for SNG based on the assumption that it would not expand into the Lake of the Ozarks. Consequently, Staff believes this approach is the most fair and reasonable considering the unique circumstance presented in this case.

SNG's Application in Case No. GO-2012-0102 requested Commission authority to encumber its Missouri assets in order to eventually secure up to $88 million of debt with a maturity of 20 years. SNG's proposal under this Application was based on its intent to establish a permanent capital structure for its existing operations. SNG indicated that its request was for purposes of recapitalizing the Company in order to target a capital structure of approximately 40 percent equity and 60 percent debt. The Company believed that normalized expected EBITDA for its existing operations would support this targeted capital structure. This is also likely the capital structure the Company's investor, IIF, uses for purposes of evaluating its investment decisions, but because the Company objected to Staff's request for such information, Staff cannot verify this to be the case.

Because Staff believes it is important to ensure that the rate of return allowed to be charged to customers of the existing operations is consistent with IIF's required return, which would have been based on the targeted capital structure, Staff recommends the Commission use this targeted capital structure in this case.

Staff believes the fact that SNG's sister company, Colorado Natural Gas Company ("CNG"), was actually capitalized with approximately 40 percent equity for purposes of its recent rate case in Colorado provides support for Staff's position that this capital structure is consistent with how IIF believes at least the established systems can and should be capitalized.

2. Embedded Cost of Debt

Because Staff's capital structure recommendation is based on the assumption that SNG's operations had remained limited to its divisions before expansion into the Lake of the Ozarks, it is also important to recommended a cost of debt that would likely have been incurred in such a situation. Because SNG had negotiated terms and conditions for recaptilazing the Company in such a situation, fortunately there is information available to provide some guidance on what the cost of debt would likely have been.

Although SNG did not provide a written response as to the projected cost of the 20-year debt, they did communicate this to Staff verbally during a November 16, 2011 conference call. Staff noted this conference call in its recommendation in Case No. GO-2012-0102. SNG projected that they would secure a fixed interest rate of approximately 5.5 percent for the 20-year debt. The Company maintained that it would have been able to do so by entering into a fixed for floating interest rate swap. Staff recently submitted a data request requesting supporting evidence for this expected cost. Until Staff receives a response providing such evidence, Staff recommends the use of the cost of debt associated with a CNG debt issuance because its effective interest rate is based on a swap arrangement similar to the anticipated arrangement SNG had initially proposed. The cost of the CNG debt issuance was approximately ** __________ ** as of December 31, 2013.[19] The overall cost of debt associated with SNG's sister company, CNG, was ** __________ ** through December 31, 2013, which is based on three separate debt issuances made between 2010 through 2012. Staff chose to use the lower cost debt issue of the three because its effective rate is also based on an interest rate swap, where one of CNG's debt issuances is based on a direct fixed rate of ** __________ ** . If SNG can provide adequate evidence that its cost of debt would have likely been closer to the 5.5 percent rate, Staff will reconsider its position.

3. Cost of Common Equity

Because SNG and its parent company, Summit Utilities, are privately held companies, Staff cannot analyze publicly-available information from stock market exchanges and equity analysts to estimate SNG's cost of common equity either directly or indirectly

[19] 2013 Annual Audited Financials for Summit Utilities, Inc.

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through its parent company as a proxy. In such situations there often is very little sophisticated analysis Staff can review to determine the private investors' cost of equity, i.e. the discount rate or required return on equity, used for purposes of discounting expected cash flows from their investment. However, this isn't the case with SNG and Summit Utilities.

As Staff explained earlier in its testimony, Summit Utilities is owned wholly by IIF, which is a multi-billion dollar infrastructure investment fund. This fund is advised by JP Morgan Asset Management, a sophisticated institutional investor. The fund is only open to qualified investors, which for the most part should be institutional investors such as pension funds and insurance companies, but may also include high net-worth individuals. Because IIF is the only shareholder of Summit Utilities, there is little doubt in Staff's mind that IIF has performed DCF analyses for purposes of its investments in Summit Utilities and for that matter, Summit Utilities' various projects, which includes those at SNG. Staff issued several data requests requesting information regarding IIF's required returns on equity for its investments in Summit Utilities and its subsidiaries, but SNG objected to each of these DRs. These DRs are directly relevant to the determination of the investors' required return, because in this unique situation, we have one sophisticated investor—IIF—that could provide us the specific analysis that shows its required return on equity and the overall weighted average cost of capital it used to determine its expected returns from its investments in Missouri. Actually, in Staff's opinion, it would not only be helpful to the Commission to required SNG's owners, IIF, to respond to Staff's data requests on investment analysis IIF performs for purposes of making decisions to invest in Missouri, but it would also be helpful for an IIF asset manager to sponsor testimony in the case to understand their investment decision making process. Therefore, IIF's required returns would be very useful to aid the Commission's understanding of how investors appproach estimating the cost of the equity capital they contribute to SNG.

In the absence of such information, Staff will go through the indirect process typically used by rate of return witnesses, which is to attempt to estimate investors' required return for a subject company by looking at market data on a proxy group of natural gas distribution companies and then make a subjective risk premium adjustment to account for risks specific to SNG. Staff estimated a natural gas distribution industry cost of common equity through a comparable company cost-of-equity analysis of a proxy group of eight companies using the Discounted Cash Flow ("DCF") methodology. Additionally, Staff used a CAPM analysis and a survey of other indicators as a check of the reasonableness of its recommendations.

a. The Proxy Group

First, Staff formed a group of comparable companies for the commensurate return analysis. Starting with 17 market-traded natural gas utilities (*see* Schedule 8-1), Staff applied a number of criteria to develop a proxy group to estimate a cost of equity for established natural gas distribution companies:

1. Stock publicly traded
(1 company eliminated, 16 remaining);

2. At least 65% Operating Income from Distribution
(5 companies eliminated, 11 remaining);

3. At least 65% of Assets are Distribution Assets
(0 companies eliminated, 11 remaining);

4. Two analysts for long term projected EPS growth available within the last 90 days
(3 companies eliminated, 8 remaining);

5. Positive historical 5-year compound annual growth rate in dividends per share;
(0 companies eliminated, 8 remaining); and

6. At least investment grade credit rating
(0 companies eliminated, 8 remaining).

This resulted in a group of eight publicly-traded natural gas utility companies ("the comparables/proxy group") that Staff used as a starting point for estimating SNG's cost of common equity. The comparables are listed on Schedule 8-2.

b. The Constant-growth DCF

Next, Staff estimated the proxy group's cost of common equity using the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. The constant-growth version of the model is usually considered appropriate for mature industries such as the regulated utility industry.[20],[21] It may be expressed algebraically as follows:

$$k = D_1/P_0 + g$$

Where: k is the cost of equity;

D_1 is the expected next 12 months dividend;

P_0 is the current price of the stock; and

G is the dividend growth rate.

The term D_1/P_0, the expected next 12 months dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the weighted average of equity analysts' projected dividends per share (DPS) for the 2014 fiscal year and 2015 fiscal year, as reported by FactSet (*see* Schedule 11), by the monthly high/low average stock price for the three months ending April 30, 2014 (*see* Schedule 12).[22] Staff weighted the the DPS projections in this manner in order to reflect the approximate amount of time remaining in the 2014 fiscal year for each comparable company. Staff used the above-described stock price because it reflects current market expectations. The projected average dividend yield for the eight comparable companies is approximately 3.80 percent, unadjusted for quarterly compounding.

c. The Inputs

In the DCF method, the cost of equity is the sum of the dividend yield and a perpetual growth rate ("g") that is intended to replicate the projected capital appreciation of the stock. In estimating a growth rate, Staff analyzed both actual and projected DPS, earnings per share ("EPS") and book value per share ("BVPS") for each of the comparable companies and also the projected DPS, EPS and BVPS (*see* Schedules 9-1 through 9-4). Staff also reviewed

[20] Aswath Damodaran, Investment Valuation: *Tools and techniques for determining the value of any asset*, University Edition, John Wiley & Sons, Inc., 1996, p. 195-196.

[21] John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity* Investments: Valuation, Association for Investment Management and Research, 2002, p. 64.

[22] The monthly high/low averaging technique minimizes the effects of short-term stock market volatility on the calculation of dividend yield. P0 is calculated by averaging the highest and the lowest price for each month during the selected period.

equity analysts' consensus estimates for long-term compound annual growth rates as reported by FactSet and provided by SNL Financial. The average consensus long-term growth rates for the proxy group is currently 3.96 percent. (*see* Schedule 9-4).

In Staff's experience, historical and projected growth rates for natural gas distribution utilities had been fairly consistent. Based on the shorter-term data shown on Schedule 9-4, it would appear that a growth rate range of 4.0 to 5.0 percent would be reasonable for an estimate of the cost of equity using the constant-growth DCF, but this does not give consideration to empirical and logical information that suggest that utility companies should grow at a rate less than that of the overall economy due to the mere fact that investors invest in utility companies for yield and not growth. In fact, considering that companies in the S&P 500 (a proxy for the U.S. capital markets) in recent years have retained approximately 65 percent to 70 percent of their earnings for reinvestment,[23] while natural gas distribution utilities' retention ratio has less than half that of the S&P 500,[24] it makes logical sense that utilities will grow at a rate less than that of nominal GDP growth. Consequently, a projected long-term, steady-state nominal GDP growth rate should be considered as an upper constraint when testing the reasonableness of growth rates used to estimate the cost of equity for a regulated gas utility.

Because the constant growth rate is assumed to last in perpetuity, the projected economic growth rates that are most pertinent for evaluating the sustainability of a growth rate for a given industry are those that are based on a steady-state economic environment for the country in which that industry operates. In the case of natural gas distribution utilities, it is important to project long-term, sustainable growth rates consistent and reasonable with the projected lower growth of the United States' developed domestic economy. Although some analysts try to infer potential future economic growth in the U.S. from historical growth rates, it is clear that most economic experts believe that the U.S. economy has developed to the extent that the growth rates of the past won't be realized again in the future, hence the current low interest rate environment. This is clear from long-term economic forecasts provided in Table 8, on page 92 of the U.S. Energy Information Administration's 2013 Annual Energy Outlook. The following table is reproduced for convenience:

[23] Table B-95 and B-96 attached to the 2013 Economic Report of the President.
[24] "Natural Gas Industry Summary," December 31, 2013, Edward Jones

Table 8. Comparisons of average annual economic growth projections, 2011-2040

Average annual percentage growth rates

Projection	2011-2015	2011-2025	2025-2040	2011-2040
AEO2013 (Reference case)	2.5	2.6	2.4	2.5
AEO2012 (Reference case)[a]	2.7	2.6	2.5	2.6
IHS Global Insight (August 2012)	2.5	2.6	2.5	2.5
OMB (January 2013)[a]	2.2	2.8	--	--
CBO (February 2013)[a]	2.6	2.7	--	--
INFORUM (November 2012)	2.6	2.6	2.4	2.5
Social Security Administration (August 2012)	2.9	2.7	2.2	2.4
IEA (2012)[b]	2.5	2.6	--	2.4
Blue Chip Consensus (October 2012)[a]	2.4	2.5	--	--
ExxonMobil	--	2.5	2.2	2.4
ICF International	--	--	--	2.6
Oxford Economics Group (January 2013)	2.7	2.7	2.6	2.6

-- = not reported or not applicable.

a OMB, CBO, and Blue Chip forecasts end in 2022, and growth rates cited are for 2011-2022. AEO2012 projections end in 2035, and growth rates cited are for 2011-2035.

b IEA publishes U.S. growth rates for certain intervals: 2010-2015 growth is 2.5 percent, 2010-2020 growth is 2.6 percent, and 2010-2035 growth is 2.4 percent.

Staff has used the Energy Information Administration, the Congressional Budget Office and the Blue Chip Consensus forecasts for purposes of evaluating projected long-term GDP growth in past rate cases. This table summarized not only these sources, but several other sources that are widely used in evaluating potential GDP growth. For example, the Federal Energy Regulatory Commission ("FERC") uses IHS Global Insight for purposes of evaluating GDP growth in gas pipeline rate cases. As can be seen in the above table, these sources provide not only a near-term projected annual compound economic growth rate, but also a projected annual compound growth rate over a very long period, which is of most relevance to a constant-growth DCF growth rate. In fact, some of these sources provide projected annual compound growth rates for the period 2025 through 2040, which provides insight as to the growth rate economists believe are sustainable given the fundamentals of the United States' developed economy. Such "trend" growth rates should be given the most weight to test the reasonableness of long-term growth rates for a mature industry, such as the regulated natural gas distribution industry. Although not included in this table, most economists expect a long-term trend growth rate in the GDP price deflator of approximately 2.0 percent. After multiplying this 2.0 percent inflation rate by a real GDP growth rate of 2.5 percent, this results in a compound growth rate of 4.55 percent for a sustainable, trend growth rate in the U.S. economy. Although some projections may be slightly higher or lower than a 4.55 percent growth rate in GDP, Staff believes this is a reasonable estimate based on the various sources it reviewed.

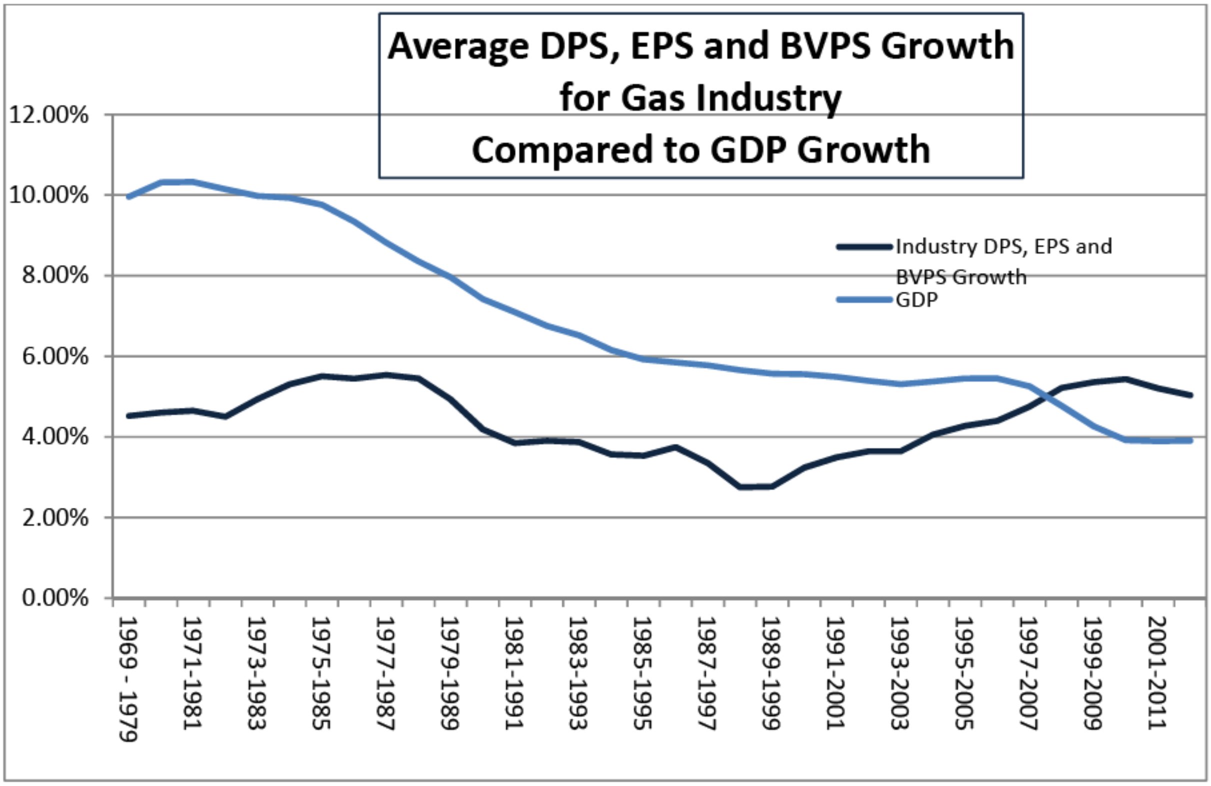
Although the fundamentals of the natural gas distribution industry do not support a growth rate higher than that of the overall economy, Staff decided it would be prudent to compare historical growth rate patterns for the natural gas distribution industry to that of GDP growth to better understand the relationship between gas industry growth and GDP growth.

In order to evaluate the gas industry's growth compared to GDP growth, Staff had to select a group of natural gas distribution companies that could be considered a good proxy for the natural gas distribution industry for a long, continuous period. Staff started with the entire set of companies that Edward Jones classified as natural gas distribution companies in its September 30, 2013 quarterly publication on the natural gas industry. Staff then researched its library of Value Line Ratings & Reports to determine which of these companies had continuous historical financial data for at least 20 years. The following companies had at least 20 years of continuous financial data: AGL Resources, Atmos Energy, Laclede Group, New Jersey Resources, Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries and WGL Holdings.[25] Actually, all of these companies, with the exception of Atmos Energy, had continuous financial data in Staff's library going back until at least the early 1970s, with most companies having information covering the entire historical period (back to 1968) in which Staff has information available in its library. Staff still included Atmos in its long-term proxy group, but Staff also analyzed trends without Atmos.

Staff's analysis of the proxy group's financial data since 1968 revealed that the actual realized growth of the natural gas distribution industry has averaged in the low 4 percent range, or about 75 percent of average GDP growth of around 7 percent over the same period. Although the natural gas distribution industry grew at a slower rate than GDP, Staff believes

[25] Edward Jones does not classify Southwest Gas Company as a natural gas distribution company. Staff's selection criteria in this case results in Southwest Gas Company being included Staff's natural gas proxy group. However, based on Southwest Gas' historical financials, it appears the Company was exposed to volatility not consistent with the other natural gas distribution utilities. Consequently, Staff still excluded Southwest Gas from its long-term proxy group.

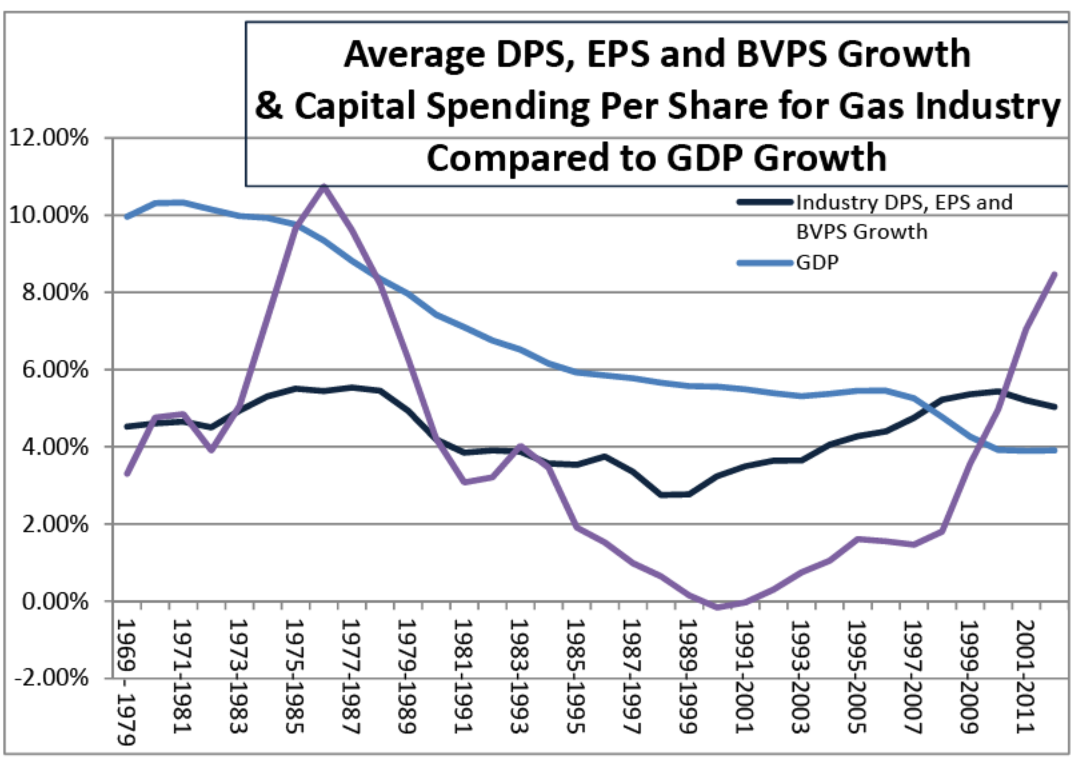
it is also important to consider that the growth in the natural gas distribution industry was not highly correlated with GDP growth over this period. Below is a graph of the natural gas distribution industries' average 10-year compound growth rates as they compare to GDP growth for the period 1968 through 2013 (this graph and the supporting data are also contained in Schedules 9-5 through 9-8):



As can be seen in the above graph, the growth for the natural gas distribution industry moved inversely to that of GDP for the 10-year periods from 1970- 1980 through 1975-1985 and 1988-1998 through 2001-2011. Consequently, empirical evidence shows that natural gas distribution utility growth has had very little correlation to that of GDP. If this is the case, then a key question for purposes of understanding the reasonableness of constant growth rates used in a DCF analysis is how one should incorporate GDP into evaluating the reasonableness of gas industry growth rates and what are the major factor(s) that will determine the sustainability of gas industry growth rates going forward?

As Staff has already explained, even though natural gas distribution industry growth has not been highly correlated to GDP in terms of growth patterns, it has on average been less than GDP growth. Therefore, long-term GDP growth is at the very least a constraint on the maximum long-term growth potential for the industry even though they don't always move together during shorter intervals. Therefore, considering the fact that average GDP growth is projected to be much lower than it had been over the past 40 years, then it is only logical to expect the long-term compound annual growth rates to be lower for the natural gas distribution industry over the same 40-year period.

The other factors that often determine potential growth for the regulated gas distribution industry are investment and demand/customer growth. Because most regulated natural gas distribution companies have moved to largely decoupled rate designs in which the recovery of the revenue requirement is not a function of usage, but of number of customers, the other major factor should be limited to expansion of the system to serve additional customers. Staff's understanding of the history of the natural gas distribution industry, at least that of the proxy group Staff analyzed, is that customer growth was a key driver of capital investment in the 1980s. In order to understand the relative magnitude of capital investment natural gas distribution companies made in the 1980s, Staff also analyzed the changes in capital spending per share from the period 1968 through the present. Staff, then compared the industry's capital spending to the average growth in DPS, EPS and BVPS and found a fairly high correlation between the two.



As can be seen, there is a higher correlation between capital spending and industry growth, then there is between GDP and industry growth. One would expect capital expenditures to be fairly highly correlated to GDP growth, but that is not the case for the gas distribution industry. The current rise in capital expenditures is not driven by expected growth in the economy, but in the perceived need to accelerate capital expenditures for infrastructure replacement.

Consequently, growth for existing systems should primarily be a function of investment growth. Staff's understanding of the investment growth in the natural gas distribution industry is that many companies have been and continue to pursue replacement of existing infrastructure in accordance with various infrastructure replacement programs and favorable rate treatment associated with these programs.[26] To the extent there is limited customer growth, this will be the primary driver of growth for the gas distribution industry in general.

Because investors are well aware of the limitations on potential growth for the industry as compared to its historical growth, as Staff discussed above, Staff believes it is important to consider the natural gas distribution industry's actual experienced growth over the long-term, when evaluating whether investment analysts' 5-year EPS growth rates are sustainable. Staff's Schedule 10-5 indicates investment analysts believe the EPS growth over the next 5-years could be around 4 percent. Based on actual historical growth over the long-term, it would appear that this growth rate would be appropriate as a proxy for constant growth. Adding this growth to the dividend yield results in a proxy group cost of common equity of 7.8 percent.

[26] Atlanta Gas Light currently has a Strategic Infrastructure Development and Enhancement ("STRIDE") program, which was approved the Georgia Public Service Commission ("GPSC"). STRIDE is a continuing 10-year infrastructure plan that is updated every three years for review and approval by the GPSC (SNL Energy Financial Focus, February 15, 2013); Approximately 60% of Atmos' 2013 capital expenditures are for infrastructure replacement projects related to safety and compliance with 90% of total capital expenditures targeted for jurisdictions that have some form of alternative ratemaking, e.g. infrastructure riders and charges (SNL Energy Financial Focus, March 28, 2013); Northwest Natural Gas plans to replace all of its bare steel pipeline in Washington by the end of 2014 and will be allowed to recover costs annually rather than waiting for a formal rate proceeding (SNL Press Release, November 11, 2013); In a December 17, 2013, Order the North Carolina Utilities Commission ("NCUC") authorized Piedmont Natural Gas the use of an integrity management rider ("IMR"), which allows the company to track and recover future capital expenditures it expects to incur to comply with federal pipeline safety and integrity requirements (Regulatory Research Associates, Regulatory Focus, December 31, 2013); Maryland and Virginia have approved five-year surcharge mechanisms to allow Washington Gas recovery of accelerated infrastructure replacement programs.

Schedule 9-5, shows the rolling average 10-year compound growth rates for EPS, DPS and BVPS for the eight natural gas distribution companies Staff analyzed. Staff calculated the historical compound growth rates consistent with Value Line's methodology, which uses a 3-year average for the beginning period and a 3-year average for the ending period. For example, even though the data Staff analyzed dates back to 1968, the 10-year compound growth rate is based on the 3-year average of per share data for the period 1968-1970 and 1978-1980. The average rolling 10-year compound growth rates for the period Staff analyzed was 4.44 percent for EPS; the rolling 10-year compound DPS growth rate was 4.24 percent; the rolling 10-year compound BVPS growth rate was 4.53 percent; and the overall average for DPS, EPS and BVPS was 4.40 percent. If Atmos is excluded from these averages, then the results are as follows: 4.22 percent for DPS; 4.51 percent for EPS; 4.48 percent for BVPS; and an overall average of 4.40 percent (*see* Schedule 9-6).

Because the gas distribution industry only achieved growth in the low 4 percent range during a period of high capital investment and higher economic growth (*see* Schedule 9-8), Staff believes investors are likely using constant-growth rates closer to 4 percent. However, because some of the more recent historical growth rates are closer to 5 percent, Staff will use an overall range of 4 percent to 5 percent. This results in a natural gas distribution industry cost of equity estimate of 7.80 percent to 8.80 percent. While Staff believes this is a reliable estimate of the cost of equity for natural gas distribution companies, Staff understands that this is below recent allowed returns for gas distribution companies around the country.

Although Staff's absolute cost of equity estimate in this case is fairly similar to the cost of equity Staff estimated in the recent Ameren Missouri and KCPL rate cases, there is a general perception in the investment community that natural gas distribution company stocks deserve a higher valuation level due to lower risks. Wells Fargo analysts stated the following in a June 4, 2013 equity research report on The Laclede Group when comparing the valuation levels of the regulated electric industry to that of the natural gas distribution industry: "The gas LDC median multiples reflect premiums ranging from 5 percent to 10 percent on 2013-15 estimated EPS, which we believe relates to the **generally lower business risk of gas LDCs versus electric utilities"** (emphasis added).[27]

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[27] See reports attached from Wells Fargo covering Laclede Group.

Additionally, Staff compared the price-to-forward earnings ratios of its natural gas distribution proxy group in this case as it compared to the price-to-forward-earnings ratios of some of the electric utility companies Staff used to estimate the cost of common equity in the Ameren Missouri and KCPL rate cases. Staff found that the gas distribution companies are trading at higher price-to-earnings multiples than the electric utility proxy group, even though the projected 5-year EPS growth for both groups were about the same. If the projected growth is about the same, then the price-to-earnings ratios should be similar if the required return on equity is similar. If the required return is lower, due to less risk, then this will cause investors to pay a higher price per unit of earnings. This is the case for the gas proxy group as it compares to the electric proxy group.

G. Tests of Reasonableness of Proxy Group Cost of Equity Using DCF Methodoloy

Staff has tested the reasonableness of its DCF results, both by use of a CAPM analysis and by consideration of other evidence.

1. The Capital Asset Pricing Model

The CAPM is built on the premise that the variance in returns is the appropriate measure of risk, but only the non-diversifiable variance (systematic risk) is rewarded. Systematic risks, also called market risks, are unanticipated events that affect almost all assets to some degree because the effects are economy wide. Systematic risk in an asset, relative to the average, is measured by the Beta of that asset. Unsystematic risks, also called asset-specific risks, are unanticipated events that affect single assets or small groups of assets. Because unsystematic risks can be freely eliminated by diversification, the reward for bearing risk depends on the level of systematic risk. The CAPM shows that the expected return for a particular asset depends on the pure time value of money (measured by the risk free rate), the reward for bearing systematic risk (measured by the market risk premium), and the amount of systematic risk (measured by Beta). The general form of the CAPM is as follows:

continued on next page

$$k = Rf + \beta (Rm - Rf)$$

Where: k is the expected return on equity for a security;

Rf is the risk-free rate;

β is beta; and

$Rm - Rf$ is the market risk premium.

Staff's CAPM is presented on Schedule 13. For inputs, Staff relied on historical capital market return information through the end of 2013. For the risk-free rate (Rf), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending April 30, 2014 – 3.60 percent. For beta (β), Staff relied on estimates directly calculated through an Excel spreadsheet designed specifically to be used with the SNL database of market and financial information. Although Staff is no longer using Value Line's published betas for purposes of its CAPM analysis in its direct testimony, because Value Line is used by many retail investors, Staff still believes Value Line's beta calculation methodology should be considered when performing a CAPM analysis. Because estimating beta is a matter of having access to financial data and performing statistical calculations, unless a financial services provider has a proprietary adjustment they make to their beta calculation, understanding the methodology used by a financial provider allows an analyst to approximately replicate betas of that provider. Fortunately, this is the case for Value Line's beta calculation methodology. Consistent with Value Line's approach to calculating beta, Staff used 5-years of historical weekly returns of the subject company and the NYSE index. The covariance of the weekly returns on the NYSE index and the weekly returns on the subject company is divided by the variance of the weekly returns on the NYSE index to determine raw beta (unadjusted beta). Staff then adjusted the raw beta using the Blume adjustment formula as used by Value Line: Adjusted Beta= (.35 + .67(Unadjusted Beta)) (*see* Schedule 13).

The average beta for the proxy group was .80. For the market risk premium (Rm – Rf) estimates, Staff relied on the historical difference between earned returns on stocks and earned returns on bonds.[28] The first risk premium was based on the long-term arithmetic

[28] From Duff & Phelps *2014 Valuation Handbook: A Guide to the Cost of Capital.*

average of historical return differences from 1926 to 2013 – 6.20 percent. The second risk premium was based on the long-term geometric average of historical return differences from 1926 to 2013 – 4.64 percent. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 8.55 and 7.31 percent, respectively.

These cost of common equity results support the reasonableness of Staff's cost of equity estimates derived from its DCF analysis. Staff again notes that both U.S. Treasury yields and utility bond yields are quite low (at levels last experienced in the early 1960s) and the spread between them is presently below their long-term average. It is not improbable that investors are only requiring returns on common equity in the 7 to 8 percent range for natural gas utility stocks. In fact, as Staff will explain in its other tests of reasonableness, these cost of equity estimates are consistent with common sense tests.

2. Other Tests

a. The "Rule of Thumb"

A "rule of thumb" method allows estimation of the cost of equity by adding a risk premium to the yield-to-maturity (YTM) of the subject company's long-term debt. Based on experience in the U.S. markets the typical risk premium is in the 3 to 4 percent range.[29]

Considering this is based on general U.S. capital market experience and regulated utilities are on the low end of the risk spectrum of the general U.S. market, a risk premium closer to 3 percent seems logical. This is especially true considering that regulated utility stocks behave like bonds. For the months of February, March and April 2014, "A" rated 30-year utility bonds and "Baa" rated 30-year utility bonds had average yields of 4.51 percent and 5.28 percent respectively.[30] Adding a 3 percent risk premium, the "rule of thumb" predicts a cost of common equity between 7.51 percent and 8.28 percent. Adding a 4 percent risk premium, the "rule of thumb" predicts a cost of common equity between 8.51 percent and 9.28 percent.

[29] John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity Investments: Valuation*, Association for Investment Management and Research, 2002, p. 54.
[30] BondsOnline.com pursuant to a subscription agreement Staff has with BondsOnline.

b. Average Authorized Returns

In the past, the Commission has applied a test of reasonableness using average authorized returns published by Regulatory Research Associates (RRA) to test the reasonableness of its allowed ROE.

According to RRA, the average authorized return on equity in the first quarter of 2014 for natural gas and electric utility companies were 9.54 percent (based on six decisions) and 10.23 percent (based on eight decisions), respectively, which is a difference of 69 basis points. The simple average authorized return on common equity for natural gas and electric utility companies for the four quarters of 2013 was 9.68 percent (based on twenty-one decisions) and 10.02 percent (based on fifty decisions), respectively, a difference of 34 basis points. Although these differences seem to imply that regulators have recognized the lower risk of natural gas utility companies as they compare to electric utility companies, there is a significant difference in the amount of decisions for gas cases compared to electric cases. As a result, Staff reviewed the difference between the annual average authorized ROEs for years prior to 2013.

Staff discovered that beginning in 2007 allowed ROEs for gas utility companies began to consistently be below that of electric utility companies. In 2007 it was only approximately 10 basis points lower, but the difference gradually increased and leveled off at approximately 30 basis points. It actually narrowed to approximately 20 basis points in 2012, but as already noted, it then widened again to 34 basis points in 2013. The difference increased to 69 basis points in the first quarter of 2014. However, there were only 6 natural gas case decisions and 8 electric utility case decisions in the first quarter of 2014.

Staff does not know if this trend will be sustained, but as can be seen in the report published April 9, 2014 allowed ROEs for gas and electric were usually about the same before 2007. The only explanation Staff can readily give for the recent difference is the fact that gas utility stocks have recently been trading at a premium to electric utility stocks. This can be due to many factors, including favorable regulatory ratemaking treatment, levelized capital expenditures, lower elasticity to economic conditions, consistently earning allowed ROE, lower natural gas prices, etc.

H. Adjustment to Proxy Group's Cost of Common Equity to Reflect SNG's Additional Risk

1. Staff's Adjustment and SNG Specific ROE Recommendation

When performing a cost of common equity analysis using a proxy group, it is important to compare the subject company's risk level to that of the proxy group. This forms the basis as to whether the proxy group's cost of common equity should be adjusted up or down to reflect the difference in risk as compared to the subject company. Staff's adjustment method is usually fairly straight forward and free from potential rate of return witness' bias because it relies on risk assessments of the proxy group's and subject company's credit ratings by ratings agencies. For example, if The Empire District Electric Company's credit rating is rated two notches below that of the average for the proxy group, Staff simply determines the difference between the bond yields for the two ratings and applies this adjustment to the proxy group's cost of common equity. Unfortunately, as Staff discussed earlier, SNG nor its parent company, Summit Utilities, has been assigned a credit rating. It is likely that the banks that executed loans with SNG have performed their own credit quality assessment, but Staff is not privy to this information and apparently SNG and Summit Utilities are not either, as they indicated such in response to Staff DR No. 0140. Consequently, Staff performed its own broad review of SNG's business risk and financial risk to develop a quantifiable cost of equity adjustment to account for the risk differential to that of the proxy group.

Staff's risk assessment included a review of financial information provided in this rate case, past Applications in which SNG requested Commission authority to pledge Missouri assets to raise debt financing, Staff's understanding of S&P and Moody's processes and procedures for assigning credit ratings and a comparison of the debt costs for SNG and its affiliates to that of general utility bond yields. Staff found the data provided in Case No. GO-2012-0102 to be particularly informative because the financial information provided in this Application presumed that SNG would not pursue the Lake of the Ozarks expansion. In Staff's analysis in that case, Staff concluded that both SNG's and Summit Utilities' risk profile were consistent with that of a Company rated below investment grade. Staff's analysis of SNG's financial ratios (then Missouri Gas Utility) in Case No. GF-2010-0334 also implied that the company's credit rating would be below investment grade if it were rated. However, Staff noted in that case that based on the anticipated cost of the debt that was the subject of the Application, SNG's debt seemed to be priced more consistent with the cost of investment grade debt.

Although Staff has yet to receive evidence supporting the Company's anticipated debt cost of approximately 5.50 percent provided in Case No. GO-2012-0102, which is the case in which the Company proposed to issue debt only for purposes of recapitalizing the existing operations without pursing the Lake of the Ozarks project, this cost seems to support the view that SNG's credit profile may be viewed more positively than the stand-alone financial ratios suggest. The average 10-year and 30-year utility bond yields for BBB rated bonds was 4.55 percent in 2012. The average 10-year and 30-year utility bond yields for BB rated bonds was 6.11 percent. The 5.5 percent anticipated rate is closer to the average for a BB rated bond, but still in between the average for investment grade and non-investment grade. Consequently, Staff believes a fair and reasonable adjustment should be based on the average spread between BB and BBB yields to that of the proxy group's A rating.

The spread between 30-year utility bonds rated within the 'A' credit rating category and those average for 'BBB' and 'BB' was approximately 200 basis points for the last three months. Applying this 200 basis point adjustment to Staff's proxy group cost of common equity estimate of 7.8 to 8.8 percent, results in a cost of common equity estimate of 9.8 to 10.8 percent.

2. Test of Reasonableness of Staff's Adjustment

Staff believes using the same rule of thumb test to evaluate the reasonableness of the proxy group's cost of common equity is appropriate to test Staff's recommended adjusted cost of common equity. Because Staff's analysis shows that SNG's and Summit Utilities' risk profile is somewhere in between investment grade and non-investment grade, it is appropriate to apply the 3 to 4 percent risk premium to average BB and BBB utility bond yields for 30-year bonds. As Staff discussed above, applying this risk premium to a 3-month average BBB utility bond yield results in a cost of common equity estimate of 8.28 percent to 9.28 percent. Applying this risk premium to a 3-month average BB utility bond yield results in a cost of common equity estimate of 10.72 percent to 11.72 percent. The average of the both BB and BBB results in a cost of common equity estimate of 9.5 percent to 10.5 percent.

It is also important to note that applying the 3 to 4 percent risk premium to the cost of long-term debt actually incurred by CNG and was expected to be incurred by SNG results in cost of common equity estimate of 8.0 percent to 9.5 percent (5 to 5.5 percent cost of debt plus 3 to 4 percent risk premium), which implies that the lower end of Staff's cost of common equity estimate is more appropriate.

I. Conclusion

Using widely-accepted methods of financial analysis, Staff has developed a weighted average cost of capital for SNG in the range of 6.92 percent to 7.32 percent (*see* Schedule 14). This rate was calculated by applying a proxy cost of long-term debt of 5.00 percent and a cost of common equity range of 9.8 percent to 10.8 percent to a capital structure consisting of 40.00 percent common equity and 60.00 percent long-term debt. Staff urges the Commission to accept its recommendation and allow SNG to earn a fair return on its net rate base of 6.92 percent to 7.32 percent.

Staff Expert/Witness: David Murray

VI. Rate Base

A. Plant in Service and Depreciation Reserve

1. Plant in Service

Accounting Schedule 3, Plant in Service, reflects the rate base value of SNG plant in service for each of the operating districts as of December 31, 2013, by account, according to the Company's General Ledger. Regarding "Transportation Equipment" and "Power Operated Equipment" accounts, Staff submitted DR No. 0164 and received a list and purchase amount of vehicles, equipment, and trailers for Account Number 1010-3960 and 1010-3920 as of December 31, 2013 for each district. Staff directly allocated the purchase amount to each district, by account numbers, according to DR No. 0164.

Staff Expert/Witness: Ashley Sarver

2. Depreciation Reserve as of December 31, 2013

The depreciation reserve represents the sum of all depreciation accruals, net of cost of removal and salvage charges that have been recorded against plant placed in service. The reserve is a subtraction from plant in the determination of rate base and the resulting balance is known as “net plant”. Accounting Schedule 6, Depreciation Reserve, reflects the rate base value of SNG depreciation reserve for each of the operating districts as of December 31, 2013, by account.

Staff Expert/Witness: Ashley Sarver

B. Gas Stored Inventory

Natural gas is purchased and injected into storage facilities by SNG during the summer months where it is held until the winter months when it is withdrawn and delivered to the SNG distribution system. The cost of the natural gas stored underground represents an investment by SNG. Therefore, it is included in rate base, which allows the Company an opportunity to earn a return on its investment. Currently SNG has storage agreements with two (2) interstate pipelines: Southern Star Central Gas Pipeline, Inc. (Southern Star) and ANR Pipeline Company. Southern Star services the Rogersville and Branson area and ANR Pipeline Company services the Gallatin area. Natural gas inventory is cyclical in nature, in that gas inventory volumes increase throughout the summer as gas is injected into storage, then decrease throughout the winter as gas is withdrawn or consumed.

Staff reviewed SNG’s General Ledger account for Gas Stored (Account 1173) and determined a 13-month average (December 2012 to December 2013) was reasonable to include as an addition to Staff’s rate base. An average is used to account for the fluctuation in inventory levels over time. The 13-month average ending total for account number 1173-0000-0000-00-0-00-00-0-06 was directly allocated to Gallatin and the 13-month average ending total for account number 1173-0000-0000-24-0-00-00-0-06 was allocated between Branson and Rogersville based on total customer bills.

Staff Expert/Witness: Ashley Sarver

C. Prepayments and Materials and Supplies

Prepayments are the costs a company incurs and pays in advance for various items needed to operate the utility system. SNG has utilized its own funds to finance prepaid items such as employee benefits, gas stored and rent, until those amounts are charged to expense by the Company. Staff reviewed SNG prepayment account balances over the last several years on a month-by-month basis.

Based on this review and discussions with the Company, Staff moved the amounts in account “Prepay Postage” to the operating expense account “Office Supplies & Expenses” and did not include in rate base. The Company also stated the invoice booked in “Prepay” for U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (DOTPHMS) should be booked to “Prepay Reg Fees” account. Staff closed the “Prepay” account due to the account not being ongoing and moved the invoice amount for DOTPHMS to the “Prepay Reg Fees” account and included it in the 13-month total to the “Prepay Reg Fees” account. The “Prepay Rent” account balance was revised to include known rent expense as of December 31, 2013. The other prepay accounts were included in Staff’s calculations of SNG’s rate base (Accounting Schedule 2) by calculating the 13-month average ending December 31, 2013, the end of the update period in this case. A 13-month average of month-ending balances is used to capture the beginning balance and ending balance of the 12-month period ending December 2013. Staff used this approach due to the fact that there was no discernible trend upward or downward in the monthly balances.

The Company also holds an inventory of materials and supplies so the items are readily available when needed in performing its utility operations. Staff reviewed the monthly balances for materials and supplies over the last several years and determined that a 13-month average as of December 31, 2013 was also appropriate for materials and supplies. Materials and supplies are included in Staff’s calculation of SNG’s rate base.

Staff Expert/Witness: Ashley Sarver

D. Customer Deposits

Customer deposits are funds received from customers as security against potential loss arising from failure to pay for utility services. These deposits are available to the utility for general use. Since the deposits are essentially loans to the Company, a representative level of customer deposits is included as an offset to the rate base investment in order to ensure that the utility does not earn a return on the value of the level of these deposits. In addition, since these funds were provided by the ratepayers and not the shareholders, the ratepayers should be allowed to earn the same rate of return on these funds as the rate of return used to compensate the shareholders for their capital invested in the utility.

The amount of customer deposits shown on Accounting Schedule 2, Rate Base represents a 13-month average of SNG customer deposits. A 13-month average of month-ending balances is used to capture the beginning balance and ending balance of the 12-month period ending December 2013, the end of the update period in this case. Staff directly allocated the balances to the district where they were received.

Interest is also accrued on these customer deposits based upon a rate specified in the SMNG (YG-2012-0399, Section 5, Page 35) and MGU (JG-2012-0371, Section 5, Page 61) tariffs. The SMNG tariff represents the Rogersville and Branson service territories and states "an interest at the rate of three percent (3%) per annum compounded annually shall be payable on all deposits." The MGU tariff represents the Gallatin, Warsaw and Lake of the Ozarks service territories and states "customer deposit interest during the calendar year will be simple interest of one percentage point (1%) above the prime rate published in the Wall Street Journal on the last business day in December of the prior year." The prime rate in effect as of December 31, 2013 was 3.25 percent, so one percent was added to this rate to derive a total 4.25 percent interest rate on customer deposits. When a customer becomes eligible for a return of his or her deposit, the amount refunded includes the accumulated interest. The annual accrual of interest on customer deposits is included in the cost of service as an expense. The amount of interest calculated on customer deposits is reflected on Accounting Schedule 10 as Adjustment S-113.1.

Staff Expert/Witness: Ashley Sarver

E. Customer Advances

Customer advances are funds provided to SNG by individual customers of the Company to assist in recovering the costs of the provision of natural gas service to those customers under certain circumstances. These funds are interest-free money to the Company. Therefore, it is appropriate to include these funds as an offset to rate base. No interest is paid to customers for the use of this money, unlike customer deposits. The customer advances account ending balance as of December 31, 2013, the end of the update period in this case, is the amount reflected in Accounting Schedule 2, Rate Base.

Staff Expert/Witness: Ashley Sarver

F. Deferred Taxes - Depreciation

SNG's deferred tax reserve represents, in effect, a prepayment of income taxes by SNG's customers. As an example, because SNG is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes is considerably higher than depreciation expense used for ratemaking cost of service purposes.

This results in what is referred to as "book-tax timing difference" and creates a deferral of income taxes to the future. The net credit balance in the deferred tax reserve represents a source of cost-free funds for SNG to use for its utility operations. Therefore, SNG's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are cost free to the Company. The most significant book-tax timing difference is caused by the differences between accelerated tax depreciation and book depreciation. Generally, deferred income taxes associated with all book-tax timing differences which are created through the ratemaking process should be reflected in rate base.

Staff factored up the September 30, 2013 Deferred Tax Liability presented in the Company's case to an estimated liability at December 31, 2013, the end of the update period. The factor was determined by computing the percentage change in net plant in service balances between September 30, 2013, and December 31, 2013, for each district and applying that percentage to the Deferred Tax Liability included in the Company's case. The result for each district was then added to the Company's filed amounts to become the basis for the Deferred Tax Liability amounts Staff included in the rate base.

The Company also included an adjustment to the Deferred Tax Liability for a deferred tax asset related to a Net Operating Loss (NOL) carry forward. Staff has excluded this adjustment in its case until Staff fully understands the implications of this NOL amount to rate base. Staff is in the process of submitting Data Requests for further information on how the NOL was calculated and, upon receipt of responses, will consider making any appropriate adjustments in Staff's true-up filing.

Staff Expert/Witness: Keith Foster

VII. Allocations

A. Corporate

As discussed earlier in this report, SUI is engaged in both regulated and non-regulated business operations. SUI performs many functions and activities on a consolidated or centralized basis for its regulated and non-regulated subsidiaries. SUI provides common administrative and management services to all operating companies and affiliates. The services provided include: executive management, finance, accounting, human resources, legal, engineering, construction, customer service, environmental and support services. SUI provides its services to SNG and its affiliates at cost. These consolidated or centralized functions are carried out for SUI-owned subsidiaries through a process of direct assignment and allocation. According to SNG's response to Staff DR No. 0011, costs are allocated to each subsidiary using the "Distrigas Method." Cost allocation factors are derived under this method by taking the composite percentage of each of the subsidiaries' direct labor, capital investments and net sales revenues divided by the total company direct labor, capital investment and net revenues, respectively. This factor is them applied to all corporate costs that are not directly assigned.

Staff reviewed the total costs allocated to SNG for the test year. After review, Staff believes that the test year average Distrigas percentage does not represent an ongoing level of costs allocated to SNG, because of a declining trend in the SNG allocation over the course of the twelve-month period. Staff calculated an average Distrigas percentage based on the last five months (May –September 2013) of the test year. Staff believes that this more accurately represents an ongoing level of costs that SUI will be allocating to SNG than the test year percentage. Staff then took this normalized total level of allocated corporate costs and applied Staff's Operations and Maintenance (O&M) factor to arrive at the amount of corporate costs that should be expensed. Lastly, the district allocation factors addressed in the next section were applied to each expense account to allocate these costs to each district. Staff will continue to review this information through the true-up in this case, the six months ending June 30, 2014.

B. District

According to the Company's CAAM, costs are directly assigned to each of SNG's Missouri districts whenever possible. However, the Company uses a two-system generating process of "allocating worksheets" along with manual processes to allocate certain costs that support multiple activities to the appropriate FERC accounts related to these activities. Many different factors are used to allocate costs among the districts that are not directly assigned. Some costs are allocated to the districts based on gross plant, net plant, customer bills or retail sales revenue. These are just a few of the different ways total SNG costs can be allocated to each district. The Company's CAAM includes a matrix that identifies all the allocation methods that may be used for each FERC account.

Staff updated the Company's district allocation factors through December 31, 2013, the update period in this case. These factors were then applied to Staff's annualized/normalized SNG expense levels to allocate the costs to each district.

Staff Expert/Witness: Amanda McMellen and *Jermaine Green*

VIII. Income Statement

A. Revenues

1. Introduction

The following section describes how Staff determined the amount of SNG's adjusted operating revenues. Since the largest component of operating revenues depends on rates charged to SNG retail customers, a comparison of operating revenues with the cost of service is essentially a test of the adequacy of the currently effective retail natural gas rates to meet the Company's current costs of providing utility service.

One of the major tasks in a rate case is to determine the magnitude of any deficiency (or excess) between a company's cost of service and its operating revenues. Test year revenues need to be appropriately normalized and annualized in order to accurately measure the amount of any deficiency (or excess) in the current level of operating revenues. Once determined, the deficiency (or excess) can only be made up (or otherwise addressed) by adjusting retail rates (i.e., rate revenue) prospectively.

2. Definitions

Operating Revenues are comprised of two components: (1) Rate Revenue and (2) Other Operating Revenue. The definitions of these components are as follows:

Rate Revenue: Test year rate revenues consist solely of the revenues derived from SNG's authorized Commission approved rates for providing natural gas service to its retail Customers. SNG's variable charges are determined by the amount of each customer's usage and the (per unit) rates that are applied to that usage. Each customer also pays a flat monthly customer charge dependent upon each customer's rate class. These rate classes include residential, commercial, industrial and transportation customer classifications.

Other Operating Revenue: Other operating revenue includes late payment charges, collection trip charges, special meter reading charges, non-sufficient funds fees (NSF), and disconnect/reconnection of service charges. Each of these charges is also established by the Commission, and all of these revenue items are taken into account in setting retail rates for SNG's gas service to customers.

3. The Development of Revenue in this Case

To determine the level of SNG's revenue, Staff applied standard ratemaking adjustments to the test year (historical) volumes (in hundreds of cubic feet ("Ccf") and customer levels). Staff made the first adjustments in order to determine the level of revenue that the Company would collect on an annual basis, under normal weather or climatic conditions, natural gas usage and customer levels, based on information that is "known and measurable" as of the end of the update period. In this particular case, the test year is the twelve months ending September 30, 2013, updated for known and measurable changes through December 31, 2013. There also will be a true-up in this case through the end of June 30, 2014 in a later stage of this proceeding.

Staff has developed and summarized SNG's revenue in two different ways: by type of regulatory adjustment and by total revenue by rate class. The attached Table (Appendix 3, Schedule JG-1) to this Report summarizes rate revenue both ways; i.e., by type of adjustment and by rate class. The rate classes shown are General Service (Residential), Commercial Service, Large Volume Service and Transportation Service. Staff workpapers provide the source numbers and analysis and present a much more detailed version of the summary table.

This Report describes the five major regulatory adjustments the Staff made to test year billed rate revenues:

a. weather normalization

b. 365-day adjustment

c. customer growth

d. large customer annualization

e. removal of gas costs

Not all of these adjustments affect both sales and rate revenue, and not all rate classes are subject to all five adjustments.

Other revenue adjustments proposed by the Staff in this proceeding are also briefly described in the following sections.

4. Customer Growth

The Company's customers are segregated into five different districts within the Company's service territory: Rogersville, Branson, Warsaw, Lake Ozark and Gallatin. Each region serves four classes of customers: Residential, Commercial General Service (CGS), Large General Service (LGS) and Large Volume customers. All revenue adjustments made by Staff in determining the Company's cost of service were priced on the margin (the total rate excluding Purchased Gas Adjustment (PGA) gas cost rate) included in SNG's tariffs. The Staff analyzed customer growth for the Residential, CGS and LGS classes. Adjustments for the large volume customers are discussed in Section VIII.7.a. of this report.

The annualization of customer revenues contains two components, the base charge and the commodity charge. The base charge is the minimum monthly charge that SNG assesses to a customer for supplying the gas service. The monthly base charge revenue is calculated by multiplying the base charge by the Staff's annualized level of customers on a monthly basis.

Natural gas customers tend to fluctuate seasonally over a 12-month period, with some customers leaving the system during the spring and summer months and then rejoining the system during the fall and winter months. This seasonality in customer numbers makes it impractical to base a customer growth adjustment on one period-ending customer number value as is normally done for electric utilities. To appropriately take into account seasonal customer number fluctuations, Staff used a three-step process to calculate customer growth for three of SNG's different classes of customers (Residential, CGS and LGS).

In the first step of this process, Staff divided each month of the year by the twelve-month total of customers for that same year to determine the percentage of customers within each month to the period-ending total. Using these percentages, Staff averaged a two year period by month to derive the monthly average of customers to the period-ending customer total for the two-year period.

In the second step, Staff divided the December 31, 2013 (update period) level of customers for each year by the twelve-month average of the following year. This process created a percentage that was totaled for the most current two years, which was then divided by two to determine a two-year average.

In the third step, Staff divided the actual customer level for each class as of December 31, 2013, by the two-year average developed in the second step above. This resulted in a monthly customer level which was then multiplied by twelve to derive an annualized level of customers. The annualized number of customers was then multiplied by the monthly percentage that was created in the first step to create average monthly customer level for each month of the 12 month period ending December 31, 2013. These average monthly customer numbers provided the basis for Staff's customer growth revenue adjustment.

An additional adjustment to revenues made by Staff is an adjustment which can be attributed to "rate switching." Rate switching occurs when a customer changes their rate classification and can occur for a number of reasons. For example, the nature of a customer's operations may have changed and another customer class may become more appropriate; a customer may find it more economical to switch to another customer class; or a customer may decide to procure its own gas, which would also make a rate switch necessary. Please refer to the next section of this report for further discussion of this topic.

Staff Expert/Witness: Jermaine Green

5. Revenue – Normal Weather

a. Weather Normal Variables Used for Weather Normalization

Natural gas usage and revenue vary from year to year based on weather conditions. The temperature pattern in the test year is the primary determinant for weather-sensitive customer gas usage and the Company's revenue in the test year. Each year's weather is unique, so rates for weather-sensitive customer classes must be based on test year usage and revenues adjusted to a level commensurate with "normal" weather conditions, rather than actual test year usages and revenues.

Staff obtained weather data from the Midwest Regional Climate Center (MRCC).[31] Kansas City International Airport ("MCI") weather data was used for the Gallatin division, while the Sedalia ("SDL") weather data was used for the Warsaw and Lake of the Ozarks divisions. The Springfield Regional Airport ("SGF") weather data was used for the Branson and Rogersville divisions. The weather data sets consist of actual daily

[31] http://mrcc.isws.illinois.edu/CLIMATE/.

maximum temperature ("Tmax") and daily minimum temperature ("Tmin") observations. Staff used these daily temperatures to develop a set of normal mean daily temperature ("MDT")[32] values.

Historical Data Used to Calculate Normal Weather Variables – According to the National Oceanic and Atmospheric Administration ("NOAA"), a climate "normal" is defined as the arithmetic mean of a climatological element computed over three consecutive decades.[33] In developing climate normal temperatures, the NOAA focusses on the monthly maximum and minimum temperature time series to produce the serially-complete monthly temperature ("SCMT") data series.[34]

Staff utilized the SCMT that was published in July 2011 by the National Climatic Data Center ("NCDC") of the NOAA. For the purposes of normalizing the test year gas usage and revenues, Staff used the NOAA's three consecutive decade convention of observed Tmax and Tmin daily temperatures for the 30-year period of January 1, 1981 through December 31, 2010, at MCI, SDL and SGF. This is the same location and period that NOAA used for its calculation of the SCMT.

There may be circumstances under which inconsistencies and biases in the 30-year time series of daily temperature observations occur, (e.g. such as the relocation, replacement, or recalibration of the weather instruments). Changes in observation procedures or in an instrument's environment may also occur during the 30-year period. The NOAA accounted for documented and undocumented anomalies in calculating its SCMT. The meteorological and statistical procedures used in the NOAA's homogenization for removing documented and undocumented anomalies from the monthly maximum and minimum temperature series is explained in a peer-reviewed publication.[35] In addition, the NCDC confirmed that the observed temperature data of SGF needs no adjustment in the period after 2001.

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[32] By National Climatic Data Center convention, MDT is average of daily maximum temperature (Tmax) and daily minimum temperature (Tmin) e.g. MDT = (Tmax + Tmin) /2.
[33] Retrieved on October 17, 2013, http://www ncdc noaa.gov/oa/climate/normals/usnormals.html.
[34] Retrieved on October 17, 2013, http://www1.ncdc noaa.gov/pub/data/normals/1981-2010/source-datasets/. The SCMT, computed by the NOAA, includes adjustments to make the time series of daily temperatures homogeneous.
[35] Menne, M.J. and C.N. Williams, Jr., (2009) Homogenization of temperature series via pairwise comparisons. *J. Climate*, 22, 1700-1717.

Weather Variables – Natural gas sales are predominantly influenced by "ambient air temperature,"[36] so MDT and the derivative measure, heating degree days ("HDD")[37] are the measures of weather used in adjusting test year natural gas sales. HDDs were originally developed as a weather measure that could be used to determine the relationship between temperature and gas usage. HDDs are based on the difference of the MDT from a comfort level of 65°F. HDDs are calculated as the difference between 65°F and the MDT when the MDT is below 65°F, and are equal to zero when the MDT is above 65°F.

Calculation of Daily Normal HDD – Subsequent to determining the homogenized monthly temperature time series described above, the NOAA calculates monthly normal temperature variables based on a 30-year normal period, e.g. maximum, minimum, average temperatures, and HDDs. These monthly normals are not directly usable for Staff's purposes, because the NOAA daily normal temperatures and HDD values are derived by statistically "fitting" smooth curves through these monthly values. As a result, the NOAA daily normal HDD values reflect smooth transitions between seasons and do not directly relate to the 30-year time series of MDT as used by Staff. However, in order for Staff to develop adjustments to normal HDD for gas usage, Staff must calculate a set of normal daily HDD values that reflect the actual daily and seasonal variability. Therefore, Staff developed a series of normal MDTs by adjusting the test year's actual daily average temperature data based on the 30 years of MDTs, such that the monthly average of the adjusted normal MDTs for a month is consistent with the NOAA's SCMT. Using these adjusted daily average temperatures, Staff calculated HDDs for each day of the 30-year period history. Staff calculated daily normal HDDs as the average of the adjusted daily actual HDD for each calendar date in the test year. For example, Staff averaged the 30 observations of the adjusted daily actual HDD for January 1 of each year for years 1981 through 2010, to determine the normal HDD for January 1.

Appendix 3, Schedule SJW-1, SJW-2 and SJW-3 presents calendar month summaries of adjusted daily actual and normal HDDs during the test year for MCI, SDL and SGF, respectively. The HDD comparison indicates that the test year (October 1, 2012 – September 30, 2013) was cooler than normal by approximately 1.8 percent for MCI and

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[36] Ambient air temperature is the outside temperature of the surrounding air without taking into account the humidity or wind in the air.
[37] Where MDT < 65°F, HDD = 65 – MDT; otherwise, HDD = 0.

5.9 percent for SDL and was warmer than normal by approximately 0.2 percent for SGF. This information was made available to Staff witnesses Michelle Bocklage, Brad Fortson and Robin Kliethermes to calculate the weather normalization adjustment factor.

Staff Expert/Witness: Seoung Joun Won

6. Revenue – Weather Normalization

a. Introduction and Summary

Since the primary use of natural gas in Missouri is for the purpose of space heating, natural gas sales are dependent upon weather conditions. Because natural gas rates are based on usage, it is important that abnormal weather influences are removed from the test year—a process called "weather normalization". This analysis addresses Staff's weather normalization of natural gas sales for SNG customers within the General Service (GS), Commercial Service (CS), Optional General Service (OGS) and Large General Service (LGS) for the test year ending September 30, 2013. The results of Staff's overall weather normalization analyses by rate class and service area are included in the table below. The adjustments reflected in the table accounts for the weather.

Territory	Class	Adjustment
Branson	GS - Residential	-0.65%
Branson	GS - Residential Optional	-0.14%
Branson	GS - Commercial (Small Commercial)	-0.02%
Branson	GS - Commercial Optional (Small Commercial)	-0.68%
Branson	CS/LGS	0.07%
Rogersville	GS - Residential	-0.61%
Rogersville	GS - Residential Optional	-0.75%
Rogersville	GS - Commercial (Small Commercial)	-0.51%
Rogersville	GS - Commercial Optional	-0.94%
Rogersville	LGS	-1.03%
Gallatin	GS - Residential	-2.43%
Gallatin	GS - Commercial (Small Commercial)	-1.58%
Gallatin	CS	-1.56%
Warsaw	GS - Residential	-5.49%
Warsaw	GS - Commercial (Small Commercial)	-3.91%
Warsaw	CS/LGS	-4.54%
Lake of Ozarks	GS - Residential	-16.75%
Lake of Ozarks	GS - Commercial	-6.20%
Lake of Ozarks	CS/LGS	-3.89%

b. Process Used to Weather Normalize Sales

SNG is currently unable to provide Staff with the number of customers and usage for each billing cycle by customer class and geographic region for each month of the test year that would allow Staff to perform the necessary and typical weather normalization analyses.

Ordinarily, Staff adjusts monthly natural gas volumes to normal by initially equalizing the annual total normal heating degree days ("HDDs") for each billing cycle and then either adding or subtracting the number of days necessary so that each billing cycle's annual total number of days equals 365 days. This adjustment is performed so that each billing cycle is set to the same total number of days and normal HDDs.

Once the billing cycle is adjusted, Staff calculates the difference between normal and actual HDDs for each billing cycle. The third step is to multiply these differences by the estimate rendered from the regression analysis. The fourth step is to sum each billing cycle's adjustment volumes by billing month. Then, add the monthly adjustments in hundreds of cubic feet ("Ccfs") to the total monthly natural gas sales to calculate normalized volumes.

After these steps, Staff calculates two sets of twelve billing month averages by customer class in the service areas specified. One set of these averages are the daily average natural gas usage in Ccfs and another set would be the daily average HDD.

The billing month averages are then calculated from the data provided by the utility on the numbers of customers, natural gas usage in Ccfs, and summed HDD from the billing cycles for each billing month by customer class. The daily average HDD in each billing month and billing cycle is weighted by the percentage of customers in that billing cycle. Thus, the billing cycles with the most customers are given more weight when computing the daily average HDD for the billing month. Staff then performs calculations to determine the twelve monthly average-usage-per-customer amounts across the billing cycles to calculate the daily average usage in Ccfs for one month. Staff's studies estimate the change in usage in Ccfs related to a change in HDD. The study is based on two sets of twelve monthly billing month averages. One set of monthly billing month averages is typically the average daily usage in Ccfs per customer and the other is the customer-weighted average daily HDD. The usage and weather billing month averages are used to study the relationship between space-heating natural gas usage in Ccfs and cold weather.

Then, Staff uses regression analyses to estimate the relationship for each of the customers in the geographic regions. The regression equation develops quantitative measures that describe the relationship between daily space-heating sales per customer in Ccf to the daily HDD. The regression equation estimates a change in the daily natural gas usage per customer whenever the daily average weather changes on HDD.

Because SNG was unable to provide Staff with the data necessary to perform its typical analysis, Staff was forced to follow a different process. First, Staff calculated the weather-sensitive usage per customer for the test year by deducting the base usage from total actual usage. Dividing the annual weather-sensitive usage by the annual actual heating degree days determines the weather dependency. Staff then multiplied the weather dependency by the heating degree day variance to calculate the monthly weather adjustment per bill.

c. Application of Weather Normalization Process

Staff completed these calculations by first subdividing SNG billing records into five geographic regions – Branson, Gallatin, Lake of the Ozarks, Rogersville and Warsaw. Staff witness Mr. Seoung Joun Won provided the daily actual and daily normal HDDs for each of the five geographic regions, using data obtained from the weather stations in Springfield, Sedalia and Kansas City. Mr. Won addresses the calculation of HDDs as part of his section of this Cost of Service Report.

After multiple conversations and data requests with SNG personnel, SNG provided multiple billing files so that Staff could calculate the monthly natural gas sales in Ccfs, customers for each billing cycle by customer class, and the geographic region for the test year. Unfortunately, that data was in a format that made it impossible to obtain the necessary information. Therefore, Staff had to use the usage and customer class count provided by SNG in response to DR No. 0001 and DR No. 0097.

Since SNG is unable to provide the data requested by Staff, Staff recommends that SNG update its system so that it captures and retains the customer usage and number of customers by bill cycle in a format that allows SNG to provide the data in an electronic format upon request for the next rate case.

In addition, the system should also ensure the integrity of the historical data. According to conversations with SNG personnel, changes made to customer records today also results in a change to the historical data of customers as well for reporting purposes. In this instance, changes made to a customer's billing cycle today would also edit the historical records for reporting purposes and not correctly reflect the actual number of customers and usage for each bill cycle. Therefore, Staff recommends that SNG modify the system so that any changes made to customer records are captured as of the effective date and forward, not historically.

SNG groups natural gas accounts into billing cycles which are then used to bill meters throughout each month based on the meter reading obtained. There are approximately twenty one (21) working days in a month; therefore, customers' accounts are usually grouped into one of approximately fourteen (14) billing cycles. Staggering the billing of customers' accounts throughout the billing month allows the Company to evenly distribute the work required in order to bill SNG customers for gas service. Staff calculated the twelve billing month averages for GS, OGS, CS and LGS classes in the geographic regions specified above.

The information regarding the adjustments was provided to Staff witness Daniel I. Beck of the Commission's Energy Engineering Unit for his calculation of total peak day demand and Staff witness Jermaine Green of the Auditing Unit for use in the customer growth revenue adjustment. These adjustments to natural gas sales do not include Staff's customer growth annualization.

Staff Expert/Witness: Michelle Bocklage

7. Revenue – Large Customer Adjustment

a. Large Volume Service Customer Adjustments

SNG provided monthly billing units and information for individual customers who took service on the Large Volume Service ("LVS") and Transportation Service tariffs during the test year and updated through December 2013. Staff used these units as the basis of its analysis and adjustments. The following adjustments were made:

i. Rate-Switching Adjustment

This type of adjustment is made when a customer takes service in two or more of the utility's rate classes during the test year. If a customer was in a rate class at the beginning of the test year, then transferred to a different rate class during the test year, Staff removed that customer's billing determinants and associated revenues from the original rate class and "priced" out that customer's billing determinants using the current tariff rates in the class that the customer switched to. This resulted in a full year of history for the customer in the rate class they were in at the end of the test year. Staff performed this analysis using information supplied by SNG for the test year, updated through December 2013. During the test year and update period, one customer switched from receiving service under the LVS class to receiving service under the Transportation Service class while another customer switched from the Large General Service class to the Transportation Service class.

Staff also removed one customer's billing determinants and associated revenues from the LVS class due to that customer not meeting the criteria to be in the LVS class.

ii. Customer Gains/Losses Adjustment

Staff made an adjustment for customers who began taking service or who discontinued service during the test year, updated through December, 2013.[38] For instance, if a customer began taking service on the SNG system during the test year, there would be less than 12 months of usage for that customer. Staff normalized the usage for the "missing" months by using either SNG's projections on the amount that the customer was expected to use, or by taking an average of the actual usage the customer used during the test year and as updated through December 2013. This resulted in a full year of history for the customer and the basis for an appropriate adjustment. During the test year and update period three new customers were added to the Transportation Service class.

Staff Expert/Witness: Brad Fortson – Large Volume Service; and,
Robin Kliethermes – Transportation Service

iii. Large Volume Service Weather Normalization Adjustment

Staff's regression analysis indicated that in two of SNG's rate districts, the LVS class was weather sensitive.[39] Staff proposes weather normalization for the LVS customers in those rate districts. Staff's weather normalized adjustments of natural gas sales account for deviations from what are considered normal weather conditions that occurred during the test year. Staff's independent variable in the weather normalization regression was HDDs per billing month and the dependent variable was usage per billing month.[40]

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[38] During the test year and update period no customers left the LVS or Transportation Service classes. If a customer had ceased operations, Staff would have removed the usage and revenues from the relevant rate class.
[39] If the result of the regression analysis reported an R2 (squared) of 0.7 or greater there is a significant relationship between the customer's usage and corresponding Heating Degree Days (HDD).
[40] All LVS customers were billed in the same billing cycle.

Staff made an adjustment to the LVS class' monthly usage to reflect normal weather based on the results of the regression analysis and the difference between the actual number of HDDs and the normal level of HDDs.[41]

Staff Expert/Witness: Brad Fortson

iv. Transportation Service Weather Normalization Adjustment

Customers served under the Transportation Service tariff are generally large customers who purchase natural gas from a third party and then use SNG's distribution facilities to transport the gas to the customer's location. Staff performed a regression analysis on each individual customer to determine which customers in the Transportation class are weather sensitive. For the customers that are weather sensitive, Staff made an adjustment to the customer's usage to reflect normal weather.[42]

Staff Expert/Witness: Robin Kliethermes

v. Transportation Service Rate Schedule for the Lake of the Ozark

On July 17, 2012 Summit was granted a Certificate of Convenience and Necessity to install, own, operate, manage and maintain a gas distribution system to provide gas service in Benton, Morgan, Camden and Miller Counties. Page 3, Condition number 14 of the Order provides that: "Summit shall not file a rate increase request for this service territory until after 42 months of the effective date of the Commission order grating the CCN in this proceeding."

Summit is proposing a Transportation Service ("TS") Rate for the Lake of the Ozarks Division. The proposed customer charge and commodity charges are equal to the Lake of the Ozarks Division Large Volume Service ("LVS") rates. Staff does not object to the TS Rate for the Lake of the Ozarks Division.

Staff Expert/Witness: Kim Cox

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[41] Normal HDDs are explained by Staff witness Seoung Joun Won.

[42] Transportation Service customers were weather normalized on an individual basis compared to a class level like all other rate classes because customers in the class are very diverse and range from schools to asphalt plants.

8. Missouri School Program Transportation Service Rate Schedule – Customer Charge

Staff recommends a change in the monthly customer charge SNG collects from school districts participating in the Missouri School Program, which allows schools to aggregate their purchasing of natural gas supplies and pipeline transportation service.

Prior to October 2013, SNG and Missouri School Boards Association (MSBA) agreed to a ** ___ ** monthly customer charge per school district participating in this program. In August 2013, SNG provided written notice to MSBA of a new transportation agreement that increased the monthly customer charge to ** ___ ** effective October 2013. These charges are assessed per school district, not per meter location, and as a result the schools are not paying the same costs that a sales customer would incur for the same service.

There may be one or multiple schools in each school district, with each school having a minimum of one to multiple meter locations (one meter at each meter location). There are currently 11 school districts participating in the Missouri School Program, all in the Rogersville division. There are 76 meter locations. Staff supports a monthly customer charge for each metered location and billed at the companion sales rate for each school participating in this program (*see* Appendix 3, Schedule PL-1 (Highly Confidential)). Missouri Revised Statutes Section 393.310.5 states that the tariffs will not have any negative financial impact on its other customers as a result of this program. All customer charges under the Missouri School Program should be equal to the Company's companion sales rate for each school and for each meter location, thereby eliminating the potential for negative financial impact on other customers. This is the same manner that they would be billed as a sales customer. In this case, SNG's tariffs do not explicitly provide for such equality between school program customer charges and the Company's companion sales customer charge. Because SNG is not charging the schools a per-meter customer charge, SNG's other customers could be suffering a negative financial impact.

In order to bring the tariff into compliance with Missouri law, Staff proposes to add a "rates" section to SNG's Missouri School Program Transportation Service Rate Schedule. In this section Staff proposes the following tariff language:

> For each metered location, the monthly commodity charge and monthly customer charge shall be billed at the companion sales rate for the applicable Summit Division and the applicable annual usage and

> applied to rate schedule General Service, Commercial Service, Large General Service or Large Volume Service. Services provided in the Pool group do not include the aggregation of customer charges.

Staff witness Robin Kliethermes is sponsoring Staff's adjustment for the customer charge revenues collected through SNG's Missouri School Program Transportation Service.

Staff Expert/Witness: Phil Lock

B. Other Revenue Adjustments

Purchased gas expenses are estimated and assessed to ratepayers outside of general rate proceedings through SNG's Purchased Gas Adjustment (PGA) Clause. The PGA Clause provides SNG an estimating methodology for recovering purchased gas expense, which is subsequently trued-up through the Actual Cost Adjustment (ACA) mechanism. Therefore, purchased gas expenses and revenues generally are netted to equal zero for purposes of general rate cases. Adjustments were made to eliminate PGA revenues for the test year from the appropriate revenue accounts. Adjustments were also made to remove the take-or-pay portion of the PGA revenues and to adjust the PGA revenue for the ACA true-up mechanism.

Staff Expert/Witness: Jermaine Green

C. Payroll and Benefits

1. Payroll, Payroll Taxes, 401(k) and Other Employee Benefit Costs

All non-exempt and exempt employees must record their time worked on the electronic time sheet provided by the Company, on a daily basis. The supervisor is responsible for reviewing and approving all entries into the electronic time sheets. The Company provided employee job descriptions and base salary at the end of the test year, September 30, 2013, as well as the update period ending December 31, 2013. Utilizing this information, Staff was able to develop an annualized level of payroll, payroll taxes, 401(k) and other employee benefit costs as of December 31, 2013, the endpoint of the update period ordered for this case by the Commission. After allocating a portion of payroll to construction associated with capital projects through the end of the update period, Staff's adjustment for payroll expenses was distributed by account, based on the actual payroll distribution experienced by the Company during the test year ending September 30, 2013. The ratio between capital projects and expense is referred to as an O&M factor. The update period ending December 31, 2013 O&M factor was 18.33 percent. The corporate allocation of payroll is discussed in the Section VII.A. of this Report.

Non-exempt employees are paid at the rate of one and one-half (1 ½) times the regular hourly rate for hours worked in excess of 40 hours during the workweek. Using the time sheet entries, Staff reviewed overtime hours from January 1, 2011 through December 31, 2013 and recorded the actual overtime hours for each employee. Overtime expense was calculated by taking a two-year average of overtime hours actually incurred, ending December 31, 2013, and multiplying that amount by the current hourly rate paid for overtime as of December 31, 2013. Staff applied the same O&M expense factor to overtime pay as it did for the payroll expense to capitalize a portion of these costs.

Staff annualized payroll taxes, which include Federal Unemployment Taxes (FUTA), State Unemployment Taxes (SUTA) and Federal Insurance Contributions Act (FICA) taxes, based on the appropriate tax rates in effect as of December 31, 2013 applied to the payroll total. Staff applied the same O&M expense factor to payroll taxes as it did for the payroll expense to determine the expense portion of these taxes.

The Company currently offers full-time employees the opportunity to make contributions to a tax-deferred 401(k) plan, as well as a Roth IRA called Summit Utilities, Inc. 401(k) Plan and Trust (the Plan). The purpose of the Plan is to provide a convenient method of savings for retirement for the employees. The Company will match contributions on behalf of each eligible participant in an amount equal to 100 percent of each participant's elective deferrals up to 5 percent of the participant's compensation. The amount built into Staff's cost of service for the 401(k) and Roth IRA plans is the Company's contribution percentage (up to 5 percent), multiplied by the ending salary of participating employees as of December 31, 2013. The total contributions were then compared with the deferral amount booked during the test year for the plans, to develop the adjustments. Staff applied the same O&M expense factor to retirement contributions as it did for the payroll expense to capitalize a portion of these costs.

The Company currently provides the following group insurance benefits to its employees: medical, dental, vision, life and long term disability through various insurance agencies. The monthly premiums for life, long-term disability and vision are paid 100 percent by SNG's parent company, SUI, and enrollment is automatic for eligible employees. Medical and dental insurance is based on monthly premiums paid through a combination of SUI and employee contributions.

Employee benefit costs were annualized based upon the current insurance rates effective as of January 1, 2014. Staff than applied the same O&M expense factor to employee benefits as it did for payroll expense to capitalize a portion of these cost.

Staff Expert/Witness: Ashley Sarver

2. Incentive Compensation and Bonuses

Staff has reviewed SNG's administrative guidelines for payment of incentive bonuses (Short Term Incentive Plan) offered to the officers and directors. The incentive bonus provides an annual cash payment (a percentage of base salary) to officers and director level employees based on corporate and personal performance goals. Corporate goals consist of increased EBITDA (earnings before interest & taxes/earnings before interest, taxes, depreciation and amortization), residential equivalent customer conversations and increased dividends. The personal performance goal is based on accomplishing performance goals developed to achieve corporate goals established at the beginning of each fiscal year.

The Commission, in general, has disallowed incentive compensation based on financial metrics to benefit the shareholders and has allowed incentive compensation based upon customer focused metrics, such as customer service and safety metrics. For example, in the Report and Order issued in Case No. GR-96-285, Missouri Gas Energy, the Commission ordered concerning incentive compensation:

> The Commission finds that the costs of MGE's incentive compensation program should not be included in MGE's revenue requirement because the incentive compensation program is driven at least primarily, if not solely, by the goals of shareholder wealth maximization, and it is not significantly driven by the interest of ratepayers. (p. 37) [footnote omitted]

In the Report and Order in MGE's 2004 Rate Case, Case No. GR-2004-0209, the Commission again concerning MGE's incentive compensation:

> The Commission agrees with Staff and Public Counsel that the financial incentive portion of the incentive compensation plan should not be recovered in rates. Those financial incentives seek to reward the company's employees for making their best efforts to improve the company's bottom line. Improvements to the company's bottom line chiefly benefit the company's shareholders, not its ratepayers. Indeed,

> some actions that might benefit a company's bottom line, such as a large rate increase, or the elimination of customer service personnel, might have an adverse effect on ratepayers.
>
> If the company wants to have an incentive compensation plan that rewards its employees for achieving financial goals that chiefly benefit shareholders, it is welcome to do so. However, the shareholders that benefit from that plan should pay the costs of that plan. The portion of the incentive compensation plan relating to the company's financial goals will be excluded from the company's cost of service revenue requirement. (p. 43)

It is my understanding that the orders issued by the Commission in MGE's 1996 and 2004 rate cases are consistent with the way the Commission decided the issue in other rate cases since the mid-1980s.

In Kansas City Power and Light (KCPL) Case No. ER-2006-0314, the Commission disallowed incentive compensation based on financial measures on page 58 of its Report and Order:

> The Commission finds that the competent and substantial evidence supports Staff's position, and finds this issue in favor of Staff. As far as compensation tied to EPS, the Commission notes that KCPL management has the right to set such goals. However, because maximizing EPS could compromise service to ratepayers, such as by reducing customer service or tree-trimming costs, the ratepayers should not have to bear that expense…
>
> KCPL's attempt to state that Staff has no evidence to support its theory that maximizing EPS might not benefit KCPL shareholders misses the point; KCPL has the burden to prove that the Commission should approve the tariffs. Further, KCPL's argument that disallowing any of its incentive compensation costs would put it at a competitive disadvantage fails. KCPL management is free to offer whatever compensation packages it wants. Nevertheless, if the method KCPL chooses to compensate employees show no tangible benefit to Missouri ratepayers, then those costs should be borne by shareholders, and not included in cost of service.

During the course of Staff's audit, Staff requested through DR No. 0158 SNG incentive plan documentation detailing the plans and evaluation, per employee, of the actual incentive bonus payouts. However, SNG only provided documentation associated with the plans and evaluations for the position of the President of SNG. No specific information related to other SNG employees was provided.

SNG should only be allowed recovery in rates of employee incentive bonus if ratepayers benefit from the achievement of the goals supporting the incentive compensation awards. SNG did not provide any defined goals support for employees eligible for a compensation bonus associated with payment of the discretionary incentive compensation awards. Without defined goals, Staff has no basis for concluding SNG's ratepayers benefit from this discretionary employee incentive compensation paid by SNG.

Based upon this review and consistent with past Commission treatment, Staff proposes not to allow bonus expense in the annualized payroll amount, at this time, based on Staff not receiving defined goals per the payout amount for fiscal year 2012, paid out during the test year ending September 30, 2013. Even if such support would be provided at a later time, certain test year incentive bonus amounts may still be subject to disallowance due to their apparent tie to achievement of certain financial measures by SNG.

Staff Expert/Witness: Ashley Sarver

D. Other Non-Labor Expenses

1. Customer Deposit Interest Expense

See the discussion in Section VI. D., Rate Base-Customer Deposits.

Staff Expert/Witness: Ashley Sarver

2. Maintenance Normalization Adjustments

Maintenance expense is the cost of maintenance chargeable to the various operating expenses and clearing accounts. It includes labor, materials, overheads and any other expenses incurred in maintaining a utility's assets. Maintenance expense normally consists of the costs of the following activities:

- Direct field supervision of maintenance;
- Inspecting, testing and reporting on condition of plant, specifically to determine the need for repairs and replacements;
- Work performed with the intent to prevent failure, restore serviceability or maintain the expected life of the plant;
- Testing for, locating and clearing trouble;
- Installing, maintaining and removing temporary facilities to prevent interruptions; and
- Replacing or adding minor items of plant, which do not constitute a retirement unit.

Staff separated SNG's maintenance expenses between labor and non-labor costs. The maintenance review was done only on non-labor maintenance and operating costs for each month from January 2010 through December 31, 2013, by account. Since Staff specifically addresses labor costs separately as a component in the cost of service analysis, labor costs were segregated from the non-labor costs to perform the review of maintenance costs. A detailed discussion concerning labor costs is located under the heading Payroll, Payroll Taxes, 401(k) in this cost of service report. Staff examined the non-labor maintenance dollars for trends or significant fluctuations from one period to another.

Staff applied the same O&M factor to "Maintenance Vehicle" account as it did for the payroll expense to capitalize a portion of these expenses. The "Maintenance Vehicle" account balance was revised to include the updated period to December 31, 2013. The other maintenance accounts Staff used the test year totals and allocated the costs to each district according to customer bills.

Staff Expert/Witness: Ashley Sarver

3. Bad Debt Expense

Bad debt expense is the portion of retail revenues that SNG is unable to collect from retail customers because of non-payment of customer bills. After a certain period of time has passed, delinquent customer accounts are written off and turned over to a third-party collection agency for recovery. If SNG is subsequently able to successfully collect some portion of previously written-off delinquent amounts owed, the amounts collected reduce the actual write-offs. This results in a net write-off total, which is used as the basis to determine the annualized level of bad debt expense.

Staff calculated the average annual bad debt expense for SNG by examining the actual net bad debt write-offs for the last two years (2012-2013). Staff normalized SNG's net bad debt expense using a two-year average based on the twelve-month periods ending December 31, 2012 and 2013.

Staff Expert/Witness: Jermaine Green

4. Advertising Expense

SNG engaged in advertising activities during the test year. Staff recommends recovery through rates of a level of expense related to advertising that is beneficial to ratepayers, but not advertising that is beneficial only to shareholders. In making its recommendation of the allowable level of SNG's advertising expense, Staff relied on the principles the Commission set forth in *Re: Kansas City Power and Light* Company, 28 MO P.S.C (N.S.) 228 (1986) (KCPL). In that proceeding, the Commission recognized five categories of advertisements and specified rate treatment for each of the following categories:

1. General: informational advertising that is useful in the provision of adequate service;
2. Safety: advertising which conveys the ways to safety use electricity and avoid accidents;
3. Promotional: advertising used to encourage or promote the use of electricity;
4. Institutional: advertising used to improve the Company's public image;
5. Political: advertising associated with political issues.

The Commission adopted these categories of advertisements because a utility's revenue requirement should: "1) always include the reasonable and necessary cost of general and safety advertisements; 2) never include the cost of institutional or political advertisements; and 3) include the cost of promotional advertisements only to the extent that the utility can provide cost-justification for the advertisement." (Report and Order in KCPL Case No. EO-85-185, 28 MO P.S.C. (N.S.) 228, 269 271 (April 23, 1986)).

In response to Staff data requests, SNG provided minimal supporting documentation for its advertising costs and copies of the actual advertisements. Staff examined each advertisement provided and classified them into the individual categories listed above. The purpose of Staff's review of SNG's advertising costs was to ensure that only advertising costs for programs necessary for the provision of safe and adequate utility service are included in SNG's cost of service. Staff directly allocated the advertising expense to each district and made adjustments to exclude promotional and institutional advertisement expenses from recovery. Staff's adjustment also excludes the costs associated with advertisements where the actual advertisements were not provided to Staff by SNG.

Staff Expert/Witness: Ashley Sarver

5. Lobbying and MEDA Activities

Staff made adjustments to remove expenses booked by SNG in the test year that relate to any and all lobbying activities. The costs removed include amounts related to the Missouri Energy Development Association (MEDA). MEDA is a lobbying organization that develops, organizes and promotes measures that advance the interests of investor-owned utilities in Missouri. Staff asserts that MEDA annual dues and other related costs should be booked below-the-line for ratemaking purposes and be absorbed by the shareholders.

Staff Expert/Witness: Jermaine Green

6. Outside Services

Various outside (independent) contractors and vendors provide legal, auditing, payroll processing and other services to SNG on an as-needed basis in order to assist the Company in carrying out its operational activities. In determining Staff's adjustment of expenses booked to SNG's Outside Services Account 923, legal and outside consulting fees incurred in 2012 and 2013 were removed from Staff's two-year normalization calculation of outside services due to lack of documentation. In DR No. 0045.1 and follow-up discussions with SNG personnel, Staff requested invoices for the outside services expenses booked to Account 923 that exceeded $500. However, as of the date of filing this cost of service report, SNG has not provided these invoices. Consequently, Staff made an adjustment to remove a portion of legal expenses booked in Account 923 – Outside Services.

Staff Expert/Witness: Jermaine Green

7. Insurance Expense

Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability (and, potentially, that of their customers) associated with unanticipated losses.

Utility companies traditionally carry the following types of coverage:

- Directors and Officers Liability Insurance
- Workers' Compensation - covers all employees
- General and Excess Liability – all liability claims against the company
- Property – covers tangible property
- Fiduciary Liability – general coverage including theft, forgery, fraud, terrorism, etc.

As an ongoing and normal expense of a utility, insurance expense should be analyzed in every rate case audit to determine whether normalization of the test year expense amount is appropriate. Premiums for insurance are normally pre-paid by utilities (i.e., payment is made by the utility to the insurance vendor in advance of the policy's effective date). Most insurance policies cover a semi-annual (six-month) period. Therefore, insurance payments are normally treated as prepayments, with the amount of the premium being booked as an asset and amortized to expense over the life of the policy. The unamortized balance of the prepaid insurance account (either the period-ending balance or a 13-month average balance) is included in rate base, with an annualized level of insurance expense, based on the most current premiums charged to the Company as of December 31, 2013, included in rates. The Company's prepayments have been analyzed separately and are included in the rate base and are discussed in Section VI.C.

Staff proposed an adjustment to annualize SNG insurance expense to reflect the premiums as of December 31, 2013, the end of the update period.

Staff Expert/Witness: Jermaine Green

8. Injuries and Damages

Injuries and damages expense represents the portion of legal claims against a utility that is not subject to reimbursement under the utility's insurance policies. Injuries and damages expense normally consists of the following components:

- General Liability
- Auto Liability
- Workers Compensation

General liability claims tend to be the largest component of injuries and damages expense, and the part that can give rise to the most controversy in rate proceedings. Generally Accepted Accounting Principles (GAAP) normally require companies to book injuries and damages claims on an accrual basis. This means the expense is based upon estimated future claims payout amounts, rather than the actual cash payments made. However, for ratemaking purposes, Staff generally takes the position that injuries and damages expense should be measured on a "cash" basis; i.e., based upon actual cash payouts by the utility for claims made against it. This approach results in the actual payments forming the basis for the amount allowed in utility rates for recovery instead of the accrued book expense.

For injuries and damages, Staff calculated a two-year average of actual cash payouts for all three categories in Account 925, and used that average to represent a normalized level of actual claims paid.

Staff Expert/Witness: Jermaine Green

9. Utility Expense

Staff examined the amounts of utility expense for SNG during the test year. Staff adjusted this expense to update through December 31, 2013, the end of the update period in this case.

Staff Expert/Witness: Jermaine Green

10. Regulatory Expenses

Rate case expenses are costs incurred by a utility in preparation and performance of its filing for a rate case. In this case, SNG has incurred expenses in conjunction with hiring consultants for regulatory legal services, gas management and planning services and performance of a depreciation study.

At the time of direct filing for this case, SNG had incurred minimal rate case expenses during the test year. SNG has since provided a set of invoices to update these costs through December 31, 2013. Staff included a three-year normalization of rate case costs through December 31, 2013 in this case, exclusive of the cost of the depreciation study. The Company's depreciation study, which was submitted as part of this rate case, fulfills the requirement to perform a study every five years. Therefore, this cost is being normalized over a five-year period. Staff proposes allocating rate case expense based on customer bills in each of the districts and then normalizing the cost over the years stated above. Rate case expense will also be examined in the true-up portion of this case. Accordingly, Staff will continue to examine the actual costs incurred by SNG relating to the processing of the rate case and include all prudently incurred expenses in the cost of service analysis.

Staff removed from Account 928, Regulatory Commission Expense, all expenses booked in the test year. Staff has made separate adjustments to add back costs associated with current Regulatory Commission Expenses.

Staff Expert/Witness: Ashley Sarver

11. Dues

Dues are expenditures made by utilities to organizations, clubs and other groups. "Dues" can be defined as the amount paid to an organization by the utility which allow the utility or individual employees of the utility company to participate in and benefit from the organization's activities.

Staff reviewed the list of membership dues paid and donations made, to various organizations that SNG charged to its utility accounts during the test year. Staff excluded some dues and donations from the cost of service consistent with the Commission's decision in Case No. GR-77-33, where the Commission found disallowances were proper when: 1) the expenses are not necessary for the provision of safe and adequate service, 2) the expenses do not provide any direct benefit to ratepayers; and 3) including such expenses in rates places the ratepayer in the position of being an involuntary donor to the organization in question.

In this case, Staff allowed SNG's area Chamber of Commerce dues. SNG's State Chamber of Commerce dues were disallowed as redundant to SNG's membership in local Chamber of Commerce organizations. Also, Staff made adjustments to move entries not associated with dues that were incorrectly booked in the wrong account.

Staff Expert/Witness: Ashley Sarver

12. Rent Expense

Rent expense costs are incurred by SNG when it rents office spaces and warehouses. The Company does not receive monthly invoices for rent expenses; therefore, the monthly amount paid is the amount listed in the contracts for the individual locations. Staff examined the cost listed in the contracts for the test year updated through December 31, 2013 and made an adjustment to annualize these costs in rates. Staff disallowed expenses for which it was not provided a contract or any supporting documentation of other expenses (taxes) that were included in the rent payment. The Jefferson City office (corporate) rent expense was based on the salary allocation between corporate and SNG for Martha Wankum, Manager of Missouri Regulatory Affairs. The SNG portion was then allocated to the districts by customer bills totals. Other rent expense was directly allocated to each district.

Staff Expert/Witness: Ashley Sarver

13. Fuel Expense

SNG uses a fleet management service to manage its fuel expenses including the costs of gasoline, vehicle maintenance and vehicle registration fees. The Company employees are issued fleet management cards, which the employees then use to charge vehicle costs. The fleet service company issues monthly invoices to SNG listing the charges for each issued card, including a monthly fee for each card. Charges are listed by a unit number, which is linked to an employee and a specific vehicle. Staff reviewed the monthly invoices for the test year period through the update period. Using a vehicle list initially provided by the Company in its response to DR No. 0041 and then subsequently updated in its response to DR No. 0164, Staff was able to determine to what SNG district each vehicle was assigned. So, the fuel expense costs associated with each district were then calculated. In some cases, the invoices contained charges for vehicles not assigned to Missouri. Staff excluded any costs for these vehicles in its adjustment. Despite the fact that vehicles are assigned to specific Missouri districts allowing for direct assignment of costs, the Company uses an allocation factor to allocate the fleet service amounts to each district for financial reporting purposes. After applying an O&M factor to the expense for each district, Staff adjusted the Company's test year amounts to reflect the actual 2013 costs incurred for the vehicles assigned to each Missouri district at December 31, 2013. Therefore, each adjusted district total reflects the actual fuel expense of the vehicles assigned to that particular district.

Staff Expert/Witness: Keith Foster

E. Depreciation Expense

Background

In Case No. GE-2014-0010, SNG requested relief from filing a full statistical depreciation study for this rate case as required by Commission Rule 4 CSR 240-3.235. In that case, Staff recommended SNG implement a number of conditions designed to remedy some deficiencies in SNG's plant records that make a full depreciation study impossible to conduct at this time. The Commission approved the waiver along with Staff's conditions.

In compliance with the Commission's order in GE-2014-0010, SNG submitted a non-statistical depreciation study conducted by a consultant, Black & Veatch (B&V). B&V's study included plant activity through September 2013.

As described in Staff's report in GE-2014-0010, SNG currently has in effect several different deprecation rates reflecting the Company's various service territories. The original depreciation rates for SNG's Southern Missouri Natural Gas (SMNG) division were approved in Case No. GA-94-127. Depreciation rates for the Missouri Gas Utility, Inc. (MGU) Gallatin district were ordered in GO-2005-0120. MGU reached a Commission-approved unanimous stipulation and agreement in GR-2008-0060 that required MGU to keep the depreciation rates from GO-2005-0120 in effect. The depreciation rates for the Warsaw district of MGU were set in case GR-2009-0264. In Case No. GR-2010-0347, the depreciation rates set for SMNG in Case No. GA-94-127 were affirmed by the Commission.

In Case No. GM-2011-0354, the Commission ordered SMNG, as part of its merger with MGU, to transfer to MGU critical historical records of SMNG's plant and retirements. However, SMNG did not transfer this data, and the unavailability of this data affects the ability to perform a future depreciation study. Even in the event that the retirement records are transferred, SNG has not experienced sufficient retirements in the account to perform a statistically valid study. Plant addition and retirement data is available for the MGU division beginning in 2007 and for the SMNG division beginning in 2012. In the recent waiver case (GE-2014-0010), the Commission ordered SNG to keep certain records going forward so as to correct the problem of missing historical plant data and provide information to support a full depreciation study in the future.

The order approving the unanimous stipulation and agreement in GM-2011-0354 in the Syllabus clearly states that "MGU will be the surviving entity" in its merger with SMNG. The unanimous stipulation and agreement in case GM 2011-0354, related to depreciation, states in paragraph 6: "For purposes of accruing depreciation expense, MGU shall ensure that the SMNG division uses the depreciation rates approved by the Commission, maintains the Property Unit Catalog (PUC) and Continuing Property Record (CPR) as detailed in 4 CSR 240-40.040 Uniform System of Accounts Gas Corporations, 4 CSR 240-3.235 Filing Requirements for Gas Utility General Rate Increase Requests and 4 CSR 240 3.275 Submission Requirements for Gas Utility Depreciation Studies."

MGU was to ensure that the ordered depreciation rates for SMNG remain in effect for the purpose of accruing expense, maintain the continuing property records and the property unit catalog of SMNG. In case GA-2012-0285, SNG received a Certificate of Convenience and Necessity (CCN) for the Lake of the Ozarks division; in this case, depreciation rates were set for the Lake of the Ozarks region. Attached is Appendix 3, Schedule JAR(DEP) - 1 that contains the currently effective Commission-ordered depreciation rates for each division or region of SNG's Missouri operations.

Staff's Investigation

The B&V Report on Depreciation Accrual Rates filed January 2, 2014 as an attachment (schedule alp-4 2013 summit depreciation report final.pdf) to the direct testimony of SNG witness Alicia Picard in the executive summary on page 1, concludes that "Summit is a relatively new natural gas utility and has not experienced retirements to most of its property accounts. … Because data isn't available to perform a statistical depreciation analyses, we primarily relied on regional utility norms as the basis for out average service lives." Staff agrees with B&V that at this time, SNG's data on plant retirements is not sufficient to perform a statistically valid actuarial analysis for use in the development of ordered depreciation rates. Due to the lack of the property records being transferred as part of the merger in 2012, it may be many years before sufficient plant retirement and addition data exists to permit SNG or Staff to perform a statistically valid study that reflects the life of SNG's assets. For acquired property, SNG is required to keep mortality records of property and property retirement which will reflect the average life of retiring property and will aid actuarial analysis of the probable service life of annual additions and aged retirements per 4 CSR 240-40.040.[43]

[43] 4 CSR 240-40.040 Uniform System of
Accounts—Gas Corporations
(3) Regarding plant acquired or placed in service after 1993, when implementing section
(1), each gas corporation subject to the commission's jurisdiction shall—
(A) Maintain plant records of the year of each unit's retirement as part of the "continuing plant inventory records," as the term is otherwise defined at Part 201 Definitions 8. and paragraph 20,001.8.;
(B) State the detailed gas plant accounts (301 to 399, inclusive) on the basis of original cost, estimated if not known, when implementing the provisions of Part 201 Gas Plant Instructions 1.C. and paragraph 20,041.1.C.;
(C) Record gas plant acquired as an operating unit or system at original cost, estimated if not known, except as otherwise provided by the text of the intangible plant accounts, when implementing the provisions of Part 201 Gas Plant Instructions 2.A. and paragraph 20,042.2.A.;
(D) Account for the cost of items not classified as units of property as it would account for the cost of individual items of equipment of small value or of short life, as provided in Part 201 Gas Plant Instructions 3.A.(3) and paragraph 20,043.3.A.(3);
(E) Include in equipment accounts any hand or other portable tools which are specifically designated as units of property, when implementing the provisions of Part 201 Gas Plant Instructions 9.B. and paragraph 20,049.9.B.;
(F) Use the list of retirement units contained in its property unit catalog when implementing the provisions of Part 201 Gas Plant Instructions 10.A. and paragraph 20,050.10.A.;

SNG has adopted the depreciation rates ordered for the Lake of the Ozarks CCN, ordered in case GA-2012-0285 and applied them to all rate districts. The Company, in its response to DR No. 0094, states that it began booking the different depreciation rates on January 1, 2012 for the former MGU divisions. The former SMNG divisions have the same depreciation rates that were ordered for the Lake of the Ozarks CCN in GA-2012-0285. Therefore, they are not at issue in this case. The regions that are of special concern to Staff are the former MGU districts due to currently ordered depreciation rates for the MGU division being different from the depreciation rates that SNG is using for all divisions that were ordered specifically for the creation of rates in the Lake of the Ozarks CCN.

Staff recommends that an adjustment be made for the difference in depreciation accruals that were ordered for the former MGU divisions in GO-2005-0120 and GA-2009-0264 versus the depreciation accruals that SNG has been using for the MGU divisions. Two years of accruals have taken place and rate payers have not received credit for their payment at higher depreciation rates that the Company is booking. Staff's initial calculation yields an adjustment of approximately $165,000 for two years of mis-booked accruals for the time frame January 1, 2012 through December 31, 2013. Staff's specific adjustments to the reserve balances are provided in Appendix 3, Schedule JAR(DEP) – 2 with the exceptions of Accounts 390 and 392 for the MGU Gallatin division. There are no adjustments for Accounts 390 and 392 since Staff used the SNG general ledger reserve totals for December 31, 2013. Staff used the SNG general ledger reserve balance for Accounts 390 and 392 when it observed that the accounts had experienced major reductions to plant in

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(G) Estimate original cost with an appropriate average of the original cost of the units by vintage year, with due allowance for any difference in size and character, when it is impracticable to determine the original cost of each unit, when implementing the provisions of Part 201 Gas Plant Instructions 10.D. and paragraph 20,050.10.D.;
(H) Charge original cost less net salvage to account 108., when implementing the provisions of Part 201 Gas Plant Instructions 10.F. and paragraph 20,050.10.F.;
(I) Keep its work order system so as to show the nature of each addition to or retirement of gas plant by vintage year, in addition to the other requirements of Part 201 Gas Plant Instructions 11.B. and paragraph 20,051.11.B.;
(J) Maintain records which classify, for each plant account, the amounts of the annual additions and retirements so as to show the number and cost of the various record units or retirement units by vintage year, when implementing the provisions of Part 201 Gas Plant Instructions 11.C. and paragraph 20,051.11.C.;
(K) Maintain subsidiary records which separate account 108. according to primary plant accounts or subaccounts when implementing the provisions of Part 201 Balance Sheet Account 108.C. and paragraph 20,011.108.C.;
(L) Maintain subsidiary records which separate account 111. according to primary plant accounts or subaccounts when implementing the provisions of Part 201 Balance Sheet Accounts 111.C. and paragraph 20,114.111.C.; and
(M) Keep mortality records of property and property retirement as will reflect the average life of retiring property and will aid actuarial analysis of the probable service life of annual additions and aged retirements when implementing the provisions of Part 201 Income Accounts 403.B. and paragraph 20,422.403.B.

service during calendar years 2012 and 2013 while the reserve totals did not reflect the reductions. Staff intends to address the adjustments for the MGU Gallatin division accounts of 390 and 392 in True-up Testimony after more discovery has been performed surrounding the reductions to plant in service and any corresponding entries to the reserve balances.

Recommendations

Staff recommends the Commission order the depreciation rates set forth in Appendix 3, Schedule JAR(DEP) - 3 that are the currently ordered depreciation rates for the MGU Gallatin, MGU Warsaw, SMNG and Lake of the Ozarks divisions of SNG as presented in Appendix 3, Schedule JAR(DEP) - 1 supplemented with a depreciation rate for a new Account 377 Compressor Station equipment at the MGU Warsaw division.

Staff recommends that the Commission order SNG to make the adjustments to the depreciation reserves for the Warsaw and Gallatin regions of the MGU division to reflect the use of the currently ordered depreciation rates for SNG for the period of January 1, 2012 through December 31, 2013 as shown in Appendix 3, Schedule JAR(DEP) - 2 with the exceptions of Accounts 390 and 392 for the MGU Gallatin division. These adjustments are subject to true-up period in this proceeding (six months ending June 30, 2014).

Staff Expert/Witness: John A. Robinett

F. Property Taxes Expense

Property taxes are those taxes assessed by state and local county taxing authorities on a utility's "real" property. Property taxes are computed using the assessed property values and property tax rates. The taxing authorities, either state or local, use an assessment date of January 1 of each year. This date is critical because it forms the basis for the property tax bill, which is generally paid at the end of that same year, no later then December 31. Utilities are required to file with the taxing authorities a valuation of its utility property based on the January 1 assessment date the first of each year. Several months later, the taxing authorities will provide the utilities with what they refer to as "assessed values" for each category of property owned. Much later in the year (typically in the late summer/fall time frame), the utilities will be given the property tax adjustment. Property tax bills are then issued to the utilities with "due dates" by December 31 based on the property tax rates applied to assessed values. Staff developed its property tax rate based on the Company's actual taxes paid as of December 31, 2013, the update period for this case. These taxes are based on the assessed value of property owned by the Company on January 1, 2013. However, Staff excluded some tax payments because no receipts were provided to validate the amounts paid. Staff has requested these receipts from the Company and, if the receipts are received before the true-up filing, Staff will include these tax payments in the true-up.

As part of its adjustment, Staff used the Company's proposed allocation method to allocate a portion of the property taxes paid in the Warsaw district (Benton and Pettis Counties) to the LOO district, to account for joint use pipe shared by the two districts. Since the LOO district is not included in this case, Staff's adjustment reduced the total property tax expense for the Warsaw district to account for the LOO portion.

In the Branson district, the Company has outstanding appeals filed with the State Tax Commission of Missouri regarding Taney County's 2013 property tax assessments. These appeals may or may not be settled before Staff's true-up filing, period ending June 30, 2014. The actual property taxes billed by Taney County were paid by the Company in protest and are included in Staff's total property tax calculation. If the appeals are settled by true-up, Staff will modify its property tax adjustment to reflect any refunds issued against the 2013 taxes paid. Otherwise, Staff recommends that, if any subsequent refund is ordered as a result of the appeals, the Commission order the Company to track the refunded amount to be considered in the next rate case for potential refund to the Company's ratepayers.

Staff Expert/Witness: Keith Foster

G. Current and Deferred Income Tax Expense

1. Current Income Tax

The calculation of current income tax expense is necessary to include as part of the revenue requirement to ensure that any given dollar increase in revenues is actually collected in rates. In other words, because the Company has to pay some portion of its earnings as income taxes to the state and federal taxing authorities, a level of income tax expense has to be collected in rates. If income taxes were not considered in rates, then the Company would not fully collect sufficient revenues to cover all its costs and would not have an opportunity to earn its authorized rate of return. For the utility to recover the full revenue increase, it has to collect a portion of revenue for income taxes in its rate structure in addition to the revenue amount determined by the Commission to be appropriate before factoring up for income taxes.

Current income tax expense is calculated by applying the statutory state and federal tax rates to Staff's taxable income amount. Expenses, as adjusted by Staff, are deducted from revenues to arrive at the net operating income before income taxes. Then, adjustments are made to convert net operating income to taxable income. These adjustments include deductions for tax depreciation and interest expense. The interest tax deduction was calculated using the interest synchronization method of applying the weighted cost of debt in the capital structure (as determined by Staff witness David Murray of the Commission's Financial Analysis Unit) to the Staff's rate base. The depreciation deduction is derived by reflecting within the taxable income calculation the higher amount of depreciation expense using "accelerated tax depreciation" methods the Company can reflect on its income tax returns, compared to the amount of straight-line book depreciation expense included in Staff's net operating income calculation. After all the expenses and tax deductions are made, the resulting amount is the taxable income to which the income tax rates are applied.

2. Deferred Income Tax

When a tax timing difference is reflected for ratemaking purposes consistent with the timing used in determining the taxable income amount for current income tax due under the Internal Revenue Code (IRC), the timing difference is given "flow-through" treatment. When a current year timing difference is deferred and recognized for ratemaking purposes in a way that is consistent with the timing used in calculating pre-tax operating income in the financial statements, then that timing difference is given "normalization" treatment for ratemaking purposes. Deferred income tax expense for a regulated utility reflects the tax impact of "normalizing" tax timing differences for ratemaking purposes. IRS rules for regulated utilities require normalization treatment for the timing difference related to accelerated tax depreciation.

SNG's deferred tax reserve represents, in effect, a prepayment of income taxes by SNG's customers. As an example, because SNG is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes is considerably higher than depreciation expense used for ratemaking cost of service purposes. This results in what is referred to as "book-tax timing difference" and creates a deferral of income taxes to the future. The net credit balance in the deferred tax reserve represents a source of cost-free funds for SNG to use for its utility operations. Therefore, SNG's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are cost free to the Company. The most significant book-tax timing difference is caused by the differences between accelerated tax depreciation and book depreciation. Generally, deferred income taxes associated with all book-tax timing differences which are created through the ratemaking process should be reflected in rate base.

Staff Expert/Witness: Keith Foster

IX. Ratepayer Funded Energy Efficiency and Low-Income Weatherization Programs; and an Energy Efficiency Advisory Group

Staff recommends the Commission authorize a natural gas energy efficiency program and a low income customer weatherization program that will be ratepayer funded through a regulatory asset account. The cost booked to these accounts will be analyzed in the next rate case for prudency. Staff also recommends that the Commission authorize an Energy Efficiency Advisory Group (EEAG) to oversee the design, implementation and evaluation of the energy efficiency and low income customer weatherization programs. The potential components of the energy efficiency program would include energy efficiency education, rebates on energy efficient gas appliances, and rebates and/or low interest financing for building shell improvements. The funds for the low income customer weatherization program would be administered by the Department of Economic Development, Division of Energy (DE) in conjunction with the federal and state funds they administer for the weatherization of homes of low income Missouri families. The DE low income weatherization has demonstrated an ability to effectively weatherize homes of low income families in Missouri and the Commission has been authorizing ratepayer funded low income customer weatherization for twenty years. Similarly, natural gas energy efficiency programs at other Missouri jurisdictional utilities have been in place several years and have been effective in promoting the utilization of higher efficiency gas appliances and building shell improvements. The regulatory asset account is a good way to fund the program. It is anticipated that it will take a few months to develop, get tariff sheets approved, and advertise measures in the natural gas energy efficiency program. So program participation may be low initially and increase over time to the goal of 0.5 percent of annual revenues.

Staff Expert/Witness: Kory Boustead

X. Appendices

Appendix 1: Staff Credentials

Appendix 2: Support for Staff Cost of Capital Recommendation – David Murray

Appendix 3: John A. Robinett - Depreciation Rates

Jermaine Green – Margin Revenue Summary

Seoung Joun Won - Actual and Normal Heating Degree Days

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Summit Natural Gas of Missouri Inc.'s Filing of Revised Tariffs To Increase its Annual Revenues For Natural Gas Service))))	Case No. GR-2014-0086

AFFIDAVIT OF MICHELLE BOCKLAGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Michelle Bocklage, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Michelle Bocklage

Michelle Bocklage

Subscribed and sworn to before me this 30th day of May, 2014.

D. Suzie Mankin

Notary Public

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Summit Natural Gas of Missouri Inc.'s Filing of Revised Tariffs To Increase its Annual Revenues For Natural Gas Service	))))	Case No. GR-2014-0086

AFFIDAVIT OF KORY BOUSTEAD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Kory Boustead, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Kory Boustead

Kory Boustead

Subscribed and sworn to before me this 30th day of May, 2014.

D. Suzie Mankin

Notary Public

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Summit Natural Gas of Missouri Inc.'s Filing of Revised Tariffs To Increase its Annual Revenues For Natural Gas Service	))))	Case No. GR-2014-0086

AFFIDAVIT OF KIM COX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Kim Cox, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Kim Cox

Kim Cox

Subscribed and sworn to before me this 30th day of May, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Summit Natural Gas of Missouri Inc.'s Filing of Revised Tariffs To Increase its Annual Revenues For Natural Gas Service	))))	Case No. GR-2014-0086

AFFIDAVIT OF BRAD J. FORTSON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Brad J. Fortson, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Brad J. Fortson

Brad J. Fortson

Subscribed and sworn to before me this 30th day of May, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Summit Natural Gas of Missouri Inc.'s Filing of Revised Tariffs To Increase its Annual Revenues For Natural Gas Service	))))	Case No. GR-2014-0086

AFFIDAVIT OF KEITH D. FOSTER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Keith D. Foster, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Keith D. Foster

Subscribed and sworn to before me this 30th day of May, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Summit Natural Gas of Missouri Inc.'s Filing of Revised Tariffs To Increase its Annual Revenues For Natural Gas Service	))))	Case No. GR-2014-0086

AFFIDAVIT OF JERMAINE GREEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Jermaine Green, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

J Green

Jermaine Green

Subscribed and sworn to before me this 30th day of May, 2014.

D. Suzie Mankin

Notary Public

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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OF THE STATE OF MISSOURI

In the Matter of Summit Natural Gas of Missouri Inc.'s Filing of Revised Tariffs To Increase its Annual Revenues For Natural Gas Service	))))	Case No. GR-2014-0086

AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Robin Kliethermes, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Robin Kliethermes

Robin Kliethermes

Subscribed and sworn to before me this 30th day of May, 2014.

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AFFIDAVIT OF PHIL LOCK

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Phil Lock, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Phil Lock
Phil Lock

Subscribed and sworn to before me this 30th day of May, 2014.

D. Suzie Mankin
Notary Public

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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AFFIDAVIT OF AMANDA C. MCMELLEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Amanda C. McMellen, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Amanda C McMellen

Amanda C. McMellen

Subscribed and sworn to before me this 30th day of May, 2014.

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D Suzie Mankin

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AFFIDAVIT OF DAVID MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Murray, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David Murray

David Murray

Subscribed and sworn to before me this 30th day of May, 2014.

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D Suzie Mankin

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AFFIDAVIT OF JOHN A. ROBINETT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

John A. Robinett, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

John A. Robinett

John A. Robinett

Subscribed and sworn to before me this 30th day of May, 2014.

D. SUZIE MANKIN
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State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
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D Suzie Mankin

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AFFIDAVIT OF ASHLEY SARVER

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Ashley Sarver, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Ashley Sarver

Ashley Sarver

Subscribed and sworn to before me this 30th day of May, 2014.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

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AFFIDAVIT OF SEOUNG JOUN WON PHD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Seoung Joun Won, PhD., of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Seoung Joun Won

Seoung Joun Won PhD.

Subscribed and sworn to before me this 30th day of May, 2014.

D. Suzie Mankin

Notary Public

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
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