BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of Summit Natural Gas of Missouri, Inc.'s Purchased Gas Adjustment	)))	**Case No. GR-2015-0101**
In the Matter of Summit Natural Gas of Missouri, Inc.'s Purchased Gas Adjustment	)))	**Case No. GR-2015-0102**

STAFF RECOMMENDATION REGARDING SUMMIT NATURAL GAS OF MISSOURI, INC.'S 2013-2014 ACTUAL COST ADJUSTMENT FILING

COMES NOW the Staff of the Missouri Public Service Commission in the above-captioned matter and files its Actual Cost Adjustment ("ACA") Recommendation in this case concerning Summit Natural Gas of Missouri, Inc.'s ("Summit" or "Company") 2013-2014 ACA filing as set forth in the accompanying Staff Recommendation Memorandum (Appendix A), and further states as follows:

1. On October 17, 2014, Summit made its ACA filings for the 2013-2014 ACA period for its Northern service area, its Southern service area, and the former Southern Missouri Natural Gas ("SMNG") service area. Summit originally filed Case No. GR-2015-0101 for its Northern and Southern service areas and Case No. GR-2015-0102 for the former SMNG service area, but these two cases were consolidated by a Commission *Order Granting Motion to Consolidate* issued on December 22, 2014, with Case No. GR-2015-0101 being denominated as the lead case.

2. The Procurement Analysis Unit ("Staff") has reviewed Summit's filings and submits its recommendation as further explained in the accompanying Staff Recommendation Memorandum marked Appendix A (which is incorporated herein by

reference). As a part of its review, the Staff conducted an analysis of Summit's gas purchasing practices to evaluate the prudence of the Company's purchasing decisions for this ACA period; a reliability analysis, including a review of estimated peak-day requirements and the capacity levels needed to meet those requirements and a review of supply plans for various weather conditions; and a hedging review to evaluate the reasonableness of the Company's hedging practices for this ACA period. Staff's review also included a comparison of the Company's billed revenues and its actual gas costs to determine whether there exists an over-recovery or under-recovery of the ACA balances. An over-recovery by the Company is shown in the accompanying Staff Recommendation Memorandum as a negative ACA balance that must be returned to customers; an under-recovery is shown in the accompanying Staff Recommendation Memorandum as a positive ACA balance that must be collected from customers.

3. Based on its review, as discussed in detail in the accompanying Staff Recommendation Memorandum, Staff recommends certain monetary adjustments to the Company's filed ACA balances as shown in the tables contained in "Section V Recommendations" of the Staff Recommendation Memorandum for the Company's Northern service area, its Southern service area, and the SMNG service area.

4. In addition to the monetary adjustments referenced above, based on its review Staff has certain concerns and recommendations as reflected in the accompanying Staff Recommendation Memorandum in the sections addressing the Company's Billed Revenue and Actual Gas Cost; Reliability Analysis and Gas Supply Planning; and Hedging. Staff recommends the Commission order Summit to respond to these concerns and recommendations within forty-five (45) days.

WHEREFORE, for the reasons stated above and discussed in detail in the accompanying Staff Recommendation Memorandum, Staff recommends the Commission issue an order directing Summit to respond within 45 days to Staff's concerns and recommendations discussed in Sections II through IV of Staff's Recommendation Memorandum, and to reflect the Staff adjustments shown in the "Staff Adjustments for 2013-2014 ACA" columns and to establish Summit's ending ACA account balances as shown in the "Staff Recommended Ending Balances" columns of the tables in Section V of the Staff Recommendation Memorandum for the Company's Northern service area, its Southern service area, and the SMNG service area.

Respectfully submitted,

/s/ Jeffrey A. Keevil
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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been mailed, hand-delivered, or transmitted by facsimile or electronic mail to counsel of record this 14th day of December, 2015.

/s/ Jeffrey A. Keevil

MEMORANDUM

TO: Missouri Public Service Commission Official Case File
Case Nos. GR-2015-0101 and GR-2015-0102 (consolidated),
Summit Natural Gas of Missouri, Inc.

FROM: Phil S. Lock, Regulatory Auditor – Procurement Analysis
Kwang Choe, Ph.D., Regulatory Economist – Procurement Analysis
Kathleen McNelis, Utility Regulatory Engineer I– Procurement Analysis

/s/ David M. Sommerer 12/14/15
Project Coordinator / Date

/s/Jeffrey A. Keevil 12/14/15
Staff Counsel's Office / Date

/s/ Lesa Jenkins P.E. 12/14/15
Utility Regulatory Engineer II / Date

SUBJECT: Staff Recommendation in Case Nos. GR-2015-0101 and GR-2015-0102 (consolidated), Summit Natural Gas of Missouri, Inc. 2013-2014 Actual Cost Adjustment Filing

DATE: December 14, 2015

EXECUTIVE SUMMARY

On April 27, 2011 Southern Missouri Gas Company (SMNG) and Missouri Gas Utility (MGU) filed an application for Commission authority to merge, with MGU as the surviving entity (Case No. GM-2011-0354). The parties filed a Unanimous Stipulation and Agreement on September 15, 2011, which the Commission approved on September 28, 2011.

On February 3, 2012, MGU filed to change its name to Summit Natural Gas of Missouri, Inc. ("SNG", "Summit" or "Company") and for Summit to adopt MGU's tariffs. On February 23, 2012, Summit filed tariff sheets to adopt SMNG's tariffs.

On October 17, 2014, Summit (successor in interest to MGU) filed its Actual Cost Adjustment (ACA) for the 2013-2014 annual period for rates to become effective November 1, 2014. Summit originally filed Case No. GR-2015-0101 for its Northern and Southern service areas and Case No. GR-2015-0102 for the former Southern Missouri Natural Gas service area, but these two cases were consolidated by a Commission Order Granting Motion to Consolidate issued on December 22, 2014, with Case No. GR-2015-0101 being the lead case. The Procurement Analysis Unit ("Staff") of the Missouri Public Service Commission has reviewed the Company's

ACA filing for the **former Southern Missouri Natural Gas (SMNG) service area** (Rogersville and Branson Division), **Northern service area** (Gallatin Division), and **Southern service area** (Warsaw and Lake of the Ozarks Division). A comparison of billed revenue recovery with actual gas costs will yield either an over-recovery or under-recovery of the ACA balance. An over-recovery by the Company is shown as a negative ACA balance that must be returned to customers; an under-recovery is shown as a positive ACA balance that must be collected from customers.

Staff conducted the following analyses:

- a review of billed revenue compared with actual gas costs;
- a reliability analysis including a review of estimated peak-day requirements and the capacity levels needed to meet these requirements and a review of supply plans for various weather conditions;
- a review of the Company's gas purchasing practices to evaluate the prudence of the Company's purchasing decisions for this ACA period; and,
- a hedging review to evaluate the reasonableness of the Company's hedging practices for this ACA period.

Based on its review, Staff recommends the following adjustments to the Company's **former SMNG service area** (Rogersville and Branson Division) filed 2013-2014 (over)/under-recovery ACA balances:

SMNG Service Area Description (+) Under-recovery (-) Over-recovery	Ending Balances Per Filing	Commission Approved Adjustments prior to 2013-2014 ACA	Staff Adjustments for 2013-2014 ACA	Staff Recommended Ending Balances
Prior ACA Balance 8-31-13	($24,408)	$0	$0	($24,408)
Cost of Gas/Storage	$6,672,569	($71,968)	$0	$6,600,601
Cost of Transportation	$2,212,653	$0	($4,523)	$2,208,130
Revenues - PGA billed	($7,989,926)	$0	$0	($7,989,926)
ACA Approach for Interest Calculation	$3,558	$0	$0	$3,558
Total ACA Balance 8-31-14	$874,446	($71,968)	($4,523)	$797,955

Staff has one transportation adjustment related to avoidable overrun charges for the SMNG service area of ($4,523) (Reliability Analysis and Gas Supply Planning section).

Based on its review, Staff recommends the following adjustments to the Company's filed 2013-2014 (over)/under-recovery ACA balances for **Summit's Northern service area** (Gallatin Division):

Northern Service Area Description (+) Under-recovery (-) Over-recovery	Ending Balances Per Filing	Commission Approved Adjustments prior to 2013-2014 ACA	Staff Adjustments for 2013-2014 ACA	Staff Recommended Ending Balances
Prior ACA Balance 8-31-13	$3,203	$0	$0	$3,203
Cost of Gas/Storage	$1,005,337	($1,608)	($11,758)	$991,971
Cost of Transportation	$128,249	$0	$0	$128,249
Revenues - PGA billed	($850,100)	$0	$0	($850,100)
Revenues Otherwise billed	($12,541)	($5,118)	$0	($17,659)
ACA Approach for Interest Calculation	$1,614	$0	$0	$1,614
Total ACA Balance 8-31-14	$275,762	($6,726)	($11,758)	$257,278

Staff has one adjustment on Summit's Northern service area: A prudence adjustment for ($11,758) pertaining to the Company decisions regarding supply and storage for the 2013/2014 winter. Staff's concerns regarding various aspects of this topic are discussed within the Reliability Analysis and Gas Supply Planning section of this memorandum.

Based on its review, Staff recommends the following adjustments to the Company's filed 2013-2014 (over)/under-recovery ACA balances for **Summit's Southern service area** (Warsaw and Lake of the Ozarks Division):

Southern Service Area Description (+) Under-recovery (-) Over-recovery	Ending Balances Per Filing	Commission Approved Adjustments prior to 2013-2014 ACA	Staff Adjustments for 2013-2014 ACA	Staff Recommended Ending Balances
Prior ACA Balance 8-31-13	$19,644	$0	$0	$19,644
Cost of Gas/Storage	$1,741,331	$0	$0	$1,741,331
Cost of Transportation	$618,930	$0	($3,529)	$615,401
Revenues – PGA billed	($2,116,852)	$0	$0	($2,116,852)
ACA Approach for Interest Calculation	$1,447	$0	$0	$1,447
ACA cost correction	$0	$2,952	$0	$2,952
Total ACA Balance 8-31-14	$264,500	$2,952	($3,529)	$263,923

Staff has one adjustment related to avoidable overrun charges on the Company's Southern service area for ($3,529) (Reliability Analysis and Gas Supply Planning section).

Staff has no adjustments related to hedging; however Staff's concerns/comments are addressed in the Hedging section of the memorandum.

Staff recommends the Commission order the Company to respond to Staff's concerns and recommendations within 45 days.

STAFF'S TECHNICAL DISCUSSION AND ANALYSIS

Staff's discussion of its findings is organized into the following five sections, which include Staff's concerns and recommendations:

I. Overview
II. Billed Revenue and Actual Gas Cost
III. Reliability Analysis and Gas Supply Planning
IV. Hedging
V. Recommendations

I. OVERVIEW

During the 2013-2014 ACA, Summit provided natural gas service to customers in the south and west-central portion of the state including the counties of Benton, Camden, Greene, Miller, Morgan and Pettis, also known as the "Southern service area." Summit served an average of 3,759 sales customers in the Southern service area. Southern Star Central Gas Pipeline (SSCGP) serves all customers in Summit's Southern service area. Summit also provides natural gas service to customers in the Northwest Missouri counties of Caldwell, Daviess and Harrison, also known as the "Northern service area." Summit served an average of 1,551 sales customers and one transportation customer in the Northern service area. ANR Pipeline Company (ANR) serves all customers in Summit's Northern service area.

During the 2013-2014 ACA, Summit also provided natural gas service to customers in the south and south-central portion of the state including communities in Greene, Webster, Wright, Howell, Texas, Douglas, Laclede, Stone and Taney counties, also known as the "SMNG service area." Summit served an average of 11,671 sales customers and 29 transportation customers for the combined Branson and Rogersville systems. Southern Star Central Gas Pipeline (SSCGP) serves all customers in Summit's former SMNG service territory.

II. BILLED REVENUE AND ACTUAL GAS COST

August 2014 Gas Supply Purchases – SMNG service area

Summit made daily gas supply purchases from ConocoPhillips for the period of August 19, 2014 to August 27, 2014. No documents exist (contracts, transaction confirmations, e-mail correspondence, logs, etc.) to substantiate the gas supply purchases from ConocoPhillips during this time (Data Request (DR) No. 0072.1). Maintaining proper documentation in support of each gas supply transaction is an integral part of the gas procurement process. In the future, Summit should make this documentation available to Staff for its review. Staff does not propose any adjustment based on this lack of documentation at this time.

ACA factor - Northern service area

Summit filed an ACA factor of $1.553 per Mcf, effective November 1, 2014, for customers on the Northern service area. This resulted from a $275,762 under-recovery of gas costs (gas costs > revenues) that developed during the 2013-2014 ACA period. Summit elected not to file a new PGA factor during the ACA period (citing resource commitments) which would have resulted in a lower under-recovered ACA balance at the end of the 2013-2014 ACA. According to the Company's current tariff sheet 51 (tariff sheet 45 in 2013-2014 ACA case).

> The Company shall have the opportunity to make up to four (4) PGA filings each year; a required Winter PGA and three (3) Optional PGAs. The Winter PGA shall be filed between October 15 and November 4 of each calendar year. **The Optional PGAs shall be filed when the Company determines that elements have changed significantly from the current effective factor**.

In this case, Staff believes that elements had changed "significantly" during this ACA. Staff encourages Summit to consider making additional PGA filing(s) during any ACA period when conditions (i.e. weather) could result in a significant change in the ACA balance (positive or negative).

Unpublished Index Prices – Northern service area

On one occasion during the month of January 2014, one occasion during the month of February 2014, and four occasions during the month of March 2014, Platts Gas Daily did not publish a REX, Clarington Ohio index price. On each of these occasions, the actual price BP charged for gas supply was higher than the average Rex, Clarington Ohio Gas Daily price calculated the day before and the day after the non-published day. Section 14 of the

General Terms and Conditions to the Base Contract governs how the parties determine the replacement price when an index price is not published. Section 14 of the NAESB contract with BP reads as follows:

Section 14 Market Disruption

> If a Market Disruption Event has occurred then the parties shall negotiate in good faith agree on a replacement price for the Floating Price (or on a method for determining a replacement price for the Floating Price) for the affected Day, and if the parties have not so agreed on or before the second Business Day following the affected Day then the replacement price for the Floating Price shall be determined within the next two following Business Days with each party obtaining, in good faith and from non-affiliated market participants in the relevant market, two quotes for prices of Gas for the affected Day of a similar quality and quantity in the geographical location closest in proximity to the Delivery Point. Once the Parties obtain the quotes, the following methodology shall be used to determine the replacement price for the Floating Price: (i) if each Party obtains two quotes, the arithmetic mean of the quotations excluding the highest and lowest values, shall be utilized; (ii) if one Party obtains two quotes and the other Party only obtains one quote, the highest and lowest values shall be excluded and the remaining quotation shall be utilized; (iii) if both Parties each obtain one quote, the arithmetic mean of the quotations shall be utilized; or (iv) if only one Party is able to obtain a quote, the obtained quotation shall be utilized. For purposes of the foregoing sentence, if more than one quotation is the same as another quotation, and such quotations are the highest and/or lowest values, only one of the quotations shall be excluded. If either party fails to provide two quotes then the average of the other party's two quotes shall determine the replacement price for the Floating Price. "Floating Price" means the price or a factor of the price agreed to in the transaction as being based upon a specified index. "Market Disruption Event" means, with respect to an index specified for a transaction, any of the following events: (a) the failure of the index to announce or publish information necessary for determining the Floating Price; (b) the failure of trading to commence or the permanent discontinuation or material suspension of trading on the exchange or market acting as the index; (c) the temporary or permanent discontinuance or unavailability of the index; (d) the temporary or permanent closing of any exchange acting as the index or (e) both parties agree that a material change in the formula for or the method of determining the Floating Price has occurred. For the purposes of the calculation of a replacement price for the Floating Price, all numbers shall be rounded to three decimal places. If the fourth decimal number is five or greater, then the third decimal number shall be increased by one and if the fourth decimal number is less than five, then the third decimal number shall remain unchanged.

On each of these occasions (from Jan 2014 to March 2014), only BP provided quotations. As indicated in option (iv) the BP quote was utilized. Summit indicated that it did not provide a quote because:

> The Company does not have reasonable access to other market based pricing alternatives for purposes of quotation. Furthermore, the Company accepted the BP replacement prices as reasonable and supportable.[1]

It is unclear how the Company determined that these prices were reasonable and supportable if it did not have reasonable access to other market based pricing alternatives. It is also unclear what other market based pricing alternatives would have been acceptable under the terms of this agreement. Staff recommends that the Company:

A. Inquire of BP what market based pricing alternatives would be acceptable to use under the terms of this contract provision; and

B. Either find a means of obtaining access to the market based pricing alternatives that are acceptable under the terms of this contract provision or work with BP to revise the contract language to include an alternative pricing mechanism that is reasonably available to the Company.

III. RELIABILITY ANALYSIS AND GAS SUPPLY PLANNING

As a natural gas corporation providing natural gas service to Missouri customers, Summit is responsible for conducting reasonable long-range supply planning to meet its customer needs. Summit must make prudent decisions based on that planning. One purpose of the ACA process is to examine the reliability of the Local Distribution Company's (LDC) natural gas supply, transportation, and storage capabilities. For this analysis, Staff reviewed the LDCs' plans and decisions regarding estimated peak-day requirements and the LDC's pipeline capacity levels to meet those requirements, peak day reserve margin and the rationale for this reserve margin, and natural gas supply plans for various weather conditions.

A. Weather Normal Data

In planning for normal, warmer and colder winters, the Company uses the 30-year normal weather data as a basis of estimating demand in response to normal, warmer and colder winter weather conditions. In the 2013/2014 ACA, the Company used the 30-year normal weather data

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[1] GR-2015-0101 DR No. 0110.

from 1971-2000, however the 30-year normal weather data from 1981-2010 was available. As noted in prior recommendations, Staff recommends the Company use the 30-year normal weather data from 1981-2010. The Company's 12-08-14 response filed in case GR-2014-0096 stated that it agreed with Staff's recommendation.

B. Peak Day Forecasting

For the 2013/2014 ACA, the Company's peak day models for the Branson portion of the SMNG service area[2] and the Southern service areas did not appear to accurately forecast actual demand on cold days.

For the Branson service area, the Company's peak day model appeared to consistently underestimate the demand per customer. The Company stated that a possible reason for underestimation in the Branson service area was the addition of larger customers (i.e. greater average demand per customer). This explanation seems reasonable; however, Staff noted that the Company's peak day demand estimate per customer for Branson appeared to decrease from 1.99 Dth/customer in the 2012/2013 ACA to 1.70 Dth/customer in the 2013/2014 ACA. This decrease in demand per customer is not consistent with a higher average demand per customer.

Since the reserve margin for the Branson area is currently high, Staff has no immediate concerns related to capacity for this system. However, given the Company's statement that the system is growing, Staff recommends that the Company attempt to refine its model of Branson peak day demand.

For the Southern service area, the Company's model appeared to consistently overestimate the demand per customer. The Company explained that the estimate relied on regression statistics from Warsaw only and was exacerbated by the disproportionally high number of expected customers. Staff acknowledges the limited data available, and will review results for the Southern service area in the 2014/2015 ACA period when the regressions include data from Lake of the Ozarks as well.

Staff noted that the Company used only data from the prior winter when performing its forecasts of peak day demand. The Company's rationale for using only the most recent data is that some areas of its system are experiencing growth. The Company has also stated that it believes

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[2] The Branson service area is part of the SMNG service area and includes Branson and Hollister. The Company has a separate transportation contract with SSCGP and the take-point is in Aurora, MO. Because of the physical separation of the Branson service area from the remaining SMNG system (Rogersville to West Plains line with Lebanon and Ava laterals), capacity needs and reserve margins are evaluated separately.

"…the use of historical usage data to project the future in an operating environment characterized by large customer growth causes the problem…" of under-predicting demand.

Staff acknowledges the Company's concern; however Staff notes that by only considering the previous winter's data the Company is limiting its evaluation to customer behavior for that winter's conditions. For example, if using only data from a warmer than normal winter, the Company would be evaluating its customer demand in a warmer than normal winter. Customer demand during a warmer than normal winter may not be representative of customer demand in a normal or colder than normal winter. Using additional data would provide a wider range of customer responses to actual weather conditions, which will inform the Company of the variability of its capacity requirements for peak day requirements. Staff suggests that the Company continue to evaluate the data and methods it uses to predict peak day demand to inform its capacity decisions.

C. Reserve Margins

The Company considers its peak day demand and future growth projections in its calculation of reserve margins. The Company calculates a 95% Upper Confidence Interval (95% UCI) peak day demand and a +2 times standard error (+2*SE) peak day that would account for variability in its peak day needs. However, it does not use these in its calculation of reserve margins. For the Northern service area for example, Staff has compared the Company's calculated reserve margins using the coefficient peak day with future projections of 95% UCI and +2*SE peak day:

Year	Estimated Customers	Company Coefficient		+2*SE Peak Day		95% UCI Peak Day	
		Peak Day	Reserve Margin	Peak Day	Reserve Margin	Peak Day	Reserve Margin
2014/2015	1,734	2,363	10.0%	2,747	-5.4%	2,745	-5.3%
2015/2016	1,786	2,434	6.8%	2,830	-8.1%	2,827	-8.0%
2016/2017	1,839	2,506	3.7%	2,914	-10.8%	2,911	-10.7%

By considering only the coefficient peak day estimates, reserve margins remain positive through 2016/2017. However when either the 95% UCI peak day or +2*SE peak day estimates are considered, reserve margins become negative as early as the 2014/2015 winter. Staff recommends that the Company consider either the 95% UCI or the +2*SE peak day or some other method to account for variability in peak day requirements when calculating reserve margins and considering capacity requirements.

D. Supply for Peak Day and Other Cold Weather Plans

The Company's peak day estimate for the 2013/2014 winter could have been met by a combination of storage withdrawal, baseload and daily supply contract flowing volumes. The Company had no winter firm swing/call or peaking contracts set up in advance of the winter months. The 2013/2014 winter was colder than normal (119% of normal for the Northern service area, 113% of normal for other service areas).

Staff has made previous recommendations regarding swing and peaking contracts:

- In its GR-2012-0115 recommendation, Staff expressed concern regarding the lack of any firm peaking or swing contracts for the Southern service area because during periods of extreme cold weather, daily gas supply may not be available.
- In GR-2014-0097 and GR-2014-0096 Staff recommended that the Company consider swing/call contracts. Staff noted that during a four day period in December 2012, the Company used storage gas intended as part of its winter hedge for the SMNG service area customers in its Southern service area because the Company was unable to timely bid out its gas supply requirements. In its 12-08-14 response, the Company stated that supply reliability is a significant determinant in the Company's annual supply planning, and that it would consider Staff's recommendation to employ swing/call agreements.
- In comments on the Company's 2015/2016 plans, Staff reiterated past recommendations and requested that the Company obtain price quotes for swing supply. The Company responded that it had obtained one quote from BP for swing supply on SSCGP.

There were occasions during the 2013/2014 winter when it appeared that the Company could have benefited by having either firm swing or peaking contracts. Examples include:

- In response to the Company's January 6, 2014 RFP for 3,000 Dth/day of incremental gas to begin flowing on January 9, 2014, the Company was informed by a supplier that supply was no longer available.[3] By contracting for firm swing or peaking gas in advance of winter, the Company may be able to obtain quotes from more suppliers.
- In February 2014 the Company noted on one incremental purchase transaction that the deal was transacted verbally due to "…difficulty finding other supply sources. Timing was critical".[4] For this transaction, the Company paid an adder of $0.50/Dth over the Gas Daily price. By contracting for firm swing or peaking gas in advance of winter, the Company could minimize its exposure to such occurrences.

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[3] GR-2015-0101, DR No. 0048 attachment for January, sheet 39 of 44.
[4] GR-2015-0101, DR No. 0048 attachment for February, sheet 15 of 42.

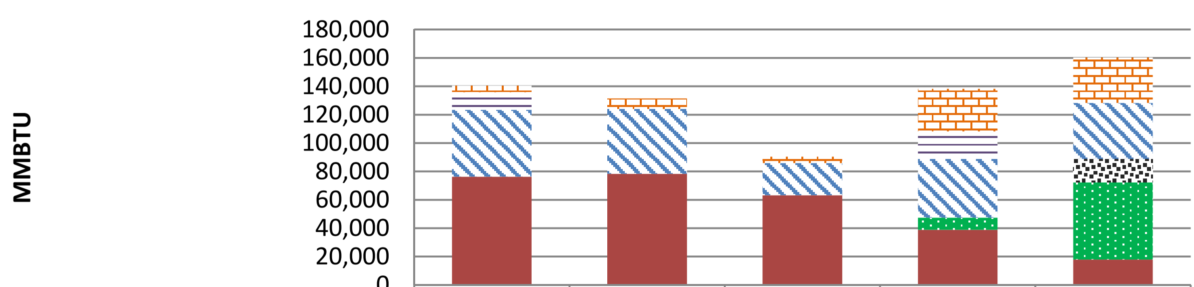
- The Company contracted for interruptible baseload supply in February 2014 because this contract provided the Company with an option of not taking gas on any given day.[5] By contracting for firm swing or peaking gas in advance of winter, the Company could avoid the reliability concerns inherent with interruptible supply.

Staff recommends the Company continue to seek bids for firm swing contracts and/or firm peaking contracts and evaluate those costs when evaluating and establishing its winter supply portfolio for the Northern service area in addition to the SMNG service area. The added measure of reliability for having a portion of the swing/incremental requirements in firm contracts must be a consideration in evaluating the costs.

E. Northern Service Area: Gas Daily vs. First of Month Index Baseload

For the Northern service area, the Company historically purchased a greater percentage of its winter supply volumes under fixed price contracts than it did during the 2013/2014 winter. During the 2013/2014 ACA winter, the Company purchased additional baseload supplies with pricing tied to Gas Daily (GD) indices, but did not seek quotes for baseload supplies tied to First of the Month (FOM) index pricing for its Northern service area:

Northern Service Area Winter Supply Volumes by Contract Type and Delivery Path (STS or FTS Transportation Contract)



	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014
STS GD Incremental (spot)	4,600	7,500	4,500	29,994	32,037
FTS GD Incremental (spot)	12,444	0	0	19,323	0
Volume Withdrawn from Storage	47,118	45,588	22,687	41,471	39,439
STS Interruptible GD Baseload	0	0	0	0	16,622
FTS GD Baseload	0	0	0	8,525	54,350
Fixed Price Baseload	76,435	78,500	63,300	39,000	18,000

5 GR-2015-0101 DR No. 0048.2.

The Company has two transportation contracts with ANR for the Northern service area: one with receipt point at the Southwest Headstation (the STS contract) and the other with receipt point at the interconnect of ANR with the Rockies Express (REX)-West Pipeline (the FTS contract). A comparison of the Company's warm winter forecasts with the FTS contract maximum daily quantity (MDQ) shows that the Company will need to utilize capacity on its STS contract during the months of December to February to meet its warm winter demand forecasts:

Northern Service Area: Warm Winter Monthly Forecasts and FTS Contract MDQ					
Description	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14
Company Forecast for Warm Winter	12,422	19,607	22,246	17,368	13,365
Average Required per day for Warm Winter	414	632	718	620	431
MDQ on FTS Contract	600	600	600	600	600
STS Contract required in Warm Winter?	no	yes	yes	yes	no

The Company stated that it is unaware of any FOM index priced gas available on its FTS contract. The Company has purchased FOM indexed baseload gas on its STS contract during non-winter months priced at ANR-Oklahoma FOM index. A comparison of the pricing the Company actually paid for baseload indexed to GD pricing with the ANR FOM-Oklahoma indicates that less expensive gas was available at FOM pricing during December 2013 through February 2014:

Description	Actual WACOG GD indexed Baseload Contracts on FTS contract	ANR FOM (Oklahoma)	Difference (Actual GD Price Paid- FOM)
December 2013 Baseload	$4.8250	$3.5500	$1.2750
January 2014 Baseload	$5.7700	$4.3300	$1.4400
February 2014 Baseload	$8.5090	$5.1500	$3.3590

During the 2013/2014 winter, approximately 64% of the Company's actual winter supply volume was priced at GD index plus a premium adder (includes GD priced baseload and incremental purchases). Based on the Company's historical utilization and warm winter forecasts, the Company will need to use the STS contract at least in the months of December to February, and the Company has been able to obtain FOM priced baseload on the STS contract in the past. However, during the 2013/2014 winter, the Company utilized this contract only for purchases tied to GD pricing index. Staff recommends that the Company evaluate using its STS transportation contract to bring on baseload supply priced at FOM index for the months of December to February.

F. Proposed Disallowance for Avoidable Capacity Over-run Charges

The Company incurred numerous overrun charges on its transportation contracts with Southern Star Central Gas Pipeline (SSCGP) for its Southern and SMNG service areas between November 2013 and March 2014. This was unexpected since the Company had sufficient total transportation capacity to meet its daily requirements in each of these service areas.

Staff reviewed the Company's gas supply nominations on SSCGP and found that the Company had preferentially nominated to selected Transportation Service Agreements (TSAs) in each service area,[6] while other available transportation capacity remained either unused or was released to third parties.

When questioned by Staff, the Company acknowledged that its scheduling practices had resulted in these overrun charges:

> …Staff has identified a flaw in Company's process of scheduling its capacity on SSCGP in a manner to avoid overrun charges. As shown by Staff, Company incurred Authorized Overrun charges on days when it did not utilize all of its contracted firm capacity…Company has adjusted its scheduling procedures to ensure it properly maximizes the use of its TSAs to avoid Authorized Overrun charges going forward.[7]

These overrun charges began in November 2013 and continued each month through March 2014. There is no evidence that the Company attempted to discover the reason(s) for the overrun charges until questioned by Staff in May 2015. The Company stated that it met with SSCGP in June of 2015 to discuss possible reversal of these overrun charges; however the Company stated that SSCGP was unwilling to provide credits or reversals of the charges.[8]

If the Company had observed and questioned the overrun charges when the charges began (SSCGP invoice for November 2013), it could have taken steps during the 2013/2014 ACA period to avoid subsequent nomination errors. Staff recommends that going forward the Company question non-routine or unexpected pipeline charges as it reviews invoices for monthly payment.

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[6] The Company had multiple transportation service agreement contracts with SSCGP serving each of its Southern and SMNG service areas during the 2013/2014 ACA period.
[7] Company response to GR-2015-0101, DR No. 0065.1.
[8] Company response to GR-2015-0101, DR No. 0065.5.

Staff is recommending a disallowance to the extent that the overrun charges were reasonably avoidable and were not off-set by capacity release credits.

Staff considered the following reductions to overrun charges:

- To the extent that daily overrun charges were off-set by capacity release credits, Staff subtracted a capacity release credit based on the amount of overrun capacity that was unavailable due to the capacity release. This is then multiplied by the capacity release unit price rate.
- SSCGP issued a partial refund of interim rates in accordance with an Unopposed Stipulation and Agreement Settling Rate Case, Docket RP13-941. Part of the refund applied to authorized overrun charges in December 2013 and January 2014. To the extent that refunds were applied to the overrun charges, Staff reduced the cost of the overruns.

Staff has calculated a "Net Avoidable Overrun" disallowance as the invoiced overrun charge minus SSCGP refunds related to allowable overruns (December 2013 through January 2014) minus capacity release credits for the overrun volumes if applicable, as summarized in the following tables for the Southern service area and the SMNG service area:

Southern Service Area Net Avoidable Overruns					
Contract	Overrun Quantity	Overrun Charge	SSCGP refund	Calculated capacity release credit on Contract TA 20684	Net Avoidable Overrun
	(a)	(b)	(c)	(d)	e = b-c-d
TA 15443	21,771	$4,142	$440	$173	$3,529

SMNG Service Area Net Avoidable Overruns					
Contract	Overrun Quantity	Overrun Charge	SSCGP refund	Calculated capacity release credit by contract	Net Avoidable Overrun
	(a)	(b)	(c)	(d)	e = b-c-d
TA 797	52,818	$10,001	$1,016	$6,792	$2,193
TA 10757	902	$153	$0	$54	$99
TA 16345	5,982	$1,238	$221	$239	$778
TA 814	10,808	$3,233	$699	$1,081	$1,453
Total	70,510	$14,625	$1,936	$8,166	$4,523

Staff's proposed disallowance for the Southern service area represents about $0.94/customer; for the SMNG service area about $0.38/customer.

G. Proposed Disallowance for Northern Service Area February 2014 Imprudent Supply Decisions

In February 2014 the Company purchased flowing supply for its Northern service area in excess of its actual usage, resulting in a net injection of gas into storage. The Company's storage plan indicates a planned withdrawal of 11,315 Dth from its ANR storage for February 2014 and a planned end February storage inventory balance of 8,546 Dth[9] (about 15.5% of the Company's contracted Maximum Storage Quantity (MSQ)). The Company actually had net injections of 1,417 Dth into storage in February 2014 and ended the month of February with a storage inventory balance of 16,557 Dth[10] (about 30.1% of its contracted MSQ).

Staff's review indicates that the Company's purchase of excess supply during February 2014 was imprudent and resulted in a material cost to customers as described below and thus an adjustment is recommended.

Based on St. Joseph, Missouri weather data, February 2014 overall was about 130% colder than normal.[11] February 2014 started and ended colder than normal, and there was a period between February 13, 2014 and February 24, 2014 when the actual weather, measured by heating degree day (HDD), was close to normal (within ± 10 HDD).

Since February 2014 was colder than normal and net February 2014 injections were not part of the Company's storage plan, Staff questioned why the Company decided to inject gas into its ANR storage in February 2014. The Company responded that:

> In the Gallatin Rate Area, storage injections and withdrawals are not nominated (scheduled) separately. This means that daily imbalances directly affect storage inventories automatically by either an injection into storage (over-delivered imbalance) or a withdrawal from storage (under-delivered imbalance).[12]

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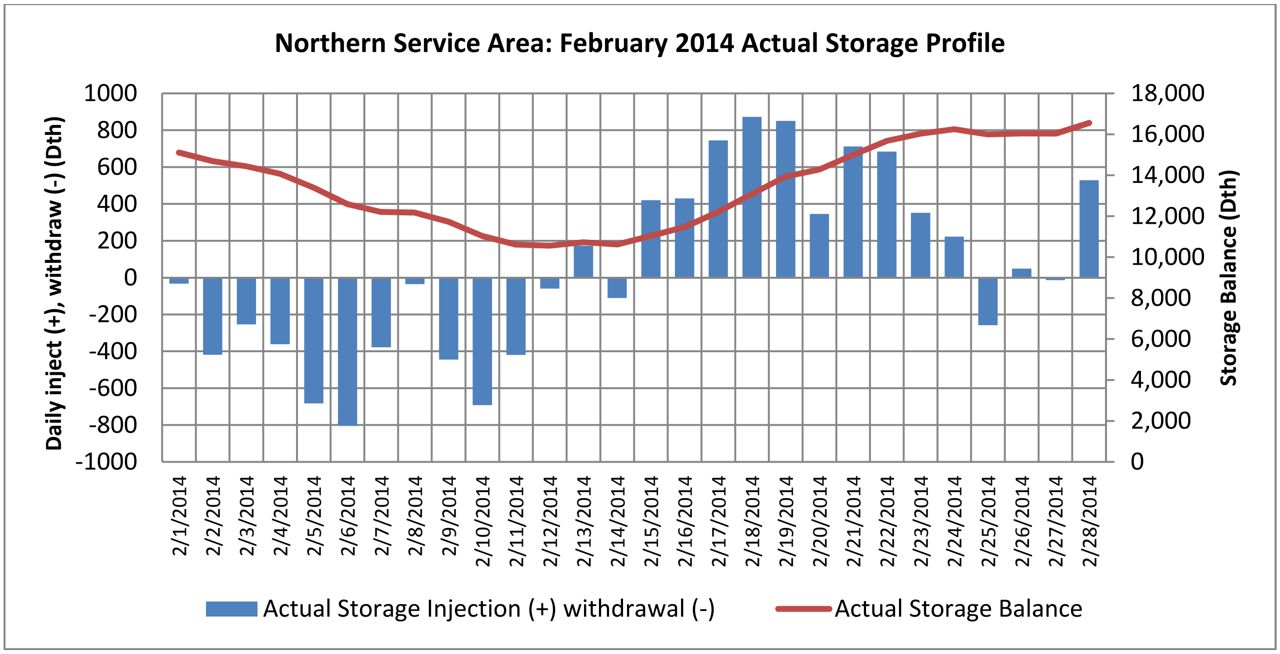
[9] GR-2015-0101, DR No. 0053 attachment referenced in DR No. 0055 "part a" response.
[10] From the Company's "attachment dr0055 and storage reports.pdf" submitted in response to GR-2015-0101, DR No. 0055 "part c" requesting a detailed inventory by month.
[11] Comparison is to 30-year normal of NOAA weather data 1981-2010.
[12] Company response to GR-2015-0101, DR No. 0055.2.

Since storage does take the swing when the Company has too much or not enough flowing gas supply, the Company's decisions regarding purchased supply do affect storage injections and withdrawals.

The Company's actual storage daily injections (+), withdrawals (-), and daily storage balances in Dth are shown in the following plot[13]:



The Company had daily withdrawals from storage until February 12, 2014, when actual withdrawals from storage slowed, and on February 13, 2014 actual injections into storage began. Staff evaluated the Company's actual February 2014 supply purchases by comparing the Company's estimated requirements for warm, normal and cold February supply[14] to the Company's actual contracted volumes for February 2014 and planned withdrawals from storage:

[13] This plot is based on actual shipped volumes from GR-2015-0101 DR No. 0096 which are reduced based on actual supply cuts. Actual shipped quantities therefore differ from contracted volumes by the amounts of these cuts.
[14] GR-2015-0101, DR No. 0060.

Summit's Northern Service Area Estimated Requirements for February 2014 Compared to Actual February 2014 Supply and Storage				
Description (all volumes are in MMBTU)	item	Warm	Normal	Cold
Company Estimated Total Volume Requirement for February 2014[15]	a	17,368	25,145	32,923
Company Planned Storage Withdrawal for February 2014[16]	b	11,315	11,315	11,315
Company Fixed Price Baseload contract for February 2014 (awarded 8/14/2013)	c	5,600	5,600	5,600
Additional Firm Baseload on FTS contract for February 2014 (awarded 1/22/2014)	d	11,200	11,200	11,200
Interruptible Baseload on STS for February 2014 (contract awarded 1/29/2014)	e	16,800	16,800	16,800
Incremental February 2014 Supply on STS (contract awarded 2/13/2014)	f	4,200	4,200	4,200
Firm Baseload as % of Estimate	g =(c+d)*100%/a	96.7%	66.8%	51.0%
Total Baseload as % of Estimate	i = (c+d+e)*100%/a	193.5%	133.6%	102.1%
Total Purchased Supply as % of Estimate	j = (c+d+e+f) *100%/a	217.6%	150.3%	114.8%
Total Supply Plus Planned February 2014 Storage Withdrawal as % of Estimate	k = (b+c+d+e+f)* 100%/a	282.8%	195.3%	149.2%

The Company's firm baseload contracts for February 2014 were approximately 97% of its warm February estimate. The Company added an interruptible baseload contract which brought the total contracted baseload to about 134% of the Company's normal February estimate or 102% of the Company's cold February estimate (assuming no storage withdrawn). The Company stated that the reason it awarded this as interruptible supply was the flexibility this allowed the Company to reduce its volumes with timely notification.[17] Since the Company could have decided not to exercise this interruptible supply at any time during the month,[18] adding this contract was not unreasonable. However, it was imprudent to allow the flow of gas on this contract when it became clear that daily flowing supply was exceeding actual daily usage.

The Company's final supply contract for the Northern service area was an "incremental" supply volume of 300 Dth/day to flow from February 15 - 28. This contract was awarded on

[15] *Id.*
[16] GR-2015-0101, DR No. 0053.
[17] Company response to GR-2015-0101 DR No. 0048.2.
[18] GR-2015-0101, DR No. 0048.2.

February 13, 2014, at the time when the actual weather was approaching February normals and actual withdrawals from storage had begun to slow and become injections into storage (see plot above). Adding this contract brought the total contracted supply (not including storage withdrawals) to 150.3% of the Company's normal February estimate and 114.8% of the Company's cold February estimate. If the Company's planned storage withdrawals are considered, total contracted supply plus planned storage withdrawals totaled 195% of the Company's normal February 2014 estimate and 149% of its cold February 2014 estimate, meaning even for its cold weather plan, it had 49% more gas than needed.

Staff questioned why the final incremental 300 Dth/day contract was awarded. The Company responded:

> Company's storage balance was approaching 10,000 dth by mid-February 2014; thus, Company desired to replenish some of its storage inventories heading into the final month of the withdrawal season.[19]

Since the Company's planned end of month storage balance for February was 8,546 Dth and actual withdrawals from storage were slowing, if not reversing to injections at the time this contract was awarded (see plot above), the Company's explanation is not persuasive.

To determine if there was an economic advantage for the February 2014 injections into storage, Staff compared the Weighted Average Cost of Gas (WACOG) of the Company's storage gas in inventory at the end of January 2014 (prior to making February 2014 storage injections) to the WACOG of the Company's purchased supply in February 2014:

January 2014 Storage Ending WACOG[20] ($/MMBTU)		February 2014 Purchased Gas WACOG ($/MMBTU)[21]				
		Overall	Fixed Price Contract	Firm GD + Baseload REX West	Interruptible Baseload ANR SWHS	Incremental Feb 15-28
$3.685		$6.909	$3.94	$8.589	$7.031	$5.88

The January 2014 storage WACOG ($3.685) was lower than the overall February 2014 purchased gas WACOG ($6.909), and lower than the lowest contract price (fixed price contract

[19] GR-2015-0101, DR No. 0048.2.
[20] GR-2015-0101, DR No. 0055.
[21] GR-2015-0101, DR No. 0096.

at $3.94/MMBTU). There was no evidence to suggest that the Company was aware of any economic advantage in purchasing excess February 2014 supply for injection into storage.

Staff then considered two reasonable approaches the Company could have used to reduce the amount of excess flowing gas brought on in February 2014 while still meeting its operational needs, described as Scenarios 1 and 2 below.

Scenario 1 assumes that the Company noticed that storage withdrawals had slowed and reversed to injections on February 13, 2014 and it did not bring on the incremental contract of 300 Dth/day on February 15, 2014. The Company would then continue to monitor its storage activity and stop the interruptible baseload when the storage inventory began to increase. Staff assumed that the Company noticed the increase in the storage inventory to above 12,000 Dth on February 19, 2014 (a Wednesday), waited another 2 days to be sure of the increasing trend, then stopped the interruptible baseload supply contract beginning February 22, 2014.

The total gas eliminated from February 2014 flowing supply in Scenario 1 was 8,227 Dth at an actual cost of $49,677 based on actual daily costs for the eliminated gas. If the Company had not purchased this excess supply in February 2014, it would eventually need to purchase this amount to fill storage in the summer of 2014. This volume of gas if purchased during the summer of 2014 would have cost an estimated $34,513;[22] therefore the savings associated with Scenario 1 is $15,164 (about $9.47 per customer).

Scenario 2 assumes that the Company brought on the incremental contract for an additional 300 Dth/day of supply starting February 15, 2014. Scenario 2 assumes that the Company would notice that the storage inventory has been increasing since February 14, 2014 (a Friday), monitor the trend and end the interruptible baseload supply beginning February 18, 2014 (a Tuesday).

Scenario 2 would eliminate 6,504 Dth[23] of February 2014 flowing supply at a WACOG of $6.00/MMBTU. The estimated total savings by purchasing in summer is $11,758 (about $7.34/customer). The ending storage balance would be 10,053 Dth (above plan of 8,546, but less

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[22] Staff estimated a "summer" WACOG averaging the Company's actual WACOG for April 2014 through August 2014, then using the ANR-Oklahoma First of Month (FOM) indices for September and October respectively and increasing FOM pricing by an adder of $0.0175/Dth. The adder of $0.0175/Dth was selected because this is the actual adder the Company contracted for in May 2014 when it purchased FOM gas priced at ANR-Oklahoma supply.

[23] This is the actual volume, including cuts of the volume flowed on the incremental supply contract for the dates of February 18-28.

than actual of 16,557) and there would have been a net withdrawal of 5,087 Dth from storage in February (plan was 11,315 Dth; actual was net injection of 2,825 Dth).

Both scenarios are reasonable and Staff is proposing a disallowance based on the lower of the two adjustments, $11,758 based on Scenario 2.

H. Northern Service Area: Supply-Storage Decisions

The Company's ANR storage serves at least two primary functions during the winter:

- First, storage is required operationally to meet demand in cold weather, and
- Second, the Company considers 100% of its contracted storage capacity to be part of its winter hedge.

Certain Company decisions regarding supply and storage for the 2013/2014 winter are discussed below with respect to the Company's winter hedging plan and operational considerations:

- *Decision 1: October 2013 Insufficient Flowing Supply Resulting in Net Storage Withdrawal*. The Company did not nominate sufficient October 2013 baseload supply to meet either its actual demand or planned injections into storage. Rather than inject into storage, the Company actually withdrew a net of amount of 3,038 Dth from storage, resulting in an actual October end of month storage balance that was 10% less than planned. The Company did not bring on any additional gas to attempt to either meet demand or replenish the depleted amount from storage. The Company's hedging plan for winter depended on storage being filled to 100% by the end of October; the Company went into the 2013/2014 winter with 10% less storage gas than planned, and 5% lower total hedged volume than planned. The Company did not adjust its October supply for the increased demand caused by a colder than normal October.
- Decision 2: Excess November 2013 Storage Withdrawals. The Company's actual storage withdrawals in November 2013 were approximately 45% above its planned withdrawals, and its November 2013 actual storage ending inventory was less than planned. The Company awarded a single baseload contract for November 2013 and did not bring on additional gas supply for the colder than normal November to replace the excess withdrawn from storage. As a result, the Company went into December 2013 with 9,058 Dth (about 16.5% of MSQ) less stored gas than planned. This further reduced the volume of gas hedged for the months of December 2013 – March 2014 and reduced the amount of gas available to meet demand during the normally colder months of winter (December – February).

- Decision 3: Excess February 2014 Supply Resulting in Net Injection Into Storage. This imprudent decision and the negative cost consequences to customers are discussed in detail above in Section III, Part G.

- Decision 4: March 2014, Did Not Adjust Supply for Known Storage Information. The Company's supply and hedging plans called for the use of approximately 55,000 Dth of storage gas during the 2013/2014 winter. At the beginning of March 2014, the Company's net withdrawals for November to February were 32,653 Dth and the storage balance was at 16,557 Dth (about 30% of its MSQ). The Company did not take either its planned total winter withdrawals or its planned March 2014 withdrawals into account. Instead, it finished March 2014 with a storage balance of 9,771 Dth (about 18% of MSQ). The Company's cost of flowing gas in March 2014 was higher than the cost of gas it could have withdrawn from its storage, the storage WACOG. The Company had sufficient volume requirements with the colder than normal March weather to reduce its storage balance.

Overall, the 2013/2014 winter was about 19% colder than normal for the St. Joseph, Missouri area. Additionally, gas prices were highly volatile during the latter part of the winter, with the Company paying as much as $27.79/Dth for gas (February 6, 2014). The Company's failure to fill storage to its planned level going into the 2013/2014 winter and its excessive withdrawals in November 2013 resulted in the Company purchasing higher volumes of expensive gas later in the winter than would otherwise have been required.

During February and March 2014, the Company did not maximize usage of the lower price gas it had in storage inventory but instead purchased more flowing supply than was needed. The Company paid higher prices for gas in February and March 2014 than the cost of its gas in storage. The Company's purchasing decisions going into and during the 2013/2014 winter resulted in higher gas costs for customers than would have been realized if the Company had followed its storage plan for the 2013/2014 winter.

Staff recommends the Company review its processes for supply purchasing decision to enhance its responsiveness to changing conditions and giving consideration to its own estimates of warm, normal and cold monthly supply requirements. Staff recommends the Company, at a minimum, reviews and evaluates storage balances versus plan on a weekly basis during winter months and on a monthly basis during non-winter months.

IV. HEDGING

Summit's winter hedging plans are primarily designed to achieve a reliable natural gas supply and to protect its customers against price spikes. The hedging plan establishes known prices for 60% of normal requirements for each of the Company's three service areas for the winter heating season. The Company's Northern service area calls for the Company to fill storage as close to its maximum capacity as possible by November 1. Additionally, fixed price purchases are a part of the hedging plan for the Northern service area.

For the Company's Southern service area, the hedging plan is to utilize fixed price purchases. There is no storage capacity contracted for the Southern service area.

For the Company's former SMNG service area, the hedging plan is to utilize storage as well as fixed price purchases.

Summit's maximum storage quantity (MSQ) represents about 45% of normal winter weather requirements for the Northern service area. However, Summit's actual storage injection by November 1 was 10% less than MSQ. Summit also purchased fixed price volumes in August 2013 for delivery during the winter periods, December 2013 - February 2014. These fixed price volumes, which represent about 15% of normal winter weather requirements, combined with actual storage at the beginning of the winter season, represent about 55% of customers' normal winter weather requirements for the Northern service area.

For the Southern service area, Summit purchased fixed price volumes in April 2012 for delivery in November 2013 through March 2014. Summit purchased additional fixed price volumes in August 2013. The fixed price volumes represent 60% of normal winter weather requirements.

For the former SMNG service area, Summit purchased fixed price volumes in April 2013 for delivery during the winter periods, December 2013 - February 2014, which represent about 25% of normal winter weather requirements. These fixed price volumes, combined with storage at the beginning of the winter season, represent 60% of normal winter weather requirements.

Conclusion

Staff has the following comments and concerns about the Company's hedging practice for this ACA's winter period:

1) It is important for the Company to evaluate the expected level of the customers' natural gas requirements that are reasonably protected (hedged) under warmer than normal, normal, and colder than normal weather scenarios.

2) Additionally, the Company should evaluate its hedging strategy in response to the changing market dynamics as to how much the existing hedging strategy actually benefits its customers while achieving the goal of stable price level.

3) A part of Summit's hedging goals is to capture the lowest price. For example, Summit purchases gas whenever it is less expensive compared to the current storage WACOG, and injects the gas into storage. However, this market-timing approach in filling storage can lead to a situation where Summit waits too long for natural gas prices to go down until it perceives them to be favorable while running the risk of higher prices.

4) Summit's hedging strategy utilizing storage is based on its plan of filling storage to its MSQ by November 1 and use of the entire MSQ by the end of March. However, the Company typically does not fill storage to MSQ. Additionally, the Company finishes the last month of the winter heating season (March) with a portion of MSQ left in storage. Therefore, its hedging plan utilizing storage overestimates an actual hedging outcome. (See above III. H. Northern Service Area: Supply-Storage Decisions for details.)

Hedging Recommendations

Staff recommends, for the 2014-2015 ACA period and beyond, that the Company:

(a) Establish and maintain a current and consistent hedging policy with stated objectives based on month-specific normal weather requirements while also considering the impacts of warmer and colder than normal weather scenarios.

(b) Consider a combination of various alternatives such as storage withdrawals, call options, and other fixed price purchases for effective hedging during the winter months.

(c) Establish what is a realistic amount of MSQ that the Company plans to inject into storage by November 1 and to withdraw by March 31. Thus, determine a realistic amount of storage that can be utilized toward hedging and calculate the hedging percent utilizing storage and the overall hedging percent accordingly.

(d) Continue to monitor the market movements diligently and with regard to timing of hedge placements employ disciplined (time-driven) as well as discretionary (price-driven) approaches in its hedging practices.

(e) Document its reasoning for executing any hedging transactions or decisions, whether by means of storage, fixed price contracting or other financial hedging instruments.

V. RECOMMENDATIONS

The Staff recommends that the Commission issue an order requiring Summit to:

1) Adjust the balances in its next ACA filing to reflect the Staff recommended ending (over)/under recovery ACA balances per the following tables:

(Rogersville-Branson) SMNG Service Area Description (+) Under-recovery (-) Over-recovery	Ending Balances Per Filing	Commission Approved Adjustments prior to 2013-2014 ACA (B)	Staff Adjustments for 2013-2014 ACA	Staff Recommended Ending Balances
Prior ACA Balance 8-31-13	($24,408)	$0	$0	($24,408)
Cost of Gas/Storage	$6,672,569	($71,968)	$0	$6,600,601
Cost of Transportation	$2,212,653	$0	(A)($4,523)	$2,208,130
Revenues – PGA billed	($7,989,926)	$0	$0	($7,989,926)
ACA Approach for Interest Calculation	$3,558	$0	$0	$3,558
Total ACA Balance 8-31-14	$874,446	($71,968)	($4,523)	$797,955

(A) Over-run charges
(B) Commission order issued April 10, 2015 approving adjusted amounts from 2012-2013 ACA. Due to the timing of Commission's order, Summit has not included these adjustments in its 2013-2014 ACA filing.

(Gallatin) Northern Service Area Description (+) Under-recovery (-) Over-recovery	Ending Balances Per Filing	Commission Approved Adjustments prior to 2013-2014 ACA (B)	Staff Adjustments for 2013-2014 ACA	Staff Recommended Ending Balances
Prior ACA Balance 8-31-13	$3,203	$0	$0	$3,203
Cost of Gas/Storage	$1,005,337	($1,608)	(A) ($11,758)	$991,971
Cost of Transportation	$128,249	$0	$0	$128,249
Revenues – PGA billed	($850,100)	$0	$0	($850,100)
Revenues Otherwise billed	($12,541)	($5,118)	$0	($17,659)
ACA Approach for Interest Calculation	$1,614	$0	$0	$1,614
Total ACA Balance 8-31-14	$275,762	($6,726)	($11,758)	$257,278

(A) February 2014 Northern service area supply and storage.
(B) Commission order issued April 10, 2015 approving adjusted amounts from 2012-2013 ACA. Due to the timing of Commission’s order, Summit has not included these adjustments in its 2013-2014ACA filing.

continued on next page

(Warsaw-Lake Ozarks) Southern Service Area Description (+) Under-recovery (-) Over-recovery	Ending Balances Per Filing	Commission Approved Adjustments prior to 2013-2014 ACA (B)	Staff Adjustments for 2013-2014 ACA	Staff Recommended Ending Balances
Prior ACA Balance 8-31-13	$19,644	$0	$0	$19,644
Cost of Gas/Storage	$1,741,331	$0	$0	$1,741,331
Cost of Transportation	$618,930	$0	(A)($3,529)	$615,401
Revenues - PGA billed	($2,116,852)	$0	$0	($2,116,852)
ACA Approach for Interest Calculation	$1,447	$0	$0	$1,447
ACA cost correction	$0	$2,952	$0	$2,952
Total ACA Balance 8-31-14	$264,500	$2,952	($3,529)	$263,923

(A) Over-run Charges
(B) Commission order issued April 10, 2015 approving adjusted amounts from 2012-2013 ACA. Due to the timing of Commission's order, Summit has not included these adjustments in its 2013-2014 ACA filing.

2) Respond to Staff's concerns/recommendations in Section II – Billed Revenue and Actual Gas Cost.

3) Respond to the concerns/recommendations expressed by Staff in the Reliability Analysis and Gas Supply Planning section (Section III).

4) Respond to Staff's recommendations in Section IV - Hedging.

5) Respond to the recommendations and concerns included herein within 45 days.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Summit Natural Gas of Missouri, Inc.'s Purchased Gas Adjustment	)))	Case No. GR-2015-0101
In the Matter of Summit Natural Gas of Missouri, Inc.'s Purchased Gas Adjustment	)))	Case No. GR-2015-0102 (consolidated)

AFFIDAVIT OF PHIL S. LOCK

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW Phil S. Lock and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Recommendation in Memorandum form; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Phil S. Lock
PHIL S. LOCK

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of December 2015.

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 Purchased Gas Adjustment	)))	Case No. GR-2015-0101
In the Matter of Summit Natural Gas of Missouri, Inc.'s Purchased Gas Adjustment	)))	Case No. GR-2015-0102 (consolidated)

AFFIDAVIT OF KWANG Y. CHOE, PhD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW Kwang Y. Choe, PhD and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Recommendation in Memorandum form; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Kwang Y. Choe

KWANG Y. CHOE, PhD

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of December 2015.

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 Purchased Gas Adjustment	)))	Case No. GR-2015-0101
In the Matter of Summit Natural Gas of Missouri, Inc.'s Purchased Gas Adjustment	)))	Case No. GR-2015-0102 (consolidated)

AFFIDAVIT OF KATHLEEN McNELIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW Kathleen McNelis and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Recommendation in Memorandum form; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Kathleen McNelis

KATHLEEN McNELIS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of December 2015.

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