BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Atmos Energy to Amend its Purchase Gas Adjustment (PGA) Schedule to Add a Demand Charge Savings and Pipeline Bypass Savings Component to the PGA	)))))	Docket No. 14-ATMG-230-TAR

APPLICATION

Atmos Energy ("Atmos") files this Application to amend its Purchased Gas Adjustment (PGA) Schedule to add a Demand Charge Savings and Pipeline Bypass Savings Component to the PGA. This Application is being filed pursuant to K.S.A. 66-117. In support of this Application, Atmos states as follows:

1. Atmos is a corporation organized and existing under the laws of the State of Texas and the Commonwealth of Virginia with its principal place of business located at Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, TX 75240. Atmos currently operates as a natural gas public utility local distribution company in the State of Kansas pursuant to certificates of convenience and necessity issued by the Kansas Corporation Commission ("Commission" or "KCC"). Atmos' principal place of business in the State of Kansas is located at 25090 W. 110th Terr., Olathe, Kansas 66061.

2. Atmos provides retail natural gas service to approximately 128,502 customers in Kansas, including natural gas service to 106 communities in 32 counties.

3. Atmos provides natural gas service to a total of approximately 3 million customers in eight states.

4. In 1995, in response to the passage of the Federal Energy Regulatory Commission's ("FERC") Order 636, and the significant change in the natural gas industry with the unbundling of

interstate pipeline capacity costs and gas costs, this Commission issued an order approving a mechanism that allowed natural gas public utilities ("LDCs") in Kansas to amend their PGA tariffs so revenues associated with the LDCs' resale of interstate pipeline capacity could be shared on a 50/50 basis with their customers. **Docket No. 190,061-U, Order dated May 1, 1995, page 10, paragraph 13.** In approving this incentive mechanism the Commission made the following statements:

> The Commission believes that allowing an LDC to share in revenue will be more likely to induce prudent and efficient capacity release than the threat of regulatory investigation alone.
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> The Commission's ultimate goal is to devise a gas cost incentive mechanism; perhaps a performance based mechanism, which addresses gas purchasing activities as a whole, rather than just the capacity resale decision.

Docket No. 190-061-U, Order dated May 1, 1995, pg. 10, paragraph 13; pg. 13, paragraph 18.

5. Over the past three years, Atmos has reduced upstream transportation costs in the PGA by approximately $3 million under this capacity release program. The savings generated by capacity release has declined steadily over the past several years from a peak in 2012 of $1.265 million in customer savings to $700,000 in 2013. The capacity release value has decreased over time primarily due to decreasing basis differentials from the Rockies to Midcontinent areas, shrinking seasonal storage spreads and a diluted secondary (capacity release) market on Southern Star Central Gas Pipeline ("Southern Star").

6. The recent and dramatic increase in shale gas production in the traditional production areas and more importantly in the traditional market areas is spawning a significant change in the natural gas industry. The natural gas market in the United States has dramatically changed since 2008 with the increase of shale gas production. This increase in gas supply has resulted in

unprecedented price stability. The increase in shale gas production has changed the pipeline flow dynamics and some pipelines have experienced decreased utilization as volumes have moved to new pipelines directly connected to the shale basins. Many interstate pipelines affected by the changing flow dynamics have responded by filing rate cases at FERC seeking to increase their fixed monthly demand charges to their captive firm customers. For example, Atmos currently receives about 80% of its upstream interstate pipeline transportation capacity requirements from Southern Star to meet a large number of its Kansas' customers' needs. Southern Star has recently filed a rate case at FERC for an estimated 47% rate increase. If this rate case is approved by FERC as filed, it would result in an estimated $6.2 million increase in demand charges (from the current $13.2 million to the proposed $19.4 million) to Atmos and its Kansas customers.

7. The changing natural gas market conditions and pipeline rate cases have created a situation where LDC customers who prudently execute traditional supply practices by purchasing pipeline capacity at the maximum FERC tariff rate will face escalating cost increases. To counter these cost increases, Atmos seeks approval to make additional enhancements similar to the Commission's current capacity release mechanism which will directly incentivize Atmos to consider non-traditional supply practices to reduce pipeline demand charges. These enhancements would allow Atmos to potentially capture these non-traditional opportunities and restructure its natural gas supply contracts which could result in substantial savings to its customers. Atmos would not enter into supply or capacity arrangements that would jeopardize the security and reliability of supply.

8. The first proposed enhancement is a Demand Charge Savings Component. Opportunities may exist on pipelines where supply could be sourced from non-traditional sources while still providing firm and reliable service to Atmos customers. Under the Demand Charge

Savings mechanism, Atmos would evaluate alternative methods of serving the Atmos markets with the ultimate goal of reducing upstream transportation charges. The proposed Demand Charge Savings Component to the PGA consists of three sub-components:

a. Segmentation Savings

b. Pipeline Discount Savings

c. Delivered Service Savings

The second proposed enhancement is referred to as a Pipeline Bypass Savings Component to the PGA. Opportunities may exist to construct new interconnects with alternative pipelines and realize an overall cost savings by increasing capacity on pipelines with lower demand charges and reducing capacity on pipelines that are more expensive. These opportunities may exist going forward because of changing supply and transportation dynamics. However, such interconnects are capital intensive and the cost could limit opportunities. Atmos would need to evaluate alternative pipeline costs and to work with pipelines to negotiate new interconnect agreements and long-term transportation contracts to cover the capital cost of new interconnects. In areas where this is possible new interconnects can provide gas supply savings, operational benefits, supply diversity and security. Further details of each of these enhancements are attached in the pre-filed testimony of Sheri W. Rowe, Manager of Gas Supply and Services.

9. The savings from these demand charge reductions would be calculated by comparing traditional pipeline demand charges to the alternative pipeline cost. Any savings would then be shared equally between Atmos and the customers consistent with how the approved capacity release incentive mechanism works. The customer's share of the savings would flow directly through the PGA via reduced demand charges in the same manner as the approved capacity release mechanism does today.

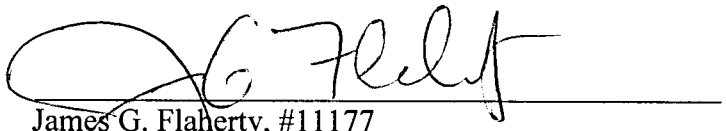
10. Supply reliability will not be compromised by these mechanisms. The control of assets and supply decisions will remain with Atmos.

11. Atmos has implemented similar shared savings mechanisms in other states with success. Ms. Rowe discusses those programs in her pre-filed testimony.

12. In support of its Application for approval of enhancements to the PGA, Atmos has attached the testimony of Sheri W. Rowe.

13. Also attached to this Application and incorporated herein by reference is a proposed red-line and clean version of Atmos' PGA schedule, which sets forth the proposed Demand Charge Savings Component and Pipeline Bypass Savings Component of the PGA. Ms. Rowe is sponsoring the proposed changes to Atmos' PGA schedule.

WHEREFORE, Atmos Energy respectfully requests that the Commission issue an order approving this Application and the proposed amendments to its PGA schedule.



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VERIFICATION

STATE OF KANSAS)
)ss:
COUNTY OF FRANKLIN)

James G. Flaherty, of lawful age, being duly sworn upon oath, deposes and says that he is attorney for Atmos Energy that he has read the above and foregoing Application, and the statements contained therein are true.

James G. Flaherty

SUBSCRIBED AND SWORN to before me this 14th day of November, 2013.

NOTARY PUBLIC - State of Kansas
RONDA ROSSMAN
My Appt. Exp. 5/25/2014

Notary Public

Appointment/Commission Expires:

CERTIFICATE OF SERVICE

I hereby certify that a copy of the above and foregoing was mailed, postage prepaid, this 14th day of November, 2013, addressed to:

Ms. Dana Bradbury
General Counsel
Kansas Corporation Commission
1500 S. W. Arrowhead Road
Topeka, Kansas 66604

Mr. David R. Springe
Consumer Counsel
Citizens' Utility Ratepayer Board
1500 S.W. Arrowhead Road
Topeka, Kansas 66604

James G. Flaherty

SCHEDULE V - PURCHASED GAS ADJUSTMENT (PGA)

SECTION 1 - PURCHASED GAS COST ADJUSTMENT PROCEDURE

A. RATE SCHEDULES COVERED

All of the Company's sales rate schedules shall be subject to a purchased gas cost adjustment:

Description Combined Kansas Rate Division and Southwest Kansas Rate Division

Firm Sales Service including: Residential, Commercial, Public Authority, School, Irrigation Engine, Agricultural Service, and Small Industrial. 910, 915, 920, 930, 940, 960, 965 Interruptible Sales Service including: School, Small Industrial, Large Industrial, and Economic Development. 955, 960

B. COMPUTATION FORMULA

1. The Company's rates for gas service are subject to adjustment for change in the average cost of gas from all sources of supply purchased. At the end of the twelve-month period ending August, the Company will project the average cost of gas for the twelve months ending August 31 of the following year. If at any time during this twelve month period the Company experiences a change or changes in supplier rates or in sources of supply, the cumulative effect of which change or

changes is to produce an increase or decrease in the new projected effective rate for purchased gas from all suppliers of at least $.010 per Ccf, then an adjusted average rate shall be determined. The annual cost of gas projection and any revised projections throughout the year will be computed using the following formula:

$$\frac{P + E + S}{V} = \text{Adjustment}$$

Where:

P = The estimated total dollar cost of purchased gas to be sold calculated by summing the products of the most recent unit cost of purchased gas from each supplier and the estimated unit purchases from each supplier for the twelve month period ending August 31. In the event that changes in the rates paid for purchased gas will take place within the current twelve month period ending August 31, as specified by contract provisions currently in effect, the estimated average unit cost of purchased gas from each supplier for the current twelve month period ending August 31, may be used in the calculation in place of the most recent unit cost.

E = Estimated net cost (positive or negative) arising from exchange gas transactions that are expected to occur during the twelve month period ending August 31 (Account 806), not including storage gas transactions.

S = Estimated cost of stored gas to be withdrawn from storage (Account 808) and sold.

V = The estimated sales volume in Ccf for the twelve month period ending August 31. (If the actual sales volume reflects a line loss factor greater than the limit value, restatement of sales volume, based on the limit value for line loss, shall be required.)

Volumes sold under Rate Schedule 955, and 960 shall not be billed the demand costs, or its equivalent, contained in the PGA computed in accordance with the above-stated formula, but shall be billed the remaining costs contained in the PGA formula. In addition to the PGA less demand costs, or its equivalent, Rate Schedule 955 and 960 shall also have applied to the volumes sold the sum of the Southern Star Central Gas Pipeline, Inc.'s maximum ITS-P and ITS-M commodity rates, adjusted for fuel reimbursement percentages, as set forth in Southern Star Central Gas Pipeline, Inc.'s tariff on file with the Federal Energy Regulatory Commission.

C. COMPUTATION PERIOD

The computation period shall be the subsequent twelve month period ending August 31.

D. COMPUTATION FREQUENCY

The computation shall be made annually or each time a change or changes occur in supplier rates or sources of supply, the cumulative effect of which change or changes is to produce an increase or decrease in the new effective rate paid for purchased gas by at least $.010/Ccf.

E. COSTS INCLUDED

The formula includes only costs which are properly included in FERC Accounts 800, 801, 802, 803, 804, 858, applicable to Kansas; 805, 806, 808, and 809.

F. SETTLEMENT PROVISIONS

Subsequent to the effective date of this clause, the Company shall maintain a continuing monthly comparison of the actual (as billed) cost of gas as shown on the books and records of the Company, exclusive of refunds, and the cost recovery for the same month calculated by applying to the volumes sold during said month the purchased gas cost adjustments calculated pursuant to these purchased gas cost adjustment provisions. For each twelve month period ended August 31, the differences of the comparisons described above including any balance or credit for the previous year shall be accumulated to produce a cumulative balance of over-recovered or under-recovered costs.

An "Actual Cost Adjustment" (ACA) shall be computed by dividing the cumulative balance of under-recovered or over-recovered costs by the volume of total sales during the twelve month period ending on that date. This adjustment shall be rounded to the nearest $.0001 per Ccf and applied to sales billed on or after the first day of the month following the month in which the adjustment has been approved by the Commission. The "Actual Cost Adjustments" shall remain in effect until superseded by subsequent "Actual Cost Adjustments" calculated according to this provision.

The Gas Cost portion of uncollectible accounts is recoverable through the ACA. The cumulative balance of over-recovered or under-recovered costs shall include the Gas Cost portion of uncollectible PGA customer accounts billed under this Schedule during the preceding Computation Year and which remain unpaid. The uncollectible amounts included in the annual ACA computation shall not contain interest or collection fees or charges. This sub-component of the ACA will be a separate line item on Sheet 1 of the Purchased Gas Adjustment.

G. CAPACITY RELEASE/DEMAND CHARGE SAVINGS/PIPELINE BYPASS SAVINGS

1. CAPACITY RELEASE

The Company shall forecast, on a monthly basis, the capacity release credits expected to be received (applicable to its Kansas jurisdiction). The Company shall then calculate a Monthly Capacity Release Factor by dividing fifty percent of this total monthly forecast by estimated monthly sales. The Total Capacity Release Factor shall be applied to the Purchased Gas Cost Factor. The Company shall maintain a continuing monthly comparison of 50% of the actual capacity release credits received and the capacity release credits distributed. The differences of the comparisons described above shall be accumulated to produce an Accumulated Capacity Release Balance, that is, a cumulative balance of under or over distributed credits. An Accumulated Capacity Release Factor will be calculated annually by dividing the accumulated balance of under or over distributed credits by the volume of actual sales during the twelve month period ending August 31. The Accumulated Capacity Release Factor will be added to the Monthly Capacity Release Factor to equal the Total Capacity Release Factor. The Accumulated Capacity Release Balance will be adjusted by the monthly capacity release under/over disbursements.

2. DEMAND CHARGE SAVINGS

The Company shall forecast, on a monthly basis, the ~~capacity release credits~~ demand charge savings expected to be received (applicable to its Kansas jurisdiction). The Company shall then calculate a Monthly ~~Capacity Release~~Demand Charge Savings Factor by dividing fifty percent of this total monthly forecast by estimated monthly sales. The Total ~~Capacity Release~~Demand Charge Savings Factor shall be applied to the Purchased Gas Cost Factor. The Company shall maintain a continuing monthly comparison of 50% of the actual ~~capacity release credits~~demand charge savings received and the ~~capacity release credits~~demand charge savings distributed. The differences of the comparisons described

above shall be accumulated to produce an Accumulated ~~Capacity Release~~Demand Charge Savings Balance, that is, a cumulative balance of under or over distributed ~~credits~~demand charge savings. An Accumulated ~~Capacity Release~~Demand Charge Savings Factor will be calculated annually by dividing the accumulated balance of under or over distributed ~~credits~~demand charge savings by the volume of actual sales during the twelve month period ending August 31. The Accumulated ~~Capacity Release~~Demand Charge Savings Factor will be added to the Monthly ~~Capacity Release~~Demand Charge Savings Factor to equal the Total ~~Capacity Release~~Demand Charge Savings Factor. The Accumulated ~~Capacity Release~~Demand Charge Savings Balance will be adjusted by the monthly ~~capacity release~~demand charge savings under/over disbursements.

3. PIPELINE BYPASS SAVINGS

The Company shall forecast, on a monthly basis, the ~~capacity release credits~~pipeline bypass savings expected to be received (applicable to its Kansas jurisdiction). The Company shall then calculate a Monthly ~~Capacity Release~~Pipeline Bypass Savings Factor by dividing fifty percent of this total monthly forecast by estimated monthly sales. The Total ~~Capacity Release~~Pipeline Bypass Savings Factor shall be applied to the Purchased Gas Cost Factor. The Company shall maintain a continuing monthly comparison of 50% of the actual ~~capacity release credits~~pipeline bypass savings received and the ~~capacity release credits~~pipeline bypass savings distributed. The differences of the comparisons described above shall be accumulated to produce an Accumulated ~~Capacity Release~~Pipeline Bypass Savings Balance, that is, a cumulative balance of under or over distributed ~~credits~~pipeline bypass savings. An Accumulated ~~Capacity Release~~Pipeline Bypass Savings Factor will be calculated annually by dividing the accumulated balance of under or over distributed ~~credits~~pipeline bypass savings by the volume of actual sales during the twelve month period ending August 31. The Accumulated ~~Capacity Release~~Pipeline Bypass Savings Factor will be added to the Monthly ~~Capacity Release~~Pipeline Bypass Savings Factor to equal the Total ~~Capacity Release~~Pipeline Bypass Savings Factor. The Accumulated ~~Capacity Release~~Pipeline Bypass Savings Balance will be adjusted by the monthly ~~capacity release~~pipeline bypass savings under/over disbursements.

H. OVERRUN PENALTIES

Overrun penalties applicable to the Company's Kansas jurisdiction shall be separately accumulated and shall be administered in compliance with the provisions contained in the Commission Order in Docket No. 190,061-U. The Company shall maintain a continuing monthly comparison of the actual penalties received (applicable to its Kansas jurisdiction) and the amount recovered from its customers. The differences of the comparisons described above shall be accumulated to produce an Accumulated Penalty Balance, that is, a cumulative balance of under or over recovered penalties. An Accumulated Penalty Recovery Factor will be calculated annually by dividing the accumulated balance of under or over recovered penalties by the volume of actual sales during the twelve month period ending August 31. The Accumulated Penalty Recovery Factor will be applied to the Purchased Gas Cost Factor each month. The Accumulated Penalty Balance will be adjusted by the monthly penalty under/over recovery.

I. REPORTING REQUIREMENTS

The Company shall submit to the Commission purchased gas cost filings at least 15 days before the filing is to be effective. Purchased gas cost filings and cost adjustment reports shall use the format prescribed by the Commission.

J. LINE LOSS LIMITATIONS

The Company shall compute one actual line loss for the entire State of Kansas. In the event that the actual line loss (unaccounted for gas) statistic for the computation period exceeds the line loss limit of 4%, the Company will compute the purchased gas adjustment using the limit value rather than the actual operating statistic value.

SECTION 2 - PURCHASED GAS COST REFUND ADJUSTMENT PROCEDURE

A. REFUND PROVISION

1. For the purpose hereof, unless the Kansas Corporation Commission shall otherwise order, refunds or a balance in the refund account in excess of $.002 per Ccf for purchased gas from all suppliers (including interest from the suppliers) in a rate area received by Company from charges paid for natural gas resold to its customers, shall be refunded to such customers as a reduction in the Purchased Gas Adjustment. Within ninety (90) days of the receipt of a refund in excess of $.002 per Ccf for purchased gas from any supplier or the balance of the refund account reaching the equivalent of $.002 per Ccf for purchased gas from all suppliers, the Company shall file with the Commission and propose to make effective, the appropriate Purchased Gas Adjustment reflecting the decrease and an associated statement showing the computation of the refund adjustment.

2. The refund adjustment per Ccf shall be determined by dividing the appropriate refund amount by the estimated Ccf sales to the rate area as shown on Line 6, Sheet KCC Form PGA 1. The amount of the unit refund adjustment shall be computed to the nearest $.00001 per Ccf.

3. The length of the refund period shall generally be twelve (12) months, except that each refund period may be lengthened or shortened by the Company to avoid a refund materially above or below the refundable amount.

4. After the refunding period is completed, the difference between the refund(s) received from the Company's suppliers and the amount refunded to the respective rate area customers shall be determined and said difference retained in the refund account until such time as a subsequent refund is received from such suppliers.

The balance in said refund account shall be added to any subsequent refund before computing a new refund adjustment.

5. In the event any refund received from the Company's supplier is less than the equivalent of $.002 per Ccf for purchased gas for a rate area, said refund shall be credited to the refund account. The credit balance in said account, exclusive of those amounts which have been included in the calculation of refunds then in progress, shall be accumulated to the equivalent of $.002 per Ccf for purchased gas before commencing a subsequent refund as hereinabove provided.

SECTION 3 - PURCHASED GAS COST SURCHARGES

A. GAS HEDGE PROGRAM

The Company shall operate its Gas Hedge Program pursuant to the relevant order in Docket No. 05-ATMG-617-HED. Costs and revenues associated with any purchase or sale of straight call options, and other alternative risk management strategies, such as call spreads, the net balance of which shall not exceed approved annual budget amount. The estimated net balance shall be recovered as a separate cost component during the months of April through October each year from all PGA customers except irrigation. Any over or under recovery, and any of the allowed budget amount not used by the Company over the course of the Hedge Program year, shall be reflected in the Company's next ACA filing. Costs and revenues generated from the settlement of all financial derivatives shall be flowed back as a separate component during the months of November through March to all PGA customers except irrigation. This settlement component shall be a volumetric charge or credit that is calculated each month from November to March by dividing the monthly estimated hedge payoff amount by the sales volume projected to occur during that respective month. The estimated payoff amount shall be adjusted to the actual payoff amount in the following month's calculation of the settlement component. No settlement component will be added if it is less ~~that~~than $.002 per Ccf, rather the amount will be accumulated until the component results in a rate more than $.002 per Ccf.

SCHEDULE V - PURCHASED GAS ADJUSTMENT (PGA)

SECTION 1 - PURCHASED GAS COST ADJUSTMENT PROCEDURE

A. RATE SCHEDULES COVERED

All of the Company's sales rate schedules shall be subject to a purchased gas cost adjustment:

Description Combined Kansas Rate Division and Southwest Kansas Rate Division

Firm Sales Service including: Residential, Commercial, Public Authority, School, Irrigation Engine, Agricultural Service, and Small Industrial. 910, 915, 920, 930, 940, 960, 965 Interruptible Sales Service including: School, Small Industrial, Large Industrial, and Economic Development. 955, 960

B. COMPUTATION FORMULA

1. The Company's rates for gas service are subject to adjustment for change in the average cost of gas from all sources of supply purchased. At the end of the twelve-month period ending August, the Company will project the average cost of gas for the twelve months ending August 31 of the following year. If at any time during this twelve month period the Company experiences a change or changes in supplier rates or in sources of supply, the cumulative effect of which change or

changes is to produce an increase or decrease in the new projected effective rate for purchased gas from all suppliers of at least $.010 per Ccf, then an adjusted average rate shall be determined. The annual cost of gas projection and any revised projections throughout the year will be computed using the following formula:

$$\frac{P + E + S}{V} = \text{Adjustment}$$

Where:

P = The estimated total dollar cost of purchased gas to be sold calculated by summing the products of the most recent unit cost of purchased gas from each supplier and the estimated unit purchases from each supplier for the twelve month period ending August 31. In the event that changes in the rates paid for purchased gas will take place within the current twelve month period ending August 31, as specified by contract provisions currently in effect, the estimated average unit cost of purchased gas from each supplier for the current twelve month period ending August 31, may be used in the calculation in place of the most recent unit cost.

E = Estimated net cost (positive or negative) arising from exchange gas transactions that are expected to occur during the twelve month period ending August 31 (Account 806), not including storage gas transactions.

S = Estimated cost of stored gas to be withdrawn from storage (Account 808) and sold.

V = The estimated sales volume in Ccf for the twelve month period ending August 31. (If the actual sales volume reflects a line loss factor greater than the limit value, restatement of sales volume, based on the limit value for line loss, shall be required.)

Volumes sold under Rate Schedule 955, and 960 shall not be billed the demand costs, or its equivalent, contained in the PGA computed in accordance with the above-stated formula, but shall be billed the remaining costs contained in the PGA formula. In addition to the PGA less demand costs, or its equivalent, Rate Schedule 955 and 960 shall also have applied to the volumes sold the sum of the Southern Star Central Gas Pipeline, Inc.'s maximum ITS-P and ITS-M commodity rates, adjusted for fuel reimbursement percentages, as set forth in Southern Star Central Gas Pipeline, Inc.'s tariff on file with the Federal Energy Regulatory Commission.

C. COMPUTATION PERIOD

The computation period shall be the subsequent twelve month period ending August 31.

D. COMPUTATION FREQUENCY

The computation shall be made annually or each time a change or changes occur in supplier rates or sources of supply, the cumulative effect of which change or changes is to produce an increase or decrease in the new effective rate paid for purchased gas by at least $.010/Ccf.

E. COSTS INCLUDED

The formula includes only costs which are properly included in FERC Accounts 800, 801, 802, 803, 804, 858, applicable to Kansas; 805, 806, 808, and 809.

F. SETTLEMENT PROVISIONS

Subsequent to the effective date of this clause, the Company shall maintain a continuing monthly comparison of the actual (as billed) cost of gas as shown on the books and records of the Company, exclusive of refunds, and the cost recovery for the same month calculated by applying to the volumes sold during said month the purchased gas cost adjustments calculated pursuant to these purchased gas cost adjustment provisions. For each twelve month period ended August 31, the differences of the comparisons described above including any balance or credit for the previous year shall be accumulated to produce a cumulative balance of over-recovered or under-recovered costs.

An "Actual Cost Adjustment" (ACA) shall be computed by dividing the cumulative balance of under-recovered or over-recovered costs by the volume of total sales during the twelve month period ending on that date. This adjustment shall be rounded to the nearest $.0001 per Ccf and applied to sales billed on or after the first day of the month following the month in which the adjustment has been approved by the Commission. The "Actual Cost Adjustments" shall remain in effect until superseded by subsequent "Actual Cost Adjustments" calculated according to this provision.

The Gas Cost portion of uncollectible accounts is recoverable through the ACA. The cumulative balance of over-recovered or under-recovered costs shall include the Gas Cost portion of uncollectible PGA customer accounts billed under this Schedule during the preceding Computation Year and which remain unpaid. The uncollectible amounts included in the annual ACA computation shall not contain interest or collection fees or charges. This sub-component of the ACA will be a separate line item on Sheet 1 of the Purchased Gas Adjustment.

G. CAPACITY RELEASE/DEMAND CHARGE SAVINGS/PIPELINE BYPASS SAVINGS

1. CAPACITY RELEASE

The Company shall forecast, on a monthly basis, the capacity release credits expected to be received (applicable to its Kansas jurisdiction). The Company shall then calculate a Monthly Capacity Release Factor by dividing fifty percent of this total monthly forecast by estimated monthly sales. The Total Capacity Release Factor shall be applied to the Purchased Gas Cost Factor. The Company shall maintain a continuing monthly comparison of 50% of the actual capacity release credits received and the capacity release credits distributed. The differences of the comparisons described above shall be accumulated to produce an Accumulated Capacity Release Balance, that is, a cumulative balance of under or over distributed credits. An Accumulated Capacity Release Factor will be calculated annually by dividing the accumulated balance of under or over distributed credits by the volume of actual sales during the twelve month period ending August 31. The Accumulated Capacity Release Factor will be added to the Monthly Capacity Release Factor to equal the Total Capacity Release Factor. The Accumulated Capacity Release Balance will be adjusted by the monthly capacity release under/over disbursements.

2. DEMAND CHARGE SAVINGS

The Company shall forecast, on a monthly basis, the demand charge savings expected to be received (applicable to its Kansas jurisdiction). The Company shall then calculate a Monthly Demand Charge Savings Factor by dividing fifty percent of this total monthly forecast by estimated monthly sales. The Total Demand Charge Savings Factor shall be applied to the Purchased Gas Cost Factor. The Company shall maintain a continuing monthly comparison of 50% of the actual Demand Charge Savings received and the Demand Charge Savings distributed. The differences of the comparisons described above shall be accumulated to produce an Accumulated Demand Charge Savings Balance, that is, a cumulative balance of under or over distributed demand charge savings. An Accumulated Demand Charge Savings Factor will be calculated annually by dividing the accumulated

balance of under or over distributed demand charge savings by the volume of actual sales during the twelve month period ending August 31. The Accumulated Demand Charge Savings Factor will be added to the Monthly Demand Charge Savings Factor to equal the Total Demand Charge Savings Factor. The Accumulated Demand Charge Savings Balance will be adjusted by the monthly demand charge savings under/over disbursements.

3. PIPELINE BYPASS SAVINGS

The Company shall forecast, on a monthly basis, the Pipeline Bypass savings expected to be received (applicable to its Kansas jurisdiction). The Company shall then calculate a Monthly Pipeline Bypass Savings Factor by dividing fifty percent of this total monthly forecast by estimated monthly sales. The Total Pipeline Bypass Savings Factor shall be applied to the Purchased Gas Cost Factor. The Company shall maintain a continuing monthly comparison of 50% of the actual Pipeline Bypass Savings received and the Pipeline Bypass Savings distributed. The differences of the comparisons described above shall be accumulated to produce an Accumulated Pipeline Bypass Savings Balance, that is, a cumulative balance of under or over distributed pipeline bypass savings. An Accumulated Pipeline Bypass Savings Factor will be calculated annually by dividing the accumulated balance of under or over distributed pipeline bypass savings by the volume of actual sales during the twelve month period ending August 31. The Accumulated Pipeline Bypass Savings Factor will be added to the Monthly Pipeline Bypass Savings Factor to equal the Total Pipeline Bypass Savings Factor. The Accumulated Pipeline Bypass Savings Balance will be adjusted by the monthly pipeline bypass savings under/over disbursements.

H. OVERRUN PENALTIES

Overrun penalties applicable to the Company's Kansas jurisdiction shall be separately accumulated and shall be administered in compliance with the provisions contained in the Commission Order in Docket No. 190,061-U. The Company shall maintain a continuing monthly comparison of the actual penalties received (applicable to its Kansas jurisdiction) and the amount

recovered from its customers. The differences of the comparisons described above shall be accumulated to produce an Accumulated Penalty Balance, that is, a cumulative balance of under or over recovered penalties. An Accumulated Penalty Recovery Factor will be calculated annually by dividing the accumulated balance of under or over recovered penalties by the volume of actual sales during the twelve month period ending August 31. The Accumulated Penalty Recovery Factor will be applied to the Purchased Gas Cost Factor each month. The Accumulated Penalty Balance will be adjusted by the monthly penalty under/over recovery.

I. REPORTING REQUIREMENTS

The Company shall submit to the Commission purchased gas cost filings at least 15 days before the filing is to be effective. Purchased gas cost filings and cost adjustment reports shall use the format prescribed by the Commission.

J. LINE LOSS LIMITATIONS

The Company shall compute one actual line loss for the entire State of Kansas. In the event that the actual line loss (unaccounted for gas) statistic for the computation period exceeds the line loss limit of 4%, the Company will compute the purchased gas adjustment using the limit value rather than the actual operating statistic value.

SECTION 2 - PURCHASED GAS COST REFUND ADJUSTMENT PROCEDURE

A. REFUND PROVISION

1. For the purpose hereof, unless the Kansas Corporation Commission shall otherwise order, refunds or a balance in the refund account in excess of $.002 per Ccf for purchased gas from all suppliers (including interest from the suppliers) in a rate area received by Company from charges paid for natural gas resold to its customers, shall be refunded to such customers as a reduction in the Purchased Gas Adjustment. Within ninety (90) days of the receipt of a refund in excess of $.002 per Ccf for purchased gas from any supplier or the balance of the refund account reaching the equivalent of $.002 per Ccf for purchased gas from all suppliers, the Company shall file with the Commission and propose to make effective, the appropriate Purchased Gas Adjustment reflecting the decrease and an associated statement showing the computation of the refund adjustment.

2. The refund adjustment per Ccf shall be determined by dividing the appropriate refund amount by the estimated Ccf sales to the rate area as shown on Line 6, Sheet KCC Form PGA 1. The amount of the unit refund adjustment shall be computed to the nearest $.00001 per Ccf.

3. The length of the refund period shall generally be twelve (12) months, except that each refund period may be lengthened or shortened by the Company to avoid a refund materially above or below the refundable amount.

4. After the refunding period is completed, the difference between the refund(s) received from the Company's suppliers and the amount refunded to the respective rate area customers shall be determined and said difference retained in the refund account until such time as a subsequent refund is received from such suppliers.

The balance in said refund account shall be added to any subsequent refund before computing a new refund adjustment.

5. In the event any refund received from the Company's supplier is less than the equivalent of $.002 per Ccf for purchased gas for a rate area, said refund shall be credited to the refund account. The credit balance in said account, exclusive of those amounts which have been included in the calculation of refunds then in progress, shall be accumulated to the equivalent of $.002 per Ccf for purchased gas before commencing a subsequent refund as hereinabove provided.

SECTION 3 - PURCHASED GAS COST SURCHARGES

A. GAS HEDGE PROGRAM

The Company shall operate its Gas Hedge Program pursuant to the relevant order in Docket No. 05-ATMG-617-HED. Costs and revenues associated with any purchase or sale of straight call options, and other alternative risk management strategies, such as call spreads, the net balance of which shall not exceed approved annual budget amount. The estimated net balance shall be recovered as a separate cost component during the months of April through October each year from all PGA customers except irrigation. Any over or under recovery, and any of the allowed budget amount not used by the Company over the course of the Hedge Program year, shall be reflected in the Company's next ACA filing. Costs and revenues generated from the settlement of all financial derivatives shall be flowed back as a separate component during the months of November through March to all PGA customers except irrigation. This settlement component shall be a volumetric charge or credit that is calculated each month from November to March by dividing the monthly estimated hedge payoff amount by the sales volume projected to occur during that respective month. The estimated payoff amount shall be adjusted to the actual payoff amount in the following month's calculation of the settlement component. No settlement component will be added if it is less than $.002 per Ccf, rather the amount will be accumulated until the component results in a rate more than $.002 per Ccf.

Issued ____ ____ 2013
Month Day Year

Effective ____ ____ 2013
Month Day Year

By ____
Signature Title

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Atmos Energy to Amend its Purchase Gas Adjustment (PGA) Schedule to Add a Demand Charge Savings and Pipeline Bypass Savings Component to the PGA	)))))	Docket No. 14-ATMG-230-TAR

PRE-FILED TESTIMONY OF SHERI W. ROWE

Q. STATE YOUR NAME, EMPLOYER, JOB TITLE AND BUSINESS ADDRESS.

A. My name is Sheri W. Rowe. I am Manager, Gas Supply and Services, for Atmos Energy ("Atmos"). My business address is 790 Liberty Road, Flowood, Mississippi 39232.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I received a Bachelor of Science degree in Accounting from Mississippi State University in 1977. I was engaged in public accounting with Arthur Andersen and Company from 1977 to 1983. From 1983 to 2001, I worked for Mississippi Valley Gas Company ("MVG") in a variety of accounting, finance and operational positions. In 2001, Atmos acquired MVG, where I assumed my current role as Manager of Gas Supply and Services.

Q. WHAT ARE YOUR DUTIES AS MANAGER OF GAS SUPPLY AND SERVICES FOR ATMOS?

A. As Manager of Gas Supply and Services, my principal duties relate to the gas supply management for Atmos' Kansas, Colorado, Mississippi and Louisiana operations. I am responsible for all gas supply and system transportation arrangements involving the interstate and intrastate pipelines that deliver gas to the Atmos system in those states. This includes pipeline capacity arrangements, gas supply acquisition planning and day to day

administration. I directly supervise five professional employees, who assist in assuring that Atmos has reliable and economical gas supply and upstream service portfolios.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony is in support of the Company's application for approval of its amendment of the Purchased Gas Adjustment Schedule to add a Demand Charge Savings Component and Pipeline Bypass Savings Component to the PGA.

Q. PLEASE EXPLAIN THE DEMAND CHARGE SAVINGS AND PIPELINE BYPASS COMPONENTS AND HOW THEY CAN REDUCE DEMAND CHARGES.

A. Atmos in its Application seeks authority to potentially capture any non-traditional opportunities, to restructure its natural gas supply contracts, and to modify the ways in which it utilizes pipeline services which can result in substantial savings to its customers. These non-traditional opportunities will require increased resources and changes in the utilization of pipeline capacity and supply sourcing to obtain these potential savings for its customers. The Demand Charge Savings Component is where an opportunity may exist on pipelines that serve the Kansas area to change how supply has traditionally been sourced. Atmos believes that supply could be sourced from non-traditional sources while at the same time continuing to provide firm and reliable service to Atmos' customers. The opportunity to generate savings on each pipeline differs and Atmos must evaluate alternative supply opportunities on existing pipelines including the availability of forward and back haul capacity, available discounts, and availability of delivered services. The Demand Charge Savings Component consists of three subcomponents:

(1) **Segmentation Savings.** Segmentation savings may be realized by dividing the path of a transportation contract into sections and utilizing the contract multiple times,

thus lowering the overall capacity demand charges. All interstate pipelines are not required to facilitate segmentation, and the right conditions must exist where a firm source of supply is available between Atmos' delivery points.

(2) **Pipeline Discount Savings.** Pipeline discount savings are generally achieved through contract negotiations with a pipeline and are typically offered when pipelines are not fully subscribed or when LDCs have multiple pipeline options.

(3) **Delivered Services Savings.** Delivered service savings can be realized through alternative contract structures typically bid through an RFP, where a supplier delivers supply to the city gate cheaper than the LDC can achieve by holding firm capacity with a pipeline. Delivered services may not be available on all pipelines and generally there is uncertainty from year to year on availability. Atmos will evaluate and consider delivered service only under the right circumstances.

The Pipeline Bypass Savings Component exists when there are opportunities to construct new interconnects with alternative pipelines and realize an overall cost savings by increasing capacity on pipelines with lower demand charges and reducing capacity on pipelines that are more expensive. These opportunities may exist going forward because of the changing supply and transportation dynamics; however the new interconnects are capital intensive and these costs could limit opportunities. Atmos would need to evaluate alternative pipeline costs and negotiate new interconnect agreements and transportation contracts to cover the capital costs with alternative pipelines. Where new interconnects are possible they can provide gas supply savings, operational benefits, supply diversity and strengthen Atmos' position in future contract negotiations.

Q. COULD THE CUSTOMERS BE NEGATIVELY IMPACTED BY INCREASED

VARIABLE COSTS FROM THE DEMAND CHARGE SAVINGS AND/OR PIPELINE BYPASS COMPONENTS?

A. No, a comparison will be made between the traditional or historical costs of Atmos' portfolio of capacity which has been prudently procured at the maximum FERC tariff rate for each pipeline. The Demand Charge Savings Component would be calculated by comparing the demand charges at the traditional rates to the actual demand charges achieved by Atmos using the methods set forth in the two proposed components. The Demand Charge Savings Component would be adjusted to reflect any cost/savings of the variable physical gas supply cost; including locational pricing differences, fuel and commodity cost differences between the traditional and replacement supply sources. Under the two proposed components, any savings would then be shared equally between Atmos and the customers consistent with how the approved capacity release incentive mechanism works today. The customers' share of the savings would flow directly through the PGA via reduced demand charges in the same manner as the approved capacity release mechanism does today. A red-line copy of Atmos' PGA tariff showing the addition of the demand charge savings component and the pipeline bypass savings component is attached to the Application.

Q. WHAT HAS CHANGED IN THE NATURAL GAS MARKET TO MAKE THIS THE APPROPRIATE TIME FOR THE ADDITIONAL ENHANCEMENTS TO BE ADDED TO THE PGA?

A. There have been significant changes in the natural gas market conditions over the past several years. The most significant change has been on the supply side where the dry natural gas production has increased over 10 BCF/day since 2008. This increase is directly related to shale supply growth in the Barnett, Haynesville, Fayetteville, Woodford, Eagle

Ford, Bakken and Marcellus shale basins where supply has grown 20 BCF/day since 2008. This prolific shale supply growth has created the need for new infrastructure to move the growing shale supply to market. The new infrastructure and location of the shale basins has directly impacted many of the traditional long haul pipelines. The pipelines have responded with rate cases requesting increases to the fixed demand charges. Changes in natural gas market conditions and increased pipeline transportation costs have increased the cost of upstream natural gas supply and services for Atmos' customers.

Q. PLEASE EXPLAIN WHY NOW IS AN APPROPRIATE TIME FOR ATMOS TO REQUEST THE ADDITIONAL ENHANCEMENTS BE ADDED TO THE PGA.

A. Atmos' Southern Star contracts expire in 2015 and any changes to the contracts would have to be negotiated in 2014. Additionally, identifying alternative supply options on Southern Star could take a year or more and building infrastructure to connect to a replacement pipeline could take even longer. These PGA enhancements present an opportunity to reduce the customers' exposure to pipeline rate increases by creating additional mechanisms similar to the current capacity release mechanism that incentivizes LDC's to seek non-traditional ways to reduce the cost of upstream natural gas supply and services.

Q. WHAT HAS ATMOS DONE IN RESPONSE TO THESE INCREASED COSTS IN OTHER STATES?

A. Atmos has done a number of things in response to these increased costs. It has intervened and protested the pipelines' FERC rate proceedings. Atmos has sought and gained approval of programs in its other states which provide Atmos an incentive to pursue opportunities to reduce the customer's exposure to these types of pipeline increased demand charges. These approved programs are structured similar to the incentive put in place by

the Commission back in 1995 to encourage utilities to resell pipeline capacity, where the utility and its customers would share equally in any savings resulting in lowering pipeline demand charges.

Q. HAS THE INCREASE IN SHALE GAS PRODUCTION AND CHANGING PIPELINE DYNAMICS HAD ANY IMPACT ON PIPELINE RATES BEING CHARGED TO ITS KANSAS CUSTOMERS?

A. Yes. Southern Star Central Gas Pipeline, Inc. ("Southern Star"), which is the main interstate pipeline that Atmos relies upon for pipeline transportation services in Kansas, currently has a rate case pending before FERC. Southern Star is seeking to significantly increase its fixed demand charges to account for lost throughput.

Q. WHAT SERVICES DOES SOUTHERN STAR PROVIDE TO ATMOS?

A. Southern Star is Atmos' upstream interstate pipeline supplier for the Olathe/Bonner Springs area served by Atmos in Northeast Kansas and the Independence/Coffeyville area served by Atmos in Southeast Kansas. The majority of Atmos' Kansas customers are located in these two areas of Kansas and Atmos relies on Southern Star to serve these two areas. Atmos has contracts with Southern Star for firm transportation and storage capacity on Southern Star' interstate pipeline, which is connected to gas fields in Kansas, Oklahoma and Wyoming. Atmos transports approximately 12 million decatherms ("Dths") annually on Southern Star.

Q. WHAT PORTION OF ATMOS' TOTAL INTERSTATE AND INTRASTATE PIPELINE CAPACITY IS PROVIDED BY SOUTHERN STAR?

A. Currently, Atmos holds a total of 200,000 Dths per day of firm capacity on multiple interstate and intrastate pipelines in Kansas. Approximately 160,000 Dths per day, or about 80% of Atmos' total pipeline capacity in Kansas is provided by Southern Star.

Additionally, Atmos has approximately 2.8 Bcf of pipeline storage capacity to serve its Kansas customers and approximately 2.7 Bcf, or about 96% of Atmos' total pipeline storage capacity in Kansas is provided by Southern Star.

Q. HAVE YOU REVIEWED SOUTHERN STAR'S RECENT RATE CASE FILING AT FERC?

A. Yes.

Q. HAS ATMOS PREPARED AN ANALYSIS ON WHAT IMPACT SOUTHERN STAR'S RATE CASE COULD HAVE ON ATMOS AND ITS CUSTOMERS?

A. Yes. Exhibit SWR-1 provides an analysis on what impact Southern Star's rate case could have on Atmos and its customers. If Southern Star's request to increase its rates is approved by FERC as filed, Atmos and its customers would experience an estimated 47% increase in what is currently paid for firm transportation and storage services. As shown on Exhibit SWR-1, our costs would increase by approximately $6.2 million per year, from approximately $13.2 million to $19.4 million.

Q. WHAT OTHER ACTIONS HAS ATMOS TAKEN IN RESPONSE TO THE SOUTHERN STAR RATE CASE?

A. Atmos, acting through outside counsel, intervened and filed a Protest of Southern Star's rate case in FERC Docket No. RP 13-941 on June 12, 2013. Atmos, acting jointly with Black Hills Utility Holdings, Inc., Kansas Gas Service, Laclede Gas Company, Missouri Gas Energy, and Midwest Energy, all similarly situated LDC customers of Southern Star, has retained an outside rate analyst to assist in all phases of the Southern Star rate case.

Q. HAS SOUTHERN STAR INDICATED IN ITS RATE CASE FILING WHY IT IS SEEKING TO SIGNIFICANTLY INCREASE ITS DEMAND CHARGE?

A. Among the reasons stated for the rate increase, Southern Star has indicated it has had to revise its system rate design quantities (throughput) due to other competing pipeline infrastructures, downward pressure on basis differentials and reduced value of Southern Star's pipeline transportation capacity and lower load factors because of supply changes.

Q. HOW DOES SOUTHERN STAR'S RATE CASE FILING RELATE TO ATMOS' REQUEST TO ADD A DEMAND CHARGE SAVINGS COMPONENT AND PIPELINE BYPASS SAVINGS COMPONENT TO ITS PGA SCHEDULE?

A. Southern Star's rate case filing clearly demonstrates that Atmos and its Kansas customers are currently facing the challenges caused by the changes to the natural gas market conditions outlined in my testimony due to the significant increase in shale gas production and changing pipeline dynamics. These changes are putting pressure on traditional interstate pipelines to increase their demand and transportation charges through rate cases due to lost throughput and changing flows on their pipelines. In order to meet these escalating challenges, Atmos is seeking permission to implement enhancements to its existing Kansas shared savings incentive mechanism (released capacity). By restructuring its natural gas supply contracts and modifying its utilization of pipeline capacity, Atmos may be able to generate savings for the Kansas customers similar to how the Commission's capacity release shared savings mechanism has benefitted customers.

Q. HOW ARE THE PROPOSED COMPONENTS CONSISTENT WITH THE COMMISSION'S GOAL FROM THE 1995 ORDER TO DEVISE A GAS COST INCENTIVE MECHANISM RATHER THAN JUST A CAPACITY RELEASE MECHANISM?

A. The approval of the components requested by Atmos would accomplish the original goal

from the 1995 Order, where the Commission stated that its "ultimate goal is to devise a gas cost incentive mechanism, perhaps a performance based mechanism, which addresses gas purchasing activities as a whole, rather than just the capacity resale decision." [1] The addition of the proposed demand charge savings and pipeline bypass savings components to the existing capacity release shared savings component will provide for a more comprehensive performance based rate mechanism. Enhancing the existing incentive mechanism with the two additional components will provide more opportunities for Atmos to reduce the cost of upstream natural gas supply and services, which in turn will result in lower costs to its Kansas customers.

Q. DOES ATMOS HAVE PERFORMANCE BASED RATE MECHANISMS IN PLACE IN OTHER STATES IN WHICH IT OPERATES AS IT RELATES TO ATMOS' GAS PURCHASING PRACTICES?

A. Yes. In addition to the capacity release shared savings mechanism that Atmos has had in place in Kansas since 1995, Atmos has a successful performance based rate mechanisms relating to its gas purchasing practices in Mississippi (demand charge mechanism, pipeline bypass mechanism, capacity release mechanism, commodity mechanism); Kentucky (demand charge mechanism, pipeline bypass mechanism, capacity release mechanism, commodity mechanism); Tennessee (demand charge mechanism, capacity release mechanism, commodity mechanism). Atmos recently received approval from the Louisiana Public Service Commission for enhancements to the Louisiana asset management program to include a demand charge savings mechanism and pipeline bypass mechanism.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

[1]Docket No. 190,061-U, Order dated May 1, 1995, page 13, paragraph 18.

A. Changes in the natural gas market driven by the dramatic increase in shale gas production are causing an increase in pipeline transportation costs, and thus, an increase in gas supply costs paid by our customers. There may be opportunities to potentially restructure the natural gas supply contracts and modify the ways in which pipeline capacity is utilized. Non-traditional supply methods could result in savings to our customers. It is likely that Southern Star's transportation charges, particularly the fixed demand component, will continue to increase under traditional supply methods. Enhancement of the existing capacity release shared savings component of Atmos' PGA, by the addition of a demand charge savings component and pipeline bypass savings component, will provide increased incentive and increased opportunities for Atmos to reduce the cost of upstream natural gas supply and services resulting in savings to our customers. The savings will be an important tool to counter the expected spiraling demand charge increases brought on by the dynamic changes in supply and pipeline flows.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VERIFICATION OF SHERI W. ROWE

STATE OF MISSISSIPPI)
)ss:
COUNTY OF HINDS)

I, Sheri W. Rowe, being first duly sworn on oath, depose and state that I am the witness identified in the foregoing Direct Testimony of Sheri W. Rowe; that I have read the testimony and am familiar with its contents; and that the facts set forth therein are true and correct.

Sheri W Rowe
Sheri W. Rowe

SUBSCRIBED AND SWORN to before me this 14 day of November, 2013.

Regina Smith
Notary Public

Appointment/Commission Expires:

STATE OF MISSISSIPPI
NOTARY PUBLIC
ID # 78175
REGINA SMITH
Commission Expires
July 5, 2017
HINDS COUNTY

Atmos Energy Corporation
Kansas Division
Southern Star Central Gas Pipeline

Firm Transportation Demand

Contract	Rate Schedule	Capacity	Annualized Capacity	Current Reservation Rate	Demand Cost with Current Reservation Rates	Proposed Reservation Rate	Demand Cost with Proposed Reservation Rates	Increase to Demand Cost
TA-15556	FTS-M	2,500	912,500	$ 0.1370	$ 125,013	$ 0.1990	$ 181,588	$ 56,575
TS-7927 (Production)	TSS-P	2,164	789,860	$ 0.1912	$ 151,021	$ 0.2954	$ 233,325	$ 82,304
TS-7928 (Production)	TSS-P	53,256	19,438,440	$ 0.1905	$ 3,703,023	$ 0.2954	$ 5,742,115	$ 2,039,092
TS-7928 (Market)	TSS-M	148,613	54,243,745	$ 0.1377	$ 7,469,364	$ 0.1990	$ 10,794,505	$ 3,325,141
					$ 11,448,421		$ 16,951,533	$ 5,503,112

Storage Deliverability Demand

Contract	Rate Schedule	Maximum Daily Withdrawal Quantity	Annualized Maximum Daily Withdrawal Quantity	Current Storage Deliverability Rate	Storage Deliverability Cost with Current Rates	Proposed Storage Deliverability Rate	Storage Deliverability Cost with Proposed Rates	Increase to Storage Deliverability Cost
TS-7927 (Production)	TSS-P	1,082	394,930	$ 0.0280	$ 11,058	$ 0.0421	$ 16,627	$ 5,569
TS-7928 (Market)	TSS-M	81,122	29,609,530	$ 0.0280	$ 829,067	$ 0.0421	$ 1,246,561	$ 417,494
					$ 840,125		$ 1,263,188	$ 423,063

Daily Storage Balance Demand

Contract	Rate Schedule	Average Daily Storage Balance	Annualized Average Daily Storage Balance	Current Daily Storage Balance Rate	Daily Storage Balance Cost with Current Rates	Proposed Daily Storage Balance Rate	Daily Storage Balance Cost with Proposed Rates	Increase to Daily Storage Balance Cost
TS-7927 (Production)	TSS-P	19,829	7,237,585	$ 0.0013	$ 9,409	$ 0.00179	$ 12,955	$ 3,546
TS-7928 (Market)	TSS-M	1,486,642	542,624,330	$ 0.0013	$ 705,412	$ 0.00179	$ 971,298	$ 265,886
					$ 714,821		$ 984,253	$ 269,432

Total Cost with Current Rates	Total Cost with Proposed Rates	Total Increased Cost
$ 13,003,367	$ 19,198,974	$ 6,195,607