Columbia Gas® of Kentucky
**A NiSource Company**

P.O. Box 14241
2001 Mercer Road
Lexington, KY 40512-4241

October 26, 2009

RECEIVED

OCT 26 2009

PUBLIC SERVICE COMMISSION

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, KY 40602

Re: Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Case No. 2009 - 00419

Dear Mr. Derouen:

Pursuant to the Commission's Order dated January 30, 2001 in Administrative Case No. 384, Columbia Gas of Kentucky, Inc. ("Columbia") hereby encloses, for filing with the Commission, an original and six (6) copies of data submitted pursuant to the requirements of the Gas Cost Adjustment Provision contained in Columbia's tariff for its December quarterly Gas Cost Adjustment ("GCA").

Columbia proposes to increase its current rates to tariff sales customers by $0.6780 per Mcf effective with its December 2009 billing cycle on November 25, 2009. The increase is composed of an increase of $0.6126 per Mcf in the Average Commodity Cost of Gas, and an increase of $0.0654 per Mcf in the Average Demand Cost of Gas. Please feel free to contact me at 859-288-0242 if there are any questions.

Sincerely,

Judy Cooper

Judy M. Cooper
Director, Regulatory Policy

Enclosures

BEFORE THE
PUBLIC SERVICE COMMISSION
OF KENTUCKY

COLUMBIA GAS OF KENTUCKY, INC.

CASE 2009 - 00419

GAS COST ADJUSTMENT AND REVISED RATES OF
COLUMBIA GAS OF KENTUCKY, INC. PROPOSED TO BECOME
EFFECTIVE DECEMBER 2009 BILLINGS

**Columbia Gas of Kentucky, Inc.**
**Comparison of Current and Proposed GCAs**

| Line No. | | November 2009 CURRENT | December-09 PROPOSED | DIFFERENCE |
|---|---|---|---|---|
| 1 | Commodity Cost of Gas | $5.1588 | $5.7714 | $0.6126 |
| 2 | Demand Cost of Gas | $1.3565 | $1.4219 | $0.0654 |
| 3 | Total: Expected Gas Cost (EGC) | $6.5153 | $7.1933 | $0.6780 |
| 4 | SAS Refund Adjustment | ($0.0002) | ($0.0002) | $0.0000 |
| 5 | Balancing Adjustment | $0.0691 | $0.0691 | $0.0000 |
| 6 | Supplier Refund Adjustment | ($0.0054) | ($0.0054) | $0.0000 |
| 7 | Actual Cost Adjustment | ($2.9537) | ($2.9537) | $0.0000 |
| 8 | Gas Cost Incentive Adjustment | $0.0584 | $0.0584 | $0.0000 |
| 9 | Cost of Gas to Tariff Customers (GCA) | $3.6835 | $4.3615 | $0.6780 |
| 10 | Transportation TOP Refund Adjustment | $0.0000 | $0.0000 | $0.0000 |
| 11 | Banking and Balancing Service | $0.0208 | $0.0207 | ($0.0001) |
| 12 | Rate Schedule FI and GSO | | | |
| 13 | Customer Demand Charge | $6.5675 | $6.5664 | ($0.0011) |

**Columbia Gas of Kentucky, Inc.**
**Gas Cost Adjustment Clause**
**Gas Cost Recovery Rate**
**Dec 09 - Feb 10**

| Line No. | Description | | Amount | Expires |
|---|---|---|---|---|
| 1 | Expected Gas Cost (EGC) | Schedule No. 1 | $7.1933 | |
| 2 | Actual Cost Adjustment (ACA) | Schedule No. 2 | ($2.9537) | 8-31-10 |
| 3 | SAS Refund Adjustment (RA) | Schedule No. 5 | ($0.0002) | 8-31-10 |
| 4 | Supplier Refund Adjustment (RA) | Schedule No. 4 | ($0.0001) | 08-31-10 |
| | | | ($0.0053) | 02-28-10 |
| | | Total Refunds | ($0.0054) | |
| 5 | Balancing Adjustment (BA) | Schedule No. 3 | $0.0691 | 2-28-10 |
| 6 | Gas Cost Incentive Adjustment | Schedule No. 6 | $0.0584 | 2-28-10 |
| 7 | Gas Cost Adjustment | | | |
| 8 | Dec 09 - Feb 10 | | $4.3615 | |
| 9 | Expected Demand Cost (EDC) per Mcf | | | |
| 10 | (Applicable to Rate Schedule IS/SS and GSO) | Schedule No. 1, Sheet 4 | $6.5664 | |

**DATE FILED: October 26, 2009** **BY: J. M. Cooper**

**Columbia Gas of Kentucky, Inc.** Schedule No. 1

**Expected Gas Cost for Sales Customers** Sheet 1

**Dec 09 - Feb 10**

| Line No. | Description | | Reference | Volume A/ Mcf (1) | Dth. (2) | Rate Per Mcf (3) | Per Dth (4) | Cost (5) |
|---|---|---|---|---|---|---|---|---|
| | **Storage Supply** | | | | | | | |
| | Includes storage activity for sales customers only | | | | | | | |
| | Commodity Charge | | | | | | | |
| 1 | Withdrawal | | | | (4,772,000) | | $0.0153 | $73,012 |
| 2 | Injection | | | | (276,000) | | $0.0153 | -$4,223 |
| 3 | Withdrawals: gas cost includes pipeline fuel and commodity charges | | | | 5,048,000 | | $4.4023 | $22,223,057 |
| | Total | | | | | | | |
| 4 | Volume | = 3 | | | 5,048,000 | | | |
| 5 | Cost | sum(1:3) | | | | | | $22,291,846 |
| 6 | Summary | 4 or 5 | | | 5,048,000 | | | $22,291,846 |
| | **Flowing Supply** | | | | | | | |
| | Excludes volumes injected into or withdrawn from storage. | | | | | | | |
| | Net of pipeline retention volumes and cost. Add unit retention cost on line 17 | | | | | | | |
| 7 | Non-Appalachian | | Sch.1, Sht. 5, Ln. 4 | | 1,668,000 | | | $11,146,000 |
| 8 | Appalachian Supplies | | Sch.1, Sht. 6, Ln. 4 | | 207,000 | | | $1,243,000 |
| 9 | Less Fuel Retention By Interstate Pipelines | | Sch. 1,Sheet 7, Lines 21, 22 | | (187,000) | | | ($1,191,688) |
| 10 | Total | 7 + 8 + 9 | | | 1,688,000 | | | $11,197,312 |
| | **Total Supply** | | | | | | | |
| 11 | At City-Gate | | Line 6 + 10 | | 6,736,000 | | | $33,489,158 |
| | Lost and Unaccounted For | | | | | | | |
| 12 | Factor | | | | -0.9% | | | |
| 13 | Volume | | Line 11 * 12 | | (60,624) | | | |
| 14 | At Customer Meter | | Line 11 + 13 | 6,322,576 | 6,675,376 | | | |
| 15 | Less: Right-of-Way Contract Volume | | | 789 | | | | |
| 16 | **Sales Volume** | | Line 14-15 | 6,321,788 | | | | |
| | **Unit Costs $/MCF** | | | | | | | |
| | Commodity Cost | | | | | | | |
| 17 | Excluding Cost of Pipeline Retention | | Line 11 / Line 16 | | | $5.2974 | | |
| 18 | Annualized Unit Cost of Retention | | Sch. 1,Sheet 7, Line 24 | | | $0.3937 | | |
| 19 | Including Cost of Pipeline Retention | | Line 17 + 18 | | | $5.6911 | | |
| 20 | Uncollectible Ratio | | CN 2009-00141 | | | 0.01410552 | | |
| 21 | Gas Cost Uncollectible Charge | | Line 19 * Line 20 | | | $0.0803 | | |
| 22 | Total Commodity Cost | | line 19 + line 21 | | | $5.7714 | | |
| 23 | Demand Cost | | Sch.1, Sht. 2, Line 10 | | | $1.4219 | | |
| 24 | Total Expected Gas Cost (EGC) | | Line 22 + 23 | | | $7.1933 | | |

A/ BTU Factor = 1.0558 Dth/MCF

**Columbia Gas of Kentucky, Inc.**
**GCA Unit Demand Cost**
**Dec 09 - Feb 10**

Schedule No. 1
Sheet 2

| Line No. | Description | | Reference | | |
|---|---|---|---|---|---|
| 1 | Expected Demand Cost: Annual Dec 2009 - Nov 2010 | | Sch. No.1, Sheet 3, Ln. 41 | $20,068,035 | |
| 2 | Less Rate Schedule IS/SS and GSO Customer Demand Charge Recovery | | Sch. No.1, Sheet 4, Ln. 10 | -$93,374 | |
| 3 | Less Storage Service Recovery from Delivery Service Customers | | | -$162,114 | |
| 4 | Net Demand Cost Applicable | 1 + 2 + 3 | | $19,812,548 | |
| | Projected Annual Demand: Sales + Choice | | | | |
| | At city-gate | | | | |
| | In Dth | | | 14,850,000 | Dth |
| | Heat content | | | 1.0558 | Dth/MCF |
| 5 | In MCF | | | 14,065,164 | MCF |
| | Lost and Unaccounted - For | | | | |
| 6 | Factor | | | 0.9% | |
| 7 | Volume | 5 * 6 | | 126,586 | MCF |
| 8 | Right of way Volumes | | | 4,775 | |
| 9 | At Customer Meter | 5 - 7- 8 | | 13,933,803 | MCF |
| 10 | Unit Demand Cost (4/ 9) | To Sheet 1, line 19 | | $1.4219 | per MCF |

**Columbia Gas of Kentucky, Inc.**
**Annual Demand Cost of Interstate Pipeline Capacity**
**Dec 2009 - Nov 2010**

Schedule No. 1
Sheet 3

| Line No. | Description | | Dth | Monthly Rate $/Dth | # Months | Expected Annual Demand Cost |
|---|---|---|---|---|---|---|
| | **Columbia Gas Transmission Corporation** | | | | | |
| | Firm Storage Service (FSS) | | | | | |
| 1 | FSS Max Daily Storage Quantity (MDSQ) | | 220,880 | $1.5050 | 12 | $3,989,093 |
| 2 | FSS Seasonal Contract Quantity (SCQ) | | 11,264,911 | $0.0289 | 12 | $3,906,671 |
| | Storage Service Transportation (SST) | | | | | |
| 3 | Summer | | 110,440 | $4.1850 | 6 | $2,773,148 |
| 4 | Winter | | 220,880 | $4.1850 | 6 | $5,546,297 |
| 5 | Firm Transportation Service (FTS) | | 20,014 | $6.0370 | 12 | $1,449,894 |
| 6 | Subtotal | sum(1:5) | | | | $17,665,103 |
| | **Columbia Gulf Transmission Company** | | | | | |
| 11 | FTS - 1 (Mainline) | | 28,991 | $3.1450 | 12 | $1,094,120 |
| | **Tennessee Gas** | | | | | |
| 21 | Firm Transportation | | 20,506 | $4.6238 | 12 | $1,137,788 |
| | **Central Kentucky Transmission** | | | | | |
| 31 | Firm Transportation | | 28,000 | $0.5090 | 12 | $171,024 |
| 41 | **Total.** Used on Sheet 2, line 1 | | | | | $20,068,035 |

**Columbia Gas of Kentucky, Inc.**
**Gas Cost Adjustment Clause**
**Expected Demand Costs Recovered Annually From Rate Schedule IS/SS and GSO Customers**
**Dec 2009 - Nov 2010**

Schedule No. 1
Sheet 4

| Line No. | Description | | Capacity Daily Dth (1) | # Months (2) | Annualized Dth (3) = (1) x (2) | Units | Annual Cost (3) |
|---|---|---|---|---|---|---|---|
| 1 | Expected Demand Costs (Per Sheet 3) | | | | | | $20,068,035 |
| | City-Gate Capacity: | | | | | | |
| | Columbia Gas Transmission | | | | | | |
| 2 | Firm Storage Service - FSS | | 220,880 | 12 | 2,650,560 | | |
| 3 | Firm Transportation Service - FTS | | 20,014 | 12 | 240,168 | | |
| 4 | Central Kentucky Transportation | | 28,000 | 12 | 336,000 | | |
| 5 | Total | 2 + 3 + 4 | | | 3,226,728 | Dth | |
| 6 | Divided by Average BTU Factor | | | | 1.0558 | Dth/MCF | |
| 7 | Total Capacity - Annualized | Line 5/ Line 6 | | | 3,056,192 | Mcf | |
| 8 | Monthly Unit Expected Demand Cost (EDC) of Daily Capacity Applicable to Rate Schedules IS/SS and GSO Line 1 / Line 7 | | | | $6.5664 | /Mcf | |
| 9 | Firm Volumes of IS/SS and GSO Customers | | 1,185 | 12 | 14,220 | Mcf | |
| 10 | Expected Demand Charges to be Recovered Annually from Rate Schedule IS/SS and GSO Customers | Line 8 * Line 9 | | | to Sheet 2, line 2 | | $93,374 |

**Columbia Gas of Kentucky, Inc.**
**Non-Appalachian Supply: Volume and Cost**
**Dec 09 - Feb 10**

Schedule No. 1
Sheet 5

Cost includes transportation commodity cost and retention by the interstate pipelines, but excludes pipeline demand costs.
The volumes and costs shown are for sales customers only.

| | | Total Flowing Supply Including Gas Injected Into Storage | | | | Net Flowing Supply for Current Consumption | |
|---|---|---|---|---|---|---|---|
| Line No. | Month | Volume A/ Dth (1) | Cost (2) | Unit Cost $/Dth (3) = (2) / (1) | Net Storage Injection Dth (4) | Volume Dth (5) = (1) + (4) | Cost (6) = (3) x (5) |
| 1 | Dec-09 | 832,000 | $5,247,000 | | 0 | 832,000 | |
| 2 | Jan-10 | 830,000 | $5,459,000 | | 0 | 830,000 | |
| 3 | Feb-10 | 6,000 | $440,000 | | 0 | 6,000 | |
| 4 | Total 1+2+3 | 1,668,000 | $11,146,000 | $6.68 | 0 | 1,668,000 | $11,146,000 |

A/ Gross, before retention.

**Columbia Gas of Kentucky, Inc.**
**Appalachian Supply: Volume and Cost**
**Dec 09 - Feb 10**

Schedule No. 1
Sheet 6

| Line No. | Month | | Dth (2) | Cost (3) |
|---|---|---|---|---|
| 1 | Dec-09 | | 67,000 | $384,000 |
| 2 | Jan-10 | | 74,000 | $452,000 |
| 3 | Feb-10 | | 66,000 | $407,000 |
| 4 | Total | 1 + 2 + 3 | 207,000 | $1,243,000 |

**Columbia Gas of Kentucky, Inc.**
**Annualized Unit Charge for Gas Retained by Upstream Pipelines**
**Dec 09 - Feb 10**

Schedule No. 1
Sheet 7

Retention costs are incurred proportionally to the volumes purchased, but recovery of the costs is allocated to quarter by volume consumed.

| | | | Units | Dec 09 - Feb 10 | Mar - May 10 | June - Aug 10 | Sept - Nov 10 | Annual Dec 2009 - Nov 2010 |
|---|---|---|---|---|---|---|---|---|
| | Gas purchased by CKY for the remaining sales customers | | | | | | | |
| 1 | Volume | | Dth | 1,875,000 | 3,228,000 | 4,405,000 | 2,519,000 | 12,027,000 |
| 2 | Commodity Cost Including Transportation | | | $12,389,000 | $20,083,000 | $27,599,000 | $16,573,000 | $76,644,000 |
| 3 | Unit cost | | $/Dth | | | | | $6.3727 |
| | Consumption by the remaining sales customers | | | | | | | |
| 11 | At city gate | | Dth | 6,035,000 | 2,417,000 | 679,000 | 2,062,000 | 11,193,000 |
| 12 | Lost and unaccounted for portion | | | 0.90% | 0.90% | 0.90% | 0.90% | |
| | At customer meters | | | | | | | |
| 13 | In Dth | (100% - 12) • 11 | Dth | 5,980,685 | 2,395,247 | 672,889 | 2,043,442 | 11,092,263 |
| 14 | Heat content | | Dth/MCF | 1.0558 | 1.0558 | 1.0558 | 1.0558 | |
| 15 | In MCF | 13 / 14 | MCF | 5,664,600 | 2,268,656 | 637,326 | 1,935,444 | 10,506,027 |
| 16 | Portion of annual | line 15, quarterly / annual | | 53.9% | 21.6% | 6.1% | 18.4% | 100.0% |
| | Gas retained by upstream pipelines | | | | | | | |
| 21 | Volume | | Dth | 187,000 | 159,000 | 187,000 | 116,000 | 649,000 |
| | Cost | | | To Sheet 1, line 9 | | | | |
| 22 | Quarterly. Deduct from Sheet 1 | 3 * 21 | | $1,191,688 | $1,013,253 | $1,191,688 | $739,229 | $4,135,857 |
| 23 | Allocated to quarters by consumption | | | $2,229,956 | $893,091 | $250,893 | $761,917 | $4,135,857 |
| | | | | To Sheet 1, line 18 | | | | |
| 24 | Annualized unit charge | 23 / 15 | $/MCF | $0.3937 | $0.3937 | $0.3937 | $0.3937 | $0.3937 |

# COLUMBIA GAS OF KENTUCKY, INC.

Schedule No. 1

Sheet 8

**DETERMINATION OF THE BANKING AND BALANCING CHARGE**
**FOR THE PERIOD BEGINNING DECEMBER 2009**

| Line No. | Description | Dth | Detail | Amount For Transportatioi Customers |
|---|---|---|---|---|
| 1 | Total Storage Capacity. Sheet 3, line 2 | 11,264,911 | | |
| 2 | Net Transportation Volume | 8,252,442 | | |
| 3 | Contract Tolerance Level @ 5% | 412,622 | | |
| 4 | Percent of Annual Storage Applicable | | | |
| 5 | to Transportation Customers | | 3.66% | |
| 6 | Seasonal Contract Quantity (SCQ) | | | |
| 7 | Rate | | $0.0289 | |
| 8 | SCQ Charge - Annualized | | $3,906,671 | |
| 9 | Amount Applicable To Transportation Customers | | | **$142,984** |
| 10 | FSS Injection and Withdrawal Charge | | | |
| 11 | Rate | | 0.0306 | |
| 12 | Total Cost | | $344,706 | |
| 13 | Amount Applicable To Transportation Customers | | | **$12,616** |
| 14 | SST Commodity Charge | | | |
| 15 | Rate | | 0.0213 | |
| 16 | Projected Annual Storage Withdrawal, Dth | | 8,355,000 | |
| 17 | Total Cost | | $177,962 | |
| 18 | Amount Applicable To Transportation Customers | | | **$6,513** |
| 19 | Total Cost Applicable To Transportation Customers | | | **$162,114** |
| 20 | Total Transportation Volume - Mcf | | | 18,658,484 |
| 21 | Flex and Special Contract Transportation Volume - Mcf | | | (10,842,191) |
| 22 | Net Transportation Volume - Mcf | line 20 + line 21 | | 7,816,293 |
| 23 | Banking and Balancing Rate - Mcf. | Line 19 / line 22. To line 11 of the GCA Comparison | | **$0.0207** |

PIPELINE COMPANY TARIFF SHEETS

Columbia Gas Transmission, LLC
FERC Gas Tariff
Third Revised Volume No. 1

Seventh Revised Sheet No. 25
Superseding
Sixth Revised Sheet No. 25

Currently Effective Rates
Applicable to Rate Schedule FTS, NTS and NTS-S
Rate Per Dth

| | | Base Tariff Rate 1/ | Transportation Cost Rate Adjustment Current | Transportation Cost Rate Adjustment Surcharge | Electric Power Costs Adjustment Current | Electric Power Costs Adjustment Surcharge | Annual Charge Adjustment 2/ | Total Effective Rate | Daily Rate |
|---|---|---|---|---|---|---|---|---|---|
| Rate Schedule FTS | | | | | | | | | |
| Reservation Charge 3/ | $ | 5.612 | 0.341 | 0.040 | 0.042 | 0.002 | - | 6.037 | 0.1985 |
| Commodity | | | | | | | | | |
| Maximum | ¢ | 1.04 | 0.23 | 0.04 | 0.58 | 0.08 | 0.19 | 2.16 | 2.16 |
| Minimum | ¢ | 1.04 | 0.23 | 0.04 | 0.58 | 0.08 | 0.19 | 2.16 | 2.16 |
| Overrun | ¢ | 19.49 | 1.35 | 0.17 | 0.72 | 0.09 | 0.19 | 22.01 | 22.01 |
| Rate Schedule NTS | | | | | | | | | |
| Reservation Charge 3/4/ | $ | 7.126 | 0.341 | 0.040 | 0.042 | 0.002 | - | 7.551 | 0.2483 |
| Commodity | | | | | | | | | |
| Maximum | ¢ | 1.04 | 0.23 | 0.04 | 0.58 | 0.08 | 0.19 | 2.16 | 2.16 |
| Minimum | ¢ | 1.04 | 0.23 | 0.04 | 0.58 | 0.08 | 0.19 | 2.16 | 2.16 |
| Overrun | ¢ | 24.47 | 1.35 | 0.17 | 0.72 | 0.09 | 0.19 | 26.99 | 26.99 |

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively. For rates by function, see Sheet No. 35.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ Minimum reservation charge is $0.00.
4/ The rates shown above for Service under Rate Schedule NTS shall be applicable to Service under Rate Schedule NTS-S except that the maximum Reservation Fee shall be adjusted to reflect the applicable expedited period of gas flow (EPF) utilizing the following formula, rounded to 3 decimal places:

NTS-S = NTS * (24/EPF) where:
NTS-S = NTS-S Reservation Fee
NTS = Applicable NTS Reservation Fee
24 = Number of Hours in a Gas Day
EPF = MDQ/MHQ

Issued by: Claire A. Burum, SVP Regulatory Affairs
Issued on: October 23, 2009
Effective on: November 1, 2009
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP09-792-000, et al., issued October 15, 2009, 129 FERC ¶ 61,037

Currently Effective Rates
Applicable to Rate Schedule SST and GTS
Rate Per Dth

| | | Base Tariff Rate 1/ | Transportation Cost Rate Adjustment Current | Transportation Cost Rate Adjustment Surcharge | Electric Power Costs Adjustment Current | Electric Power Costs Adjustment Surcharge | Annual Charge Adjustment 2/ | Total Effective Rate | Daily Rate |
|---|---|---|---|---|---|---|---|---|---|
| Rate Schedule SST | | | | | | | | | |
| Reservation Charge 3/ 4/ | $ | 5.442 | 0.341 | 0.040 | 0.042 | 0.002 | - | 5.867 | 0.1929 |
| Commodity | | | | | | | | | |
| Maximum | ¢ | 1.02 | 0.23 | 0.04 | 0.58 | 0.08 | 0.19 | 2.14 | 2.14 |
| Minimum | ¢ | 1.02 | 0.23 | 0.04 | 0.58 | 0.08 | 0.19 | 2.14 | 2.14 |
| Overrun 4/ | ¢ | 18.91 | 1.35 | 0.17 | 0.72 | 0.09 | 0.19 | 21.43 | 21.43 |
| Rate Schedule GTS | | | | | | | | | |
| Commodity | | | | | | | | | |
| Maximum | ¢ | 74.77 | 2.47 | 0.30 | 0.86 | 0.09 | 0.19 | 78.68 | 78.68 |
| Minimum | ¢ | 3.08 | 0.35 | 0.30 | 0.68 | 0.09 | 0.19 | 4.69 | 4.69 |
| MFCC | ¢ | 71.69 | 2.12 | 0.00 | 0.18 | 0.00 | - | 73.99 | 73.99 |

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively. For rates by function, see Sheet No. 35.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ Minimum reservation charge is $0.00.
4/ In addition to the above reflected Base Tariff SST Demand Rate, shippers utilizing the Eastern Market Expansion (EME) facilities for Rate Schedule SST service will pay an additional demand charge of $12.201 per Dth per month, for a total SST reservation charge of $17.643. If EME customers incur an overrun for SST services that is provided under their EME Project service agreements, they will pay an additional 40.11 cents for such overruns, for a total overrun rate of 59.02 cents. The applicable EME demand charge and EME overrun charge can be added to the Total Effective Rate above to calculate the EME Total Effective Rates.

Currently Effective Rates
Applicable to Rate Schedule FSS, ISS, and SIT
Rate Per Dth

| | | Base Tariff Rate 1/ | Transportation Cost Rate Adjustment Current | Transportation Cost Rate Adjustment Surcharge | Electric Power Costs Adjustment Current | Electric Power Costs Adjustment Surcharge | Annual Charge Adjustment 2/ | Total Effective Rate | Daily Rate |
|---|---|---|---|---|---|---|---|---|---|
| Rate Schedule FSS | | | | | | | | | |
| Reservation Charge 3/ | $ | 1.505 | - | - | - | - | - | 1.505 | 0.0495 |
| Capacity 3/ | ¢ | 2.89 | - | - | - | - | - | 2.89 | 2.89 |
| Injection | ¢ | 1.53 | - | - | - | - | - | 1.53 | 1.53 |
| Withdrawal | ¢ | 1.53 | - | - | - | - | - | 1.53 | 1.53 |
| Overrun 3/ | ¢ | 10.90 | - | - | - | - | - | 10.90 | 10.90 |
| Rate Schedule ISS | | | | | | | | | |
| Commodity | | | | | | | | | |
| Maximum | ¢ | 5.94 | - | - | - | - | - | 5.94 | 5.94 |
| Minimum | ¢ | 0.00 | - | - | - | - | - | 0.00 | 0.00 |
| Injection | ¢ | 1.53 | - | - | - | - | - | 1.53 | 1.53 |
| Withdrawal | ¢ | 1.53 | - | - | - | - | - | 1.53 | 1.53 |
| Rate Schedule SIT | | | | | | | | | |
| Commodity | | | | | | | | | |
| Maximum | ¢ | 4.12 | - | - | - | - | - | 4.12 | 4.12 |
| Minimum | ¢ | 1.53 | - | - | - | - | - | 1.53 | 1.53 |

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ In addition to the above reflected Base Tariff Reservation Charge (MDSQ) and Capacity (SCQ) Rate, shippers utilizing the Eastern Market Expansion (EME) facilities for FSS service will pay an additional incremental reservation charge of $2.626 per Dth per month, for a total FSS MDSQ reservation charge of $4.131 and an additional 3.91 cents per Dth per month, for a total FSS SCQ capacity rate of 6.80 cents. If EME customers incur an overrun for FSS services that is provided under their EME Project service agreements, they will pay an additional 12.54 cents for such overruns, for a total FSS overrun rate of 23.44 cents. The additional EME demand charges and EME overrun charges can be added to the Total Effective Rate above to develop the EME Total Effective Rate.

Currently Effective Rates
Applicable to Rate Schedule FTS-1
Rates per Dth

| | Base Rate (1) $ | Annual Charge Adjustment (2) $ 1/ | Subtotal (3) $ | Total Effective Rate (4) $ | Daily Rate (5) $ | Unaccounted For (6) % | Company Use and Unaccounted For (7) % |
|---|---|---|---|---|---|---|---|
| Rate Schedule FTS-1 | | | | | | | |
| Rayne, LA To Points North | | | | | | | |
| Reservation Charge 2/ | 3.1450 | - | 3.1450 | 3.1450 | 0.1034 | | |
| Commodity | | | | | | | |
| Maximum | 0.0170 | 0.0019 | 0.0189 | 0.0189 | 0.0189 | 0.644 | 3.028 |
| Minimum | 0.0170 | 0.0019 | 0.0189 | 0.0189 | 0.0189 | 0.644 | 3.028 |
| Overrun | 0.1204 | 0.0019 | 0.1223 | 0.1223 | 0.1223 | 0.644 | 3.028 |

1/ Pursuant to Section 154.402 of the Commission's Regulations. Rate applies to all Gas Delivered and is non-cumulative, i.e., when transportation involves more than one zone, rate will be applied only one time.

2/ The Minimum Rate under Reservation Charge is zero (0).

Currently Effective Rates
Applicable to Rate Schedules FTS and ITS
Rate per Dth

| | | Base Tariff Rate | Annual Charge Adjustment | Total Effective Rate | Daily Rate |
|---|---|---|---|---|---|
| Rate Schedule FTS | | | | | |
| Reservation Charge | | | | | |
| Maximum | $ | 0.509 | - | 0.509 | 0.0167 |
| Minimum | $ | 0.509 | - | 0.509 | 0.0167 |
| Commodity Charge | | | | | |
| Maximum | ¢ | 0.00 | 0.19 | 0.19 | 0.19 |
| Minimum | ¢ | 0.00 | 0.19 | 0.19 | 0.19 |
| Overrun | ¢ | 1.67 | 0.19 | 1.86 | 1.86 |
| Rate Schedule ITS | | | | | |
| Commodity Charge | | | | | |
| Maximum | ¢ | 1.67 | 0.19 | 1.86 | 1.86 |
| Minimum | ¢ | 1.67 | 0.19 | 1.86 | 1.86 |

RETAINAGE PERCENTAGE
Transportation Retainage 0.553%

DETAIL SUPPORTING

DEMAND/COMMODITY SPLIT

**Columbia Gas of Kentucky, Inc.**
**CKY Choice Program**
**100% Load Factor Rate of Assigned FTS Capacity**
**Balancing Charge**
**Dec 09 - Feb 10**

| Line No. | Description | | Contract Volume Dth Sheet 3 (1) | Retention (2) | Monthly demand charges $/Dth Sheet 3 (3) | # months A/ (4) | Assignment proportions lines 4, 5 (5) | Adjustment for retention on downstream pipe, if any (6) = 1 / (100%-col2) | Annual costs $/Dth (7) = 3 * 4 * 5 * 6 | Annual costs $/MCF |
|---|---|---|---|---|---|---|---|---|---|---|
| **City gate capacity assigned to Choice marketers** | | | | | | | | | | |
| 1 | Contract | | | | | | | | | |
| 2 | CKT FTS/SST | | 28,000 | 0.553% | | | | | | |
| 3 | TCO FTS | | 20,014 | 2.129% | | | | | | |
| 4 | Total | | 48,014 | | | | | | | |
| 5 | | | | | | | | | | |
| 6 | Assignment Proportions | | | | | | | | | |
| 7 | CKT FTS/SST | 1 / 3 | 58.32% | | | | | | | |
| 8 | TCO FTS | 2 / 3 | 41.68% | | | | | | | |
| 9 | | | | | | | | | | |
| 10 | | | | | | | | | | |
| **Annual demand cost of capacity assigned to choice marketers** | | | | | | | | | | |
| 11 | CKT FTS | | | | $0.5090 | 12 | 0.5832 | 1.0000 | $3.5620 | |
| 12 | TCO FTS | | | | $6.0370 | 12 | 0.4168 | 1.0000 | $30.1973 | |
| 13 | Gulf FTS-1, upstream to CKT FTS | | | | $3.1450 | 12 | 0.5832 | 1.0056 | $22.1310 | |
| 14 | TGP FTS-A, upstream to TCO FTS | | | | $4.6238 | 12 | 0.4168 | 1.0218 | $23.6316 | |
| 15 | | | | | | | | | | |
| 16 | Total Demand Cost of Assigned FTS, per unit | | | | | | | | $79.5218 | $83.9591 |
| 17 | | | | | | | | | | |
| 18 | 100% Load Factor Rate (10 / 365 days) | | | | | | | | | $0.2300 |
| 19 | | | | | | | | | | |
| 20 | | | | | | | | | | |
| **Balancing charge, paid by Choice marketers** | | | | | | | | | | |
| 21 | Demand Cost Recovery Factor in GCA, per Mcf per CKY Tariff Sheet No. 5 | | | | | | | | | $1.3009 |
| 22 | Less credit for cost of assigned capacity | | | | | | | | | ($0.2300) |
| 23 | Plus storage commodity costs incurred by CKY for the Choice marketer | | | | | | | | | $0.0914 |
| 24 | | | | | | | | | | |
| 25 | Balancing Charge, per Mcf sum(12:14) | | | | | | | | | $1.1622 |

**COLUMBIA GAS OF KENTUCKY**
**CASE NO. 2009- Effective December 2009 Billing Cycle**

CALCULATION OF DEMAND/COMMODITY SPLIT OF GAS COST ADJUSTMENT FOR TARIFFS

| | $/MCF | |
|---|---|---|
| Demand Component of Gas Cost Adjustment | | |
| Demand Cost of Gas (Schedule No. 1, Sheet 1, Line 23) | $1.4219 | |
| Demand ACA (Schedule No. 2 ) | -0.1154 | |
| Total Refund Adjustment | -0.0054 | |
| SAS Refund Adjustment (Schedule No. 5 ) | -0.0002 | |
| Total Demand Rate per Mcf | $1.3009 | <--- to Att. E, line 21 |
| Commodity Component of Gas Cost Adjustment | | |
| Commodity Cost of Gas (Schedule No. 1, Sheet 1, Line 22) | $5.7714 | |
| Commodity ACA (Schedule No. 2 ) | -$2.8383 | |
| Balancing Adjustment (Schedule No. 3 ) | $0.0691 | |
| Gas Cost Incentive Adjustment (Case No. 2009-00036) | $0.0584 | |
| Total Commodity Rate per Mcf | $3.0606 | |
| CHECK: | $1.3009 | |
| | $3.0606 | |
| COST OF GAS TO TARIFF CUSTOMERS (GCA) | $4.3615 | |
| Calculation of Rate Schedule SVGTS - Actual Gas Cost Adjustment | | |
| Commodity ACA (Schedule No. 2) | -$2.8383 | |
| Balancing Adjustment (Schedule No. 3) | $0.0691 | |
| Gas Cost Incentive Adjustment (Case No. 2009-00036) | $0.0584 | |
| Total Commodity Rate per Mcf | -$2.7108 | |

PROPOSED TARIFF SHEETS

**COLUMBIA GAS OF KENTUCKY, INC.**

## CURRENTLY EFFECTIVE BILLING RATES

| SALES SERVICE | Base Rate Charge | Gas Cost Adjustment[1/] | | Total Billing Rate | |
|---|---|---|---|---|---|
| | | Demand | Commodity | | |
| | $ | $ | $ | $ | |
| **RATE SCHEDULE GSR** | | | | | |
| Customer Charge per billing period | 12.35 | | | 12.35 | |
| Delivery Charge per Mcf | 1.8715 | 1.3009 | 3.0606 | 6.2330 | I |
| **RATE SCHEDULE GSO** | | | | | |
| Commercial or Industrial | | | | | |
| Customer Charge per billing period | 25.13 | | | 25.13 | |
| Delivery Charge per Mcf - | | | | | |
| First 50 Mcf or less per billing period | 1.8715 | 1.3009 | 3.0606 | 6.2330 | I |
| Next 350 Mcf per billing period | 1.8153 | 1.3009 | 3.0606 | 6.1768 | I |
| Next 600 Mcf per billing period | 1.7296 | 1.3009 | 3.0606 | 6.0911 | I |
| Over 1,000 Mcf per billing period | 1.5802 | 1.3009 | 3.0606 | 5.9417 | I |
| **RATE SCHEDULE IS** | | | | | |
| Customer Charge per billing period | 583.39 | | | 583.39 | |
| Delivery Charge per Mcf | | | | | |
| First 30,000 Mcf per billing period | 0.5467 | | 3.0606 [2/] | 3.6073 | I |
| Over 30,000 Mcf per billing period | 0.2905 | | 3.0606 [2/] | 3.3511 | I |
| Firm Service Demand Charge | | | | | |
| Demand Charge times Daily Firm | | | | | |
| Volume (Mcf) in Customer Service Agreement | | 6.5664 | | 6.5664 | R |
| **RATE SCHEDULE IUS** | | | | | |
| Customer Charge per billing period | 331.50 | | | 331.50 | |
| Delivery Charge per Mcf | | | | | |
| For All Volumes Delivered | 0.7750 | 1.3009 | 3.0606 | 5.1365 | I |

1/ The Gas Cost Adjustment, as shown, is an adjustment per Mcf determined in accordance with the "Gas Cost Adjustment Clause" as set forth on Sheets 48 through 51 of this Tariff. The Gas Cost Adjustment applicable to a customer who is receiving service under Rate Schedule GS or IUS and received service under Rate Schedule SVGTS shall be $7.1933 per Mcf only for those months of the prior twelve months during which they were served under Rate Schedule SVGTS I

2/ IS Customers may be subject to the Demand Gas Cost, under the conditions set forth on Sheets 14 and 15 of this tariff.

**DATE OF ISSUE:** October 26, 2009

**DATE EFFECTIVE:** November 25, 2009
(December Unit 1 Billing)

**ISSUED BY:** Herbert A. Miller, Jr.

President

## CURRENTLY EFFECTIVE BILLING RATES

(Continued)

| TRANSPORTATION SERVICE | Base Rate Charge $ | Gas Cost Adjustment[1/] Demand $ | Gas Cost Adjustment[1/] Commodity $ | Total Billing Rate $ | |
|---|---|---|---|---|---|
| **RATE SCHEDULE SS** | | | | | |
| Standby Service Demand Charge per Mcf | | | | | |
| Demand Charge times Daily Firm | | | | | |
| Volume (Mcf) in Customer Service Agreement | | 6.5664 | | 6.5664 | R |
| Standby Service Commodity Charge per Mcf | | | 3.0606 | 3.0606 | I |
| **RATE SCHEDULE DS** | | | | | |
| Administrative Charge per account per billing period | | | | 55.90 | |
| Customer Charge per billing period [2/] | | | | 583.39 | I |
| Customer Charge per billing period (GDS only) | | | | 25.13 | I |
| Customer Charge per billing period (IUDS only) | | | | 331.50 | |
| Delivery Charge per Mcf[2/] | | | | | |
| First 30,000 Mcf | 0.5467 | | | 0.5467 | |
| Over 30,000 Mcf | 0.2905 | | | 0.2905 | |
| – Grandfathered Delivery Service | | | | | |
| First 50 Mcf or less per billing period | | | | 1.8715 | |
| Next 350 Mcf per billing period | | | | 1.8153 | |
| Next 600 Mcf per billing period | | | | 1.7296 | |
| All Over 1,000 Mcf per billing period | | | | 1.5802 | |
| – Intrastate Utility Delivery Service | | | | | |
| All Volumes per billing period | | | | 0. 7750 | |
| Banking and Balancing Service | | | | | |
| Rate per Mcf | | 0.0207 | | 0.0207 | |
| **RATE SCHEDULE MLDS** | | | | | |
| Administrative Charge per account each billing period | | | | 55.90 | |
| Customer Charge per billing period | | | | 200.00 | |
| Delivery Charge per Mcf | | | | 0.0858 | |
| Banking and Balancing Service | | | | | |
| Rate per Mcf | | 0.0207 | | 0.0207 | |

1/ The Gas Cost Adjustment, as shown, is an adjustment per Mcf determined in accordance with the "Gas Cost Adjustment Clause" as set forth on Sheets 48 through 51 of this Tariff.

2/ Applicable to all Rate Schedule DS customers except those served under Grandfathered Delivery Service or Intrastate Utility Delivery Service.

**DATE OF ISSUE:** October 26, 2009

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(December Unit 1 Billing)

**ISSUED BY:** Herbert A. Miller, Jr. President

Revised Sheet No. 7

**COLUMBIA GAS OF KENTUCKY, INC.** P.S.C. Ky. No. 5

## CURRENTLY EFFECTIVE BILLING RATES

| | | Billing Rate $ |
|---|---|---|
| **RATE SCHEDULE SVGTS** | | |
| General Service Residential | | |
| Customer Charge per billing period | | 12.35 |
| Delivery Charge per Mcf | | 1.8715 |
| General Service Other - Commercial or Industrial | | |
| Customer Charge per billing period | | 25.13 |
| Delivery Charge per Mcf - | | |
| First 50 Mcf or less per billing period | | 1.8715 |
| Next 350 Mcf per billing period | | 1.8153 |
| Next 600 Mcf per billing period | | 1.7296 |
| Over 1,000 Mcf per billing period | | 1.5802 |
| Intrastate Utility Service | | |
| Customer Charge per billing period | | 331.50 |
| Delivery Charge per Mcf | | $ 0.7750 |
| Actual Gas Cost Adjustment 1/ | | |
| For all volumes per billing period per Mcf | ($ 2.7108) | |
| **RATE SCHEDULE SVAS** | | |
| Balancing Charge – per Mcf | $ 1.1622 | |

I

1/ The Gas Cost Adjustment is applicable to a customer who is receiving service under Rate Schedule SVGTS and received service under Rate Schedule GS, IS, or IUS for only those months of the prior twelve months during which they were served under Rate Schedule GS, IS or IUS.

**DATE OF ISSUE:** October 26, 2009

**DATE EFFECTIVE:** November 25, 2009 (December Unit 1 Billing)

**ISSUED BY:** Herbert A. Miller, Jr. President