Columbia Gas of Kentucky
A NiSource Company

September 30, 2014

Case No. 2014-00350

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

RECEIVED

SEP 30 2014

PUBLIC SERVICE COMMISSION

RE: Case No. 2012-00593

Dear Mr. Derouen:

Pursuant to the Commission's Order issued on October 25, 2013, in the above referenced case, Columbia Gas of Kentucky, Inc. ("Columbia") submits an original and ten (10) copies of its evaluation of other Kentucky LDC's Performance Based Rate Mechanisms and its application to modify and extend its existing Gas Cost Incentive and Off-System Sales and Capacity Release Revenue Sharing Mechanism. Columbia seeks to consolidate its mechanisms and convert to a performance-based rate mechanism that aligns with that approved by the Commission for Atmos Energy Corporation and Louisville Gas and Electric Company.

If you have questions, please don't hesitate to contact me at 859-288-0242 or jmcoop@nisource.com.

Sincerely,

Judy M. Cooper

Judy M. Cooper
Director, Regulatory Policy

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. TO CONSOLIDATE AND CONVERT ITS GAS COST INCENTIVE MECHANISM AND ITS OFF-SYSTEM SALES AND CAPACITY RE-LEASE REVENUE SHARING MECHANISM INTO A PERFORMANCE-BASED RATE MECHANISM.	))))))	Case No. 2014-00350 Case No. 2012-00593

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SEP 30 2014

PUBLIC SERVICE COMMISSION

APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC.

The petition of Columbia Gas of Kentucky, Inc. ("Columbia") respectfully states:

(a) Columbia is engaged in the business of furnishing natural gas services to the public in certain counties in the Commonwealth of Kentucky, pursuant to authority granted by the Commission.

(b) Columbia's full name and post office address is:

Columbia Gas of Kentucky, Inc.
2001 Mercer Road
P.O. Box 14241
Lexington, KY 40512-4241

(c) Pursuant to 807 KAR 5:001, Section 14(2), Columbia is a Kentucky corporation that was originally incorporated, as the Central Kentucky Natural

Gas Company, on October 11, 1905, changed its name to Columbia Gas of Kentucky, Inc. on March 13, 1957, and is currently in good standing.

(d) By Order dated October 25, 2013, in Case No. 2012-00593, the Commission ordered Columbia to evaluate its gas cost incentive mechanism ("GCIM") and off-system sales and capacity release revenue sharing mechanism ("OSS/CR RSM") as compared to other Kentucky LDCs' performance-based rate ("PBR") mechanisms.[1] The order further required this evaluation to be filed "along with any request to revise [Columbia's] incentive mechanisms or to continue them without modification."[2] The Commission noted that these revisions may include "modifications to the 50/50 sharing included in [Columbia's] current mechanisms," "the inclusion of additional months in its GCIM mechanism, as opposed to continuing to limit the time period to April through October, and including elements of its gas cost other than just its gas commodity cost."[3]

(e) Pursuant to this directive, Columbia evaluated its GCIM and OSS/CR RSM and compared its mechanisms to the PBR mechanisms of other Kentucky LDCs. This evaluation is attached to this application as Attachment A. Based on this evaluation and to be more consistent with other Kentucky LDCs, Columbia seeks Commission authorization to modify and extend the GCIM and

[1] Case No. 2012-00593, *Application of Columbia Gas of Kentucky, Inc. to Extend Its Gas Cost Incentive Mechanism and Revenue Sharing Mechanism* (Ky. PSC October 25, 2013) at 8.
[2] Case No. 2012-00593, *Application of Columbia Gas of Kentucky, Inc.* (Ky. PSC October 25, 2013) at 8.
[3] Case No. 2012-00593, *Application of Columbia Gas of Kentucky, Inc.* (Ky. PSC October 25, 2013) at 7.

OSS/CR RSM through the adoption of a PBR mechanism, alike to the PBR mechanisms of Atmos Energy Corporation ("Atmos") and Louisville Gas and Electric Company ("LG&E"). The proposed PBR mechanism will consolidate and extend the current GCIM and OSS/CR RSM. The PBR mechanism also modifies Columbia's existing mechanisms to address the components listed in the October 25, 2013 Order, which the Commission identified as areas where Columbia differed from other Kentucky LDCs. The proposed PBR mechanism discussed herein is further outlined in Attachment A, and the corresponding tariff changes are shown in Attachment B. To timely implement a modified mechanism at the expiration of the current OSS/CR RSM, Columbia requests an effective date of April 1, 2015 to implement the PBR mechanism.

PBR Mechanism

(f) The PBR Mechanism, as a three-part mechanism, has been utilized in Kentucky since 1997.[4] The Commission-approved Atmos and LG&E PBR mechanisms contain three components: (1) Gas Acquisition Index Factor ("GAIF"), (2) Transportation Index Factor ("TIF"), and (3) Off-System Sales Index Factor ("OSSIF").[5] To model this composition, Columbia proposes to adopt a three-prong PBR mechanism: (1) Gas Cost Incentive ("GCI"), that is a modified GCIM; (2) Transportation Cost Incentive ("TCI"), a new initiative modeled after

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[4] Case No. 2012-00593, *Application of Columbia Gas of Kentucky, Inc.* (Ky. PSC October 25, 2013) at 4.
[5] Case No. 2012-00593, *Application of Columbia Gas of Kentucky, Inc.* (Ky. PSC October 25, 2013) at 4.

the TIF, which includes capacity release credits; and (3) Off-System Sales Incentive ("OSSI"), that is a modified OSS/CR RSM. By adopting this mechanism composition, as well as revising key program components of the existing GCIM and OSS/CR RSM, Columbia's incentive mechanism will model those approved for other LDCs and result in a consistent performance-based rate mechanism being applied throughout Kentucky.

<u>GCI</u>

(g) As part of its Application filed in Case No. 2004-00462, Columbia proposed its initial GCIM for a period from April 1, 2005 to October 31, 2008. The Commission approved the GCIM as proposed by Order dated March 29, 2005. The Commission conditioned its approval, however, upon the annual filing of a GCIM report by November 30. Thereafter, Columbia was authorized to extend the GCIM through October 31, 2012, by a Commission Order dated April 15, 2009 in Case No. 2008-00433. The Commission subsequently extended the GCIM an additional two years by its October 25, 2013 Order in Case No. 2012-00593. The GCIM, without an approved extension, will expire on October 31, 2014.

(h) Columbia's existing GCIM compares the market standard to the summer (April through October) gas purchases, excluding those purchases made at the city gate, as there is no city gate index for Columbia. The market standard, or benchmark, is based on the NYMEX natural gas futures contract price adjusted for the prices published in Platt's *Inside FERC's Gas Market Report* for Henry Hub and the pipeline location at which Columbia purchases gas.[6] The effectiveness of the existing GCIM is measured when the summer monthly actual gas costs incurred by Columbia are below that benchmark price. Any value then realized by the GCIM are evenly shared between Columbia and customers through an adjustment to the Gas Cost Adjustment.[7]

(i) The GCIM has been a successful program to lower gas costs and share value with customers. Between 2005 and 2014, Columbia's efforts have resulted in a gas cost savings of approximately $2.5 million passed on to Columbia's customers.

(j) By its October 25, 2013 Order, the Commission directed Columbia to compare its GCIM to the LG&E and Atmos GAIF. As discussed in Attachment A, this evaluation revealed several differences between the GAIF and Columbia's existing GCIM. Based on its analysis of these differences, Columbia is proposing to incorporate its existing GCIM as the Gas Cost Incentive in the proposed PBR mechanism. Along with incorporating the GCI into the proposed PBR mechanism, Columbia proposes three significant modifications to the GCI to align Columbia's mechanism with that of other Kentucky LDCs. First, Columbia proposes to revise its 50/50 sharing percentage to model the percentage authorized for

[6] Columbia Gas of Kentucky, Inc. Tariff, P.S.C. Ky. No. 5, Eighth Revised Sheet No. 50.
[7] Columbia Gas of Kentucky, Inc. Tariff, P.S.C. Ky. No. 5, Eighth Revised Sheet No. 50.

Atmos. Adopting this modification would adjust Columbia's current 50/50 sharing percentage to a two-band sharing percentage: the first band covering variances from the actual cost benchmark ranging from 0% to 2% to be shared 70/30 in favor of customers; and, the second band covering variances over 2% to be shared 50/50 evenly between customers and Columbia. Second, Columbia proposes to extend the GCI program scope from seven months to a twelve-month, calendar year program to ensure customers capture any variance from peak season gas cost. Finally, Columbia proposes to revise the indices utilized in its market standard benchmark price by substituting the adjusted NYMEX price with the first-of-the-month *Inside FERC's Gas Market Report* price for each pipeline feeding into Columbia's system.

(k) With a modified GCI, Columbia will continue to file a report on the GCI with the Commission, but will move this report to June 1 of each year, beginning with the report filed on June 1, 2015. Therefore, Columbia recommends the modification and extension of the GCI as described herein.

OSSI

(l) As part of its Application filed in Case No. 2004-00462, Columbia proposed to implement on a permanent basis a re-established OSS/CR RSM. The Commission approved Columbia's proposal by Order dated March 29, 2005, with the condition that Columbia operate the OSS/CR RSM as a pilot program with a term ending March 31, 2009. By Orders dated April 15, 2009 and May 22, 2009 in Case No. 2008-00433, the Commission extended Columbia's OSS/CR RSM through March 31, 2013. The Commission further extended the OSS/CR RSM an additional two years by its October 25, 2013 Order in Case No. 2012-00593.Without an approved extension, the OSS/CR RSM will end on March 31, 2015.

(m) Columbia's existing OSS/CR RSM determines "all revenues generated from off-system sales ("OSS") and capacity release (other than those revenues generated by operational sales, administrative capacity release, or Rate Schedule SVAS capacity assignments), net of costs," and shares those revenues evenly between Columbia and customers.[8] All of Columbia's sales customers and CHOICE® program participants likewise receive the benefit of the OSS/CR RSM credits through an adjustment to the Gas Cost Adjustment.

(n) The OSS/CR RSM has been a successful program to lower costs and share value with customers. Between April 2005 and June 2014, Columbia's efforts have resulted in a gas cost savings of approximately $16.3 million passed on to Columbia's customers.

(o) By its October 25, 2013 Order, the Commission directed Columbia to examine its OSS/CR RSM as it compared to the LG&E and Atmos OSSIF. As

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[8] Columbia Gas of Kentucky, Inc. Tariff, P.S.C. Ky. No. 5, Eighth Revised Sheet No. 50a.

discussed in Attachment A, Columbia reviewed the components of the LG&E and Atmos OSSIF, and noted the differences between the OSSIF and Columbia's existing OSS/CR RSM. Based on its analysis of these differences, Columbia proposes to incorporate its existing OSS/CR RSM as the Off-System Sales Incentive (OSSI) into the proposed PBR mechanism. Along with incorporating the OSSI into the proposed PBR mechanism, Columbia proposes two modifications to the OSSI to align Columbia's mechanism with that of other Kentucky LDCs. First, the capacity release credits will be removed from this mechanism and included in Columbia's TCI formula to offset actual transportation costs. This model mirrors Atmos' approved TIF, which lessens its Total Annual Actual Transportation Costs by actual capacity release credits.[9] Second, similar to the GCI mechanism, Columbia proposes to adjust the sharing percentage to model the percentage authorized for Atmos. Adopting this modification would adjust Columbia's current 50/50 sharing percentage to a two-band sharing percentage: the first band covering variances from the actual cost benchmark ranging from 0% to 2% to be shared 70/30 in favor of customers; and, the second band covering variances over 2% to be shared 50/50 evenly between customers and Columbia.

(p) Therefore, Columbia recommends the modification and extension of the proposed OSSI effective on April 1, 2015.

[9] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 27.

TCI

(q) In addition to the modifications explained above, Columbia proposes to incorporate into the proposed PBR mechanism any value recognized through the negotiation of pipeline transportation contracts. Similar to Atmos and LG&E's TIF mechanism, the Transportation Cost Incentive ("TCI") is designed to capture and share any value realized between Columbia's pipeline transportation costs and the pipeline transportation rates filed and approved by the Federal Energy Regulatory Commission ("FERC"), less any actual capacity release credits. This incentive encourages Columbia to lower costs through negotiated pipeline transportation contract as a more cost efficient to the traditional method pipelines charge for firm pipeline transportation service. Including the TCI mechanism into Columbia's PBR mechanism will further align Columbia's incentives with those of Atmos and LG&E, both companies which have included such transportation cost value since 1997 and 1998, respectively.[10]

(r) Therefore, Columbia requests the approval of a TCI component to the PBR mechanism to further align Columbia's program with Atmos and LG&E and to provide another incentivizing opportunity to increase customer savings.

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[10] Case No. 2012-00593, *Application of Columbia Gas of Kentucky, Inc.* (Ky. PSC October 25, 2013) at 4.

WHEREFORE, Columbia respectfully requests that the Commission issue an order authorizing Columbia to adopt its proposed PBR mechanism, with a new TCI and a modified and extended GCI and OSSI, for the reasons described herein.

Dated at Columbus, Ohio, this 30th day of September, 2014.

Respectfully submitted,

COLUMBIA GAS OF KENTUCKY, INC.

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COLUMBIA GAS OF KENTUCKY, INC.

REPORT AND EVALUATION OF PERFORMANCE-BASED MECHANISMS

Commission-Ordered Evaluation
Case No. 2012-00593

Introduction

This evaluation and report responds to the Commission's Order dated October 25, 2013 in Case No. 2012-00593, in which the Commission ordered Columbia, no later than September 30, 2014, to file an evaluation of other Kentucky LDCs' PBR mechanisms, along with any request to revise or to continue without modification its incentive mechanisms.[11] The Commission further ordered Columbia to analyze each component of its Gas Cost Incentive Mechanism ("GCIM") and Off-System Sales and Capacity Release revenue sharing mechanism ("OSS/CR RSM") to assess: (1) the reasonableness of sharing between Columbia and customers; (2) the reasonableness of benchmarks; (3) the reasonableness of the time period and gas cost components covered by the GCIM; and, (4) the risk Columbia assumes and the cost involved in performing activities related to these incentives.[12] Based upon the Commission's directive, Columbia evaluated these components of its mechanisms and recommends the modifica-

[11] Case No. 2012-00593, *Application of Columbia Gas of Kentucky, Inc. to Extend Its Gas Cost Incentive Mechanism and Revenue Sharing Mechanism* (Ky. PSC October 25, 2013) at 8.
[12] *Id.*

tion of both the GCIM and OSS/CR RSM to further align these mechanisms with the PBR mechanisms of Atmos Energy Corporation ("Atmos") and Louisville Gas and Electric Company ("LG&E"). Specifically, Columbia recommends adopting a PBR mechanism, incorporating a modified Gas Cost Incentive ("GCI") and Off-System Sales Incentive ("OSSI"), and implementing a new Transportation Cost Incentive ("TCI") to share any value realized by pipeline transportation contracts.

I. Case History of Atmos, LG&E, and Columbia's Mechanisms

A. Atmos Energy Corporation

1. *Case History of Atmos PBR Mechanism*

Case No. 97-00513

On June 1, 1998, the Commission approved a three-year, experimental performance-based ratemaking ("PBR") mechanism for Atmos.[13] The Atmos PBR mechanism was composed of three components: (1) the Gas Acquisition Index Factor ("GAIF"), an incentive mechanism for gas commodity costs; (2) the Transportation Index Factor ("TIF"), an incentive mechanism for pipeline transportation costs, including capacity release revenues; and (3) the Off-System Sales In-

[13] Case No. 97-513, *Modification to Western Kentucky Gas Company, a Division of Atmos Energy Corporation (WKG) Gas Cost Adjustment to Incorporate an Experimental Performance-Based Ratemaking Mechanism (PBR)* (Ky. PSC June 1, 1998) at 1.

dex Factor ("OSSIF"), an incentive mechanism for off-system sales.[14] The GAIF compared Atmos's commodity costs to a benchmark based on the average for four indices: *Gas Daily, Natural Gas Week, Inside FERC,* and the NYMEX closing price.[15] The TIF compared Atmos's pipeline transportation costs to a benchmark based on Atmos's pipeline suppliers' FERC-approved transportation rates, and contained a capacity release threshold that Atmos was required to exceed before shareholders could realize value though capacity release activities.[16] The OSSIF realized the net of Atmos's revenues from off-system sales compared to the costs for such transactions.[17] The PBR provided for a 50/50 sharing between Atmos customers and shareholders of the variation of costs varying from the benchmarks.[18]

The Commission further defined each mechanism and its operation. The GAIF mechanism was to include no labor-related expenses or O&M expenses covered through the Gas Cost Adjustment mechanism. Second, the TIF mechanism benchmark was to be calculated using any discounted rate charged by any pipeline supplier. Finally, with the OSSIF mechanism, the out-of-pocket storage

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[14] Id. at 2.
[15] Case No. 2001-317, *Modification to Western Kentucky Gas Company, a Division of Atmos Energy Corporation, Gas Cost Adjustment to Incorporate an Experimental Ratemaking Mechanism (PBR)* (Ky. PSC Oct. 15, 2001) at 1.
[16] Case No. 2001-317, (Ky. PSC Oct. 15, 2001) at 2.
[17] Case No. 2001-317, (Ky. PSC Oct. 15, 2001) at 2.
[18] Case No. 2012-00593, *Application of Columbia Gas of Kentucky, Inc. to Extend its Gas Cost Incentive Mechanism and Revenue Sharing Mechanism* (Ky. PSC Oct. 25, 2013) at 4.

costs associated with Tennessee Gas Pipeline no-notice service was to be priced at the average price of gas in storage. During the first three years of the PBR, Atmos reported a totaled savings of $9 million.[19] Due to shareholders not being able to participate in savings achieved from capacity release activity, customers retained $4.75 million of savings and shareholders received $4.25 million.[20]

Case No. 2001-00317

On September 28, 2001, Atmos requested an extension of its PBR mechanism and a modification to the PBR mechanism to include a new Storage Development and Cost Recovery Factor ("SDRF") Mechanism.[21] On February 18, 2002, Atmos reached a settlement with the Kentucky Attorney General. As part of this settlement, Atmos withdrew its request for the SDRF mechanism; removed NYMEX from the GAIF benchmark if gas supply was managed in-house; eliminated the capacity threshold from the TIF; and expanded the OSSIF to include off-system sales of storage services. Importantly, the settlement established a two-band sharing mechanism for gas cost savings or expenses in excess gas costs.[22] If Atmos entered into a third-party gas supply agreement, then the sharing ratio for the first band (0% to 2% variance) would be 70/30 in favor of customers, with the

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[19] Case No. 2001-317, (Ky. PSC Oct. 15, 2001) at 3.
[20] Case No. 2001-317, (Ky. PSC Oct. 15, 2001) at 3.
[21] Case No. 2001-317, (Ky. PSC Oct. 15, 2001) at 1.
[22] Case No. 2001-317, (Ky. PSC Oct. 15, 2001) at 4. *See also* Case No. 2001-317, Settlement Agreement of Atmos and the Kentucky AG (Feb. 18, 2002) at 3.

second band (2% or greater variance) to be shared 50/50.[23] If Atmos did not enter into a third-party gas supply agreement or managed such gas supply "in-house" then the sharing ratio for the first band (0% to 2%) would be 75/25 in favor of customers, with the second band (2% or greater) to be shared 50/50.[24] The Commission approved the settlement and ordered the revised PBR to be extended for an additional four years.[25]

Case No. 2005-00321

On July 29, 2005, Atmos again requested a five-year extension of its PBR mechanism and a modification. Over a three-year period, the PBR mechanism recognized $9 million in savings, with Atmos's customers receiving $6.15 million.[26] Atmos proposed to modify the PBR mechanism to include the Gas Acquisition Index Factor for Asset Management ("GAIFAM"), which would recognize fixed supplier discounts not directly tied to per unit natural gas purchases.[27] Atmos also proposed to decrease the Percentage of Total Actual Gas Supply Costs

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[23] *Id.*
[24] *Id.*
[25] Case No. 2001-317, (Ky. PSC Oct. 15, 2001) at 4-5.
[26] Case No. 2005-00321, *Modification to Atmos Energy Corporation's Gas Cost Adjustment to Incorporate Performance-based Ratemaking Mechanism*, Submission of Report and Motion to Modify and Extend Performance-Based Ratemaking Mechanism (Jul. 29, 2005) at 1-2.
[27] Case No. 2005-00321, Submission of Report and Motion to Modify and Extend Performance-Based Ratemaking Mechanism (Jul. 29, 2005) at 10.

from the 2% threshold to 1%.[28] Atmos argued that such a decrease would recognize the current market conditions essentially doubled the Company's hurdle to receive 50/50 sharing.[29] The Commission reviewed Atmos's proposal, and approved the inclusion of the GAIFAM.[30] The Commission noted that not all gas supply bidders offer a discount, and that such a mechanism would allow Atmos greater flexibility with selecting an asset manager.[31] The Commission, however, rejected Atmos's request to decrease the sharing percentage threshold for 50/50 sharing from 2.0% to 1.0%, finding such a decrease would not benefit customers.[32] Finally, the Commission approved the extended term of the PBR mechanism for an additional five years through May 31, 2011.[33]

Case No. 2010-00353

On August 31, 2010, Atmos requested a five-year extension of its PBR mechanism and a slight modification to the GAIF mechanism.[34] Atmos requested removing the *Natural Gas Week* and *Gas Daily* indices from the Supply Area Index

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[28] Case No. 2005-00321, Submission of Report and Motion to Modify and Extend Performance-Based Ratemaking Mechanism (Jul. 29, 2005) at 11.
[29] Case No. 2005-00321, Submission of Report and Motion to Modify and Extend Performance-Based Ratemaking Mechanism (Jul. 29, 2005) at 11.
[30] Case No. 2005-00321, *Modification of Atmos Energy Corporation's Gas Cost Adjustment to Incorporate Performance Based Ratemaking Mechanism (PBR)* (Ky. PSC Feb. 8, 2006).
[31] Case No. 2005-00321, (Ky. PSC Feb. 8, 2006) at 5.
[32] Case No. 2005-00321, (Ky. PSC Feb. 8, 2006) at 5.
[33] *Id.* at 7.
[34] Case No. 2010-00353, *Modification of Atmos Energy Corporation's Gas Cost Adjustment to Incorporate Performance Based Ratemaking Mechanism (PBR)*, Submission of Report and Motion to Modify and Extend Performance Based Ratemaking Mechanism (Aug. 31, 2010).

factor for Base Load and the Delivery Area Index factor for Base Load because neither index directly pertained to the first-of-month or base load purchases.[35] The Commission approved the modification to the GAIF mechanism to remove the two indices, and further approved the PBR mechanism for an additional five-year term through May 31, 2015.[36]

2. *Current Atmos PBR Mechanism*

The Atmos PBR mechanism remains composed of three elements: (1) the Gas Acquisition Index Factor ("GAIF"); (2) the Transportation Index Factor ("TIF"); and, (3) the Off-System Sales Index Factor ("OSSIF").[37] The GAIF is the sum of the base load, swing load, and asset management indices.[38] The base load and swing load indices are calculated by comparing the benchmark gas commodity costs to the actual gas commodity costs.[39] The asset management index factor ("GAIFAM") represents "the portion of fixed discounts provided by the supplier for asset management rights, if any, not directly tied to per unit natural gas purchase."[40] These indices are added together to create the total value recog-

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[35] Case No. 2010-00353, Submission of Report and Motion to Modify and Extend Performance Based Ratemaking Mechanism (Aug. 31, 2010) at 12.

[36] Case No. 2010-00353, *Modification of Atmos Energy Corporation's Gas Cost Adjustment to Incorporate Performance Based Ratemaking Mechanism (PBR)* (Ky. PSC Dec. 7, 2010).

[37] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 18.

[38] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 19.

[39] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 19.

[40] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 19.

nized under the GAIF.[41] Atmos's TIF likewise continues to compare the benchmarked transportation costs with the actual transportation costs incurred by Atmos.[42] Such actual transportation costs include pipeline demand and volumetric costs, applicable FERC approved surcharges, and direct bills less actual capacity release credits.[43] Finally, the OSSIF is comprised of the total revenue generated by off-system sales less the out-of-pocket costs associated with off-system sales transactions.[44]

Atmos then calculates the sum of the GAIF, TIF, and OSSIF, applies its PRM Mechanism sharing mechanism.[45] For all shared value less than 2%, Atmos shares 70/30 in favor of customers; however, if the shared value varies greater than 2%, it shares 50/50 with its customers.[46]

B. Louisville Gas and Electric Company

1. *Case History of LG&E PBR Mechanism*

Case No. 97-00171

On September 30, 1997, the Commission approved a three-year, experimental performance-based ratemaking ("PBR") mechanism for the Louisville

[41] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 19.
[42] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 26.
[43] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 27.
[44] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 28.
[45] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 18.
[46] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 29.

Gas and Electric Company ("LG&E").[47] Similar to Atmos, the LG&E PBR mechanism was composed of three components: (1) the Gas Acquisition Index Factor ("GAIF"), an incentive mechanism for gas commodity costs; (2) the Transportation Index Factor ("TIF"), an incentive mechanism for pipeline transportation costs, including capacity release revenues; and, (3) the Off-System Sales Index Factor ("OSSIF"), an incentive mechanism for off-system sales.[48] The GAIF compared LG&E's commodity costs to a benchmark based on the average for four indices: *Gas Daily, Natural Gas Week, Inside FERC,* and the NYMEX closing price.[49] The GAIF also included LG&E's pipeline reservation fees that were benchmarked against the average actual reservation fees incurred by LG&E for the two most recent years. The TIF compared LG&E's pipeline transportation costs to a benchmark based on LG&E's pipeline suppliers' FERC-approved transportation rates, and contained a capacity release threshold that LG&E was required to exceed before shareholders could realize value though capacity release activities.[50] The OSSIF realized the net of LG&E's revenues from off-system sales compared to the costs for such transactions.[51] The PBR provided for a 50/50 sharing between

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[47] Case No. 97-00171, *Modifications To Louisville Gas and Electric Company's Gas Supply Clause To Incorporate An Experimental Performance-Based Ratemaking Mechanism* (Ky. PSC Sept. 30, 1997).
[48] Case No. 2001-00017, *Modifications To Louisville Gas and Electric Company's Gas Supply Clause To Incorporate An Experimental Performance-Based Ratemaking Mechanism* (Ky. PSC Oct. 26, 2001).
[49] Case No. 2001-00017, *Modifications To Louisville Gas and Electric Company's Gas Supply Clause To Incorporate An Experimental Performance-Based Ratemaking Mechanism* (Ky. PSC Oct. 26, 2001).
[50] Case No. 2001-00017, (Ky. PSC Oct. 26, 2001).
[51] Case No. 2001-00017, (Ky. PSC Oct. 26, 2001).

LG&E customers and shareholders of the variation of costs varying from the benchmarks.[52]

The Commission further defined LG&E's originally proposed mechanisms and their operation. The GAIF mechanism was not to include net financial transaction costs associated with risk management activities against gas cost savings, labor-related expenses or O&M expenses covered through the Gas Cost Adjustment mechanism.[53] LG&E was also ordered to include all Texas Gas Pipeline's No-Notice Service ("NNS") storage injection volumes and cost in the GAIF.[54] The TIF mechanism included a capacity release threshold for LG&E to exceed before shareholders could participate in the value from capacity release.[55] During the first three years of the PBR, LG&E reported a totaled savings of $19.6 million.[56] Due to shareholders not being able to participate in savings achieved from capacity release active, customers retained $10.7 million of savings and shareholders received $8.9 million.[57]

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52 Case No. 2001-00017, (Ky. PSC Oct. 26, 2001).

53 Case No. 97-00171, *Modifications To Louisville Gas and Electric Company's Gas Supply Clause To Incorporate An Experimental Performance-Based Ratemaking Mechanism* (Ky. PSC Sept. 30, 1997) at 2.

54 Case No. 97-00171, (Ky. PSC Sept. 30, 1997) at 5.

55 Case No. 97-00171, (Ky. PSC Sept. 30, 1997) at 3.

56 Case No. 2001-00017, (Ky. PSC Oct. 26, 2001) at 2.

57 Case No. 2001-00017, (Ky. PSC Oct. 26, 2001) at 2.

Case No. 2001-00017

On December 28, 2000, LG&E requested an extension of its PBR mechanism and a modification to the PBR mechanism to include the sale of storage-related services as part of the OSSIF and to add a new Storage Development and Cost Recovery Factor ("SDRF") to the PBR mechanism.[58] The Commission reviewed LG&E's application, and approved the continuation of the PBR mechanism for an additional four years, with some modifications, and denied LG&E's proposed SDRF. First, the Commission removed the NYMEX from the GAIF because the more appropriate balance of indices included *Inside FERC* for monthly purchase, *Natural Gas Week* for weekly purchases, and *Gas Daily* for daily purchases.[59] The Commission also approved LG&E's request to expand the OSSIF to include off-system sales of storage services.[60]

Finally, though LG&E did not propose a change to the existing sharing ratio, the Commission explained that this issue was raised in both data requests and cross-examination at hearing. Both the Kentucky Attorney General and LG&E noted that if the sharing ratio changed, "such a change should reflect changes in the levels of risk to which LG&E is exposed."[61] The Commission determined that LG&E had the greatest exposure of risk with capacity release and

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[58] Case No. 2001-00017, (Ky. PSC Oct. 26, 2001) at 1.
[59] Case No. 2001-00017, (Ky. PSC Oct. 26, 2001) at 7.
[60] Case No. 2001-00017, (Ky. PSC Oct. 26, 2001) at 9.
[61] Case No. 2001-00017, (Ky. PSC Oct. 26, 2001) at 11.

supply reservation fees. Therefore, the Commission removed the capacity release threshold from the PBR, but retained the supply reservation fees as a component of the GAIF.[62] The Commission next determined that during the pilot period, LG&E consistently beat the benchmarks by 4 to 6 percent, with an average savings of 4.7%. Because LG&E could not demonstrate that customers were better off under the PBR mechanism than traditional ratemaking, the 50/50 sharing was revised to reflect this percentage.[63] Therefore, in the event the total shared value varied from the benchmarks less than 4.5%, LG&E was ordered to share 75/25 in favor of customers; however, if shared value was greater than 4.5%, the Commission ordered a 50/50 sharing between LG&E and its customers.

Case No. 2005-00031

On December 30, 2004, LG&E requested a five-year extension of its PBR mechanism and a modification. LG&E proposed to modify the PBR sharing mechanism. In lieu of the 4.5% threshold for shared value, LG&E proposed the following sliding scale: 0% to 2% will result in a 30/70 split in favor of customers; 2% to 3% will result in a 40/60 in favor of customers; 3% to 4% will result in a 50/50 split; and 4% and greater will result in 60/40 split in favor of LG&E. The Commission rejected this proposed modification because such a scheme would

[62] Case No. 2001-00017, (Ky. PSC Oct. 26, 2001) at 11-12.
[63] *Id.*

"unnecessarily complicate the mechanism."[64] The Commission did, however, approve the extended term of the PBR mechanism for an additional five years through October 31, 2010.[65] During this time period, LG&E realized $45.7 million in savings, with LG&E's customers realizing $33.165 million and LG&E receiving $12.5 million.[66]

Case No. 2009-00550

On December 30, 2009, LG&E requested a five-year extension of its PBR mechanism and a slight modification to the GAIF mechanism.[67] LG&E requested the inclusion of a new Supply Area Index ("SAI") to reflect the availability the new interstate pipeline, the Rockies Express Pipeline LLC.[68] The Commission approved the modification to the GAIF mechanism, and further approved the PBR mechanism for an additional five-year term through October 31, 2015.[69]

2. *Current LG&E PBR Mechanism*

The LG&E PBR mechanism remains composed of three elements: the Gas Acquisition Index Factor ("GAIF); the Transportation Index Factor ("TIF"); and,

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[64] Case No. 2005-00031, (Ky. PSC May 27, 2005).
[65] *Id.* at 7.
[66] Case No. 2009-00550, *Request of Louisville Gas and Electric Company for Modification and Extension of its Gas Supply Cost Performance-Based Ratemaking Mechanism* (Ky. PSC April 30, 2010).
[67] Case No. 2009-00550, (Ky. PSC April 30, 2010).
[68] Case No. 2009-00550, (Ky. PSC April 30, 2010).
[69] Case No. 2009-00550, (Ky. PSC April 30, 2010).

the Off-System Sales Index Factor ("OSSIF").[70] The GAIF compares (1) the benchmark gas commodity costs and 24-month average historical supply reservation fees[71] with (2) the actual gas commodity costs and supply reservation fees plus the gains and/or losses from the financial hedging instruments and the financial transaction costs associated therewith.[72] LG&E's TIF likewise compares the benchmarked monthly transportation costs with the actual transportation costs incurred by LG&E.[73] Such actual transportation costs include pipeline demand and volumetric costs, applicable FERC approved surcharges, and direct bills.[74] Finally, the OSSIF is comprised of the total revenue generated by off-system sales less the out-of-pocket costs associated with off-system sales transactions.[75]

LG&E then calculates the sum of the GAIF, TIF, and OSSIF, applies its PRM Mechanism sharing mechanism.[76] For the shared value is less than 4.5%, LG&E shares 75/25 in favor of customers; however, if the shared value varies greater than 4.5%, it shares 50/50 with its customers.[77]

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[70] Louisville Gas and Electric Company Tariff, PSC Ky. Gas No. 9, First Revision of Original Sheet No. 87.

[71] LG&E Tariff, PSC Ky. Gas No. 9, First Revision of Original Sheet No. 87 – 87.1.

[72] LG&E Tariff, PSC Ky. Gas No. 9, First Revision of Original Sheet Nos. 87, 87.4.

[73] LG&E Tariff, PSC Ky. Gas No. 9, First Revision of Original Sheet No. 87.4.

[74] LG&E Tariff, PSC Ky. Gas No. 9, First Revision of Original Sheet Nos. 87.4 – 87.5.

[75] LG&E Tariff, PSC Ky. Gas No. 9, First Revision of Original Sheet No. 87.6.

[76] LG&E Tariff, PSC Ky. Gas No. 9, First Revision of Original Sheet Nos. 87, 87.7.

[77] LG&E Tariff, PSC Ky. Gas No. 9, First Revision of Original Sheet No. 87.7.

C. Columbia Gas of Kentucky, Inc.

1. *Case History of Columbia GCIM and OSS/CR Mechanism*

Case No. 1996-00079

The Commission first approved Columbia's OSS/CR RSM in Case No. 1996-00079 by Order dated July 31, 1996.[78] Columbia originally proposed an OSS mechanism with a 50/50 sharing percentage and a CR mechanism with a 65/35 sharing percentage; however, the Commission denied this proposal.[79] The Commission ordered the utilization of a 65/35 sharing percentage for both the OSS and CR mechanisms.[80] For the OSS mechanism, the Commission ordered a larger percentage of sharing to customers because "some of the off-system sales may be bundled with capacity paid for by ratepayers, and because all of the sales will be effected by Columbia resources that were developed to provide a public utility service...."[81] Likewise, the Commission approved Columbia's CR mechanism as proposed, but required Columbia to adopt a benchmark to ensure a measure of success under the program.[82] Both the OSS and CR mechanisms were approved

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[78] Case No. 1996-00079, *Tariff Filing of Columbia Gas of Kentucky, Inc. To Implement Gas Cost Incentive Rate Mechanisms* (Ky. PSC July 31, 1996). Columbia originally filed an application to implement an OSS/CR RSM in Case No. 95-00353, but it filed a motion to withdraw this application on January 29, 1996, and the Commission granted its motion to withdrawn by Order dated January 31, 1996. Columbia refiled its application for approval of an OSS/CR RSM in Case No. 96-00079 on March 1, 1996.

[79] Case No. 1996-00079, *Tariff Filing of Columbia Gas of Kentucky, Inc. To Implement Gas Cost Incentive Rate Mechanisms* (Ky. PSC July 31, 1996) at 1.

[80] Case No. 1996-00079, (Ky. PSC July 31, 1996) at 2, 5.

[81] Case No. 1996-00079, (Ky. PSC July 31, 1996) at 2.

[82] Case No. 1996-00079, (Ky. PSC July 31, 1996) at 4-5.

for a period of two years on a pilot basis through July 31, 1998.[83] The Commission extended these programs for an additional year by Order dated July 27, 1998, but ordered Columbia to broaden the scope of its incentive programs with any application to continue to OSS and CR mechanisms.[84]

Case No. 1999-00165

On April 22, 1999, Columbia filed an application with the Commission to implement its CHOICE® program and to request approval to extend its OS and CR mechanisms.[85] In its application, Columbia proposed continuing both at the current sharing percentage of 65/35. The Commission, however, denied the extension of the mechanisms[86] and ordered Columbia to attribute its capacity release revenues to decrease gas costs[87] and off-system sales to offset stranded costs.[88] In response to the Commission's denial to extend its gas cost incentive program, Columbia filed a petition for rehearing.[89] The Commission granted this request,[90] and ordered the continuation of the OSS mechanism, and permitted Columbia to retain 25 percent of the revenues, with 75 percent of the revenues

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[83] Case No. 1996-00079, (Ky. PSC July 31, 1996) at 5.
[84] Case No. 1996-00079, (Ky. PSC July 27, 1998) at 2.
[85] Case No. 1999-00165, *Tariff Filing of Columbia Gas of Kentucky, Inc. To Implement A Small Volume Gas Transportation, To Continues Its Gas Cost Incentive Mechanisms, and To Continue Its Customer Assistance Program* (Ky. PSC Jan. 27, 2000) at 1.
[86] Case No. 1999-00165, (Ky. PSC Jan. 27, 2000) at 22-23.
[87] Case No. 1999-00165, (Ky. PSC Jan. 27, 2000) at 12.
[88] Case No. 1999-00165, (Ky. PSC Jan. 27, 2000) at 13.
[89] Case No. 1999-00165, (Ky. PSC Mar. 6, 2000) at 1.
[90] Case No. 1999-00165, (Ky. PSC Mar. 6, 2000).

funding stranded costs under the CHOICE® program.[91] The Commission further ordered that if any excess revenues existed at the end of the CHOICE® pilot program, that such revenues should be credited to both sales and CHOICE® customers.

Case No. 2004-00462

On November 30, 2004, Columbia filed an application to extend the CHOICE® Program and to implement a new OSS/CR RSM, a summer GCIM and Hedging Program.[92] Columbia specifically requested authority to re-establish the OSS/CR RSM similar to the program established prior to the implementation of the CHOICE® Program.[93] The GCIM was proposed as a summer only program (April 1 through October 31) to credit customers the value of summer gas purchases, while crediting customers with the value of winter gas purchases through its proposed hedging program running from November 1 through March 31.[94] Both the GCIM and OSS/CR RSM were proposed with a 50/50 sharing percentage.

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[91] Case No. 1999-00165, (Ky. PSC May 19, 2000) at 1-2, 4.

[92] Case No. 2004-00462, *The Application of Columbia Gas of Kentucky, Inc. to Implement a New Small Volume Gas Transportation Service, A Gas Price Hedging Plan, An Off-System Sales and Capacity Release Revenue Sharing Mechanism, and A Gas Cost Incentive Mechanism* (Ky. PSC March 29, 2005).

[93] Case No. 2004-00462, (Ky. PSC March 29, 2005) at 3.

[94] Case No. 2004-00462, (Ky. PSC March 29, 2005) at 3.

The AG challenged Columbia's proposed sharing percentage as inappropriate and punitive, claiming such a ratio was different than LG&E and Atmos.[95] Columbia responded that a higher percentage was necessary "in order to recognize that the higher sharing percentage is more of an incentive to participate in a segment of the energy business that is not a core segment of an LDC's regulated business."[96] Columbia further argued that differences between the levels of the sharing mechanism was appropriate because Atmos and LG&E's "incentives included the sharing of reductions in demand costs from pipelines, such as through flexed rates."[97] By including these discounts in their incentive mechanisms, LG&E and Atmos were able to benefit from the "credits for discounts received on their transportation contracts with interstate pipelines."[98] Thus, Columbia argued to keep its 50/50 sharing mechanism.

The AG also argued against the proposed GCIM benchmark of the NYMEX closing price. According to the AG, such a benchmark did not represent an "apples-to-apples comparison of Columbia's total summer purchasing practice and gas supply management."[99] Columbia responded that the NYMEX closing prices provide an appropriate benchmark by setting a base price "for the very same months at the very same locations at which Columbia is negotiating its

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[95] Case No. 2004-00462, Comments of the Attorney General (Feb. 14, 2005) at 4.
[96] Case No. 2004-00462, Comments of Columbia Gas of Kentucky, Inc. (February 24, 2005) at 4-5.
[97] Case No. 2004-00462, Comments of Columbia Gas of Kentucky, Inc. (February 24, 2005) at 5-6.
[98] Case No. 2004-00462, Comments of Columbia Gas of Kentucky, Inc. (February 24, 2005) at 6.
[99] Case No. 2004-00462, Comments of the Attorney General (Feb. 14, 2005) at 6.

prices."[100] Thus, Columbia recommended the approval of its GCIM and, in response to the AG's recommendation, offered to provide an annual review after each summer comparing its monthly purchases to the monthly benchmarks.[101]

By Order dated March 29, 2005, the Commission approved the GCIM and OSS/CR RSM as proposed, with a few conditions and modification. The Commission approved the OSS/CR RSM as a pilot program effective through March 31, 2009, to correspond with the term of the CHOICE® Program.[102] The Commission also approved the GCIM through October 31, 2008, but required Columbia to file a report by November 30 each year.[103]

Case No. 2008-00433

On October 3, 2008, Columbia filed an application to extend its GCIM and OSS/CR RSM for an additional four years without modification.[104] Interstate Gas Supply, Inc. ("IGS") moved to intervene and requested that the Commission limit both mechanisms to a two-year extension.[105] Both IGS and Columbia reached a settlement in the case recommending the four-year extension of both mecha-

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[100] Case No. 2004-00462, Comments of Columbia Gas of Kentucky, Inc. (February 24, 2005) at 8-9.
[101] Case No. 2004-00462, Comments of Columbia Gas of Kentucky, Inc. (February 24, 2005) at 9.
[102] Case No. 2004-00462, (Ky. PSC March 29, 2005) at 8-9.
[103] Case No. 2004-00462, (Ky. PSC March 29, 2005) at 8-9.
[104] Case No. 2008-00433, *Application of Columbia Gas of Kentucky, Inc. to Extend Its Gas Cost Incentive Program and Its Off-System Sales And Capacity Release Sharing Mechanism* (Ky. PSC April 15, 2009) at 1.
[105] Case No. 2008-00433, (Ky. PSC April 15, 2009) at 2.

nisms.[106] The Commission, however, found that the Stipulation contained contradictory language regarding the continuation of the 50/50 sharing percentage with the OSS/CR RSM as it was tied to the CHOICE® Program.[107] The Commission found that "the reasonableness of continuing the current 50 percent sharing ratio and the terms thereof should be addressed in a future proceeding regardless of Columbia's plans for the future of the CHOICE® Program."[108]

Nonetheless, the Commission found that the GCIM and OSS/CR RSM had operated as projected and found that the programs had "provided adequate incentives to Columbia to manage its gas supply so that its management thereof has inured to the benefit of its customers."[109] The Commission approved the extension of Columbia's GCIM through October 31, 2012, and the OSS/CR RSM through March 31, 2013, but cautioned that the continuation of 50 percent sharing ratio beyond March 31, 2011 would be determined in a future proceeding.[110]

Case No. 2012-00593

On December 28, 2012, Columbia filed another application to extend the GCIM and OSS/CR RSM without modification for an additional four years.[111] By

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[106] Case No. 2008-00433, (Ky. PSC April 15, 2009) at 2-3.
[107] Case No. 2008-00433, (Ky. PSC April 15, 2009) at 4-5.
[108] Case No. 2008-00433, (Ky. PSC April 15, 2009) at 5.
[109] Case No. 2008-00433, (Ky. PSC April 15, 2009) at 5.
[110] Case No. 2008-00433, (Ky. PSC April 15, 2009) at 6.
[111] Case No. 2012-00593, *Application of Columbia Gas of Kentucky Inc. To Extend Its Gas Cost Incentive and Revenue Sharing Mechanism* (Ky. PSC March 27, 2013).

Order dated March 27, 2013, the Commission approved the continued use of the GCIM and OSS/CR RSM until its final Order would be issued in the proceeding.[112] Seven months later, the Commission issued its final order, approving the extension of the GCIM and OSS/CR RSM as proposed until October 31, 2014 and March 31, 2015, respectively.[113] Notwithstanding this extension, the Commission ordered Columbia to evaluate its GCIM and OSS/CS RSM before September 30, 2014.[114] The Commission outlined the components of the evaluation and charged Columbia to review its mechanisms versus the existing performance-based mechanisms of other Kentucky LDCs.[115]

2. *Current Columbia GCIM and OSS/CR Mechanism*

Columbia's GCIM and OSS/CR Mechanism have been unchanged since Case No. 2004-00462, when the current mechanisms were proposed. The GCIM compares (1) the benchmark gas commodity cost, which is based on the NYMEX gas futures contract settlement price for the month adjusted for the difference between the Henry Hub first-of-the-month price in Platt's *Inside FERC's Gas Market Report* and the pipeline location at which Columbia purchases gas,[116] and (2) the

[112] Case No. 2012-00593, (Ky. PSC March 27, 2013).
[113] Case No. 2012-00593, *Application of Columbia Gas of Kentucky Inc. To Extend Its Gas Cost Incentive and Revenue Sharing Mechanism* (Ky. PSC October 25, 2013).
[114] Case No. 2012-00593, (Ky. PSC October 25, 2013) at 8.
[115] Case No. 2012-00593, (Ky. PSC October 25, 2013) at 7.
[116] Columbia Gas of Kentucky, Inc. Tariff, PSC Ky. No. 5, Eighth Revised Sheet No. 50.

actual gas commodity costs.[117] The GCIM (known as the Gas Cost Incentive Adjustment in Columbia's tariff), then applies a 50% allocation to the shared value realized, and credits this 50% to Columbia's customers.[118] Columbia's GCIM does not include supply purchase reservation fees in its calculation of actual costs. Likewise, the OSS/CR RSM credits to customer 50% of all revenues generated by off-system sales and capacity release, other than revenues generated by operational sales, administrative capacity release, or Rate Schedule SVAS capacity assignments, less the costs associated with off-system sales and capacity release transactions.[119]

From 2004 to 2014 Columbia's GCIM and OSS/CR RSM reported a total customer savings of $18.8 million.

II. Evaluation and Modification of Columbia's PBR Mechanism

Columbia was charged with evaluating its GCIM and OSS/CS RSM by Order dated October 25, 2013. The Commission required Columbia to "perform a review of the PBR mechanisms discussed in this Order, as well as any other mechanisms or information available concerning best practices with regard to gas cost incentive mechanisms."[120] Such an evaluation should explore "possible

[117] Columbia Gas of Kentucky, Inc. Tariff, PSC Ky. No. 5, Eighth Revised Sheet No. 50.
[118] Columbia Gas of Kentucky, Inc. Tariff, PSC Ky. No. 5, Eighth Revised Sheet No. 50.
[119] Columbia Gas of Kentucky, Inc. Tariff, PSC Ky. No. 5, Fifth Revised Sheet No. 50a.
[120] Case No. 2012-00593, *Application of Columbia Gas of Kentucky, Inc. To Extend Its Gas Cost Incentive Mechanism and Revenue Sharing Mechanism* (Ky. PSC October 25, 2013) at 7.

modifications to the 50/50 sharing included in its current mechanisms," "the inclusion of additional months in its GCIM mechanism, as opposed to continuing to limit the time period to April through October, and including elements of its gas cost other than just its gas commodity cost."[121]

The Commission further ordered that when Columbia filed its evaluation, it should also include a request to revise the mechanisms or continue them without modification. Accompanying the extension request would be a detailed analysis of each component of the proposed GCIM and OSS/CS RSM "including the reasonableness of the benchmarks, the reasonableness of the sharing between Columbia and customers, the reasonableness of the time period and gas cost components covered by the GCIM, and the risk Columbia assumes, and the cost involved in performing activities related to these incentives."[122]

Pursuant to the Commission's Order, Columbia has reviewed the Atmos and LG&E PBR mechanisms and is proposing modifications to its GCIM and OSS/CR RSM to align Columbia's incentive mechanisms with those adopted by the other Kentucky LDCs.

A. Adoption of a PBR Mechanism

Columbia's GCIM and OSS/CR RSM have operated as two independent mechanisms. Such a composition is vastly different from the LG&E and Atmos

[121] Case No. 2012-00593, (Ky. PSC October 25, 2013) at 7.
[122] Case No. 2012-00593, (Ky. PSC October 25, 2013) at 8.

PBR mechanism model. The PBR mechanism, as approved by the Commission beginning in 1997, is a three-part, integrated mechanism incorporating three incentive factors: (1) Gas Acquisition Index Factor ("GAIF"), (2) Transportation Index Factor ("TIF"), and (3) Off-System Sales Index Factor ("OSSIF").[123] This model aggregates the value garnered by the GAIF, TIF, and OSSIF, compares such value to the actual gas costs, and then proportionally splits shared value based on a variance from the benchmark. Allowing each incentive mechanism to work cohesively to consolidate and share the value is a more efficient and effective way to incent Columbia and share savings with customers.

To model this composition, Columbia is proposing to modify its two, independent incentive mechanisms into a three-component PBR mechanism. Columbia proposes to adopt a three-prong PBR mechanism with the following incentives: (1) Gas Cost Incentive ("GCI"), a modified GCIM; (2) Transportation Cost Incentive ("TCI"), a new initiative modeled after the TIF, which includes capacity release credits; and (3) Off-System Sales Incentive ("OSSI"), a modified OSS/CR RSM. The proposed GCI is an initiative incorporating three modifications to Columbia's existing GCIM: changed sharing percentage, year-long program, and revised benchmark indices. Likewise, the OSSI is an initiative incorporating two modifications to Columbia's existing OSS/CR RSM – changing the

[123] Case No. 2012-00593, (Ky. PSC October 25, 2013) at 4.

sharing percentage and transferring the capacity release credits to the TCI. The TCI is an initiative incorporating the LG&E and Atmos TIF factor into Columbia's incentive sharing program. A more complete description of the PBR mechanism's incentives is contained below.

By adopting a three-prong PBR mechanism, as well as revising key program components of the existing GCIM and OSS/CR RSM, Columbia's incentive mechanism will model the PBR mechanism approved for LG&E and Atmos, and will result in a consistent performance-based rate mechanism being applied throughout Kentucky.

1. Gas Cost Incentive ("GCI")

Columbia's existing GCIM mechanism is structured similarly to the Atmos and LG&E mechanisms. All three LDCs compare the actual gas costs incurred with a benchmark based upon certain indices. However, as noted by the Commission in its October 25, 2013 Order, in certain aspects, Columbia's existing GCIM mechanism has differed significantly from those of Atmos and LG&E. These differences have prompted Columbia to request inclusion of the existing GCIM into Columbia's proposed PBR mechanism, and to modify three aspects of the mechanism: (1) sharing percentage; (2) duration of the program; and, (3) benchmark's indices.

a. **Sharing Percentage**

Columbia's 50/50 sharing percentage for the existing GCIM, as well as the OSS/CR RSM, was controversial when it was originally adopted in Case No. 2004-00462. When arguing for a higher percentage, Columbia explained that such a higher sharing percentage ratio incentivized Columbia to participate in a segment of the energy business that is not a core segment of an LDC's regulated business.[124] Columbia also noted that both LG&E and Atmos "included the sharing of reductions in demand costs from pipelines, such as through flexed rates" and such activity rewarded these companies with "credits for discounts received on their transportation contracts with interstate pipelines."[125] Likewise, in Case No. 2008-00433, the Commission adopted a Stipulation continuing the 50/50 sharing mechanism for the OSS CR RSM mechanism, but the Commission cautioned that continuation of this ratio after March 31, 2011 would be determined in a later proceeding.[126]

In contrast, both Atmos and LG&E began with the 50/50 sharing percentage for their PBR mechanisms. However, in each company's second PBR mechanism proceedings, the Commission adjusted the sharing percentage downward.

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[124] Case No. 2004-00462, Reply Comments of Columbia Gas of Kentucky, Inc. (February 24, 2005) at 4-5.

[125] Case No. 2004-00462, Reply Comments of Columbia Gas of Kentucky, Inc. (February 24, 2005) at 5.

[126] Case No. 2008-00433, *Application of Columbia Gas of Kentucky, Inc. to Extend Its Gas Cost Incentive Program and Its Off-System Sales and Capacity Release Sharing Mechanism* (Ky. PSC April 15, 2009).

For Atmos, the Commission lowered the percentage to a 70/30 ratio for the first 2% variance from the benchmark of actual gas costs, and increased the percentage to 50/50 for any shared value in excess of 2%. Likewise, for LG&E, the Commission lowered the sharing percentage to a 75/25 ratio for the first 4.5% variance from the benchmark of actual gas costs, and increased the percentage to 50/50 for any shared value in excess of a 4.5% variance.

Columbia recognizes that its sharing mechanism is unique because its incentive mechanisms currently do not share pipeline transportation contract value, unlike the LG&E and Atmos TIF. Columbia acknowledges that to move its incentive programs to align with other Kentucky LDCs, it should revise its sharing percentage to reward customers with a greater portion of savings and, in the unlikely event of a negative performance, expenses. Therefore, Columbia proposes to adjust its sharing percentage to mirror that of Atmos. By adopting the Atmos sharing percentage, Columbia would implement a two-band sharing percentage for all of the shared value under the proposed PBR mechanism, including the GCI value. The first band would cover variances from the actual cost benchmark ranging from 0% to 2% to be shared 70/30 in favor of customers. The second band would cover variances over 2% of the actual cost benchmark to be shared 50/50 evenly between customers and Columbia. This mechanism will provide for a lesser initial opportunity for Columbia to share in savings up to a certain pre-established level, with the ability to share 50/50 only after it reaches that threshold. Because both LG&E and Atmos have established such a threshold, Columbia proposes to likewise adopt a revised sharing percentage for a consistent sharing opportunity for Kentucky customers.

b. Duration of the GCI

Columbia originally proposed its GCIM as a summer mechanism. The mechanism was originally designed to record the summer months when there is an incentive to find supply that is cheaper than the benchmarked average price of gas. Columbia recognizes that both the LG&E and Atmos PBR mechanisms run year-round. Though the program was developed around maximizing Columbia's buying power in the summer months, Columbia agrees that a year round, twelve-month program would maximize the potential value available to its customers. Therefore, Columbia proposes to include in its proposed PBR mechanism a modified GCI that captures gas cost purchases for an entire calendar year.

c. Benchmark Indices

The indices utilized by LG&E, Atmos and Columbia to benchmark each company's gas cost incentive mechanism differs greatly. Columbia's existing GCIM utilizes the NYMEX closing price as is published in *Inside FERC's Gas Monthly Report* for the months and locations in which it purchases, adjusted for the difference in gas value based on the Henry Hub price and the actual locations at which Columbia purchases gas. Conversely, LG&E and Atmos create a benchmark by averaging the daily, weekly, and monthly prices for each pipeline serving its system. Both LG&E and Atmos no longer utilize the NYMEX closing price.

For example, LG&E calculates its gas commodity benchmark commodity costs as follows:

> **BMGCC** represents Benchmark Gas Commodity Costs and shall be calculated on a monthly basis and accumulated for the PBR period. BMGCC shall be calculated as follows:
>
> **BMGCC = Sum {[SZFQE%i x (APV - PEFDCQ)x SAIi]} + [PEFDCQ x DAI]**
>
> Where:
>
> **SZFQE%** is the Supply Zone Firm Quantity Entitlement Percentage derived from Company's firm entitlements by pipeline and by zone for which indices are posted. The percentage represents the pro-rata portion of Company's firm lateral and mainline receipt point quantity entitlements by zone for each transportation contract by pipeline.
>
> i represents each supply area.
>
> **APV** is the actual purchased volumes of natural gas for system supply for the month. The APV shall include purchases necessary to cover retention volumes required by the pipeline as fuel.
>
> **PEFDCQ** are the Purchases In Excess of Firm Daily Contract Quantities delivered to Company's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.
>
> **SAI** is the Supply Area Index factor to be established for each supply area in which Company has firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission - Zone SL), TGT-1 (Texas Gas Transmission - Zone 1), TGT-4 (Texas Gas Transmission – Zone 4), TGPL-0 (Tennessee Gas Pipeline - Zone 0), and TGPL-1 (Tennessee Gas Pipeline - Zone 1).

The monthly SAI for TGT-SL, TGT-1, TGT-4, TGPL-0 and TGPL-1 shall be calculated using the following formula:

$$\mathbf{SAI = [I(1) + I(2) + I(3)] / 3}$$

DAI is the Delivery Area Index to be established for purchases made by Company when Company has fully utilized its pipeline quantity entitlements on a daily basis and which are for delivery to Company's city gate from either Texas Gas Transmission's Zone 4 or Tennessee Gas Pipeline's Zone 2.

The monthly DAI for TGT-4 and TGPL-2 shall be calculated using the following formula:

$$\mathbf{DAI = [I(1) + I(2) + I(3)] / 3}$$

Where:

I represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

Columbia recognizes the need to adjust its benchmarks to more appropriately recognize the pipelines that feed its system. Therefore, similar to LG&E and Atmos, Columbia proposes modifying the benchmark indices utilized in the proposed GCI.

Columbia currently purchase gas supplies from Columbia Gulf mainline, Columbia Gas Transmission interconnects and pooling points, and Tennessee Gas Pipeline 500 Leg. The benchmark for each of these pipelines will be determined by utilizing the first-of-the-month index posting, as reported in Platt's *Inside FERC's Gas Market Report* for each supply area in which Columbia purchases gas supplies. The benchmark cost ("BC") for each supply area will be calculated by multiplying the monthly actual volumes purchased by supply area, by the applicable supply area index as described below.

1) BC–COLML for purchases made on Columbia Gulf mainline.
   BC–COLML is the Platt's *Inside FERC's Gas Market Report* first-of-the-month posting (midpoint) for Columbia Gulf mainline

multiplied by the monthly volumes purchased on the Columbia Gulf Mainline.

2) BC–COLTCO for purchases made on Columbia Gas Transmission at interconnects and pooling points.

BC–COLTCO is the Platt's *Inside FERC's Gas Market Report* first-of-the-month posting (midpoint) for Columbia Appalachia multiplied by the monthly volumes purchased on the Columbia Gas Transmission Pipeline.

3) BC–TGP500 for purchases made on Tennessee Gas Pipeline 500 Leg

BC–TGP500 is the Platt's *Inside FERC's Gas Market Report* first-of-the-month posting (midpoint) for Tennessee Gas 500 Leg multiplied by the monthly volumes purchased on the Tennessee Gas Pipeline 500 Leg.

Though Columbia purchases a majority, if not all, of its gas supplies from these pipelines, there are times when Columbia may purchase gas at a point not reported in Platt's *Inside FERC's Gas Market Report*. In those rare occasions, Columbia proposes to use the next closest index on the applicable pipeline upstream of the purchase point and add to that the 100% load factor cost of firm transportation between the index location and the purchase point. If an applicable index ceases to exist, Columbia will choose a suitable replacement index and immediately report the change to the Commission.

Columbia believes this more comprehensive benchmark reflecting the gas supply pipelines in which Columbia receives service more accurately benchmarks the actual cost to receive gas than the NYMEX closing price. Changing the benchmark as described above moves Columbia's gas cost benchmark closer to that of LG&E and Atmos. Therefore, Columbia proposes to modify its benchmark to the indices described above for the proposed GCI.

d. Cost and Risk Associated with GCI

Finally, Columbia examined the risk it assumes and the costs involved in performing activities related to the existing GCIM. Under the Columbia's existing GCIM when the Actual Cost for gas purchased in the month is less than the Benchmark cost, the result is a positive performance. When the Columbia's gas purchase costs are greater than the Benchmark Cost, the result for the month is a negative performance. The resulting negative or positive performance amount is shared between Columbia and its sales customers.[127] The only cost included in this total is the actual cost to purchase the gas, whether by contract or on the market. Such a practice is similar to Atmos, which offsets its GAIF benchmark against the total monthly actual gas commodity costs for its base load and swing load.[128] Likewise, LG&E only includes the actual commodity costs and nets out the, supply reservation fees, the gains and/or losses from the use of financial hedging instruments, and the financial transaction costs associated with such instruments paid by the company to its suppliers.[129] Because its program is structured similar to that of Atmos and LG&E, in that the only costs which are fac-

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[127] Columbia Gas of Kentucky, Inc. Tariff, PSC Ky. No. 5, Eighth Revised Sheet No. 50.
[128] Atmos Energy Corporation Tariff, PSC Ky. No. 2, Original Sheet No. 22.
[129] LG&E Tariff, PSC Ky. Gas No. 9, First Revision of Original Sheet No. 87.4.

tored into the existing GCIM are those directly tied to the price paid by Columbia to purchase the gas commodity, Columbia recommends not changing its mechanism to include additional costs into its proposed GCI.

Likewise, Columbia reviewed the risk associated with the existing GCIM. Because Columbia is proposing to move from a summer-month program to a twelve-month program, Columbia may be required to purchase additional supplies during the winter period, in a gas market in which gas prices have increased above the first of the month price. Columbia will strive to mitigate this increased risk, however Columbia's primary objective is to provide firm reliable gas service to meet all firm supply demand requirements. There is no way to estimate the value of this potential increased program risk.

2. OSSI

a. Sharing Percentage

The rationale underlying Columbia's 50/50 sharing percentage for the existing OSS/CR RSM mirrors its rationale for the existing GCIM. And similarly, Columbia recognizes that its sharing mechanism is unique because its existing program currently does not share the pipeline transportation contract value, unlike the PBR mechanism adopted by and LG&E. Corresponding with the proposed modification to the GCI, coupled with the adoption of a lower sharing percentage for a band for shared value, Columbia proposes to likewise modify the OSSI to include the Atmos sharing percentage model. By adopting the Atmos sharing percentage, Columbia would implement a two-band sharing percentage for all shared value under the proposed PBR mechanism, including the OSSI. The first band would cover variances from the actual cost benchmark ranging from 0% to 2% to be shared 70/30 in favor of customers. The second band would cover variances over 2% of the actual cost benchmark to be shared 50/50 evenly between customers and Columbia. The guarantee of more value shared through the 2% variance from the benchmark provides additional benefits to customers and incentivizes Columbia to achieve more savings to reach the 50/50 sharing threshold.

b. Capacity Release Credits

Columbia, in addition to reviewing the sharing percentage, also reviewed other LDCs' treatment of capacity release credits. Columbia existing OSS/CR RSM adds capacity release credits to its off-system sales to produce shared value credited to customers. Conversely, LG&E does not recognize capacity release credits, and Atmos includes its capacity release credits to offset its Total Annual Actual Transportation Costs, to increase the likelihood of shared value under its TIF program. Columbia believes such credits are a valuable and integral part of the PBR mechanism. Moreover, Columbia only releases pipeline capacity to counterparties that have established adequate credit with the corresponding interstate pipeline company. Therefore, to model Atmos's approved TIF model, Columbia is proposing to move its capacity release credits from the existing OSS/CR RSM, to the newly proposed TCI.

c. Cost and Risk Associated with OSSI

Finally, Columbia examined the risk it assumes and the costs involved in performing activities related to the existing OSS/CR RSM. Columbia has very limited risk associated with off system sales. All costs, which includes the cost of the commodity and, if applicable, transportation, associated with an OSS are considered and included when a sale is agreed to with a counterparty. Columbia only makes sales to creditworthy counterparties that have an executed North American Energy Standards Board ("NAESB") agreement.

Therefore, because the risk is low and the costs are limited to the actual costs associated with acquiring and transporting the commodity, Columbia believes no additional modification is warranted for the OSS/CR RSM than is proposed above.

3. TCI

Stemming from the evaluation of its existing GCIM and OSS/CR RSM, Columbia noted a marked difference between its incentive mechanisms and other Kentucky LDCs – transportation incentive factor. When initially adopting its

GCIM mechanism in Case No. 2004-00462, Columbia argued to keep a different sharing percentage than LG&E and Atmos due to this difference.[130] Notwithstanding this difference, Columbia recognizes that its sharing mechanism should be revised to better align with the sharing percentages applied to the value generated under LG&E and Atmos programs. Likewise, Columbia requests to include a new incentive in its program to share the value generated by pipeline transportation contracts.

Columbia proposes to incorporate a Transportation Cost Incentive, which operates similar to the Atmos and LG&E TIF. The TCI will compare Columbia's Total Benchmark Transportation Costs ("TBTC") to the Total Actual Transportation Costs ("TATC").[131] To determine the benchmark transportation costs, Columbia will determine a benchmark for each of the three interstate pipelines where it purchases gas for its system, based on the pipeline's tariffed demand and commodity rate, plus any additional surcharges, direct bills, and other tariffed amounts approved by FERC. Then Columbia will compare this benchmark to the actual transportation costs, which includes the pipeline demand and vol-

[130] Case No. 2004-00462, Reply Comments of Columbia Gas of Kentucky, Inc. (February 24, 2005) at 5.

[131] See the tariffs attached hereto as Attachment B at First Sheet 50c.

umetric costs paid by Columbia, plus any additional surcharges, direct bills, less any capacity release credits (originally included in the existing OSS/CR RSM).[132]

Therefore, because Columbia is proposing to adjust its sharing percentage downward to the sharing percentages adopted by Atmos, Columbia likewise requests the implementation of its TCI correspondingly share any value created by its pipeline transportation contract.

Conclusion

Through this evaluation of its existing GCIM and OSS/CR RSM, Columbia requests modifying both mechanisms and incorporating them into a PBR mechanism, modeled after the PBR mechanisms adopted by LG&E and Atmos. Columbia's request adjusts the sharing percentage to give customers are larger percentage of initial shared value up to a 2% threshold, thus incentivizing Columbia to further increase the shared value between customers and the company. The modifications also extend the time period of the GCI, and incorporate indices similar to those utilized by LG&E and Atmos. Finally, Columbia's proposed PBR mechanism includes the sharing of the value from pipeline transportation contract through the TCI, designed to model LG&E and Atmos's TIF.

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[132] See the tariffs attached hereto as Attachment B at First Sheet 50c.

The changes proposed by Columbia herein moves the Kentucky LDCs closer to more consistent mechanisms, giving Kentucky LDCs the same incentive to produce savings and customers an equal opportunity to share in the value created by the PBR mechanisms.

ATTACHMENT B

COLUMBIA GAS OF KENTUCKY, INC. TARIFF
PSC KY. NO. 5

SHEET NOS. 48 – 50D

CLEAN AND REVISED

COLUMBIA GAS OF KENTUCKY, INC.

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Determination of Gas Cost Adjustment (GCA)

Company shall file a quarterly report with the Commission which shall contain an updated Gas Cost Adjustment (GCA) Rate and shall be filed at least thirty (30) days prior to the beginning of each quarterly calendar period. The GCA shall become effective for billing with the final meter readings of the first billing cycle of each quarterly calendar period.

The gas cost adjustment is comprised of:

(1) The Expected Gas Cost Component (EGC), on a dollar-per-Mcf basis, is made up of two components: (a) Expected Commodity Gas Cost which applies to Rate Schedules GS, IS, and IUS, and represents the average expected commodity cost of gas supplied, and (b) Expected Demand Gas Cost which applies to Rate Schedules GS,IUS and SVAS, and represents the average expected demand cost of gas supplied, excluding the Standby Service demand costs to be recovered from IS Customers and General Service Delivery Service Customers.

(2) The supplier Refund Adjustment (RA), on a dollar-per-Mcf basis, which reflects refunds received during the reporting period plus interest at a rate equal to the average of the "three month commercial paper rate" for the immediately preceding twelve month period. In the event of any large or unusual refunds, Company may apply to the Commission for the right to depart from the refund procedure herein set forth.

(3) The Actual Cost Adjustment (ACA), on a dollar-per-Mcf basis, which compensates for any previous over or undercollections of gas costs experienced by the company through the operation of this gas cost recovery procedure. The ACA shall be based on the twelve months ended June 30th each year, with the ACA factor to be in effect for twelve months beginning September 1st of each year.

(4) The Balancing Adjustment (BA), on a dollar-per-Mcf basis, which compensates for any under or overcollections which have occurred as a result of prior adjustments.

(5) The Performance Based Rate Adjustment (PBRA), on a dollar-per–Mcf basis, which is calculated annually based on the prior twelve month period ending March 31, with the PBRA factor to be in effect for twelve months beginning June 1st each year.

NOTE: All adjustments will be assigned to the Expected Demand Gas Cost or Expected Commodity Gas Cost components.

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ISSUED BY	Herbert A. Miller, Jr.
TITLE	President

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Gas Cost Adjustment Clause – (Continued)

~~(7)~~ (6)The Gas Cost Uncollectible Rate (GCUR) on a dollar-per-Mcf basis, which is calculated by multiplying the Expected Commodity Gas Cost times the uncollectible accrual rate used to establish rates in Columbia's most recent rate case. T

Billing

The Gas Cost Adjustment (GCA) shall be the sum of the following components:

GCA = EGC + RA + ACA + BA + PBRA + GCUR T, N

The GCA will be added to (or subtracted from) the tariff rates prescribed by the Commission Order on Company's latest rate case and will be included in the tariff rates stated on each applicable rate sheet in this tariff.

Definitions

For the purpose of this tariff:

(a) "Average expected cost" is the cost of gas supplies purchased during the latest available twelve month period, including associated transportation charges, storage charges and Take-or-Pay charges, which is determined by the application of suppliers' rates currently in effect, or reasonably expected to be in effect during the quarterly calendar period, less banking and balancing charges, and less the demand costs to be recovered from IS and General Service Delivery Service Customers, divided by the sales volumes for the latest available twelve month period. Where the calculations require the use of volumes used during a given period, and those volumes did not exist for a particular source for the entire period, or Company expects the volumes to change substantially, Company may make appropriate adjustments in its calculations. Any adjustments of this type shall be described in the Quarterly Gas Cost Adjustment report.

(b) "Quarterly calendar period" means each of the four three month periods of (1) September through November, (2) December through February, (3) March through May, and (4) June through August.

(c) "Reporting period" means the three month accounting period that ended approximately thirty (30) days prior to the filing date of the updated gas recovery rates, i.e. the three months ended June 30th, September 30th, December 31st, and March 31st each year.

D

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ISSUED BY Herbert A. Miller, Jr.
TITLE President

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Gas Cost Adjustment Clause – (Continued)

Performance Based Rate Adjustment ("PBRA") T, N

The Performance Based Rate Adjustment (PBRA) shall be calculated annually as follows:

PBRA = CPS / PSV

Where:

PSV = Projected Sales Volume in Mcf, as reflected in the Company's GCA filing for the upcoming twelve month period

CPS = Company Performance Share

CPS = TPBR x ASP

Where:

TPBR = Total Performance Based Results. The TPBR shall be savings or expenses created during the twelve month period and shall be calculated as follows:

TPBR = (GCI + TCI + OSSI)

ASP = Applicable Sharing Percentage

GCI

GCI = Gas Cost Incentive will measure, on a monthly basis, the Company's Actual gas Costs **(AC)** during the twelve month period for system supply natural gas purchases, against a Benchmark Cost **(BC)** during the same period to determine a Performance Value **(PV).**

The monthly **PV** shall be calculated as follows:

PV = (BC-COLML – AC-COLML) + (BC-COLTCO – AC-COLTCO) + (BC-TGP500 – AC-TGP500)

Where:

BC–COLML = is the Platt's *Inside FERC's Gas Market Report* first-of-the-month index posting (midpoint) for Columbia Gulf Mainline multiplied by the monthly volumes purchased on the Columbia Gulf Mainline.

AC-COLML = is the total, actual monthly cost of volumes purchased by Columbia on the Columbia Gulf Mainline.

D

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ISSUED BY Herbert A. Miller, Jr.
TITLE President

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Gas Cost Adjustment Clause – (Continued)

BC–COLTCO = is the Platt's *Inside FERC's Gas Market Report* first-of-the-month index posting (midpoint) for Columbia Appalachia multiplied by the monthly volumes purchased on the Columbia Gas Transmission Pipeline.

AC-COLTCO = is the total, actual monthly cost of volumes purchased by Columbia on the Columbia Gas Transmission Pipeline.

BC-TGP500 = is the Platt's *Inside FERC's Gas Market Report* first-of-the-month index posting (midpoint) for Tennessee Gas 500 Leg multiplied by the monthly volumes purchased on the Tennessee Gas Pipeline 500 Leg.

AC-TGP500 = is the total, actual monthly cost of volumes purchased by Columbia on the Tennessee Gas Pipeline 500 Leg.

When the Company's Actual Cost for gas purchased in the month is less than the Benchmark Cost, the result for the month is a positive performance. When the Company's gas purchase costs are greater than the Benchmark Cost, the result for the month is a negative performance. The resulting negative or positive Performance Value (PV) will be shared between the Company and its sales customers pursuant to the GCA calculation.

If the Company purchases gas at a point not reported in the applicable index publication. The Company will use the next closest index on the applicable pipeline upstream of the purchase point, and add to that index the 100% load factor cost of firm transportation on that pipeline between the index location and the purchase point.

Purchases made at Columbia's own city gate as well as any supply reservation fees are excluded from the GCI process and calculation.

If the index used to develop the Benchmark Cost ceases to exist or ceases to adequately report those prices required in the normal implementation of this GCI, the Company shall choose a suitable replacement index, assuming an acceptable index is available, and immediately report that change in writing to the Commission.

TCI

I

TCI = Transportation Cost Incentive. The Transportation Cost Incentive shall be calculated by comparing the annual Total Benchmark Transportation Costs **(TBTC)** of natural gas transportation services during the twelve month period to the annual Total Actual Transportation Costs **(TATC)** during the same period as follows:

TCI = (TBTC – TATC)

Where:

TBTC = Annual sum of monthly **BTC**

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TITLE President

COLUMBIA GAS OF KENTUCKY, INC.

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

N

Gas Cost Adjustment Clause – (Continued)

BTC = Sum [BM (TCO) + BM (TGP) + BM (CKT) + BM (CGT) + BM (PPL)]

Where:

BM (TCO) is the benchmark associated with Columbia Gas Transmission.

BM (TGP) is the benchmark associated with Tennessee Gas Pipeline Company.

BM (CKT) is the benchmark associated with Central Kentucky Transmission.

BM (CGT) is the benchmark associated with Columbia Gulf Transmission.

BM (PPL) is the benchmark associated with a proxy pipeline. This benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from nontraditional sources.

The benchmark associated with each pipeline shall be calculated as follows:

BM (TCO) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM (TGP) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM (CKT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM (CGT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM (PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.

DQ is the Demand Quantities contracted for by the Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable charges approved by the Federal Energy Regulatory Commission (FERC).

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TITLE	President

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Gas Cost Adjustment Clause – (Continued)

N

The Total Actual Transportation Costs (TATC) paid by Company for the period shall include both pipeline demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC approved surcharges, direct bills included in S&DB, less actual capacity release credits. Such costs shall exclude labor related or other expenses typically classified as operating and maintenance expenses.

Should one of the Company's pipeline transporters file a rate change effective during any period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12 month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

OSSI

T, N

OSSI = Off-system Sales Incentive. The OSSI shall be equal to the revenues net of costs from off-system sales (other than those revenues generated by operational sales).

Results of operation sales, administrative capacity releases and Rate Schedule SVAS capacity assignments will be credited 100% to gas cost.

ASP

N

ASP = Applicable Sharing Percentage. The ASP shall be determined based on the Percentage of Actual gas costs **(PAC)**.

Where:

PAC = TPBR / AGC

Where:

AGC = Actual Gas Costs. AGC is the sum of the actual gas costs used in determination of the **GCI** and **TCI**.

If the absolute value of PAC is less than or equal to 2.0%, then the ASP of 30% shall be applied to the total savings or expenses of the TPBR. If the absolute value of the PAC is greater than 2.0%, then the ASP of 30% shall be applied to the amount of the sum of the TPBR that is equal to 2.0% of AGC to determine that portion of the total savings or expense, and the ASP of 50% shall be applied to the sum of the TPBR that is in excess of 2.0% of AGC to determine that portion of the total savings or expense.

COLUMBIA GAS OF KENTUCKY, INC.

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Gas Cost Adjustment Clause – (Continued)

Delivery Service

FERC approved direct billed pipeline supplier charges relating to the buyout of Take-or-Pay liabilities will be billed to Delivery Service Fixed Rate Volumes.

Banking and Balancing Service

This rate is based on the percentage of the portion of storage capacity allocated to Delivery Service Customers to Company's total annual storage capacity, applied to:

(1) Columbia Transmission's FSS seasonal capacity charge, annualized,

(2) Columbia Transmission's SST commodity charge, and

(3) Columbia Transmission's FSS injection and withdrawal charges as calculated in the Gas Cost Adjustment.

Interim Gas Cost Adjustments

Should any significant change in supplier rates occur, Company may apply to the Commission for an Interim Gas Cost Adjustment Clause in addition to the regular quarterly Gas Cost Adjustment Clause filings.

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ISSUED BY Hubert A. Miller, Jr.
TITLE President

COLUMBIA GAS OF KENTUCKY, INC.

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Determination of Gas Cost Adjustment (GCA)

Company shall file a quarterly report with the Commission which shall contain an updated Gas Cost Adjustment (GCA) Rate and shall be filed at least thirty (30) days prior to the beginning of each quarterly calendar period. The GCA shall become effective for billing with the final meter readings of the first billing cycle of each quarterly calendar period.

The gas cost adjustment is comprised of:

(1) The Expected Gas Cost Component (EGC), on a dollar-per-Mcf basis, is made up of two components: (a) Expected Commodity Gas Cost which applies to Rate Schedules GS, IS, and IUS, and represents the average expected commodity cost of gas supplied, and (b) Expected Demand Gas Cost which applies to Rate Schedules GS,IUS and SVAS, and represents the average expected demand cost of gas supplied, excluding the Standby Service demand costs to be recovered from IS Customers and General Service Delivery Service Customers. ~~The Commodity Gas Cost component of the EGC includes the gains and losses resulting from the settlement of gas futures contracts entered into pursuant to the Company's Commission approved hedging plan and all transaction fees and other brokerage fees or costs associated with the use of those gas futures contracts.~~

(2) The supplier Refund Adjustment (RA), on a dollar-per-Mcf basis, which reflects refunds received during the reporting period plus interest at a rate equal to the average of the "three month commercial paper rate" for the immediately preceding twelve month period. In the event of any large or unusual refunds, Company may apply to the Commission for the right to depart from the refund procedure herein set forth.

(3) The Actual Cost Adjustment (ACA), on a dollar-per-Mcf basis, which compensates for any previous over or undercollections of gas costs experienced by the company through the operation of this gas cost recovery procedure. The ACA shall be based on the twelve months ended June 30th each year, with the ACA factor to be in effect for twelve months beginning September 1st of each year.

(4) The Balancing Adjustment (BA), on a dollar-per-Mcf basis, which compensates for any under or overcollections which have occurred as a result of prior adjustments.

(5) The Performance Based Rate Adjustment ~~Gas Cost Incentive Adjustment~~ (~~GCIA~~PBRA), on a dollar-per–Mcf basis, which is calculated annually based on the prior twelve month period ending March 31~~April through October period~~, with the PBRA ~~GCIA~~ factor to be in effect for twelve months beginning June~~March~~ 1st each year.

~~(6) The Off-System Sales and Capacity Release Adjustment (OSCRA), on a dollar-per-Mcf basis, which is calculated annually based on the twelve months ended September 30th of each year, with the OSCRA factor to be in effect for twelve months beginning December 1st of each year.~~

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ISSUED BY	~~Herbert A. Miller, Jr.~~
TITLE	President

NOTE: All adjustments will be assigned to the Expected Demand Gas Cost or Expected Commodity Gas Cost components.

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Gas Cost Adjustment Clause – (Continued)

~~(7)~~ (6)The Gas Cost Uncollectible Rate (GCUR) on a dollar-per-Mcf basis, which is calculated by multiplying the Expected Commodity Gas Cost times the uncollectible accrual rate used to establish rates in Columbia's most recent rate case. T

Billing

The Gas Cost Adjustment (GCA) shall be the sum of the following components:

GCA = EGC + RA + ACA + BA + PBRA ~~GCIA + OSCRA~~ + GCUR T, N

The GCA will be added to (or subtracted from) the tariff rates prescribed by the Commission Order on Company's latest rate case and will be included in the tariff rates stated on each applicable rate sheet in this tariff.

Definitions

For the purpose of this tariff:

(a) "Average expected cost" is the cost of gas supplies purchased during the latest available twelve month period, including associated transportation charges, storage charges and Take-or-Pay charges, which is determined by the application of suppliers' rates currently in effect, or reasonably expected to be in effect during the quarterly calendar period, less banking and balancing charges, and less the demand costs to be recovered from IS and General Service Delivery Service Customers, divided by the sales volumes for the latest available twelve month period. Where the calculations require the use of volumes used during a given period, and those volumes did not exist for a particular source for the entire period, or Company expects the volumes to change substantially, Company may make appropriate adjustments in its calculations. Any adjustments of this type shall be described in the Quarterly Gas Cost Adjustment report.

(b) "Quarterly calendar period" means each of the four three month periods of (1) September through November, (2) December through February, (3) March through May, and (4) June through August.

(c) "Reporting period" means the three month accounting period that ended approximately thirty (30) days prior to the filing date of the updated gas recovery rates, i.e. the three months ended June 30th, September 30th, December 31st, and March 31st each year.

~~Hedging Plan~~

~~In accordance with the Company's hedging plan approved by the Commission, the Company will utilize gas futures and/or fixed price gas contracts for the purpose of hedging the price of its gas purchases within the parameters established in the hedging plan. By June 1 of each year, the Company shall file a report with the Commission that details said hedging activity during the twelve month period ended March 31. The report will include details of hedge positions taken for future months.~~ D

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TITLE President

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Gas Cost Adjustment Clause – (Continued)

Performance Based Rate Adjustment ("PBRA") T, N

The Performance Based Rate Adjustment (PBRA) shall be calculated annually as follows:

PBRA = CPS / PSV ~~Gas Cost Incentive Adjustment~~

~~The Gas Cost Incentive Adjustment (GCIA) shall be calculated as follows:~~

~~GCIA = PV x 50% / PSV~~

~~PV = Performance Value = BC – AC~~
~~BC = Benchmark Cost~~
~~AC = Actual Cost~~
~~PSV = Projected Sales Volume~~Where:

PSV = Projected Sales Volume in Mcf, as reflected in the Company's GCA filing for the upcoming twelve month period

CPS = Company Performance Share

CPS = TPBR x ASP

Where:

TPBR = Total Performance Based Results. The TPBR shall be savings or expenses created during the twelve month period and shall be calculated as follows:

TPBR = (GCI + TCI + OSSI)

ASP = Applicable Sharing Percentage

GCI

GCI = Gas Cost Incentive will measure, on a monthly basis, the Company's A~~a~~ctual gas C~~c~~osts **(AC)** during the twelve month period for system supply natural gas purchases, against a B~~b~~enchmark C~~c~~ost **(BC)** during the same period to determine a P~~p~~erformance V~~v~~alue **(PV).**

The monthly **PV** shall be calculated as follows:

PV = (BC-COLML – AC-COLML) + (BC-COLTCO – AC-COLTCO) + (BC-TGP500 – AC-TGP500)

Where:

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DATE EFFECTIVE ~~May 22, 2009~~ April 1, 2015

ISSUED BY ~~Herbert A. Miller, Jr.~~
TITLE President

~~Issued by authority of an Order of the Public Service Commission in Case No. 2004-00462 dated March 29, 2005~~

BC–COLML = is the Platt's *Inside FERC's Gas Market Report* first-of-the-month index posting (midpoint) for Columbia Gulf Mainline multiplied by the monthly volumes purchased on the Columbia Gulf Mainline.

AC-COLML = is the total, actual monthly cost of volumes purchased by Columbia on the Columbia Gulf Mainline.

~~The GCIA will measure the Company's gas purchase performance in the months of April through October each year against a Market Standard.~~

~~For each gas purchase made during the months of April through October, the Company will calculate a Market Standard price by taking the NYMEX natural gas futures contract settlement price for the month and adjusting for basis. Basis is calculated as the difference between the prices published in the first publication of the month of *Inside FERC's Gas Market Report*, under the column labeled "Index" for the Henry Hub and for the pipeline location at which Columbia made the gas purchase.~~

~~A monthly Benchmark Cost will be calculated by multiplying the applicable Market Standard for each purchase by the gas volume of each applicable purchase, and summing the results for all applicable purchases that month.~~

~~When the Company's Actual Cost for gas purchased in the month is less than the Benchmark Cost, the result for the month is a positive performance. When the Company's gas purchase costs are greater than the Benchmark Cost, the result for the month is a negative performance.~~

~~The resulting negative or positive Performance Amount will be shared equally between the Company and its sales customers.~~

~~If the Company purchases gas at a point not reported in the applicable index publication, The Company will use the next closest index on the applicable pipeline upstream of the purchase point, and add to that index the 100% load factor cost of firm transportation on that pipeline between the index location and the purchase point.~~

~~Purchases made at Columbia's own city gate are excluded from the GCIA process and calculation.~~

~~If the index used to develop the Market Standard price ceases to exist or ceases to adequately report those prices required in the normal implementation of this GCIA, the Company shall choose a suitable replacement index, assuming an acceptable index is available, and immediately report that change in writing to the Commission.~~

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TITLE	President

~~Issued by authority of an Order of the Public Service Commission in Case No. 2004-00462 dated March 29, 2005~~

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Gas Cost Adjustment Clause – (Continued)

BC–COLTCO = is the Platt's *Inside FERC's Gas Market Report* first-of-the-month index posting (midpoint) for Columbia Appalachia multiplied by the monthly volumes purchased on the Columbia Gas Transmission Pipeline. N

AC-COLTCO = is the total, actual monthly cost of volumes purchased by Columbia on the Columbia Gas Transmission Pipeline.

BC-TGP500 = is the Platt's *Inside FERC's Gas Market Report* first-of-the-month index posting (midpoint) for Tennessee Gas 500 Leg multiplied by the monthly volumes purchased on the Tennessee Gas Pipeline 500 Leg.

AC-TGP500 = is the total, actual monthly cost of volumes purchased by Columbia on the Tennessee Gas Pipeline 500 Leg.~~Off-System Sales and Capacity Release Adjustment:~~

~~Fifty percent (50%) of all revenues generated from off-system sales and capacity release (other than those revenues generated by operational sales, administrative capacity release, or Rate Schedule SVAS capacity assignments), net of costs, will be credited to the calculation of the Off-System Sales and Capaci~~ D

When the Company's Actual Cost for gas purchased in the month is less than the Benchmark Cost, the result for the month is a positive performance. When the Company's gas purchase costs are greater than the Benchmark Cost, the result for the month is a negative performance. The resulting negative or positive Performance Value (PV) will be shared between the Company and its sales customers pursuant to the GCA calculation. T

If the Company purchases gas at a point not reported in the applicable index publication. The Company will use the next closest index on the applicable pipeline upstream of the purchase point, and add to that index the 100% load factor cost of firm transportation on that pipeline between the index location and the purchase point.

Purchases made at Columbia's own city gate as well as any supply reservation fees are excluded from the GCIA process and calculation. T

If the index used to develop the Benchmark Cost ceases to exist or ceases to adequately report those prices required in the normal implementation of this GCIA, the Company shall choose a suitable replacement index, assuming an acceptable index is available, and immediately report that change in writing to the Commission.~~ty Release Adjustment factor.~~

~~Results of operational sales, administrative capacity releases, and Rate Schedule SVAS capacity assignments will be credited 100% to gas cost.~~

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~~Herbert A. Miller, Jr.~~
TITLE President

~~Issued by authority of an Order of the Public Service Commission in Case No. 2004-00462 dated March 29, 2005~~

TCI

TCI = Transportation Cost Incentive. The Transportation Cost Incentive shall be calculated by comparing the annual ~~monthly~~ Total ~~Total~~ Benchmark Transportation Costs **(TBTC)** of natural gas transportation services during the twelve month period to the annual Total Actual Transportation Costs **(TATC)** during the same period as follows:

TCI = (TBTC – TATC)

Where:

TBTC = Annual sum of monthly **BTC**

~~Delivery Service~~

~~FERC approved direct billed pipeline supplier charges relating to the buyout of Take-or-Pay liabilities will be billed to Delivery Service Fixed Rate Volumes.~~

~~Banking and Balancing Service~~

~~This rate is based on the percentage of the portion of storage capacity allocated to Delivery Service Customers to Company's total annual storage capacity, applied to:~~

~~Columbia Transmission's FSS seasonal capacity charge, annualized,~~

~~Columbia Transmission's SST commodity charge, and~~

~~Columbia Transmission's FSS injection and withdrawal charges as calculated in the Gas Cost Adjustment.~~

~~Interim Gas Cost Adjustments~~

~~Should any significant change in supplier rates occur, Company may apply to the Commission for an Interim Gas Cost Adjustment Clause in addition to the regular quarterly Gas Cost Adjustment Clause filings.~~

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COLUMBIA GAS OF KENTUCKY, INC.

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

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Gas Cost Adjustment Clause – (Continued)

BTC = Sum [BM (TCO) + BM (TGP) + BM (CKT) + BM (CGT) + BM (PPL)]

Where:

BM (TCO) is the benchmark associated with Columbia Gas Transmission.

BM (TGP) is the benchmark associated with Tennessee Gas Pipeline Company.

BM (CKT) is the benchmark associated with Central Kentucky Transmission.

BM (CGT) is the benchmark associated with Columbia Gulf Transmission.

BM (PPL) is the benchmark associated with a proxy pipeline. This benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from nontraditional sources.

The benchmark associated with each pipeline shall be calculated as follows:

BM (TCO) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM (TGP) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM (CKT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM (CGT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM (PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.

DQ is the Demand Quantities contracted for by the Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable charges approved by the Federal Energy Regulatory Commission (FERC).

DATE OF ISSUE September 30, 2014

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ISSUED BY
TITLE President

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Gas Cost Adjustment Clause – (Continued)

The Total Actual Transportation Costs (TATC) paid by Company for the period shall include both pipeline demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC approved surcharges, direct bills included in S&DB, less actual capacity release credits. Such costs shall exclude labor related or other expenses typically classified as operating and maintenance expenses. N

Should one of the Company's pipeline transporters file a rate change effective during any period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12 month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

OSSI

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OSSI = Off-system Sales Incentive. The OSSI shall be equal to the revenues net of costs from off-system sales (other than those revenues generated by operational sales).

Results of operation sales, administrative capacity releases and Rate Schedule SVAS capacity assignments will be credited 100% to gas cost.

ASP

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ASP = Applicable Sharing Percentage. The ASP shall be determined based on the Percentage of Actual gas costs **(PAC)**.

Where:

PAC = TPBR / AGC

Where:

AGC = Actual Gas Costs. AGC is the sum of the actual gas costs used in determination of the **GCI** and **TCI**.

If the absolute value of PAC is less than or equal to 2.0%, then the ASP of 30% shall be applied to the total savings or expenses of the TPBR. If the absolute value of the PAC is greater than 2.0%, then the ASP of 30% shall be applied to the amount of the sum of the TPBR that is equal to 2.0% of AGC to determine that portion of the total savings or expense, and the ASP of 50% shall be applied to the sum of the TPBR that is in excess of 2.0% of AGC to determine that portion of the total savings or expense.

COLUMBIA GAS OF KENTUCKY, INC.

GAS COST ADJUSTMENT CLAUSE
APPLICABLE TO ALL RATE SCHEDULES

Gas Cost Adjustment Clause – (Continued)

Delivery Service

FERC approved direct billed pipeline supplier charges relating to the buyout of Take-or-Pay liabilities will be billed to Delivery Service Fixed Rate Volumes.

Banking and Balancing Service

This rate is based on the percentage of the portion of storage capacity allocated to Delivery Service Customers to Company's total annual storage capacity, applied to:

(1) Columbia Transmission's FSS seasonal capacity charge, annualized,

(2) Columbia Transmission's SST commodity charge, and

(3) Columbia Transmission's FSS injection and withdrawal charges as calculated in the Gas Cost Adjustment.

Interim Gas Cost Adjustments

Should any significant change in supplier rates occur, Company may apply to the Commission for an Interim Gas Cost Adjustment Clause in addition to the regular quarterly Gas Cost Adjustment Clause filings.