Columbia Gas of Kentucky
A NiSource Company

June 16, 2009

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JUN 16 2009

PUBLIC SERVICE COMMISSION

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

RE: Case No. 2009-00141

Dear Mr. Derouen,

Enclosed for docketing with the Commission is an original and ten copies of Columbia Gas of Kentucky, Inc.'s responses to the Second Data Request of Commission Staff. Should you have any questions about this filing, please contact me at 614-460-4648. Thank you!

Sincerely,

Stephen B Seiple

Stephen B. Seiple
Assistant General Counsel

Enclosures

cc: All Parties of Record
Hon. Richard S. Taylor

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing responses of Columbia Gas of Kentucky, Inc., were served upon all parties of record by regular U. S. mail this 16th day of June, 2009.

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Attorney for
COLUMBIA GAS OF KENTUCKY INC.

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COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 001:

Refer to Page 3 of the Prepared Direct testimony of Herbert A. Miller, Jr. ("Miller Testimony") and the response to Item 36 of the Commission Staff's First Data Request ("Staff's First Request"). Columbia had 133 employees in the test year. Provide a breakdown showing 1) the number of union employees, 2) the number of exempt employees and 3) the number of non-exempt employees.

Response:

Please refer to the table below.

Union	92
Exempt	23
Non-Exempt	18
Total	133

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COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 002:

Refer to Page 9 of the Miller Testimony.

a. Explain how Columbia chose 30 years as the period of time over which to implement its Accelerated Main Replacement Program ("AMRP").

b. Given that it would otherwise take roughly 50 years to replace the 525 miles of mains that fall into the priority pipe category described in the testimony, explain why the number of years for the AMRP is not substantially less than 30 years.

c. Nearly $210 million is listed as the amount that Columbia will invest in its AMRP. Provide the amount invested in the AMRP during the test year.

Response:

a. Deciding on the duration of a replacement program requires balancing risk, resource availability, and financial impact to our customers. Choosing a duration that is too long will eventually result in accelerated leakage rates as buried piping ages. Ultimately the leakage rate will increase to point that it will overwhelm our resources, increase risk to public safety, and impose additional financial burden on our customers. Choosing a duration that is too short will reduce that risk, but will effectively amortize the returns over a shorter period of time, imposing a greater financial impact on customers at any given time.

While deciding on a suitable replacement duration for Columbia's operating system we considered the following 4 factors;

- Age distribution of the priority pipe,
- Current leakage rate trends,
- Resources available (both physical and capital)
- Tools available to help manage risk.

Looking at the data extracted from DOT annual reports and the data assembled by witness Vitale, with Black and Veatch, the oldest pipe pre-dates 1940 aging it at least 70 years. Furthermore, about half of the priority pipe was installed before 1950 and the majority of the remaining pipe footage from approximately 1950 to 1969 aging the last of the priority pipe approximately 40 years.

Taking the age distribution of the priority pipe together with current resource availability, the current leakage rate, and assuming that all the factors affecting pipe integrity and risk remain the same, at the end of a 30-year replacement period, the oldest pipe will be less than 70 years and certainly no older than our oldest pipe today. Thus assuming a similar level of risk as today we can provide adequate resources to operate and maintain our distribution system.

We believe that this analysis is a reasonable approach and strikes a balance between operating risk and financial considerations. While 30-years is a reasonable estimate for project duration in the beginning, we also recognize that a strictly linear approach to replacement will not likely realize the desired results. For this reason Columbia routinely considers the input from newly acquired risk management tools, and cross-functional teams comprised of engineering, operations, and construction to validate the assumptions made when selecting projects and establishing annual budgets. By using this method Columbia will likely accelerate or decelerate its replacement program in any given year based on unforeseen safety, operating or maintenance considerations, resource availability, and financial impacts to its customers. Furthermore, based on the comparative analysis of Columbia's infrastructure performed by Black and Veatch, they formed an opinion that this rate of replacement is a reasonable expectation and that it should provide a significant improvement in the safety and reliability of Columbia's distribution system.

b. Columbia's average replacement rate of problem pipe between the years 1998-2007 was 9.4 miles per year. The AMRP program replaces almost twice that amount each year. The objective of Columbia's replacement schedule is to replace priority pipe in a manner in a reasonable timeframe, continue to operate and maintain our gas systems safely, and minimize the financial impact on our customers. A 30-year program, as described in (a) best achieves that objective.

c. The replacement spend in the test year was $10,885,000.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 003:

Refer to Page 12 of the Miller Testimony and Pages 5-7 of the Prepared Direct Testimony of Amy L. Efland ("Efland Testimony") which discuss the declines in weather-normalized usage per customer as well as in numbers of customers.

a. To what does Columbia attribute the decline in the number of customers for each customer class?

b. For the 2009 decline in usage by major industrial and commercial customers, to what extent does Columbia believe these declines to be temporary due to the current economic recession?

c. What was the number of customers in each customer class on (1) January 30, 2009; (2) February 28, 2009; (3) March 31, 2009; and (4) April 30, 2009?

Response:

a. Kentucky's relatively low electric rates, along with the reduction in the number of new homes being constructed have contributed to the decline in the number of customers in the residential and commercial classes. The number of total building permits in Kentucky has steadily declined since 2004 corresponding with the decline in customers that Columbia has experience. Attrition is also a factor in the decline. Average attrition over the period 2003-2008 is 1.2% of the customer base for the residential class and 2% for the commercial class.

	2004	2005	2006	2007	2008
Total KY Permits	22,024	18,906	14,659	12,521	9,296

b. CKY's 2009 usage decline to date, is primarily attributable to the business decline in the automotive, automotive supplier, and steel segments coupled with ongoing energy conservation initiatives. These declines are also influenced by the respective competitiveness of the particular Kentucky-based asset in relation to the overall industry and particular company's structure.

c.

Month	Residential	Commercial	Industrial	Public Utilities
January 30, 2009	123,958	14,394	110	2
February 28, 2009	124,111	14,422	111	2
March 31, 2009	123,592	14,344	116	2
April 30, 2009	122,665	14,244	116	2

PSC Case No. 2009-00141
Staff Set 2 DR No. 004
Respondent(s): Amy Efland

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 004:

At the end of the test year, how many of Columbia's residential customers did not use natural gas for space-heating purposes? Provide the average monthly usage of Columbia's non-space-heating residential customers.

Response:

At the end of the test year 2008, there were 2,287 Columbia residential customers that did not use natural gas for space-heating purposes. Their average monthly consumption for the test year was 3,605 MCF, or 1.6 MCF/Customer.

PSC Case No. 2009-00141
Staff Set 2 DR No. 005
Respondent(s): Mark Balmert

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 005:

Has Columbia performed any kind of sensitivity analysis to determine the customer charge level that would result in fuel-switching by 1) non-space-heating residential, and 2) space-heating residential customers? If yes, provide the results of the analysis.

Response:

Columbia has not performed a sensitivity analysis to determine the customer charge level that would result in fuel-switching by either the non-space-heating residential or the space-heating residential customers.

Columbia has already recognized in response to data request PSC Staff Set 2 No. 003 that relatively low electric rates charged in Kentucky have contributed toward reductions in residential customers. However the loss in customers experienced by Columbia has been attributed to the difference in overall gas versus electric rates, and not limited to customer charge revenue.

In addition to the customer charge, the cost of gas, which currently makes up 74% of an average residential customer's bill, the economy, the housing and credit markets, and the price of electric rates will all play roles in Columbia's ability to retain or increase its customer base.

The non-heat customers will be particularly at risk because as the residential customer charge changes from the current $9.30 to $17.92 in 2009 and to $26.53 in 2010, the amount becomes a much greater percentage increase than for the heat customers even after factoring in the fact the volumetric base rate will go down from the current $1.8715/Mcf to $1.4604/Mcf in 2009 and $0.0000/Mcf in 2010.

Conversely, the heat customers, especially those on Columbia's budget payment plan will see on average almost no change in their annual bill from what it would have been if the revenue requirement increase in this case had been applied to the volumetric base rate instead of the customer charge.

Columbia must balance this risk of possible future loss of customers with the risk of losing investors by not requesting a increase in revenues to achieve a fair and reasonable return. Columbia must also ensure that its rates are fair in that it does not require its non-residential class of customers to subsidize the cost of serving the residential class. Columbia must also be fair to the customers within the residential class to move toward a reduction of subsidization of non-heat residential customers by the heat residential customers caused by the current rate design.

From an economic viewpoint, if Columbia were to lose all of its 2,287 non-heat residential customers as of December 31, 2008 it would amount to about 1.6% of its total 139,227 customers shown on Schedule M-2.1 Page 2 Line 17 and about $728,089 ($26.53 x 2,287 x 12 mos.). This compares to the average annual loss resulting from the current volumetric based rate design in effect of $1,909,651 ($19,096,507 / 10 yrs) shown on attachment MPB-9 page 2.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 006:

Is Columbia aware of fuel-switching by the residential customers of other NiSource subsidiaries that could be attributed to a partial or complete shift to a straight-fixed variable ("SFV") rate design? If yes, identify the subsidiaries, the jurisdictions in which they operate, and the extent to which fuel-switching has been realized.

Response:

Columbia Gas of Ohio (COH) is the only NiSource subsidiary that has been granted authority to shift to a straight-fixed variable rate design. COH partially shifted its Small General Service customers to SFV in December 2008 and will completely shift to SFV in December 2009. At this point COH has not seen any indication of fuel shifting.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 007:

Refer to Page 19 of the Miller Testimony, which indicates that Columbia's proposed increase in base rates would have to be adjusted if the Commission does not approve the proposed Gas Cost Uncollectible Charge. Provide the amount of such an adjustment along with revised versions of all schedules, exhibits and work papers that will be affected by this adjustment.

Response:

Please see attached revised Schedule M-2.3 (Annualized test Year Revenue at Proposed Rates), Schedule M (Revenues at Present and Proposed Rates), Attachment MPB-6 (Rate Design) to Direct Testimony of Mark Balmert, and Schedule N (Bill Comparison) for sales rate schedules GSR, GSO, and IUS and transportation rate schedules GTR, GTO and GDS reflecting the elimination of Columbia's proposed Gas Cost Uncollectible Charge.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)		Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1		**Sales Service**								
2	GSR	General Service - Residential		1,185,131	6,825,692.4		32,079,464.70	50.69	69,092,388.75	101,171,853.45
3	G1C	LG&E Commercial		48	6,675.8		10,867.78	0.02	67,575.12	78,442.90
4	G1R	LG&E Residential		281	2,390.1		8,641.00	0.01	24,193.55	32,834.55
5	IN3	Inland Gas General Service - Residential		120	1,480.4		592.16	0.00	0.00	592.16
6	IN3	Inland Gas General Service - Commercial		12	56.4		22.56	0.00	0.00	22.56
7	IN4	Inland Gas General Service - Residential		12	112.2		61.71	0.00	0.00	61.71
8	IN5	Inland Gas General Service - Residential		60	721.2		432.72	0.00	0.00	432.72
9	LG2	LG&E Residential		12	633.9		221.87	0.00	0.00	221.87
10	LG2	LG&E Commercial		12	938.2		328.37	0.00	0.00	328.37
11	LG3	LG&E Residential		12	482.8		176.07	0.00	0.00	176.07
12	LG4	LG&E Residential		12	266.5		106.60	0.00	0.00	106.60
13	GSO	General Service - Commercial		133,374	4,029,933.7		11,337,100.41	17.92	40,792,600.88	52,129,701.29
14	GSO	General Service - Industrial		522	155,474.1		286,348.62	0.45	1,573,771.03	1,860,119.65
15	GST	General Service - Trans Fallback - Comm	[3]	0	0.0		0.00	0.00	0.00	0.00
16	GST	General Service - Trans Fallback - Ind	[3]	0	0.0		0.00	0.00	0.00	0.00
17	IST	Interruptible Service - Commercial	[3]	0	0.0		0.00	0.00	0.00	0.00
18	IST	Interruptible Service - Industrial	[3]	0	0.0		0.00	0.00	0.00	0.00
19	IUS	Intrastate Utility Service - Wholesale		24	19,134.0		26,670.97	0.04	193,682.00	220,352.97
20		**Transportation Service**								
21	GTR	GTS Choice - Residential		310,965	1,995,520.2		8,734,360.51	13.80	0.00	8,734,360.51
22	GTO	GTS Choice - Commercial		38,712	1,417,583.7		3,730,427.03	5.89	0.00	3,730,427.03
23	GTO	GTS Choice - Industrial		96	34,057.4		62,131.17	0.10	0.00	62,131.17

[1] Reflects Normalized Volumes.
[2] See Schedule M-2.3 Pages 3 through 38 for detail.
[3] Customers are included under Transportation Rate Schedules

Colu⁻ ' ᴵa Gas of Kentucky, Inc.
ase No. 2009-00141
Annualized Test Yeaı Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1		**Transportation Service**							
2	DS	GTS Delivery Service - Commercial	312	1,463,233.4		1,010,886.66	1.60	0.00	1,010,886.66
3	DS	GTS Delivery Service - Industrial	538	6,668,558.0		3,471,823.93	5.49	0.00	3,471,823.93
4	GDS	GTS Grandfathered Delivery Service - Commercia	204	243,928.7		436,409.01	0.69	0.00	436,409.01
5	GDS	GTS Grandfathered Delivery Service - Industrial	109	157,300.0		277,974.53	0.44	0.00	277,974.53
6	DS3	GTS Main Line Service - Industrial	17	213,976.0		22,709.44	0.04	0.00	22,709.44
7	FX1	GTS Flex Rate - Commercial	12	305,721.5		45,563.63	0.07	0.00	45,563.63
8	FX2	GTS Flex Rate - Industrial	12	5,202.2		7,998.72	0.01	0.00	7,998.72
9	FX4	GTS Flex Rate - Industrial	12	52,333.0		24,247.47	0.04	0.00	24,247.47
10	FX5	GTS Flex Rate - Industrial	36	5,633,272.0		492,547.14	0.78	0.00	492,547.14
11	FX6	GTS Flex Rate - Industrial	12	346,158.0		32,771.16	0.05	0.00	32,771.16
12	FX7	GTS Flex Rate - Industrial	12	519,685.0		197,160.49	0.31	0.00	197,160.49
13	FX8	GTS Flex Rate - Industrial	12	29,145.0		23,172.81	0.04	0.00	23,172.81
14	SAS	GTS Special Agency Service	12	50,508.9		35,726.18	0.06	0.00	35,726.18
15	SC2	GTS Special Rate - Industrial	12	671,369.0		163,828.56	0.26	0.00	163,828.56
16	SC3	GTS Special Rate - Industrial	12	4,145,865.0		761,882.06	1.20	0.00	761,882.06
17		Total Sales and Transportation	1,670,729	34,997,408.7		63,282,656.04	100.00	111,744,211.33	175,026,867.37
18		**Other Gas Department Revenue**							
19		Acct. 487 Forfeited Discounts							457,733.00
20		Acct. 488 Miscellaneous Service Revenue							293,159.00
21		Acct. 495 Non-Traditional Sales							0.00
22		Acct. 495 Prior Yr. Rate Refund - Net.							0.00
23		Acct. 495 Other Gas Revenues - Other							343,888.00
24		Total Other Gas Department Revenue							1,094,780.00
25		Total Gross Revenue							176,121,647.37

[1] Reflects Normalized Volumes.
[2] See Schedule M-2.3 Pages 3 through 38 for detail.

Annualized Test Yea. Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GSR	General Service - Residential							
2		**RESIDENTIAL**							
3		Customer Delivery Charge:	1,185,131		18.14	21,498,276.34	67.0	0.00	21,498,276.34
4		Commodity Charge:							
5		All Gas Consumed		6,825,692.4	1.4977	10,222,839.51	31.9	69,092,388.75	79,315,228.26
6		Gas Cost Uncollectible Charge			0.0000	0.00	0.0	0.00	0.00
7		EAP Recovery			0.0525	358,348.85	1.1	0.00	358,348.85
8		Total	1,185,131	6,825,692.4		32,079,464.70	100.0	69,092,388.75	101,171,853.45

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	G1C	LG&E Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	48		16.50	792.00	7.3	0.00	792.00
4		Commodity Charge:							
5		All Gas Consumed		6,675.8	1.5093	10,075.78	92.7	67,575.12	77,650.90
6		Total	48	6,675.8		10,867.78	100.0	67,575.12	78,442.90

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
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Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	G1R	LG&E Residential							
2		RESIDENTIAL							
3		Customer Charge:	281		8.50	2,388.50	27.6	0.00	2,388.50
4		Commodity Charge:							
5		All Gas Consumed		2,390.1	2.6160	6,252.50	72.4	24,193.55	30,446.05
6		Total	281	2,390.1		8,641.00	100.0	24,193.55	32,834.55

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Colur[illegible] Gas of Kentucky, Inc.
[illegible]se No. 2009-00141
Annualized Test Yea[illegible] Revenues at Proposed Rates
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1	IN3	Inland Gas General Service - Residential							
2		**RESIDENTIAL**							
3		Customer Charge:	120		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		1,480.4	0.4000	592.16	100.0	0.00	592.16
6		Total	120	1,480.4		592.16	100.0	0.00	592.16

[1] Reflects Normalized Volumes.

Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IN3	Inland Gas General Service - Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	12		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		56.4	0.4000	22.56	100.0	0.00	22.56
6		Total	12	56.4		22.56	100.0	0.00	22.56

[1] Reflects Normalized Volumes.

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1	IN4	Inland Gas General Service - Residential							
2		**RESIDENTIAL**							
3		Customer Charge:	12		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		112.2	0.5500	61.71	100.0	0.00	61.71
6		Total	12	112.2		61.71	100.0	0.00	61.71

[1] Reflects Normalized Volumes.

Columbia Gas of Kentucky, Inc.
[illegible]ase No. 2009-00141
Annualized Test Ye[illegible] Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
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Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IN5	Inland Gas General Service - Residential							
2		**RESIDENTIAL**							
3		Customer Charge:	60		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		721.2	0.6000	432.72	100.0	0.00	432.72
6		Total	60	721.2		432.72	100.0	0.00	432.72

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	LG2	LG&E Residential							
2		**RESIDENTIAL**							
3		Customer Charge:	12		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		633.9	0.3500	221.87	100.0	0.00	221.87
6		Total	12	633.9		221.87	100.0	0.00	221.87

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	LG2	LG&E Commercial							
2		COMMERCIAL							
3		Customer Charge:	12		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		938.2	0.3500	328.37	100.0	0.00	328.37
6		Total	12	938.2		328.37	100.0	0.00	328.37

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	LG3	LG&E Residential							
2		RESIDENTIAL							
3		Customer Charge:	12		1.20	14.40	8.2	0.00	14.40
4		Commodity Charge:							
5		First 2 Mcf		20.9	0.0000	0.00	0.0	0.00	0.00
6		Over 2 Mcf		461.9	0.3500	161.67	91.8	0.00	161.67
7		Total	12	482.8		176.07	100.0	0.00	176.07

[1] Reflects Normalized Volumes.

Annualized Test Year Revenues at Proposed Vs. Most Current Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	LG4	LG&E Residential							
2		**RESIDENTIAL**							
3		Customer Charge:	12		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		266.5	0.4000	106.60	100.0	0.00	106.60
6		Total	12	266.5		106.60	100.0	0.00	106.60

[1] Reflects Normalized Volumes.

Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GSO	General Service - Commercial							
2		COMMERCIAL							
3		Customer Charge:	133,374		30.61	4,082,578.14	36.0	0.00	4,082,578.14
4		Commodity Charge:							
5		First 50 Mcf		1,525,963.6	1.8715	2,855,840.88	25.2	15,446,413.94	18,302,254.82
6		Next 350 Mcf		1,586,648.3	1.8153	2,880,242.66	25.4	16,060,688.75	18,940,931.41
7		Next 600 Mcf		461,089.8	1.7296	797,500.92	7.0	4,667,335.39	5,464,836.31
8		Over 1,000 Mcf		456,232.0	1.5802	720,937.81	6.4	4,618,162.80	5,339,100.61
9		Gas Cost Uncollectible Charge			0.0000	0.00	0.0	0.00	0.00
10		Total	133,374	4,029,933.7		11,337,100.41	100.0	40,792,600.88	52,129,701.29

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GSO	General Service - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	522		30.61	15,978.42	5.6	0.00	15,978.42
4		Commodity Charge:							
5		First 50 Mcf		14,708.0	1.8715	27,526.02	9.6	148,880.26	176,406.28
6		Next 350 Mcf		61,807.5	1.8153	112,199.15	39.2	625,640.24	737,839.39
7		Next 600 Mcf		39,321.6	1.7296	68,010.64	23.8	398,028.96	466,039.60
8		Over 1,000 Mcf		39,637.0	1.5802	62,634.39	21.8	401,221.57	463,855.96
9		Gas Cost Uncollectible Charge			0.0000	0.00	0.0	0.00	0.00
10		Total	522	155,474.1		286,348.62	100.0	1,573,771.03	1,860,119.65

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GST	General Service - Trans Fallback - Comm							
2		COMMERCIAL							
3		Customer Charge:	0		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		0.0	0.0000	0.00	0.0	0.00	0.00
6		Total	0	0.0		0.00	0.0	0.00	0.00

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GST	General Service - Trans Fallback - Ind							
2		**INDUSTRIAL**							
3		Customer Charge:	0		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		0.0	0.0000	0.00	0.0	0.00	0.00
6		Total	0	0.0		0.00	0.0	0.00	0.00

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IST	Interruptible Service - Commercial							
2		COMMERCIAL							
3		Customer Charge:	0		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		0.0	0.0000	0.00	0.0	0.00	0.00
6		Total	0	0.0		0.00	0.0	0.00	0.00

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IST	Interruptible Service - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	0		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		0.0	0.0000	0.00	0.0	0.00	0.00
6		Total	0	0.0		0.00	0.0	0.00	0.00

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Colur a Gas of Kentucky, Inc.
ase No. 2009-00141
Annualized Test Yea. Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IUS	Intrastate Utility Service - Wholesale							
2		**WHOLESALE**							
3		Customer Charge:	24		331.50	7,956.00	29.8	0.00	7,956.00
4		Commodity Charge:							
5		All Gas Consumed		19,134.0	0.9781	18,714.97	70.2	193,682.00	212,396.97
6		Gas Cost Uncollectible Charge			0.0000	0.00	0.0	0.00	0.00
7		Total	24	19,134.0		26,670.97	100.0	193,682.00	220,352.97

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GTR	GTS Choice - Residential							
2		**RESIDENTIAL**							
3		Customer Delivery Charge:	310,965		18.14	5,640,905.10	64.6	0.00	5,640,905.10
4		Commodity Charge:							
5		All Gas Consumed		1,995,520.2	1.4977	2,988,690.60	34.2	0.00	2,988,690.60
6		EAP Recovery			0.0525	104,764.81	1.2	0.00	104,764.81
7		Total	310,965	1,995,520.2		8,734,360.51	100.0	0.00	8,734,360.51

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GTO	GTS Choice - Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	38,712		30.61	1,184,974.32	31.8	0.00	1,184,974.32
3		Commodity Charge:							
4		First 50 Mcf		494,625.5	1.8715	925,691.62	24.8	0.00	925,691.62
5		Next 350 Mcf		568,367.4	1.8153	1,031,757.34	27.7	0.00	1,031,757.34
6		Next 600 Mcf		185,270.2	1.7296	320,443.34	8.6	0.00	320,443.34
7		Over 1,000 Mcf		169,320.6	1.5802	267,560.41	7.1	0.00	267,560.41
8		Total	38,712	1,417,583.7		3,730,427.03	100.0	0.00	3,730,427.03

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GTO	GTS Choice - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	96		30.61	2,938.56	4.7	0.00	2,938.56
4		Commodity Charge:							
5		First 50 Mcf		3,306.3	1.8715	6,187.74	10.0	0.00	6,187.74
6		Next 350 Mcf		12,616.5	1.8153	22,902.73	36.9	0.00	22,902.73
7		Next 600 Mcf		9,677.7	1.7296	16,738.55	26.9	0.00	16,738.55
8		Over 1,000 Mcf		8,456.9	1.5802	13,363.59	21.5	0.00	13,363.59
9		Total	96	34,057.4		62,131.17	100.0	0.00	62,131.17

[1] Reflects Normalized Volumes.

Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	DS	GTS Delivery Service - Commercial							
2		COMMERCIAL							
3		Customer Charge:	312		620.18	193,496.16	19.1	0.00	193,496.16
4		Administrative Charge:	312		55.90	17,440.80	1.7	0.00	17,440.80
5		Commodity Charge:							
6		First 30,000 Mcf		1,463,233.4	0.5467	799,949.70	79.1	0.00	799,949.70
7		Over 30,000 Mcf		0.0	0.2905	0.00	0.1	0.00	0.00
8		Total	312	1,463,233.4		1,010,886.66	100.0	0.00	1,010,886.66

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	DS	GTS Delivery Service - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	538		620.18	333,656.84	9.6	0.00	333,656.84
4		Administrative Charge:	538		55.90	30,074.20	0.9	0.00	30,074.20
5		Commodity Charge:							
6		First 30,000 Mcf		4,570,167.0	0.5467	2,498,510.30	72.0	0.00	2,498,510.30
7		Over 30,000 Mcf		2,098,391.0	0.2905	609,582.59	17.5	0.00	609,582.59
8		Total	538	6,668,558.0		3,471,823.93	100.0	0.00	3,471,823.93

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GDS	GTS Grandfathered Delivery Service - Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	204		30.61	6,244.44	1.4	0.00	6,244.44
4		Administrative Charge:	204		55.90	11,403.60	2.6	0.00	11,403.60
5		Commodity Charge:							
6		First 50 Mcf		10,200.0	1.8715	19,089.30	17.1	0.00	19,089.30
7		Next 350 Mcf		69,538.6	1.8153	126,233.42	28.9	0.00	126,233.42
8		Next 600 Mcf		93,608.1	1.7296	161,904.57	37.1	0.00	161,904.57
9		Over 1,000 Mcf		70,582.0	1.5802	111,533.68	12.9	0.00	111,533.68
10		Total	204	243,928.7		436,409.01	100.0	0.00	436,409.01

[1] Reflects Normalized Volumes.

Annualized Test Yea[illegible] Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GDS	GTS Grandfathered Delivery Service - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	109		30.61	3,336.49	1.2	0.00	3,336.49
4		Administrative Charge:	109		55.90	6,093.10	2.2	0.00	6,093.10
5		Commodity Charge:							
6		First 50 Mcf		20,585.0	1.8715	38,524.83	41.1	0.00	38,524.83
7		Next 350 Mcf		28,309.0	1.8153	51,389.33	18.5	0.00	51,389.33
8		Next 600 Mcf		49,047.0	1.7296	84,831.69	30.5	0.00	84,831.69
9		Over 1,000 Mcf		59,359.0	1.5802	93,799.09	6.5	0.00	93,799.09
10		Total	109	157,300.0		277,974.53	100.0	0.00	277,974.53

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	DS3	GTS Main Line Service - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	17		200.00	3,400.00	0.0	0.00	3,400.00
4		Administrative Charge:	17		55.90	950.30	4.2	0.00	950.30
5		Commodity Charge:							
6		All Gas Consumed		213,976.0	0.0858	18,359.14	95.8	0.00	18,359.14
7		Total	17	213,976.0		22,709.44	100.0	0.00	22,709.44

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX1	GTS Flex Rate - Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	12		547.37	6,568.44	14.4	0.00	6,568.44
4		Administrative Charge:	12		65.00	780.00	1.7	0.00	780.00
5		Commodity Charge:							
6		Rate Schedule FX1		305,721.5	0.1250	38,215.19	83.9	0.00	38,215.19
7		Total	12	305,721.5		45,563.63	100.0	0.00	45,563.63

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX2	GTS Flex Rate - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	12		547.37	6,568.44	82.1	0.00	6,568.44
4		Administrative Charge:	12		65.00	780.00	9.8	0.00	780.00
5		Commodity Charge:							
6		All Gas Consumed		5,202.2	0.1250	650.28	8.1	0.00	650.28
7		Total	12	5,202.2		7,998.72	100.0	0.00	7,998.72

[1] Reflects Normalized Volumes.

Annualized Test Yea. Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX4	GTS Flex Rate - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	12		547.37	6,568.44	27.1	0.00	6,568.44
4		Administrative Charge:	12		55.90	670.80	2.8	0.00	670.80
5		Commodity Charge:							
6		All Gas Consumed		52,333.0	0.3250	17,008.23	70.1	0.00	17,008.23
7		Total	12	52,333.0		24,247.47	100.0	0.00	24,247.47

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX5	GTS Flex Rate - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	36		200.00	7,200.00	1.5	0.00	7,200.00
4		Administrative Charge:	36		55.90	2,012.40	0.4	0.00	2,012.40
5		Commodity Charge:							
6		All Gas Consumed		5,633,272.0	0.0858	483,334.74	98.1	0.00	483,334.74
7		Total	36	5,633,272.0		492,547.14	100.0	0.00	492,547.14

[1] Reflects Normalized Volumes.

Annualized Test Yeaı Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX6	GTS Flex Rate - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	12		200.00	2,400.00	7.3	0.00	2,400.00
4		Administrative Charge:	12		55.90	670.80	2.0	0.00	670.80
5		Commodity Charge:							
6		All Gas Consumed		346,158.0	0.0858	29,700.36	90.7	0.00	29,700.36
7		Total	12	346,158.0		32,771.16	100.0	0.00	32,771.16

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX7	GTS Flex Rate - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	12		547.37	6,568.44	0.0	0.00	6,568.44
4		Administrative Charge:	12		55.90	670.80	0.3	0.00	670.80
5		Commodity Charge:							
6		First 25,000 Mcf		300,000.0	0.4500	135,000.00	68.5	0.00	135,000.00
7		Over 25,000 Mcf		219,685.0	0.2500	54,921.25	31.2	0.00	54,921.25
8		Total	12	519,685.0		197,160.49	100.0	0.00	197,160.49

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX8	GTS Flex Rate - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	12		547.37	6,568.44	0.0	0.00	6,568.44
4		Administrative Charge:	12		55.90	670.80	2.9	0.00	670.80
5		Commodity Charge:							
6		First 30,000		29,145.0	0.5467	15,933.57	68.8	0.00	15,933.57
7		Over 30,000		0.0	0.2905	0.00	28.3	0.00	0.00
8		Total	12	29,145.0		23,172.81	100.0	0.00	23,172.81

[1] Reflects Normalized Volumes.

Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	SAS	GTS Special Agency Service							
2		INDUSTRIAL							
3		Customer Charge:	12		620.18	7,442.16	20.8	0.00	7,442.16
4		Administrative Charge:	12		55.90	670.80	1.9	0.00	670.80
5		Commodity Charge:							
6		First 30,000		50,508.9	0.5467	27,613.22	77.3	0.00	27,613.22
7		Over 30,000		0.0	0.2905	0.00	0.0	0.00	0.00
8		Total	12	50,508.9		35,726.18	100.0	0.00	35,726.18

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	SC2	GTS Special Rate - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	12		200.00	2,400.00	1.5	0.00	2,400.00
4		Administrative Charge:	12		25.00	300.00	0.2	0.00	300.00
5		Commodity Charge:							
6		All Gas Consumed		671,369.0	0.2400	161,128.56	98.3	0.00	161,128.56
7		Total	12	671,369.0		163,828.56	100.0	0.00	163,828.56

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	SC3	GTS Special Rate - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	12		200.00	2,400.00	0.3	0.00	2,400.00
4		Administrative Charge:	12		25.00	300.00	0.0	0.00	300.00
5		Commodity Charge:							
6		First 150,000 Mcf		1,693,997.0	0.2600	440,439.22	57.8	0.00	440,439.22
		Over 150,000 Mcf		2,451,868.0	0.1300	318,742.84	41.9	0.00	318,742.84
7		Total	12	4,145,865.0		761,882.06	100.0	0.00	761,882.06

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Line No.	Rate Classification (A)	Revenue At Present Rates (B) ($)	Revenue At Proposed Rates (C) ($)	Revenue Change (D=C-B) ($)	% Of Revenue Change (E=D/B) (%)
1	**Sales Service**				
2	General Service - Residential	93,246,739.23	101,171,853.45	7,925,114.22	8.50
3	LG&E Commercial	78,442.90	78,442.90	0.00	0.00
4	LG&E Residential	32,834.55	32,834.55	0.00	0.00
5	Inland Gas General Service - Residential	592.16	592.16	0.00	0.00
6	Inland Gas General Service - Commercial	22.56	22.56	0.00	0.00
7	Inland Gas General Service - Residential	61.71	61.71	0.00	0.00
8	Inland Gas General Service - Residential	432.72	432.72	0.00	0.00
9	LG&E Residential	221.87	221.87	0.00	0.00
10	LG&E Commercial	328.37	328.37	0.00	0.00
11	LG&E Residential	176.07	176.07	0.00	0.00
12	LG&E Residential	106.60	106.60	0.00	0.00
13	General Service - Commercial	51,242,764.19	52,129,701.29	886,937.10	1.73
14	General Service - Industrial	1,856,648.35	1,860,119.65	3,471.30	0.19
15	General Service - Trans Fallback - Comm	0.00	0.00	0.00	0.00
16	General Service - Trans Fallback - Ind	0.00	0.00	0.00	0.00
17	Interruptible Service - Commercial	0.00	0.00	0.00	0.00
18	Interruptible Service - Industrial	0.00	0.00	0.00	0.00
19	Intrastate Utility Service - Wholesale	211,100.63	220,352.97	9,252.34	4.38
20	**Transportation Service**				
21	GTS Choice - Residential	6,731,355.36	8,734,360.51	2,003,005.15	29.76
22	GTS Choice - Commercial	3,472,992.23	3,730,427.03	257,434.80	7.41
23	GTS Choice - Industrial	61,492.77	62,131.17	638.40	1.04
24	GTS Delivery Service - Commercial	988,169.94	1,010,886.66	22,716.72	2.30
25	GTS Delivery Service - Industrial	3,432,652.15	3,471,823.93	39,171.78	1.14
26	GTS Grandfathered Delivery Service - Comm	435,052.41	436,409.01	1,356.60	0.31
27	GTS Grandfathered Delivery Service - Indust	277,249.68	277,974.53	724.85	0.26
28	GTS Main Line Service - Industrial	22,709.44	22,709.44	0.00	0.00
29	GTS Flex Rate - Commercial	45,563.63	45,563.63	0.00	0.00
30	GTS Flex Rate - Industrial	7,998.72	7,998.72	0.00	0.00
31	GTS Flex Rate - Industrial	24,247.47	24,247.47	0.00	0.00
32	GTS Flex Rate - Industrial	492,547.14	492,547.14	0.00	0.00
33	GTS Flex Rate - Industrial	32,771.16	32,771.16	0.00	0.00
34	GTS Flex Rate - Industrial	197,160.49	197,160.49	0.00	0.00
35	GTS Flex Rate - Industrial	23,172.81	23,172.81	0.00	0.00
36	GTS Special Agency Service	30,684.02	35,726.18	5,042.16	16.43
37	GTS Special Rate - Industrial	163,828.56	163,828.56	0.00	0.00
38	GTS Special Rate - Industrial	761,882.06	761,882.06	0.00	0.00
39	Total Sales and Transportation	163,872,001.95	175,026,867.37	11,154,865.42	6.81

'ata: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Line No.	Rate Classification (A)	Revenue At Present Rates (B) ($)	Revenue At Proposed Rates (C) ($)	Revenue Change (D=C-B) ($)	% Of Revenue Change (E=D/B) (%)
1	Other Gas Department Revenue				
2	Acct. 487 Forfeited Discounts	192,713.00	457,733.00	265,020.00	137.52
3	Acct. 488 Miscellaneous Service Revenue	147,314.00	293,159.00	145,845.00	99.00
4	Acct. 495 Non-Traditional Sales	0.00	0.00	0.00	0.00
5	Acct. 495 Prior Yr. Rate Refund - Net.	0.00	0.00	0.00	0.00
6	Acct. 495 Other Gas Revenues - Other	343,888.00	343,888.00	0.00	0.00
7	Total Other Gas Departnemt Revenue	683,915.00	1,094,780.00	410,865.00	60.08
8	Total Gross Revenue	164,555,916.95	176,121,647.37	11,565,730.42	7.03

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.	DESCRIPTION	Adjusted Volumes (1) MCF	Revenue @ Current Rates (2) $	Proposed Increase (3) $	Revenue @ Proposed Rates (4) $	Proposed Increase (5=3/2) %
	Gas Service Revenues					
1	GSR/GTR Residential	8,821,212.6	$99,978,095	$9,927,831	$109,905,926	9.93%
2	GSO/GTO/GDS	6,038,277.6	57,346,200	1,150,067	58,496,267	2.01%
3	DS/SAS	8,182,300.3	4,451,506	66,929	4,518,435	1.50%
4	IUS	19,134.0	211,101	10,039	221,140	4.76%
5	IN3	1,536.8	615	0	615	0.00%
6	IN4	112.2	62	0	62	0.00%
7	IN5	721.2	433	0	433	0.00%
5	G1C	6,675.8	78,443	0	78,443	0.00%
6	G1R	2,390.1	32,835	0	32,835	0.00%
7	LG2 Residential	633.9	222	0	222	0.00%
8	LG2 Commercial	938.2	328	0	328	0.00%
9	LG3 Residential	482.8	176	0	176	0.00%
10	LG4 Residential	266.5	107	0	107	0.00%
11	DS3	213,976.0	22,709	0	22,709	0.00%
12	FX1	305,721.5	45,564	0	45,564	0.00%
13	FX2	5,202.2	7,999	0	7,999	0.00%
14	FX4	52,333.0	24,247	0	24,247	0.00%
15	FX5	5,633,272.0	492,547	0	492,547	0.00%
16	FX6	346,158.0	32,771	0	32,771	0.00%
17	FX7	519,685.0	197,160	0	197,160	0.00%
18	FX8	29,145.0	23,173	0	23,173	0.00%
19	SC2	671,369.0	163,829	0	163,829	0.00%
20	SC3	4,145,865.0	761,882	0	761,882	0.00%
21	Other Gas Department Revenue					
22	Acct. 487 Forfeited Discounts		192,713	265,020	457,733	
23	Acct. 488 Miscellaneous Service Revenue		147,314	145,845	293,159	
24	Acct. 495 Non-Traditional Sales		0	0	0	
25	Acct. 495 Prior Yr. Rate Refund - Net.		0	0	0	
26	Acct. 495 Other Gas Revenues - Other		343,888	0	343,888	
27	Total Gas Service Revenues	34,997,408.7	$164,555,917	$11,565,731	$176,121,648	7.03%

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.			Bills	Mcf	Proposed Rate	Proposed Revenue ($)	Current Rev Revenue ($)	Pct. Of Current Rev	Current Rate	Proposed Inc. (Dec.)
1		GSR/GTR Rate Design								
2		Total Revenue @ Proposed Rates				109,905,926				
3	Less:	Gas Cost Revenue				69,092,389				
4	Less:	Gas Cost Uncollectible Charge [1]		6,825,692	0.0000	0	0			0
5	Less:	EAP Revenue				463,114				
6	Less:	Administrative Charge Revenue				0				
7	Less:	Customer Delivery Charge Revenue	1,496,096		**18.14**	27,139,181	13,913,693		9.30	13,225,488
8		Net Volumetric Base Revenue				13,211,242				
9		All Gas Consumed		8,821,212.6	**1.4977**	13,211,530	16,508,899		1.8715	(3,297,369)
10		Total								9,928,119
11		GSO/GTO/GDS Rate Design								
12		Total Revenue @ Proposed Rates				58,496,267				
13	Less:	Gas Cost Revenue				42,366,372				
14	Less:	Gas Cost Uncollectible Charge [1]		4,185,408	0.0000	0	0			0
15	Less:	EAP Revenue				0				
16	Less:	Administrative Charge Revenue	313		**55.90**	17,497	17,497		55.90	0
17	Less:	Customer Charge Revenue	173,017		**30.61**	5,295,554	4,145,487		23.96	1,150,067
18		Net Volumetric Base Revenue				10,816,844				1,150,067
19	Less:	First 50 Mcf		2,069,388.4	**1.8715**	3,872,860	3,872,860	0.358039785	1.8715	(0)
20		Next 350 Mcf		2,327,287.3	**1.8153**	4,224,725	4,224,725	0.390569074	1.8153	0
21		Next 600 Mcf		838,014.4	**1.7296**	1,449,430	1,449,430	0.133997472	1.7296	0
22		Over 1,000 Mcf		803,587.5	**1.5802**	1,269,829	1,269,829	0.117393669	1.5802	0
23		Total		6,038,277.6		10,816,844	10,816,844	1.000000000		1,150,067

[1] See MPB-6 Sheet 3.

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.		Bills	Mcf	Proposed Rate	Proposed Revenue ($)	Current Rev Revenue ($)	Pct. Of Current Rev	Current Rate	Proposed Inc. (Dec.)
1	DS/SAS Rate Design								
2	Total Revenue @ Proposed Rates				4,518,435				
3 Less:	Gas Cost Revenue				0				
4 Less:	Gas Cost Uncollectible Charge [1]		0	0.0000	0	0			0
5 Less:	EAP Revenue				0				
6 Less:	Customer Charge Revenue	862		**620.18**	534,593	467,665		547.37	66,929
7 Less:	Administrative Charge Revenue	862		**55.90**	48,186	48,186		55.90	0
8	Net Volumetric Base Revenue				3,935,656				66,929
9	First 30,000 Mcf		6,083,909.3	**0.5467**	3,326,073	3,326,073	0.845112830	0.5467	(0)
10	Over 30,000 Mcf		2,098,391.0	**0.2905**	609,583	609,583	0.154887170	0.2905	0
11	Total		8,182,300.3		3,935,656	3,935,656	1.000000000		66,929
12	DS3 (Mainline) Customer Charge Rate Design Change								
13	Total Revenue @ Proposed Rates				22,709				
14 Less:	Gas Cost Revenue				0				
15 Less:	Gas Cost Uncollectible Charge [1]		0	0.0000	0	0			0
16 Less:	EAP Revenue				0				
17 Less:	Customer Charge Revenue	17		**200.00**	3,400	3,400		200.00	0
18 Less:	Administrative Charge Revenue	17		**55.90**	950	950		55.90	(0)
19	Net Volumetric Base Revenue				18,359				(0)
20	All Gas Consumed		213,976.0	**0.0858**	18,359	18,359		0.0858	(0)
21	Total								(1)
22	IUS Rate Design								
23	Total Revenue @ Proposed Rates				221,140				
24 Less:	Gas Cost Revenue				193,682				
25 Less:	Gas Cost Uncollectible Charge [1]		19,134	0.0000	0	0			0
26 Less:	EAP Revenue				0				
27 Less:	Administrative Charge Revenue				0				
28 Less:	Customer Charge Revenue	24		**331.50**	7,956	6,120		255.00	1,836
29	Net Volumetric Base Revenue				19,502				1,836
30	All Gas Consumed		19,134.0	**0.9781**	18,715	11,299		0.5905	7,416
31	Total		19,134.0		18,715	11,299			9,252

[1]	Gas Cost Uncollectible Charge to GCA Customers	
	Expected Gas Cost Commodity Rate as of March 1, 2009 ($/Mcf)	6.8373
	Uncollectible Expense Accrual Rate (See Schedule D-2.1 Sheet 5)	1.410552%
	Proposed Rate / Mcf	**0.0000**

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.		Reference	Detail ($)	Amount ($)
1	**Change in Forfeited Discounts Revenue**			
2	Test Year Forfeited Discounts (Account 487)	Schedule M-2.1		192,713.00
3	Test Year Revenue Subject to Late Payment Penalties:			
4 G1C	LG&E Commercial	Schedule M-2.1	76,888.46	
5 GSO	General Service - Commercial	Schedule M-2.1	59,683,440.58	
6 GSO	General Service - Industrial	Schedule M-2.1	2,355,847.53	
7 IUS	Intrastate Utility Service - Wholesale	Schedule M-2.1	254,639.38	
8 GTO	GTS Choice - Commercial	Schedule M-2.1	3,595,137.38	
9 GTO	GTS Choice - Industrial	Schedule M-2.1	64,589.67	
10 DS	GTS Delivery Service - Commercial	Schedule M-2.1	1,020,173.08	
11 DS	GTS Delivery Service - Industrial	Schedule M-2.1	3,435,275.12	
12 GDS	GTS Grandfathered Delivery Service - Commercial	Schedule M-2.1	434,838.25	
13 GDS	GTS Grandfathered Delivery Service - Industrial	Schedule M-2.1	204,801.06	
14 DS3	GTS Main Line Service - Industrial	Schedule M-2.1	22,709.43	
15 FX1	GTS Flex Rate - Commercial	Schedule M-2.1	136,239.48	
16 FX2	GTS Flex Rate - Industrial	Schedule M-2.1	8,079.95	
17 FX4	GTS Flex Rate - Industrial	Schedule M-2.1	24,257.89	
18 FX5	GTS Flex Rate - Industrial	Schedule M-2.1	492,547.14	
19 FX6	GTS Flex Rate - Industrial	Schedule M-2.1	32,771.16	
20 FX7	GTS Flex Rate - Industrial	Schedule M-2.1	197,160.49	
21 FX8	GTS Flex Rate - Industrial	Schedule M-2.1	20,647.13	
22 SAS	GTS Special Agency Service	Schedule M-2.1	31,680.71	
23 SC2	GTS Special Rate - Industrial	Schedule M-2.1	157,598.52	
24 SC3	GTS Special Rate - Industrial	Schedule M-2.1	719,002.12	
25 Total				72,968,324.53
26	Ration of Late Payment Penalties to Total Revenue	Line 2 / Line 25		0.002641050
27	Proposed Revenue Subject to Late Payment Penalties:			
28	GSR/GTR Residential	MPB-6 Page 1	109,905,926	
29	GSO/GTO/GDS	MPB-6 Page 1	58,496,267	
30	DS/SAS	MPB-6 Page 1	4,518,435	
31	IUS	MPB-6 Page 1	221,140	
32	G1C	MPB-6 Page 1	615	
33	G1R	MPB-6 Page 1	62	
34	DS3	MPB-6 Page 1	433	
35	FX1	MPB-6 Page 1	78,443	
36	FX2	MPB-6 Page 1	32,835	
37	FX4	MPB-6 Page 1	222	
38	FX5	MPB-6 Page 1	328	
39	FX6	MPB-6 Page 1	176	
40	FX7	MPB-6 Page 1	107	
41	FX8	MPB-6 Page 1	22,709	
42	SC2	MPB-6 Page 1	7,999	
43	SC3	MPB-6 Page 1	24,247	
44 Total				173,309,942
45	Proposed Forfeited Discounts (Account 487)	Line 26 x Line 45		457,720
46	**Proposed Adjustment to Account 487 Revenue**	**Line 46 - Line 2**		**265,007**

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED TRANSPORTATION SERVICE RATES
TYPICAL BILL COMPARISON
As of December 31, 2008

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

PSC Data Request Set 2 No. 7
Schedule N

Witness: M. P. Balmert

				Monthly Customer Charge				Transportation Commodity Charge						
Line No.	Rate Code	Level of Demand (A)	Monthly Transp Volume (MCF) (B)	Current Monthly Customer Charge ($) (C)	Proposed Step 1 Monthly Customer Charge ($) (D)	Dollar Increase (Decrease) (D - C) ($) (E)	Percent Increase (Decrease) (E/C) (%) (F)	Current Commodity Charge ($) (G)	Proposed Step 1 Commodity Charge ($) (H)	Dollar Increase (Decrease) (H - G) ($) (I)	Percent Increase (Decrease) (I/G) (%) (J)	Total Current Bill (C + G) ($) (K)	Total Proposed Step 1 Bill (D + H) ($) (L)	Percent Increase (Decrease) (L - K)/K (%) (M)
1	GTR	Not	1	$9.30	$18.14	$8.84	95.1%	$1.93	$1.56	-$0.37	-19.2%	$11.23	$19.70	75.4%
2	GTS	Applicable	3	$9.30	$18.14	$8.84	95.1%	$5.81	$4.69	-$1.12	-19.3%	$15.11	$22.83	51.1%
3	Choice		6	$9.30	$18.14	$8.84	95.1%	$11.62	$9.38	-$2.24	-19.3%	$20.92	$27.52	31.5%
4	Residential		8	$9.30	$18.14	$8.84	95.1%	$15.49	$12.50	-$2.99	-19.3%	$24.79	$30.64	23.6%
5			10	$9.30	$18.14	$8.84	95.1%	$19.37	$15.63	-$3.74	-19.3%	$28.67	$33.77	17.8%
6			12	$9.30	$18.14	$8.84	95.1%	$23.24	$18.75	-$4.49	-19.3%	$32.54	$36.89	13.4%
7			16	$9.30	$18.14	$8.84	95.1%	$30.98	$25.00	-$5.98	-19.3%	$40.28	$43.14	7.1%
8			20	$9.30	$18.14	$8.84	95.1%	$38.73	$31.25	-$7.48	-19.3%	$48.03	$49.39	2.8%
9			30	$9.30	$18.14	$8.84	95.1%	$58.10	$46.88	-$11.22	-19.3%	$67.40	$65.02	-3.5%
10			40	$9.30	$18.14	$8.84	95.1%	$77.46	$62.51	-$14.95	-19.3%	$86.76	$80.65	-7.0%
11			50	$9.30	$18.14	$8.84	95.1%	$96.83	$78.14	-$18.69	-19.3%	$106.13	$96.28	-9.3%

Average monthly bill = 6

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED TRANSPORTATION SERVICE RATES
TYPICAL BILL COMPARISON
As of December 31, 2008

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

PSC Data Request Set 2 No. 7
Schedule N

Witness: M. P. Balmert

Line No.	Rate Code	Level of Demand (A)	Monthly Transp Volume (MCF) (B)	Monthly Customer Charge: Current Monthly Customer Charge ($) (C)	Proposed Monthly Customer Charge ($) (D)	Dollar Increase (Decrease) (D - C) ($) (E)	Percent Increase (Decrease) (E/C) (%) (F)	Transportation Commodity Charge: Current Commodity Charge ($) (G)	Proposed Commodity Charge ($) (H)	Dollar Increase (Decrease) (H - G) ($) (I)	Percent Increase (Decrease) (I/G) (%) (J)	Total Current Bill (C + G) ($) (K)	Total Proposed Bill (D + H) ($) (L)	Percent Increase (Decrease) (L - K)/K (%) (M)
1	GTO	Not	10	$23.96	$30.61	$6.65	27.8%	$18.84	$18.84	$0.00	0.0%	$42.80	$49.45	15.5%
2	GTS	Applicable	30	$23.96	$30.61	$6.65	27.8%	$56.52	$56.52	$0.00	0.0%	$80.48	$87.13	8.3%
3	Choice		37	$23.96	$30.61	$6.65	27.8%	$69.71	$69.71	$0.00	0.0%	$93.67	$100.32	7.1%
4	Commercial		50	$23.96	$30.61	$6.65	27.8%	$94.20	$94.20	$0.00	0.0%	$118.16	$124.81	5.6%
5	and		70	$23.96	$30.61	$6.65	27.8%	$130.76	$130.76	$0.00	0.0%	$154.72	$161.37	4.3%
6	Industrial		100	$23.96	$30.61	$6.65	27.8%	$185.59	$185.59	$0.00	0.0%	$209.55	$216.20	3.2%
7			150	$23.96	$30.61	$6.65	27.8%	$276.97	$276.97	$0.00	0.0%	$300.93	$307.58	2.2%
8			200	$23.96	$30.61	$6.65	27.8%	$368.36	$368.36	$0.00	0.0%	$392.32	$398.97	1.7%
9			250	$23.96	$30.61	$6.65	27.8%	$459.74	$459.74	$0.00	0.0%	$483.70	$490.35	1.4%
10			300	$23.96	$30.61	$6.65	27.8%	$551.13	$551.13	$0.00	0.0%	$575.09	$581.74	1.2%
11			350	$23.96	$30.61	$6.65	27.8%	$642.51	$642.51	$0.00	0.0%	$666.47	$673.12	1.0%
12			400	$23.96	$30.61	$6.65	27.8%	$733.90	$733.90	$0.00	0.0%	$757.86	$764.51	0.9%
13			450	$23.96	$30.61	$6.65	27.8%	$821.00	$821.00	$0.00	0.0%	$844.96	$851.61	0.8%
14			355	$23.96	$30.61	$6.65	27.8%	$655.51	$655.51	$0.00	0.0%	$679.47	$686.12	1.0%
15			500	$23.96	$30.61	$6.65	27.8%	$908.10	$908.10	$0.00	0.0%	$932.06	$938.71	0.7%
16			700	$23.96	$30.61	$6.65	27.8%	$1,256.50	$1,256.50	$0.00	0.0%	$1,280.46	$1,287.11	0.5%
17			1,000	$23.96	$30.61	$6.65	27.8%	$1,779.10	$1,779.10	$0.00	0.0%	$1,803.06	$1,809.71	0.4%
18			1,200	$23.96	$30.61	$6.65	27.8%	$2,097.62	$2,097.62	$0.00	0.0%	$2,121.58	$2,128.23	0.3%

Average monthly bill = 37 (Commercial)
Average monthly bill = 355 (Industrial)

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED TRANSPORTATION SERVICE RATES
TYPICAL BILL COMPARISON
As of December 31, 2008

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

Schedule N

Witness: M. P. Balmert

				Monthly Customer Charge				Monthly Administrative Charge				Transportation Commodity Charge						
Line No.	Rate Code	Level of Demand (A)	Monthly Transp Volume (MCF) (B)	Current Monthly Customer Charge ($) (C)	Proposed Monthly Customer Charge ($) (D)	Dollar Increase (Decrease) (D - C) ($) (E)	Percent Increase (Decrease) (E/C) (%) (F)	Current Monthly Administrative Charge ($) (G)	Proposed Monthly Administrative Charge ($) (H)	Dollar Increase (Decrease) (H - G) ($) (I)	Percent Increase (Decrease) (I/G) (%) (J)	Current Commodity Charge ($) (K)	Proposed Commodity Charge ($) (L)	Dollar Increase (Decrease) (L - K) ($) (M)	Percent Increase (Decrease) (M/K) (%) (N)	Total Current Bill (C + G + K) ($) (O)	Total Proposed Bill (D + H + L) ($) (P)	Percent Increase (Decrease) (P - O)/O (%) (Q)
1	DS	Not	10	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$5.80	$5.80	$0.00	0.0%	$609.07	$681.88	12.0%
2	GTS	Applicable	150	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$86.99	$86.99	$0.00	0.0%	$690.26	$763.07	10.5%
3	Interruptible		300	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$173.97	$173.97	$0.00	0.0%	$777.24	$850.05	9.4%
4	Service		500	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$289.95	$289.95	$0.00	0.0%	$893.22	$966.03	8.2%
5	Commercial		1,000	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$579.90	$579.90	$0.00	0.0%	$1,183.17	$1,255.98	6.2%
6	and		3,000	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$1,739.70	$1,739.70	$0.00	0.0%	$2,342.97	$2,415.78	3.1%
7	Industrial		4,690	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$2,719.73	$2,719.73	$0.00	0.0%	$3,323.00	$3,395.81	2.2%
8			5,000	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$2,899.50	$2,899.50	$0.00	0.0%	$3,502.77	$3,575.58	2.1%
9			10,000	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$5,799.00	$5,799.00	$0.00	0.0%	$6,402.27	$6,475.08	1.1%
10			12,395	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$7,187.87	$7,187.87	$0.00	0.0%	$7,791.14	$7,863.95	0.9%
11			15,000	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$8,698.50	$8,698.50	$0.00	0.0%	$9,301.77	$9,374.58	0.8%
12			20,000	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$11,598.00	$11,598.00	$0.00	0.0%	$12,201.27	$12,274.08	0.6%
13			25,000	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$14,497.50	$14,497.50	$0.00	0.0%	$15,100.77	$15,173.58	0.5%
14			30,000	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$17,397.00	$17,397.00	$0.00	0.0%	$18,000.27	$18,073.08	0.4%
15			35,000	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$19,015.50	$19,015.50	$0.00	0.0%	$19,618.77	$19,691.58	0.4%
16			40,000	$547.37	$620.18	$72.81	13.3%	$55.90	$55.90	$0.00	0.0%	$20,634.00	$20,634.00	$0.00	0.0%	$21,237.27	$21,310.08	0.3%

Average monthly bill = 4,690 (Commercial)
Average monthly bill = 12,395 (Industrial)

Note: Customers electing Standby Service pay an additional $6.5482/Mcf per contracted volumes per month.

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED TRANSPORTATION SERVICE RATES
TYPICAL BILL COMPARISON
As of December 31, 2008

PSC Data Request Set 2 No. 7
Schedule N

Witness: M. P. Balmert

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

				Monthly Customer Charge				Monthly Administrative Charge				Transportation Commodity Charge						
Line No.	Rate Code	Level of Demand (A)	Monthly Transp Volume (MCF) (B)	Current Monthly Customer Charge ($) (C)	Proposed Monthly Customer Charge ($) (D)	Dollar Increase (Decrease) (D - C) ($) (E)	Percent Increase (Decrease) (E/C) (%) (F)	Current Monthly Administrative Charge ($) (G)	Proposed Monthly Administrative Charge ($) (H)	Dollar Increase (Decrease) (H - G) ($) (I)	Percent Increase (Decrease) (I/G) (%) (J)	Current Commodity Charge ($) (K)	Proposed Commodity Charge ($) (L)	Dollar Increase (Decrease) (L - K) ($) (M)	Percent Increase (Decrease) (M/K) (%) (N)	Total Current Bill (C + G + K) ($) (O)	Total Proposed Bill (D + H + L) ($) (P)	Percent Increase (Decrease) (P - O)/O (%) (Q)
1	GDS	Not	10	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$19.05	$19.05	$0.00	0.0%	$98.91	$105.56	6.7%
2	GTS	Applicable	30	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$57.14	$57.14	$0.00	0.0%	$137.00	$143.65	4.9%
3	General		50	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$95.24	$95.24	$0.00	0.0%	$175.10	$181.75	3.8%
4	Service		70	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$132.22	$132.22	$0.00	0.0%	$212.08	$218.73	3.1%
5	Commercial		100	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$187.67	$187.67	$0.00	0.0%	$267.53	$274.18	2.5%
6	and		150	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$280.09	$280.09	$0.00	0.0%	$359.95	$366.60	1.8%
7	Industrial		200	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$372.52	$372.52	$0.00	0.0%	$452.38	$459.03	1.5%
8			250	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$464.94	$464.94	$0.00	0.0%	$544.80	$551.45	1.2%
9			300	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$557.37	$557.37	$0.00	0.0%	$637.23	$643.88	1.0%
10			350	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$649.79	$649.79	$0.00	0.0%	$729.65	$736.30	0.9%
11			400	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$742.22	$742.22	$0.00	0.0%	$822.08	$828.73	0.8%
12			450	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$830.36	$830.36	$0.00	0.0%	$910.22	$916.87	0.7%
13			500	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$918.50	$918.50	$0.00	0.0%	$998.36	$1,005.01	0.7%
14			700	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$1,271.06	$1,271.06	$0.00	0.0%	$1,350.92	$1,357.57	0.5%
15			1000	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$1,799.90	$1,799.90	$0.00	0.0%	$1,879.76	$1,886.41	0.4%
16			1,196	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$2,116.13	$2,116.13	$0.00	0.0%	$2,195.99	$2,202.64	0.3%
17			1,200	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$2,122.58	$2,122.58	$0.00	0.0%	$2,202.44	$2,209.09	0.3%
18			1,443	$23.96	$30.61	$6.65	27.8%	$55.90	$55.90	$0.00	0.0%	$2,514.63	$2,514.63	$0.00	0.0%	$2,594.49	$2,601.14	0.3%

Average monthly bill = 1,196 (Commercial)
Average monthly bill = 1,443 (Industrial)

Note: Customers electing Standby Service pay an additional $6.5482/Mcf per contracted volumes per month.

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED TRANSPORTATION SERVICE RATES
TYPICAL BILL COMPARISON
As of December 31, 2008

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

Schedule N
Page 28 of 30
Witness: M. P. Balmert

				Monthly Customer Charge				Monthly Administrative Charge				Transportation Commodity Charge						
Line No.	Rate Code	Level of Demand (A)	Monthly Transp Volume (MCF) (B)	Current Monthly Customer Charge ($) (C)	Proposed Monthly Customer Charge ($) (D)	Dollar Increase (Decrease) (D - C) ($) (E)	Percent Increase (Decrease) (E/C) (%) (F)	Current Monthly Administrative Charge ($) (G)	Proposed Monthly Administrative Charge ($) (H)	Dollar Increase (Decrease) (H - G) ($) (I)	Percent Increase (Decrease) (I/G) (%) (J)	Current Commodity Charge ($) (K)	Proposed Commodity Charge ($) (L)	Dollar Increase (Decrease) (L - K) ($) (M)	Percent Increase (Decrease) (M/K) (%) (N)	Total Current Bill (C + G + K) ($) (O)	Total Proposed Bill (D + H + L) ($) (P)	Percent Increase (Decrease) (P - O)/O (%) (Q)
1	SAS	Not	10	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$5.59	$5.59	$0.00	0.0%	$261.49	$681.67	160.7%
2	GTS	Applicable	150	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$83.87	$83.87	$0.00	0.0%	$339.77	$759.95	123.7%
3	Special		300	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$167.73	$167.73	$0.00	0.0%	$423.63	$843.81	99.2%
4	Rate		500	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$279.55	$279.55	$0.00	0.0%	$535.45	$955.63	78.5%
5	Industrial		1,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$559.10	$559.10	$0.00	0.0%	$815.00	$1,235.18	51.6%
6			3,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$1,677.30	$1,677.30	$0.00	0.0%	$1,933.20	$2,353.38	21.7%
7			4,209	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$2,353.25	$2,353.25	$0.00	0.0%	$2,609.15	$3,029.33	16.1%
8			5,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$2,795.50	$2,795.50	$0.00	0.0%	$3,051.40	$3,471.58	13.8%
9			10,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$5,591.00	$5,591.00	$0.00	0.0%	$5,846.90	$6,267.08	7.2%
10			15,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$8,386.50	$8,386.50	$0.00	0.0%	$8,642.40	$9,062.58	4.9%
11			20,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$11,182.00	$11,182.00	$0.00	0.0%	$11,437.90	$11,858.08	3.7%
12			25,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$13,977.50	$13,977.50	$0.00	0.0%	$14,233.40	$14,653.58	3.0%
13			30,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$16,773.00	$16,773.00	$0.00	0.0%	$17,028.90	$17,449.08	2.5%
14			35,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$18,287.50	$18,287.50	$0.00	0.0%	$18,543.40	$18,963.58	2.3%
15			40,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$19,802.00	$19,802.00	$0.00	0.0%	$20,057.90	$20,478.08	2.1%
16			45,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$21,316.50	$21,316.50	$0.00	0.0%	$21,572.40	$21,992.58	1.9%
17			50,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$22,831.00	$22,831.00	$0.00	0.0%	$23,086.90	$23,507.08	1.8%
18			55,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$24,345.50	$24,345.50	$0.00	0.0%	$24,601.40	$25,021.58	1.7%
19			60,000	$200.00	$620.18	$420.18	210.1%	$55.90	$55.90	$0.00	0.0%	$25,860.00	$25,860.00	$0.00	0.0%	$26,115.90	$26,536.08	1.6%

Average monthly bill = 4209

*SAS Monthly Gas Cost not included.

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED SALES SERVICE RATES
TYPICAL BILL COMPARISON
12 Months Ending December 31, 2008

PSC Data Request Set 2 No. 7
Schedule N
Page 1 of 30
Witness: M. P. Balmert

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

Line No.	Rate Code	Level of Demand (A)	Level of Use (MCF) (B)	Current Bill ($) (C)	Proposed Step 1 Bill ($) (D)	Increase (D - C) ($) (E)	Increase (E/C) (%) (F)	Gas Cost ($) (G)	Total Current Bill ($) (H) (C + G)	Total Proposed Step 1 Bill ($) (I) (D + G)	Percent Increase (%) (J) (I - H) / H
1	GSR	Not	1	$11.23	$19.70	$8.47	75.4%	$10.12	$21.35	$29.82	39.7%
2	General	Applicable	3	$15.10	$22.82	$7.72	51.1%	$30.37	$45.47	$53.19	17.0%
3	Service		5	$18.98	$25.95	$6.97	36.7%	$50.61	$69.59	$76.56	10.0%
4	Residential		6	$20.92	$27.52	$6.60	31.5%	$60.73	$81.65	$88.25	8.1%
5			8	$24.79	$30.64	$5.85	23.6%	$80.98	$105.77	$111.62	5.5%
6			10	$28.67	$33.77	$5.10	17.8%	$101.22	$129.89	$134.99	3.9%
7			12	$32.54	$36.89	$4.35	13.4%	$121.47	$154.01	$158.36	2.8%
8			16	$40.28	$43.14	$2.86	7.1%	$161.96	$202.24	$205.10	1.4%
9			20	$48.03	$49.39	$1.36	2.8%	$202.45	$250.48	$251.84	0.5%
10			30	$67.40	$65.02	-$2.38	-3.5%	$303.67	$371.07	$368.69	-0.6%
11			40	$86.76	$80.65	-$6.11	-7.0%	$404.90	$491.66	$485.55	-1.2%
12			50	$106.13	$96.28	-$9.85	-9.3%	$506.12	$612.25	$602.40	-1.6%

Average monthly bill = 6

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED SALES SERVICE RATES
TYPICAL BILL COMPARISON
12 Months Ending December 31, 2008

PSC Data Request Set 2 No. 7
Schedule N
Page 13 of 30
Witness: M. P. Balmert

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

Line No.	Rate Code	Level of Demand (A)	Level of Use (MCF) (B)	Current Bill ($) (C)	Proposed Bill ($) (D)	Increase (D - C) ($) (E)	Increase (E/C) (%) (F)	Gas Cost ($) (G)	Total Current Bill ($) (H) (C + G)	Total Proposed Bill ($) (I) (D + G)	Percent Increase (%) (J) (I - H) / H
1	GSO	Not	10	$42.80	$49.45	$6.65	15.5%	$101.22	$144.02	$150.67	4.6%
2	General	Applicable	30	$80.48	$87.13	$6.65	8.3%	$303.67	$384.15	$390.80	1.7%
3	Service		30	$80.48	$87.13	$6.65	8.3%	$303.67	$384.15	$390.80	1.7%
4	Commercial &		50	$118.16	$124.81	$6.65	5.6%	$506.12	$624.28	$630.93	1.1%
5	Industrial		70	$154.72	$161.37	$6.65	4.3%	$708.57	$863.29	$869.94	0.8%
6			100	$209.55	$216.20	$6.65	3.2%	$1,012.24	$1,221.79	$1,228.44	0.5%
7			150	$300.93	$307.58	$6.65	2.2%	$1,518.36	$1,819.29	$1,825.94	0.4%
8			200	$392.32	$398.97	$6.65	1.7%	$2,024.48	$2,416.80	$2,423.45	0.3%
9			250	$483.70	$490.35	$6.65	1.4%	$2,530.60	$3,014.30	$3,020.95	0.2%
10			298	$571.43	$578.08	$6.65	1.2%	$3,016.48	$3,587.91	$3,594.56	0.2%
11			300	$575.09	$581.74	$6.65	1.2%	$3,036.72	$3,611.81	$3,618.46	0.2%
12			350	$666.47	$673.12	$6.65	1.0%	$3,542.84	$4,209.31	$4,215.96	0.2%
13			400	$757.86	$764.51	$6.65	0.9%	$4,048.96	$4,806.82	$4,813.47	0.1%
14			450	$844.96	$851.61	$6.65	0.8%	$4,555.08	$5,400.04	$5,406.69	0.1%
15			500	$932.06	$938.71	$6.65	0.7%	$5,061.20	$5,993.26	$5,999.91	0.1%
16			700	$1,280.46	$1,287.11	$6.65	0.5%	$7,085.68	$8,366.14	$8,372.79	0.1%
17			1,000	$1,803.06	$1,809.71	$6.65	0.4%	$10,122.40	$11,925.46	$11,932.11	0.1%
18			1,200	$2,121.58	$2,128.23	$6.65	0.3%	$12,146.88	$14,268.46	$14,275.11	0.0%

Average monthly bill = 30 (Commercial)
Average monthly bill = 298 (Industrial)

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED SALES SERVICE RATES
TYPICAL BILL COMPARISON
12 Months Ending December 31, 2008

PSC Data Request Set 2 No. 7
Schedule N

Witness: M. P. Balmert

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

Line No.	Rate Code	Level of Demand (A)	Level of Use (MCF) (B)	Current Bill ($) (C)	Proposed Bill ($) (D)	Increase (D - C) ($) (E)	Increase (E/C) (%) (F)	Gas Cost ($) (G)	Total Current Bill ($) (H) (C + G)	Total Proposed Bill ($) (I) (D + G)	Percent Increase (%) (J) (I - H) / H
1	IUS	Not	500	$556.45	$826.75	$270.30	48.6%	$5,061.20	$5,617.65	$5,887.95	4.8%
2	Intrastate	Applicable	797	$735.51	$1,120.93	$385.42	52.4%	$8,067.55	$8,803.06	$9,188.48	4.4%
3	Utility		1,000	$857.90	$1,322.00	$464.10	54.1%	$10,122.40	$10,980.30	$11,444.40	4.2%
4	Service		2,000	$1,460.80	$2,312.50	$851.70	58.3%	$20,244.80	$21,705.60	$22,557.30	3.9%
5	Wholesale		3,000	$2,063.70	$3,303.00	$1,239.30	60.1%	$30,367.20	$32,430.90	$33,670.20	3.8%
6			4,000	$2,666.60	$4,293.50	$1,626.90	61.0%	$40,489.60	$43,156.20	$44,783.10	3.8%
7			5,000	$3,269.50	$5,284.00	$2,014.50	61.6%	$50,612.00	$53,881.50	$55,896.00	3.7%
8			6,000	$3,872.40	$6,274.50	$2,402.10	62.0%	$60,734.40	$64,606.80	$67,008.90	3.7%
9			7,000	$4,475.30	$7,265.00	$2,789.70	62.3%	$70,856.80	$75,332.10	$78,121.80	3.7%
10			8,000	$5,078.20	$8,255.50	$3,177.30	62.6%	$80,979.20	$86,057.40	$89,234.70	3.7%
11			10,000	$6,284.00	$10,236.50	$3,952.50	62.9%	$101,224.00	$107,508.00	$111,460.50	3.7%
12			15,000	$9,298.50	$15,189.00	$5,890.50	63.3%	$151,836.00	$161,134.50	$167,025.00	3.7%
13			20,000	$12,313.00	$20,141.50	$7,828.50	63.6%	$202,448.00	$214,761.00	$222,589.50	3.6%
14			30,000	$18,342.00	$30,046.50	$11,704.50	63.8%	$303,672.00	$322,014.00	$333,718.50	3.6%
15			40,000	$24,371.00	$39,951.50	$15,580.50	63.9%	$404,896.00	$429,267.00	$444,847.50	3.6%

Average monthly bill = 797

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 008:

Refer to Page 16 of the Prepared Direct Testimony of David E. Mueller, specifically concerning the need to replace service lines as part of the AMRP. Provide a schedule which shows the length (feet, miles, etc) of pipe to be replaced over the 30-year life of the program broken down by category of line (i.e., service lines, distribution mains, etc.). Include the estimated cost to replace each category.

Response:

30 Year Replacement Schedule	Ave. Miles Replacement Main Installed per Year	Ave. Miles Priority Main Retired per Year	Ave. Number Services Replaced	Average Annual Priority Pipe Capital		
				Mains	Services	Total
Annual	15.6 (Miles)	17.5 (Miles)	891(Units)	$5,400,453	$1,589,064	$6,989,518
Units	82,368 (Ft.)	92,400 (Ft.)	66,795 (Ft.)			
Total 30 Year Program	468 (Miles)	525 (Miles)	26,730 (Units)	$162,013,604	$47,671,931	$209,685,535
Units	2,471,040 (Ft.)	2,772,000 (Ft.)	2,004,750(Ft.)			

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 009:

Refer to Pages 3-5 of the Prepared Direct Testimony of Judy M. Cooper ("Cooper Testimony").

a. Provide the number of disconnections and related reconnections, other than those requested by customers, by month, from January 2007 through the most recent month for which information is available.

b. Has Columbia experienced a higher level of customers unable to reconnect as a result of the higher reconnect fee approved in Case No. 2007-00008?[1] Is there any concern that an increase to a $60 reconnect fee could impact the ability of low-income customers to reconnect?

c. Explain whether the 75 percent behavioral adjustment has any basis in research or fact.

d. Refer to Attachment JMC-1 to the Cooper Testimony. Provide a breakdown of the $26.14 for labor and the $38.06 for overheads and vehicle charges contained in the Cost Analysis of the Reconnect Fee.

e. Provide the number of disconnections and related reconnections requested by customers, by month from January 2007 through the most recent month for which information is available. Does Columbia know or can it estimate how many of these are actual seasonal disconnects/reconnects and how many are not?

f. In the event that it waives a fee for the cost of a remote meter reading device, explain whether Columbia is proposing to absorb the cost.

Response:

a. See Attachment 1.

b. Columbia did experience a higher level of customers that did not reconnect service after they were turned off for non payment in 2008 as compared to

[1] Case No. 2007-00008, Adjustment of Rates of Columbia Gas of Kentucky, Inc. (Ky. PSC Aug. 29, 2007).

2007 data. However, we do not believe the higher level of customers not reconnecting service is due to the increase in the reconnection fee. We believe it is due to several different factors including customers switching to a different energy source and also a change in the way collection orders are worked. Our goal is not to turn off customers who will pay us – we want to collect those dollars without shutting the gas off and only turn gas off to customers who have a higher probability of not paying us to reconnect service. Columbia does not believe that a $60.00 reconnection fee will prevent low income customers from reconnecting gas service.

c. As stated in my testimony, Columbia utilized the same proposed 75% behavioral factor in Case No. 2007-00008, and with the proposed increase, it is highly unlikely that Columbia would experience a constant activity level when the fee is increased. Because a drop in occurrences is expected based upon the proposed increase, Columbia estimated that it would only realize 75% of the additional revenue that it would have otherwise received if the drop in occurrences were not to occur. Actual experience has shown a decline in occurrences subsequent to increasing the charge. No additional studies or analyses were necessary to develop the 75% behavioral factor.

d. Labor – The labor amount of $26.14 is the hourly raw labor rate. The average amount of time to work a reconnect order is one hour, determined by the time charged by service employees for reconnect work orders tracked in Columbia's customer information system. This includes all testing procedures necessary before re-establishing gas service.

   Overheads – The amount of $38.06 for overheads and vehicle charges breaks down to $4.33 for vacation and non-productive time accrual and $15.42 for benefits and payroll taxes applied to the raw labor rate. Plus, construction overheads for supervision, engineering and administration of $8.71 and the hourly truck rate of $9.60.

e. See Attachment 2. Not all of the requested information is available. The reconnections that relate to disconnections requested by customers are either for "seasonal" or for any "other" reason excluding reconnections after disconnection for non payment.

f. If the cost of a remote meter reading device is waived for a customer, the entire cost of the device and its installation would be incurred by Columbia and recorded on its books.

Month/Year	Disconnections for Non Payment	Reconnections related to Non Payment
Jan-07	507	449
Feb-07	468	379
Mar-07	1,351	689
Apr-07	1,412	666
May-07	1,448	634
Jun-07	1,026	435
Jul-07	469	272
Aug-07	529	314
Sep-07	304	228
Oct-07	330	547
Nov-07	205	679
Dec-07	167	270
Jan-08	512	343
Feb-08	391	331
Mar-08	1,321	555
Apr-08	1,385	531
May-08	1,222	432
Jun-08	1,070	311
Jul-08	719	283
Aug-08	672	307
Sep-08	600	315
Oct-08	756	958
Nov-08	221	829
Dec-08	274	361
Jan-09	176	236
Feb-09	528	298
Mar-09	1,225	519
Apr-09	1,538	503

Month/Year	Disconnections requested by customers*	Reconnections not related to non payment**
Jan-07	372	Not Available
Feb-07	203	Not Available
Mar-07	119	Not Available
Apr-07	452	4
May-07	330	5
Jun-07	362	5
Jul-07	347	5
Aug-07	444	4
Sep-07	389	6
Oct-07	560	18
Nov-07	628	27
Dec-07	330	7
Jan-08	415	7
Feb-08	331	7
Mar-08	483	9
Apr-08	462	4
May-08	434	3
Jun-08	323	5
Jul-08	374	6
Aug-08	385	3
Sep-08	392	6
Oct-08	508	31
Nov-08	446	21
Dec-08	351	11
Jan-09	319	7
Feb-09	373	4
Mar-09	526	10
Apr-09	520	2

**Includes disconnections where gas is turned off at meter. Does not include transfer of service.*
***Includes accounts reconnected for "seasonal" or an "other" reason. Does not include customers reconnected for non payment.*

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 010:

Refer to Page 7 of the Cooper Testimony.

a. Explain why Columbia proposes to change the manner in which customers enroll in its budget plan from that of the customer choosing to opt in to the plan to one of automatically being enrolled unless choosing to opt out.

b. Describe in detail how, under Columbia's proposal, a new customer will be informed of 1) the automatic enrollment and 2) the option of not participating in the budget plan.

c. Is there any possibility that new customer may not know he/she is a budget plan customer until the first bill for service is received? Explain the response.

Response:

a. Columbia of Kentucky currently has approximately 40% of residential customers enrolled in the budget payment plan. This is the highest residential budget enrollment of any of the NiSource distribution companies. Customers in Kentucky clearly like the budget payment plan and we think the proposed process change will: 1) be more convenient for customers by allowing them to sign up for the budget at the same time they are initiating service; 2) make certain all customers are aware of the budget program before they encounter payment problems; and 3) help customers to manage their bills more effectively. Columbia desires to move to automatic budget enrollment as a means to proactively provide good customer service and make it easier for our customers to enjoy budget billing.

b. Columbia will explain to customers that they will be set up on the budget with their first bill at the time they initiate service. We will not enroll them on the budget if the customer indicates they do not want to be on the budget.

c. A customer should know that he/she is on the budget payment plan as they will be advised by the Customer Service Representative at the time they initiate service and will be allowed to opt out of the enrollment at that time. The customer would also have the option of being removed from the budget when they receive their first bill.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 011:

Refer to Page 8 of the Cooper Testimony. Columbia is proposing to change the start month of the budget plan from August to May and the settlement month from July to May.

a. Explain why Columbia's tariff does not include this information.

b. First Revised Sheet No. 76 shows a deletion of the "Off Season Equal Payment Plan". How many customers would be affected by this deletion?

c. Explain why Columbia is proposing to recover AMRP costs; Pension and Other Post-retirement employee Benefits ("OPEB") Mechanism ("POM") expenses; and Demand-Side Management ("DSM") costs and incentives on a per-customer basis as opposed to a volumetric basis.

d. Columbia has historically provided for an adjustment to customers' budget amounts at, or shortly after, the end of the heating season. Explain whether changing the budget year as proposed means there will no longer be an opportunity for such an adjustment.

Response:

a. The Budget Payment Plan is a required offering for residential gas and electric customers pursuant to 807 KAR 5:006. The Regulation provides that the provisions of the plan should be included in the utility's tariff and that bills under the plan should be adjusted to, "bring each participating customer current once each twelve (12) month period". A review of the tariffs of the other large gas distribution companies yielded a defined budget year in the tariff of only one other company. Columbia's proposed tariff does not state the specific months or define the budget year because the tariff is meant to provide for the continued operation of Columbia's current Budget Payment Plan and the future conversion to a budget year that would begin in May rather than August. The upcoming budget year will begin in August 2009. A conversion could not begin prior to May 2010.

b. The "Off Season Equal Payment Plan" that is described on Sheets 76 and 77 permits the customer to join the budget plan throughout the year with the same ending date of the regular budget plan (Twelve Month Equal Payment Plan). Columbia reports indicate the total number of customers enrolled in the budget payment plan, but does not track customers who join the budget plan in an off cycle month separately. With the proposed tariff revisions, customers will still be able to join the budget plan throughout the year and new language has been inserted on Sheet 76 that does provide for this to occur:

A customer may enroll in the plan at any time during the Company's budget year. A Customer applying for the Plan for the first time will be accepted in any month and their payment will be determined by dividing their estimated bill for the remainder of the budget period by the number of months remaining in that budget period.

c. Columbia is proposing a per customer basis recovery for its Riders AMRP, POM and DSM because the costs that the charges are designed to recover are primarily fixed charges, not volumetric based charges. The applicable charges are calculated based upon fixed budgets for each individual program and a balancing component is included in the individual mechanisms to incorporate any variability. The approach is consistent with Columbia's overall approach to rate design as described by Columbia witness Balmert.

d. Changing the budget year will still allow Columbia to review the customer's budget during the heating season and adjust as appropriate.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 012:

Refer to Third Revised Sheet No. 70 which describes reconnection of service.

a. The proposed charge of $143.36 for reconnection after customer requested disconnection is calculated by multiplying the proposed customer charge of $17.92 times eight months. Explain why this is fair to a customer who elects to be off the system for less than eight months, for example, four or six months.

b. Given the $83.36 difference between the cost to reconnect after being discontinued for non-payment and the cost to reconnect after discontinuance at the customer request, explain whether Columbia believes some customers in the latter group may elect to be cut off for non-payment, thereby saving $83.36.

c. Given that 807 KAR 5:011, Section 10, requires that nonrecurring charges cover the specific cost of the activity, explain why it is reasonable to charge an amount other than the actual cost of the reconnection.

Response:

a. The fee for reconnection of service discontinued at the request of a customer is meant to be a disincentive for disconnection of service for short period of time. A reconnection fee calculated as the customer charge times the number of months the customer was disconnected would just be a deferral of the billing of the customer charge and less of a deterrent to repeated disconnect/reconnect activity.

b. Columbia does not believe that customers elect to be cut off for non-payment rather than requesting disconnection of service to achieve a lesser reconnect fee. A similar disparity exists currently, but most disconnects requested by customers do not result in reconnections. Reference Attachment 2 to PSC Set 2, No. 9.

c. Please see response to part a., above.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 013:

Refer to Seventh Revised Sheet No. 82 which describes elements of the customer bill content. Number 12, Gas Supply Cost, adds the uncollectible gas cost charge to the definition of the "cost of natural gas itself". Explain whether Columbia proposes to set out the uncollectible gas cost charge as a separate element on the customer bill, or roll it into the calculation.

Response:

Columbia proposes to include the uncollectible gas cost charge in the calculation of the amount shown on the customer bill as the Gas Supply Cost line and identified as Number 12 in the bill content description.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 014:

Refer to page 10 of the Cooper Testimony.

a. Ms. Cooper states that Columbia modeled its Rider AMRP on the rider approved for Duke Energy Kentucky. Identify and describe all differences between the two programs other than the program years, miles of pipe, and total investment noted on this page.

b. Ms. Cooper also states that Columbia proposes to submit its annual adjustment of Rider AMRP on or about April 1 of each year to be effective on and after its June billing cycle and that the adjustment would be subject to Commission review. Describe the effects on Columbia if the Commission review is not completed by the June billing cycle.

c. Provide examples of the AMRP filing formats Columbia would propose utilizing for its annual AMRP Rider filing.

Response:

a. The difference between Columbia's Rider AMRP and the Rider AMRP of Duke Energy Kentucky is in the rate design used for recovery of the annual required revenue increase. The method of determining the amount of revenue to be recovered from each customer class is the same for both companies but, Columbia has proposed that the recovery be a customer charge for all rate schedules. Duke utilizes a combination of customer charge and throughput charge with the throughput charge applicable to its transportation service rate schedules. Columbia's proposed tariff sheet Third Revised Sheet No. 58 should be corrected by deleting the last sentence of the first paragraph under the heading, "Accelerated Main Replacement Program Factors".

b. The effects on Columbia of an extended Commission review would be increased carrying costs, regulatory uncertainty and possible financial impairment that could result in the inability of the company to maintain its AMRP.

c. Please see Staff Set 2 DR No. 014 Attachment 1 for the proposed format for the annual AMRP Rider filing.

AMRP Form 1.0

Columbia Gas of Kentucky
Annual Adjustment to the Accelerated Main Replacement Program
AMRP Rider by Rate Schedule

Line No.	Rate Schedule (1)	Revenue as Approved PSC Case No.2009-00141 (2)	Allocation Percent /1 (3)	Revenue Requirement (4)	Billing Determinant # of Customers (5)	Monthly AMRP Rider (6)
1	GSR	23,796,002	47.73%	434,479	98,761	$0.37
2						
3	GSO	10,733,041	21.52%	195,893	11,158	$1.46
4						
5	IS	0	0.00%	-	-	$0.00
6						
7	IUS	17,419	0.03%	273	2	$11.38
8						
9	SVGTS	10,161,076	20.37%	185,425	29,148	$0.53
10						
11	DS	4,420,822	8.86%	80,651	71	$94.88
12						
13	GDS	712,302	1.43%	13,017	26	$41.59
14						
15	SAS	30,684	0.06%	546	1	$45.50
16						
17	TOTAL	49,871,345	100%	910,284	139,167	

/1 Allocation percent is based on the overall base revenue distribution approved in PSC Case No. 2009-00141.

AMRP Form 1.1

Columbia Gas of Kentucky
Annual Adjustment to the Accelerated Main Replacement Program

Line No.		Actual Thru December 31, 2008 (1)	Activity Thru December 31, 2009 (2)	Total As Of December 31, 2009 (3)	Reference (4)
1	**Return on Investment**				
2	**Rate Base**				
3	AMRP Investment-Property, Plant and Equipment	-	7,000,000	7,000,000	Form 2.0
4	Cost of Removal	-	500,000	(5,135,688)	Form 2.0
5	Accumulated Reserve for Depreciation	-	(65,965)	(5,135,688)	Form 2.0
6	Net PP&E		7,434,035	(5,135,688)	
7					
8	Deferred Taxes on Liberalized Depreciation	-	(1,114,200)	(1,114,200)	Form 2.1
9					
10	Net Rate Base		6,319,835	6,319,835	Line 6 + Line 8
11					
12	Authorized Rate of Return, Adjusted for Income Taxes		13.06%		Form 1.2
13					
14	Return on AMRP Related Investment	-	825,193	825,193	Line 10 * Line 12
15					
16	**Operating Expenses**				
17	Annualized Depreciation	-	131,930	131,930	Form 2.0
18					
19	Current Year O & M Account 887	-	1,450,000	1,450,000	Financial Statement
20	O&M Account 887 as approved in Case No. 2009-00141	-	1,496,839	1,496,839	
21	O&M Savings Realized	-	(46,839)	(46,839)	Line 19 less Line 20
22					
23	Total Operating Expenses	-	85,091	85,091	Line 17 + Line 21
24					
25	**Total Annual Revenue Requirement**	-	910,284	910,284	Line 14 + Line 23

AMRP Form 1.2

Columbia Gas of Kentucky
Annual Adjustment to the Accelerated Main Replacement Program
Rate of Return

Line No.	Capital Structure (1)	Ratio (2)	Cost (3)	Weighted Cost (4)	Pre-Tax @ Effect tax of 38.90% (5)
1	Short term Debt	5.425%	3.24%	0.18%	0.18%
2	Long term Debt	42.559%	5.76%	2.45%	2.45%
3	Equity	52.016%	12.25%	6.37%	10.43%
4					
5	Total	100.00%		9.00%	13.06%

AMRP Form 2.0

Columbia Gas of Kentucky
Annual Adjustment to the Accelerated Main Replacement Program
Book Depreciation 1/

Line No.	Description (1)	Account Number (2)	2009 Beginning Plant Balance (3)	Depr Rates (4)	Depr on Beginning Balance (5)=(3)*(4)	2009 Additions & Retirements Plant (6)	Depr on Adds/(Ret) (7)=(4)*(6)*50%	Annualized Depreciation (8)=(3+6)*(3)
1	**Additions**							
2	Mains-AMRP	376.25	-	2.12%	-	6,000,000	63,600	127,200
3	Services	380.25	-	2.12%	-	800,000	8,480	16,960
4	Meter Relocations	382.25	-	3.33%		100,000	1,665	3,330
5	House Regulators	383.25		3.08%		100,000	1,540	3,080
6			-		-		-	-
7								
8	Total Additions		-		-	7,000,000	75,285	150,570
9								
10	**Retirements 2/**							
11	Mains-Coated	376.20	-	2.12%	-	(200,000)	(2,120)	(4,240)
12	Mains-Bare Steel	376.30		1.80%		(300,000)	(2,700)	(5,400)
13	Mains-Plastic	376.40		2.12%		(100,000)	(1,060)	(2,120)
14	Mains-Cast Iron	376.80		1.72%		(400,000)	(3,440)	(6,880)
15								
16			-		-	-	-	-
17	Total Retirements		-		-	(1,000,000)	(9,320)	(18,640)
18								
19	**Total Plant**		-		-	6,000,000	65,965	131,930
20								
21	**Cost of Removal 2/**		-			500,000		

1/ Depreciation is calculated assuming half year convention. Depreciation on actual filing may be calculated by month.

2/ Amounts detailed are for illustrative purposes only and are not an indication of expected retirements or removal costs.

AMRP Form 2.1

Columbia Gas of Kentucky, Inc.
Annual Adjustment to the Accelerated Main Replacement Program

Ln. No.	2008-2009 Tax Rate Life Rates (1) %	After 2009 Tax Rate Life Rates (2) %	Year (3)	2009 Year 1* Additions (4) ($)	2010 Year 2 Additions (5) ($)	2011 Year 3 Additions (6) ($)	2012 Year 4 Additions (7) ($)	2013 Year 5 Additions (8) ($)	2014 Year 6 Additions (9) ($)	2015 Year 7 Additions (10) ($)	2016 Year 8 Additions (11) ($)	2017 Year 9 Additions (12) ($)	2018 Year 10 Additions (13) ($)	2019 Year 11 Additions (14) ($)	2020 Year 12 Additions (15) ($)	2021 Year 13 Additions (16) ($)	2022 Year 14 Additions (17) ($)	2023 Year 15 Additions (18) ($)	2024 Year 16 Additions (19) ($)	2025 Year 17 Additions (20) ($)	2026 Year 18 Additions (21) ($)
1				6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
									Tax Depreciation												
2	0.05000	0.03750	1	3,150,000																	
3	0.09500	0.07219	2	285,000	300,000																
4	0.08550	0.06677	3	256,500	570,000	225,000															
5	0.07700	0.06177	4	231,000	513,000	433,140	225,000														
6	0.06930	0.05713	5	207,900	462,000	400,620	433,140	225,000													
7	0.06230	0.05285	6	186,900	415,800	370,620	400,620	433,140	225,000												
8	0.05900	0.04888	7	177,000	373,800	342,780	370,620	400,620	433,140	225,000											
9	0.05900	0.04522	8	177,000	354,000	317,100	342,780	370,620	400,620	433,140	225,000										
10	0.05910	0.04462	9	177,300	354,000	293,280	317,100	342,780	370,620	400,620	433,140	225,000									
11	0.05900	0.04461	10	177,000	354,600	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000								
12	0.05910	0.04462	11	177,300	354,000	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000							
13	0.05900	0.04461	12	177,000	354,600	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000						
14	0.05910	0.04462	13	177,300	354,000	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000					
15	0.05900	0.04461	14	177,000	354,600	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000				
16	0.05910	0.04462	15	177,300	354,000	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000			
17	0.02950	0.04461	16	88,500	354,600	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000		
18	-	0.04462	17	-	177,000	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000	
19	-	0.04461	18	-	-	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000
20	-	0.04462	19	-	-	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140
21	-	0.04461	20	-	-	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620
22	-	0.02231	21	-	-	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620
23					-	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780
24						133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100
25							133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280
26								133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320
27									133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720
28									-	133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660
29									-	-	133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720
30									-			133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660
31									-			-	133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720
32													-	133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660
33														-	133,860	267,660	267,720	267,660	267,720	267,660	267,720
34															-	133,860	267,660	267,720	267,660	267,720	267,660
35																-	133,860	267,660	267,720	267,660	267,720
36																	-	133,860	267,660	267,720	267,660
37																	-	-	133,860	267,660	267,720
38																	-			133,860	267,660
39																					133,860
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58				6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000

AMRP Form 2.1

Columbia Gas of Kentucky, Inc.
Annual Adjustment to the Accelerated Main Replacement Program

Ln. No.	2008-2009 Tax Rate Life Rates (1) %	After 2009 Tax Rate Life Rates (2) %	2027 Year 19 Additions (22) ($)	2028 Year 20 Additions (23) ($)	2029 Year 21 Additions (24) ($)	2030 Year 22 Additions (25) ($)	2031 Year 23 Additions (26) ($)	2032 Year 24 Additions (27) ($)	2033 Year 25 Additions (28) ($)	2034 Year 26 Additions (29) ($)	2035 Year 27 Additions (30) ($)	2036 Year 28 Additions (31) ($)	2037 Year 29 Additions (32) ($)	2038 Year 30 Additions (33) ($)	Annual Tax Depreciation (34) ($)	Book Deprec. 1/ 2/ (35) ($)	Difference (36) ($)	Deferred Tax @ 38.900% (37) ($)	Accumulated Deferred Inc. Taxes (38) ($)
1			6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000		180,000,000			
														180,000,000					
2	0.05000	0.03750													3,150,000	-	3,150,000	1,114,200	1,114,200
3	0.09500	0.07219													585,000	0	585,000	238,680	1,352,880
4	0.08550	0.06677													1,051,500	-	1,051,500	419,038	1,771,918
5	0.07700	0.06177													1,402,140	(200,000)	1,602,140	632,241	2,404,159
6	0.06930	0.05713													1,728,660	(2,120)	1,730,780	681,381	3,085,540
7	0.06230	0.05285													2,032,080	(4,240)	2,036,320	799,417	3,884,957
8	0.05900	0.04888													2,322,960	-	2,322,960	910,534	4,795,491
9	0.05900	0.04522													2,620,260	-	2,620,260	1,026,184	5,821,675
10	0.05910	0.04462													2,913,840	-	2,913,840	1,140,399	6,962,073
11	0.05900	0.04461													3,185,460	-	3,185,460	1,246,047	8,208,120
12	0.05910	0.04462													3,452,880	-	3,452,880	1,350,085	9,558,205
13	0.05900	0.04461													3,720,840	-	3,720,840	1,454,310	11,012,515
14	0.05910	0.04462													3,988,260	-	3,988,260	1,558,348	12,570,863
15	0.05900	0.04461													4,256,220	-	4,256,220	1,662,573	14,233,436
16	0.05910	0.04462													4,523,640	-	4,523,640	1,766,611	16,000,047
17	0.02950	0.04461													4,703,100	-	4,703,100	1,832,958	17,833,004
18	-	0.04462													4,704,720	-	4,704,720	1,830,136	19,663,140
19	-	0.04461													4,795,380	-	4,795,380	1,865,403	21,528,543
20	-	0.04462	225,000												5,063,100	-	5,063,100	1,969,546	23,498,089
21	-	0.04461	433,140	225,000											5,330,760	-	5,330,760	2,073,666	25,571,755
22	-	0.02231	400,620	433,140	225,000										5,598,480	-	5,598,480	2,177,809	27,749,564
23			370,620	400,620	433,140	225,000									5,866,140	-	5,866,140	2,281,928	30,031,492
24			342,780	370,620	400,620	433,140	225,000								6,000,000	-	6,000,000	2,334,000	32,365,492
25			317,100	342,780	370,620	400,620	433,140	225,000							6,000,000	-	6,000,000	2,334,000	34,699,492
26			293,280	317,100	342,780	370,620	400,620	433,140	225,000						6,000,000	-	6,000,000	2,334,000	37,033,492
27			271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000					6,000,000	-	6,000,000	2,334,000	39,367,492
28			267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000				6,000,000	-	6,000,000	2,334,000	41,701,492
29			267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000			6,000,000	-	6,000,000	2,334,000	44,035,492
30			267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000		6,000,000	-	6,000,000	2,334,000	46,369,492
31			267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	225,000	6,000,000	-	6,000,000	2,334,000	48,703,492
32			267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	433,140	5,775,000				
33			267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	400,620	5,341,860				
34			267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	370,620	4,941,240				
35			267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	342,780	4,570,620				
36			267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	317,100	4,227,840				
37			267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	293,280	3,910,740				
38			267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	271,320	3,617,460				
39			267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	3,346,140				
40			133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	3,078,420				
41				133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	2,810,760				
42					133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	267,660	2,543,040				
43						133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	267,720	2,275,380				
44							133,860	267,660	267,720	267,660	267,720	267,660	267,720	267,660	2,007,660				
45								133,860	267,660	267,720	267,660	267,720	267,660	267,720	1,740,000				
46									133,860	267,660	267,720	267,660	267,720	267,660	1,472,280				
47										133,860	267,660	267,720	267,660	267,720	1,204,620				
48											133,860	267,660	267,720	267,660	936,900				
49												133,860	267,660	267,720	669,240				
50													133,860	267,660	401,520				
51														133,860	133,860				
52																			
53																			
54															-				
55															-				
56															-				
57															-				
58			6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	180,000,000	180,000,000			

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 015:

Refer to page 6 of the Prepared Direct Testimony of William Steven Seelye ("Seelye Testimony"). Mr. Seelye states that Columbia's proposed DSM program is modeled on that approved for Delta Natural Gas Company. Identify and describe all differences between the two programs.

Response:

Both Delta Natural Gas Company's and Columbia Gas's DSM programs include Energy Audit Programs. Columbia Gas's High Efficiency Appliance Rebate Program provides the same rebates for high-efficiency heating systems as Delta Natural Gas Company's High Efficiency Heating Systems Rebate Program. Columbia Gas is not proposing a High-Efficiency Water Heating Systems Rebate Program offered by Delta Natural Gas Company. Instead, Columbia Gas Company is proposing a Low-Income High Efficiency Furnace Replacement Program, which was not included in Delta Natural Gas Company's DSM program.

PSC Case No. 2009-00141
Staff Set 2 DR No. 016
Respondent(s): William Steven Seelye
Judy M. Cooper

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 016:

Refer to page 7 of the Seelye Testimony. Mr. Seelye states that the program costs will include the costs of planning, developing, implementing, managing, monitoring and evaluating the DSM programs, and will include cost for consultants, employees and administrative services. How will Columbia ensure that the costs incurred are reasonable?

Response:

Columbia Gas plans to use qualified outside contractors to provide services under the Energy Audit Program and the Low-Income High Efficiency Furnace Replacement Program. For the Energy Audit Program, Columbia will require outside contactors to submit reports identifying the premises for which audits are performed, the date when the audit is performed, and detailing the audit tasks performed at each premise. For the Low-Income High Efficiency Furnace Replacement Program, Columbia will pre-approve all replacements and will require outside contractors to submit reports identifying the premises for which the replacement work is performed, describing the type and condition of the facilities replaced, and detailing the cost of the furnace systems replaced. Columbia Gas will contact on a random basis approximately 10 percent of the customers for which audits are performed to verify that the audit work was actually performed by the contractors. Columbia Gas will contact each customer for which a furnace replacement was conduced to verify that the replacement work as represented by the contractor was actually performed. Outside contractors providing services under both programs will also be subject to comprehensive audits conducted by or on behalf of Columbia Gas.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 017:

Refer to pages 10-11 of the Seelye Testimony where he describes methods utilities use to protect against revenue losses resulting from implementing DSM programs and states that Columbia's proposed Energy Efficiency/Conservation Program (i'EECP'') contains a "Revenue from Lost Sales" component. Mr. Seelye also describes an SFV rate design and states that adoption of such a rate design with only a fixed billing charge removes the need for a "Revenue from Lost Sales" component. If an SFV rate design eliminates the need for a "Revenue from Lost Sales component", does having a Revenue from Lost Sales component in rates have the effect of eliminating the need for an SFV rate design? Explain the response in detail.

Response:

No. The Revenue from Lost Sales component is designed to recover contributions to fixed costs that are lost due to the specific DSM measures provided by Columbia Gas under its DSM programs. Therefore, the Revenue from Lost Sales component serves to protect Columbia Gas from lost contributions to fixed costs related *solely* to the proposed DSM programs. The Revenue from Lost Sales component therefore does not protect Columbia Gas from lost contributions to fixed costs related to conservation efforts initiated by customers outside of Columbia Gas's DSM program. Columbia Gas's proposed SFV rate design, on the other hand, would serve to protect Columbia Gas from lost contributions to fixed costs related to *both* the proposed DSM programs *and* customer-initiated conservation efforts. Consequently, an SFV rate design is a broader and more comprehensive way to preserve Columbia Gas's recovery of fixed costs in an environment where customers are reducing their gas usage as a result of conservation efforts – either Company-initiated efforts or customer-initiated efforts.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 018:

Refer to pages 10-17 of the Seelye Testimony where he states that any difference between the lost revenues collected by the EECP Revenue from Lost Sales component and actual lost revenues will be reconciled in future billings under the EECP Balance Adjustment ("EE CP BA ').

a. Describe in detail how the "actual lost revenues'' discussed on page 10 will be calculated.

b. Page 13 contains an estimate of the EECPBA. Explain whether this true-up will adjust for the difference between estimated and actual costs, estimated and actual lost sales, and estimated and actual net resource savings (which are the basis of the incentive collection).

c. Explain how Columbia determined that its incentive for administering the EECP should be 15 percent.

d. Provide the basis for the estimate of 4,000 audits mentioned on page 15, as well as the $50 cost per audit.

e. Provide the basis for the 1,600 estimated participants in the High-Efficiency Appliance Rebate Program mentioned on page 16.

f. For the High-Efficiency Appliance Rebate Program, explain how Columbia developed the rebate amounts.

g. Mr. Seelye states on page 16 of his testimony that, under the Low-Income High Efficiency Furnace Replacement Program, Columbia will provide up to $2,200 toward the cost of installing a high-efficiency furnace. Does Columbia expect that, in most cases, the $2,200 will cover the entire cost of the furnace and installation, or does it expect that customers will incur a portion of the cost? If the latter is expected, provide the estimated amount to be incurred by the customer.

h. Provide the basis for the 140 estimated participants in the Low-Income High Efficiency Furnace Replacement Program mentioned on page 17.

i. Have guidelines been developed regarding the details of the DSM programs? If yes, provide the guidelines.

Response:

a. The "actual lost revenues'' discussed on page 10 will be calculated by multiplying the unit savings determined based on engineering estimates by the *actual* DSM measures provided by the Company. Columbia Gas, for example, estimates that there would be 4,000 participants in its Energy Audit Program. The program is estimated to produce annual savings of 12,000 Mcf based on 3.0 Mcf per participant. If only 3,000 customers participate in the program rather than 4,000 customers as projected by the Company then the actual lost revenues would be determined by multiplying 3,000 customers by the 3.0 Mcf savings per participant and then multiplying this product by the delivery charge approved by the Commission in this proceeding.

b. This true-up will adjust for all three differences.

c. Columbia Gas used the same incentives percentage that was approved for Delta Natural Gas, Louisville Gas and Electric Company, and Kentucky Utilities Company.

d. The 4,000 audits represent a target number of audits based on a commitment by the Company to provide $200,000 in support of energy audits at a cost of $50 per audit. The $50 is based on the estimate utilized by Delta Natural Gas Company, increased slightly to reflect possible cost increases and to reflect additional audit procedures that will likely be performed under Columbia Gas's program. A true-up adjustment will be made to made to reconcile the actual number of audits performed and the actual cost of the audits.

e. The 1,600 participants represent a target number of rebates based on a commitment by the Company to provide $400,000 in support of the appliance rebates.

f. Columbia Gas rebates were based on the rebates which were approved for Delta Natural Gas Company.

g. Replacements will be capped at $2,200. Columbia expects that in most cases this amount will not cover the entire cost of the required replacement work. Customers will likely provide anywhere from $0 to $2,000 per replacement.

h. The 140 participants represent a target number of replacements based on a commitment by the Company to provide $308,000 in support of the low-income furnace replacements.

i. Columbia Gas plans to jointly develop specific guidelines with Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nichols Counties, Inc. ("CAC"). These guidelines currently have not been developed.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 019:

Refer to Attachment Seelye-2.

a. Explain the use of the $2.00 amount in calculating Annual Lost Revenues.

b. Provide the calculations for the $104,614 and $69,797 Incentive Amounts.

c. Provide the calculation for the estimated customer-month total of 1,496,096.

Response:

a. The amount should correspond to the delivery charge, which is proposed to be $1.4604. The Annual Lost Revenues amount has been revised in the attached spreadsheet to reflect the proposed delivery charge. Ultimately, the delivery charge approved by the Commission should be utilized to determine the Annual Lost Revenues amount.

b. See attached.

c. See Attachment MPB-6, Sheet 2 of Mr. Balmert's testimony.

Columbia Gas of Kentucky, Inc.
Conservation/Efficiency Program Cost Recovery
Calculation of Monthly Adjustment Factors
for Schedule GSR

					Conservation/Efficiency Program Cost Recovery (CEPCR)		CEP Revenue From Lost Sales (CEPLS)		CEP Incentive (CEPI)	
Program	Estimated Participants	Est Annual Mcf Savings per Participant	Total Est Annual Mcf Savings	Estimated Cust-Months	Program Cost	CEPCR Adjustment	Annual Lost Revenues	CEPLS Adjustment	Incentive Amount	CEPI Adjustment
							$ 1.4604			
Energy Audit Program	4000	3.0	12,000.0	1,496,096	$ 200,000	$ 0.13	$ 17,525	$ 0.01	$ 104,614	$ 0.07
High Efficiency Furnace Rebate Program	1460	6.4	9,312.6	1,496,096	400,000	0.27	13,600	0.01	69,797	0.05
Low-Income High Efficiency Furnace Rebate Program	140	6.6	922.5	1,496,096	308,000	0.21	1,347	0.00	-	-
Total						$ 0.61		$ 0.02		$ 0.12
										$ 0.75

Net Benefits Analysis
Energy Audit Program

Year	Estimated Annual Mcf Savings	Projected Gas Cost	Commodity Savings	PV Factor	Present Value Savings
1	12000	12.02	144240	0.917431	132,330.28
2	12000	11.85	142200	0.841680	119,686.90
3	12000	11.65	139800	0.772183	107,951.25
4	12000	11.50	138000	0.708425	97,762.68
5	12000	11.42	137040	0.649931	89,066.60
6	12000	11.37	136440	0.596267	81,354.71
7	12000	11.38	136560	0.547034	74,703.00
8	12000	11.53	138360	0.501866	69,438.22
9	12000	11.73	140760	0.460428	64,809.81
10	12000	11.90	142800	0.422411	60,320.26

Discount Rate	0.09	
Present Value Savings	$	897,424
Program Cost	$	200,000
Net Benefits	$	697,424

Net Benefits Analysis
High Efficiency Furnace Rebate Program

Year	Estimated Annual Mcf Savings	Projected Gas Cost	Commodity Savings	PV Factor	Present Value Savings
1	9312.645902	12.52	116594.3267	0.938967	109,478.24
2	9312.645902	12.44	115849.315	0.881659	102,139.62
3	9312.645902	12.36	115104.3033	0.827849	95,288.99
4	9312.645902	12.38	115290.5563	0.777323	89,618.01
5	9312.645902	12.53	116687.4531	0.729881	85,167.94
6	9312.645902	12.75	118736.2352	0.685334	81,373.99
7	9312.645902	13.06	121623.1555	0.643506	78,265.26
8	9312.645902	13.55	126186.352	0.604231	76,245.73
9	9312.645902	14.14	131680.813	0.567353	74,709.53
10	9312.645902	14.72	137082.1477	0.532726	73,027.23

Discount Rate	0.065	
Present Value Savings	$	865,315
Program Cost	$	400,000
Net Benefits	$	465,315

Net Benefits Analysis
Low-Income High Efficiency Furnace Rebate Program

Year	Estimated Annual Mcf Savings	Projected Gas Cost	Commodity Savings	PV Factor	Present Value Savings
1	922.517037	12.52	11549.9133	0.938967	10,844.99
2	922.517037	12.44	11476.11194	0.881659	10,118.02
3	922.517037	12.36	11402.31058	0.827849	9,439.39
4	922.517037	12.38	11420.76092	0.777323	8,877.62
5	922.517037	12.53	11559.13847	0.729881	8,436.79
6	922.517037	12.75	11762.09222	0.685334	8,060.96
7	922.517037	13.06	12048.0725	0.643506	7,753.01
8	922.517037	13.55	12500.10585	0.604231	7,552.95
9	922.517037	14.14	13044.3909	0.567353	7,400.78
10	922.517037	14.72	13579.45079	0.532726	7,234.13

Discount Rate	0.065	
Present Value Savings	$	85,719
Program Cost	$	308,000
Net Benefits	$	(222,281)

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 020:

Refer to Original Sheet No. 51e at Tab L of Volume 6 of the application.

a. The third paragraph on this page begins, "Recovery of revenues ..."Is a correction needed to this paragraph or is it written as intended?

b. Refer to the second to the last paragraph, the second line. Should the fifth word on this line be "of" rather than "on"?

c. Refer to the last paragraph on this page. Explain what is meant by "February Unit 1 billing cycle".

Response:

a. Yes. The sentence should read as follows – "Recovery of revenues from lost sales calculated for a twelve-month period shall be included in the EECPLS as long as a volumetric delivery charge is included in applicable standard rate, Rate Schedule GSR or Rate Schedule GSO, or until the next general rate case of the company.

b. Yes.

c. The February Unit 1 billing cycle date represents the date of Unit 1 billing in Columbia's February billing cycle and is designed to allow implementation of the balance adjustment after actual accounting information is cleared for an October year-end.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 021:

21. Refer to pages 6-9 of the Prepared Direct Testimony of James F. Racher ("Racher Testimony") and Attachment JFR-1 regarding the proposed rate base adjustment for gas stored underground.

a. The answer starting at the bottom of page 6 of the Racher Testimony states that Columbia uses the annualized Last-In-First-Out ("LIFO") method to value gas inventory. Provide a detailed explanation for why this is the method used by Columbia. At a minimum, the answer should discuss the merits of LIFO in general, as well as why the annualized LIFO method is Columbia's preferred method.

b. The answer at the bottom of page 8 refers to Attachment JFR-1 and a 13-month average balance of gas in storage for the test year of ($32,765,396). However, the attachment (and Commission Staffs calculation) indicates a positive balance of $32,765,395. Clarify whether Mr. Racher is testifying that the 13-month test year balance is positive or negative.

c. Attachment JFR-1 covers Columbia's calendar year 2008 test year. Provide the same injection, withdrawal, and balance information, in the same format as in Attachment JR-1, for Columbia's gas in storage for the years 2004 through 2007.

Response:
a. The LIFO method of accounting to value gas inventory was adopted for book and tax purposes in the 1970's. Although documentation does not appear to exist as to why this method was adopted, one could ascertain that LIFO was adopted because gas cost recovery based on LIFO more closely approximates the cost to replace current inventory since injections and withdrawals are priced at the current year commodity gas price. By pricing storage activity at current year prices, LIFO also provides customers a current price signal of their gas costs so that they can better make consumption and conservation decisions.

The Company is not proposing to change from the LIFO method for book or tax purposes. The Company is proposing to change its valuation of storage for rate making purposes to reflect in rate base the cost of the Company's long-term investment in storage made on behalf of its customers for their future consumption.

b. The 13-month test year balance is positive. The parentheses were intended to set out the number from the surrounding text.

c. Please refer to PSC DR Set 2-021 Attachment 1 for the requested information.

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2004

		LIFO							
		MCF			Rate	Dollars			
Line No.	Month	Injection	Withdrawal	Balance		Injection	Withdrawal	YTD Adj	Balance
1	Dec-03			3,969,291	$2.2296				$8,849,912
2									
3									
4	Jan-04	73,063	(1,610,751)	2,431,603	$6.2919	$459,705	($10,134,684)		($825,067)
5	YTD rate adjustment				$6.2919				
6									
7	Feb-04	15,754	(854,306)	1,593,051	$6.2919	$99,123	($5,375,208)		($6,101,153)
8	YTD rate adjustment	73,063	(1,610,751)		$6.2919				($6,101,153)
9									
10	Mar-04	107,006	(611,617)	1,088,440	$6.2957	$673,678	($3,850,557)		($9,278,032)
11	YTD rate adjustment	88,817	(2,465,057)		$0.0038	$338	($9,367)	($9,030)	($9,287,062)
12									
13	Apr-04	580,536	(87,513)	1,581,463	$6.2957	$3,654,880	($550,956)		($6,183,137)
14	YTD rate adjustment	195,823	(3,076,674)		$0.0000	$0	$0	$0	($6,183,137)
15									
16	May-04	779,556	3,641	2,364,660	$6.2957	$4,907,851	$22,923		($1,252,364)
17	YTD rate adjustment	776,359	(3,164,187)		$0.0000	$0	$0	$0	($1,252,364)
18									
19	Jun-04	1,023,453	1,719	3,389,832	$6.5008	$6,653,263	$11,175		$5,412,074
20	YTD rate adjustment	1,555,915	(3,160,546)		$0.2051	$319,118	($648,228)	($329,110)	$5,082,965
21									
22	Jul-04	797,030	118	4,186,980	$6.5008	$5,181,333	$767		$10,265,064
23	YTD rate adjustment	2,579,368	(3,158,827)		$0.0000	$0	$0	$0	$10,265,064
24									
25	Aug-04	814,435	0	5,001,415	$6.5008	$5,294,479	$0		$15,559,543
26	YTD rate adjustment	3,376,398	(3,158,709)		$0.0000	$0	$0	$0	$15,559,543
27									
28	Sep-04	643,151	(1,163)	5,643,403	$6.8134	$4,382,045	($7,924)		$19,933,664
29	YTD rate adjustment	4,190,833	(3,158,709)		$0.3126	$1,310,054	($987,412)	$322,642	$20,256,306
30									
31	Oct-04	250,277	(50,487)	5,843,193	$6.8134	$1,705,237	($343,988)		$21,617,556
32	YTD rate adjustment	4,833,984	(3,159,872)		$0.0000	$0	$0	$0	$21,617,556
33									
34	Nov-04	883	(567,511)	5,276,565	$6.8134	$6,016	($3,866,679)		$17,756,892
35	YTD rate adjustment	5,084,261	(3,210,359)		$0.0000	$0	$0	$0	$17,756,892
36									
37	Dec-04	8,379	(1,190,359)	4,094,585	$7.2782	$60,984	($8,663,671)		$9,154,206
38	YTD rate adjustment	5,085,144	(3,777,870)		$0.4648	$2,363,575	($1,755,954)	$607,621	$9,761,826
39									
40									
41	Thirteen Month Average Account 164 / 242								**$6,577,022**

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2004

Line		*Average - 13 months ended December 31, 2004*							
		MCF			Rate	Dollars			
No.	Month	Injection	Withdrawal	Balance		Injection	Withdrawal	YTD Adj	Balance
1	Oct-04			5,843,193	$3.6996				$21,617,556
2									
3	Dec-03			3,969,291	$3.6996				$14,684,789
4	Jan-04	73,063	(1,610,751)	2,431,603	$3.6996	$270,304	($5,959,134)		$8,995,958
5	Feb-04	15,754	(854,306)	1,593,051	$3.6996	$58,283	($3,160,590)		$5,893,651
6	Mar-04	107,006	(611,617)	1,088,440	$3.6996	$395,879	($2,262,738)		$4,026,793
7	Apr-04	580,536	(87,513)	1,581,463	$3.6996	$2,147,751	($323,763)		$5,850,781
8	May-04	779,556	3,641	2,364,660	$3.6996	$2,884,045	$13,470		$8,748,296
9	Jun-04	1,023,453	1,719	3,389,832	$3.6996	$3,786,367	$6,360		$12,541,022
10	Jul-04	797,030	118	4,186,980	$3.6996	$2,948,692	$437		$15,490,151
11	Aug-04	814,435	0	5,001,415	$3.6996	$3,013,084	$0		$18,503,235
12	Sep-04	643,151	(1,163)	5,643,403	$3.6996	$2,379,401	($4,303)		$20,878,334
13	Oct-04	250,277	(50,487)	5,843,193	$3.6996	$925,925	($186,782)		$21,617,477
14	Nov-04	883	(567,511)	5,276,565	$3.6996	$3,267	($2,099,564)		$19,521,180
15	Dec-04	8,379	(1,190,359)	4,094,585	$3.6996	$30,999	($4,403,852)		$15,148,327
16									
17	Thirteen Month Average Account 164 / 242								**$13,223,076**

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2005

Line No.	Month		LIFO MCF Injection	MCF Withdrawal	MCF Balance	Rate	Dollars Injection	Dollars Withdrawal	Dollars YTD Adj	Dollars Balance
1		Dec-04			4,094,585	$2.3841				$9,761,823
2										
3										
4		Jan-05	265,364	(505,884)	3,854,065	$7.1257	$1,890,904	($3,604,778)		$8,047,950
5	YTD rate adjustment									
6										
7		Feb-05	(16,526)	(1,152,545)	2,684,994	$8.5987	($142,102)	($9,910,389)		($2,004,541)
8	YTD rate adjustment		265,364	(505,884)		$1.4730	$390,881	($745,167)	($354,286)	($2,358,827)
9										
10		Mar-05	(980)	(1,279,264)	1,404,750	$9.3700	($9,183)	($11,986,704)		($14,354,713)
11	YTD rate adjustment		248,838	(1,658,429)		$0.7713	$191,929	($1,279,146)	($1,087,218)	($15,441,931)
12										
13		Apr-05	1,780,388	3,910	3,189,048	$8.4483	$15,041,252	$33,033		($367,646)
14	YTD rate adjustment		247,858	(2,937,693)		($0.9217)	($228,451)	$2,707,672	$2,479,221	$2,111,575
15										
16		May-05	1,728,160	(21,420)	4,895,788	$7.5845	$13,107,230	($162,460)		$15,056,344
17	YTD rate adjustment		2,028,246	(2,933,783)		($0.8638)	($1,751,999)	$2,534,202	$782,203	$15,838,547
18										
19		Jun-05	1,161,880	1,240	6,058,908	$7.7447	$8,998,412	$9,603		$24,846,563
20	YTD rate adjustment		3,756,406	(2,955,203)		$0.1602	$601,776	($473,424)	$128,353	$24,974,915
21										
22		Jul-05	1,514,946	0	7,573,854	$8.2485	$12,496,032	$0		$37,470,947
23	YTD rate adjustment		4,918,286	(2,953,963)		$0.5038	$2,477,832	($1,488,207)	$989,626	$38,460,573
24										
25		Aug-05	1,417,156	0	8,991,010	$8.1762	$11,586,951	$0		$50,047,524
26	YTD rate adjustment		6,433,232	(2,953,963)		($0.0723)	($465,123)	$213,572	($251,551)	$49,795,973
27										
28		Sep-05	1,398,501	0	10,389,511	$9.0783	$12,696,012	$0		$62,491,985
29	YTD rate adjustment		7,850,388	(2,953,963)		$0.9021	$7,081,835	($2,664,770)	$4,417,065	$66,909,050
30										
31		Oct-05	637,013	(153,497)	10,873,027	$9.2196	$5,873,005	($1,415,181)		$71,366,874
32	YTD rate adjustment		9,248,889	(2,953,963)		$0.1413	$1,306,868	($417,395)	$889,473	$72,256,347
33										
34		Nov-05	327,628	(615,188)	10,585,467	$9.2591	$3,033,540	($5,696,087)		$69,593,800
35	YTD rate adjustment		9,885,902	(3,107,460)		$0.0395	$390,493	($122,745)	$267,748	$69,861,549
36										
37		Dec-05	15,882	(2,103,945)	8,497,404	$9.6751	$153,660	($20,355,878)		$49,659,330
38	YTD rate adjustment		10,213,530	(3,722,648)		$0.4160	$4,248,828	($1,548,622)	$2,700,207	$52,359,537
39										
40										
41	Thirteen Month Average Account 164 / 242									$30,198,237

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2005

		Average - 13 months ended December 31, 2005								
		MCF			Rate	Dollars			
Line No.	Month	Injection	Withdrawal	Balance		Injection	Withdrawal	YTD Adj	Balance
1	Oct-05			10,873,027	$6.6455				$72,256,347
2									
3	Dec-04			4,094,585	$6.6455				$27,210,565
4	Jan-05	265,364	(505,884)	3,854,065	$6.6455	$1,763,476	($3,361,852)		$25,612,189
5	Feb-05	(16,526)	(1,152,545)	2,684,994	$6.6455	($109,824)	($7,659,238)		$17,843,128
6	Mar-05	(980)	(1,279,264)	1,404,750	$6.6455	($6,513)	($8,501,349)		$9,335,266
7	Apr-05	1,780,388	3,910	3,189,048	$6.6455	$11,831,568	$25,984		$21,192,818
8	May-05	1,728,160	(21,420)	4,895,788	$6.6455	$11,484,487	($142,347)		$32,534,959
9	Jun-05	1,161,880	1,240	6,058,908	$6.6455	$7,721,274	$8,240		$40,264,473
10	Jul-05	1,514,946	0	7,573,854	$6.6455	$10,067,574	$0		$50,332,047
11	Aug-05	1,417,156	0	8,991,010	$6.6455	$9,417,710	$0		$59,749,757
12	Sep-05	1,398,501	0	10,389,511	$6.6455	$9,293,738	$0		$69,043,495
13	Oct-05	637,013	(153,497)	10,873,027	$6.6455	$4,233,270	($1,020,064)		$72,256,701
14	Nov-05	327,628	(615,188)	10,585,467	$6.6455	$2,177,252	($4,088,232)		$70,345,721
15	Dec-05	15,882	(2,103,945)	8,497,404	$6.6455	$105,544	($13,981,766)		$56,469,498
16									
17	Thirteen Month Average Account 164 / 242								**$42,476,201**

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2006

		LIFO							
		MCF			Rate	Dollars			
Line No.	Month	Injection	Withdrawal	Balance		Injection	Withdrawal	YTD Adj	Balance
1	Dec-05			8,497,404	$6.1618				$52,359,540
2									
3									
4	Jan-06	16,343	(1,067,942)	7,445,805	$11.3122	$184,875	($12,080,773)		$40,463,641
5	YTD rate adjustment								
6									
7	Feb-06	(1,316)	(1,928,955)	5,515,534	$8.8512	($11,648)	($17,073,566)		$23,378,427
8	YTD rate adjustment	16,343	(1,067,942)		($2.4610)	($40,220)	$2,628,205	$2,587,985	$25,966,412
9									
10	Mar-06	190,220	(648,650)	5,057,104	$8.3182	$1,582,288	($5,395,600)		$22,153,099
11	YTD rate adjustment	15,027	(2,996,897)		($0.5330)	($8,009)	$1,597,346	$1,589,337	$23,742,436
12									
13	Apr-06	691,034	41,866	5,790,004	$8.6650	$5,987,810	$362,769		$30,093,015
14	YTD rate adjustment	205,247	(3,645,547)		$0.3468	$71,180	($1,264,276)	($1,193,096)	$28,899,919
15									
16	May-06	302,879	(143,524)	5,949,359	$8.8983	$2,695,108	($1,277,120)		$30,317,907
17	YTD rate adjustment	896,281	(3,603,681)		$0.2333	$209,102	($840,739)	($631,636)	$29,686,271
18									
19	Jun-06	379,191	105,418	6,433,968	$8.7212	$3,307,001	$919,371		$33,912,643
20	YTD rate adjustment	1,199,160	(3,747,205)		($0.1771)	($212,371)	$663,630	$451,259	$34,363,902
21									
22	Jul-06	1,528,762	2,504	7,965,234	$8.4079	$12,853,678	$21,053		$47,238,633
23	YTD rate adjustment	1,578,351	(3,641,787)		($0.3133)	($494,497)	$1,140,972	$646,474	$47,885,107
24									
25	Aug-06	1,235,089	0	9,200,323	$9.1124	$11,254,625	$0		$59,139,732
26	YTD rate adjustment	3,107,113	(3,639,283)		$0.7045	$2,188,961	($2,563,875)	($374,914)	$58,764,819
27									
28	Sep-06	1,482,132	0	10,682,455	$8.2219	$12,185,941	$0		$70,950,760
29	YTD rate adjustment	4,342,202	(3,639,283)		($0.8905)	($3,866,731)	$3,240,782	($625,949)	$70,324,810
30									
31	Oct-06	437,529	(437,236)	10,682,748	$8.6089	$3,766,643	($3,764,121)		$70,327,333
32	YTD rate adjustment	5,824,334	(3,639,283)		$0.3870	$2,254,017	($1,408,403)	$845,615	$71,172,948
33									
34	Nov-06	(16,824)	(1,160,385)	9,505,539	$8.4513	($142,185)	($9,806,762)		$61,224,001
35	YTD rate adjustment	6,261,863	(4,076,519)		($0.1576)	($986,870)	$642,459	($344,410)	$60,879,591
36									
37	Dec-06	28,318	(1,413,003)	8,120,854	$8.4847	$240,270	($11,988,907)		$49,130,954
38	YTD rate adjustment	6,245,039	(5,236,904)		$0.0334	$208,584	($174,913)	($414,573)	$48,716,381
39									
40									
41	Thirteen Month Average Account 164 / 242								**$45,632,752**

Note: December includes an adjustment of $448,245

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2006

Line No.	Month	*Average - 13 months ended December 31, 2006* MCF Injection	Withdrawal	Balance	Rate	Dollars Injection	Withdrawal	YTD Adj	Balance
1	Oct-06			10,682,748	$6.6624				$71,172,948
2									
3	Dec-05			8,497,404	$6.6624				$56,613,104
4	Jan-06	16,343	(1,067,942)	7,445,805	$6.6624	$108,884	($7,115,057)		$49,606,931
5	Feb-06	(1,316)	(1,928,955)	5,515,534	$6.6624	($8,768)	($12,851,470)		$36,746,694
6	Mar-06	190,220	(648,650)	5,057,104	$6.6624	$1,267,322	($4,321,566)		$33,692,450
7	Apr-06	691,034	41,866	5,790,004	$6.6624	$4,603,945	$278,928		$38,575,323
8	May-06	302,879	(143,524)	5,949,359	$6.6624	$2,017,901	($956,214)		$39,637,009
9	Jun-06	379,191	105,418	6,433,968	$6.6624	$2,526,322	$702,337		$42,865,668
10	Jul-06	1,528,762	2,504	7,965,234	$6.6624	$10,185,224	$16,683		$53,067,575
11	Aug-06	1,235,089	0	9,200,323	$6.6624	$8,228,657	$0		$61,296,232
12	Sep-06	1,482,132	0	10,682,455	$6.6624	$9,874,556	$0		$71,170,788
13	Oct-06	437,529	(437,236)	10,682,748	$6.6624	$2,914,993	($2,913,041)		$71,172,740
14	Nov-06	(16,824)	(1,160,385)	9,505,539	$6.6624	($112,088)	($7,730,949)		$63,329,703
15	Dec-06	28,318	(1,413,003)	8,120,854	$6.6624	$188,666	($9,413,991)		$54,104,378
16									
17	Thirteen Month Average Account 164 / 242								**$51,682,969**

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2007

Line			LIFO							
			MCF			Rate	Dollars			
No.	Month		Injection	Withdrawal	Balance		Injection	Withdrawal	YTD Adj	Balance
1		Dec-06			8,120,854	$5.9989				$48,716,381
2										
3										
4		Jan-07	(21,238)	(2,907,851)	5,191,765	$7.5815	($161,016)	($22,045,872)		$26,509,492
5	YTD rate adjustment									
6										
7		Feb-07	65,730	(2,824,253)	2,433,242	$8.7253	$573,514	($24,642,455)		$2,440,552
8	YTD rate adjustment		(21,238)	(2,907,851)		$1.1438	($24,292)	($3,326,000)	($3,350,292)	($909,740)
9										
10		Mar-07	1,127,724	(1,043,614)	2,517,352	$8.3100	$9,371,386	($8,672,432)		($210,786)
11	YTD rate adjustment		44,492	(5,732,104)		($0.4153)	($18,478)	$2,380,543	$2,362,065	$2,151,279
12										
13		Apr-07	1,173,880	(137,035)	3,554,197	$8.8960	$10,442,836	($1,219,063)		$11,375,052
14	YTD rate adjustment		1,172,216	(6,775,718)		$0.5860	$686,919	($3,970,571)	($3,283,652)	$8,091,400
15										
16		May-07	1,563,071	(13,739)	5,103,529	$8.4970	$13,281,414	($116,740)		$21,256,074
17	YTD rate adjustment		2,346,096	(6,912,753)		($0.3990)	($936,092)	$2,758,188	$1,822,096	$23,078,170
18										
19		Jun-07	1,673,301	0	6,776,830	$8.5900	$14,373,656	$0		$37,451,826
20	YTD rate adjustment		3,909,167	(6,926,492)		$0.0930	$363,553	($644,164)	($280,611)	$37,171,214
21										
22		Jul-07	1,654,283	0	8,431,113	$8.3200	$13,763,635	$0		$50,934,849
23	YTD rate adjustment		5,582,468	(6,926,492)		($0.2700)	($1,507,266)	$1,870,153	$362,886	$51,297,736
24										
25		Aug-07	748,777	(7,512)	9,172,378	$8.2320	$6,163,932	($61,839)		$57,399,829
26	YTD rate adjustment		7,236,751	(6,926,492)		($0.0880)	($636,834)	$609,531	($27,303)	$57,372,526
27										
28		Sep-07	1,311,838	834	10,485,050	$8.0230	$10,524,876	$6,691		$67,904,094
29	YTD rate adjustment		7,985,528	(6,934,004)		($0.2090)	($1,668,975)	$1,449,207	($219,769)	$67,684,325
30										
31		Oct-07	224,570	(66,382)	10,643,238	$7.9120	$1,776,798	($525,214)		$68,935,909
32	YTD rate adjustment		9,297,366	(6,933,170)		($0.1110)	($1,032,008)	$769,582	($262,426)	$68,673,483
33										
34		Nov-07	20,309	(924,088)	9,739,459	$7.8980	$160,400	($7,298,447)		$61,535,436
35	YTD rate adjustment		9,521,936	(6,999,552)		($0.0140)	($133,307)	$97,994	($35,313)	$61,500,123
36										
37		Dec-07	12,938	(1,513,606)	8,238,791	$7.8141	$101,099	($11,827,469)		$49,773,753
38	YTD rate adjustment		9,542,245	(7,923,640)		($0.0839)	($800,594)	$664,793	($135,801)	$49,637,952
39										
40										
41	Thirteen Month Average Account 164 / 242									**$38,536,488**

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2007

Line		Average - 13 months ended December 31, 2007							
		MCF			Rate	Dollars			
No.	Month	Injection	Withdrawal	Balance		Injection	Withdrawal	YTD Adj	Balance
1	Oct-07			10,643,238	$6.4523				$68,673,483
2									
3	Dec-06			8,120,854	$6.4523				$52,398,186
4	Jan-07	(21,238)	(2,907,851)	5,191,765	$6.4523	($137,034)	($18,762,327)		$33,498,825
5	Feb-07	65,730	(2,824,253)	2,433,242	$6.4523	$424,110	($18,222,928)		$15,700,007
6	Mar-07	1,127,724	(1,043,614)	2,517,352	$6.4523	$7,276,414	($6,733,711)		$16,242,710
7	Apr-07	1,173,880	(137,035)	3,554,197	$6.4523	$7,574,226	($884,191)		$22,932,745
8	May-07	1,563,071	(13,739)	5,103,529	$6.4523	$10,085,403	($88,648)		$32,929,500
9	Jun-07	1,673,301	0	6,776,830	$6.4523	$10,796,640	$0		$43,726,140
10	Jul-07	1,654,283	0	8,431,113	$6.4523	$10,673,930	$0		$54,400,070
11	Aug-07	748,777	(7,512)	9,172,378	$6.4523	$4,831,334	($48,470)		$59,182,935
12	Sep-07	1,311,838	834	10,485,050	$6.4523	$8,464,372	$5,381		$67,652,688
13	Oct-07	224,570	(66,382)	10,643,238	$6.4523	$1,448,993	($428,317)		$68,673,365
14	Nov-07	20,309	(924,088)	9,739,459	$6.4523	$131,040	($5,962,493)		$62,841,911
15	Dec-07	12,937	(1,513,606)	8,238,790	$6.4523	$83,473	($9,766,240)		$53,159,145
16									
17	Thirteen Month Average Account 164 / 242								**$44,872,171**

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2008

		LIFO							
		MCF			Rate	Dollars			
Line No.	Month	Injection	Withdrawal	Balance		Injection	Withdrawal	YTD Adj	Balance
1	Dec-07			8,238,790	$6.0249				$49,637,944
2									
3									
4	Jan-08	(7,460)	(3,393,179)	4,838,151	$8.9880	($67,050)	($30,497,893)		$19,073,001
5	YTD rate adjustment								
6									
7	Feb-08	28,374	(2,485,139)	2,381,386	$9.2530	$262,545	($22,994,991)		($3,659,446)
8	YTD rate adjustment	(7,460)	(3,393,179)		$0.2650	($1,977)	($899,192)	($901,169)	($4,560,615)
9									
10	Mar-08	198,810	(1,469,664)	1,110,532	$10.3370	$2,055,099	($15,191,917)		($17,697,433)
11	YTD rate adjustment	20,914	(5,878,318)		$1.0840	$22,671	($6,372,097)	($6,349,426)	($24,046,859)
12									
13	Apr-08	851,463	(170,336)	1,791,659	$10.2190	$8,701,100	($1,740,664)		($17,086,422)
14	YTD rate adjustment	219,724	(7,347,982)		($0.1180)	($25,927)	$867,062	$841,134	($16,245,288)
15									
16	May-08	1,877,996	(1,921)	3,667,734	$11.0250	$20,704,906	($21,179)		$4,438,439
17	YTD rate adjustment	1,071,187	(7,518,318)		$0.8060	$863,377	($6,059,764)	($5,196,388)	($757,948)
18									
19	Jun-08	1,785,822	0	5,453,556	$11.8800	$21,215,565	$0		$20,457,617
20	YTD rate adjustment	2,949,183	(7,520,239)		$0.8550	$2,521,551	($6,429,804)	($3,908,253)	$16,549,364
21									
22	Jul-08	2,118,057	0	7,571,613	$12.0210	$25,461,163	$0		$42,010,527
23	YTD rate adjustment	4,735,005	(7,520,239)		$0.1410	$667,636	($1,060,354)	($392,718)	$41,617,809
24									
25	Aug-08	1,517,643	0	9,089,256	$11.6880	$17,738,211	$0		$59,356,021
26	YTD rate adjustment	6,853,062	(7,520,239)		($0.3330)	($2,282,070)	$2,504,240	$222,170	$59,578,191
27									
28	Sep-08	1,295,318	(174,336)	10,210,238	$11.0150	$14,267,928	($1,920,311)		$71,925,807
29	YTD rate adjustment	8,370,705	(7,520,239)		($0.6730)	($5,633,484)	$5,061,121	($572,364)	$71,353,444
30									
31	Oct-08	785,062	8,384	11,003,684	$11.5140	$9,039,204	$96,533		$80,489,181
32	YTD rate adjustment	9,666,023	(7,694,575)		$0.4990	$4,823,345	($3,839,593)	$983,753	$81,472,934
33									
34	Nov-08	(64,936)	(845,938)	10,092,810	$11.5840	($752,219)	($9,799,346)		$70,921,369
35	YTD rate adjustment	10,451,085	(7,686,191)		$0.0700	$731,576	($538,033)	$193,543	$71,114,912
36									
37	Dec-08	11,482	(865,848)	9,238,444	$11.5293	$132,379	($9,982,621)		$61,264,670
38	YTD rate adjustment	10,386,149	(8,532,129)		($0.0547)	($568,122)	$466,707	($101,415)	$61,163,255
39									
40									
41	Thirteen Month Average Account 164 / 242								$32,765,396

COLUMBIA GAS OF KENTUCKY, INC
GAS STORED UNDERGROUND
AVERAGE OF THIRTEEN MONTHLY BALANCES ENDED
DECEMBER 31, 2008

		Average - 13 months ended December 31, 2008								
		MCF			Rate	Dollars				
Line No.	Month	Injection	Withdrawal	Balance		Injection	Withdrawal	YTD Adj	Balance
1	Oct-08			11,003,684	$7.4042				$81,472,934
2									
3	Dec-07			8,238,790	$7.4042				$61,001,649
4	Jan-08	(7,460)	(3,393,179)	4,838,151	$7.4042	($55,235)	($25,123,776)		$35,822,638
5	Feb-08	28,374	(2,485,139)	2,381,386	$7.4042	$210,087	($18,400,466)		$17,632,258
6	Mar-08	198,810	(1,469,664)	1,110,532	$7.4042	$1,472,029	($10,881,686)		$8,222,601
7	Apr-08	851,463	(170,336)	1,791,659	$7.4042	$6,304,402	($1,261,202)		$13,265,802
8	May-08	1,877,996	(1,921)	3,667,734	$7.4042	$13,905,058	($14,223)		$27,156,636
9	Jun-08	1,785,822	0	5,453,556	$7.4042	$13,222,583	$0		$40,379,219
10	Jul-08	2,118,057	0	7,571,613	$7.4042	$15,682,518	$0		$56,061,737
11	Aug-08	1,517,643	0	9,089,256	$7.4042	$11,236,932	$0		$67,298,669
12	Sep-08	1,295,318	(174,336)	10,210,238	$7.4042	$9,590,794	($1,290,819)		$75,598,644
13	Oct-08	785,062	8,384	11,003,684	$7.4042	$5,812,756	$62,077		$81,473,477
14	Nov-08	(64,936)	(845,938)	10,092,810	$7.4042	($480,799)	($6,263,494)		$74,729,184
15	Dec-08	11,482	(865,848)	9,238,444	$7.4042	$85,015	($6,410,912)		$68,403,287
16									
17	Thirteen Month Average Account 164 / 242								**$48,234,292**

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 022:

Refer to page 14 of the Racher Testimony, Schedule D-2.2 in Volume 6 of Columbia's application, and Workpaper WPD-2.2 in Volume 8 of the application.

a. The proposed adjustment for labor costs includes expected merit increases for union employees effective with wages beginning December 1, 2009. Explain what is meant by the descriptive phrase "expected merit increases" and whether it means the amounts of such increases are tentative rather than firm amounts.

b. The 2009 increases for non-union employees include a 3.0 percent increase effective March 1, 2009 for non-exempt employees and front line leaders and September 1, 2009 for other exempt employees. Provide Columbia's definition of front line leaders and clarify what employees are considered exempt.

c. The Commission has traditionally limited how far outside the test year it will allow post-test-year expense adjustments, especially if such adjustments are made in isolation from similar adjustments to revenues, rate base and capitalization. Explain why adjustments for wage and salary increases scheduled to take effect as much as eight months after the test year for other exempt employees, and 11 months after the test year for union employees, should be allowed for ratemaking purposes.

d. WPD-2.2, Sheet 8 of 15, shows the 2009 increases separately for clerical, exempt and union employees. Provide the 2009 increases with the amounts shown separately based on the respective effective dates of March 1, September 1, and December 1, 2009.

Response:

a. "Expected merit increases" means that the increase will occur in the future. The union increase is a firm amount based on the effective union contract provided in response to request 46 of the Commission Staff's first set of data requests. Refer to Pages 59 and 60 of the December 1, 2006 contract. Schedule 3 on Page 59 shows the hourly wage range effective December 1, 2008 for the job classifications and Schedule 4 on Page 60 shows the hourly wage ranges effective December 1, 2009. Schedule 4 includes a $0.15/hour structure adjustment. Adjusting the Schedule 4 ranges for the effect of the $0.15/hour structure adjustment yields a 3.5% wage increase in addition to the structure adjustment.

b. Front Line Leaders are exempt employees who supervise clerical and union employees. Exempt employees are paid a salary, not an hourly wage, and are not eligible for overtime pay. There are eight Front Line Leaders in the exempt employee list on WPD 2.2 Sheet 11. They are noted as Employee ID's 5, 6, 7, 10, 11, 12, 14, and 15.

c. The post-test-year adjustments for wage and salary adjustments have traditionally been included in prior cases as they have been considered to be known and measurable. The exempt employee salary increase for exempt employees other than front line leaders has been postponed from March 1, 2009 to September 1, 2009. As of early June, 2009, senior leadership's plan is to deliver merit increases on 9/1/09 to exempt employees who were not eligible on 3/1/09. The Information Technology group is programming the merit application tool to allow for a 9/1/09 merit effective date process which will roll out in late July or early August. The union increase effective December 1, 2009 is based on the union contract noted in part a. above.

d. The 2009 increase for each classification by date is shown below:

Classification	Effective Date	Amount of Increase
Clerical	March 1, 2009	$23,230
Exempt Front Line Leaders (FLL)	March 1, 2009	$17,574
Exempt (non-FLL)	September 1, 2009	$37,208
Union	December 1, 2009	$150,427

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 023:

Refer to page 15 of the Racher Testimony and Schedule B.3-2, which relate to the proposed depreciation expense adjustment and the proposed changes in annual depreciation accrual rates. Provide a second version of Schedule B.3-2 based on Columbia's existing annual depreciation rates.

Response:

Please see Columbia's response to AG Set 1 DR No. 007 Attachment 1.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 024:

Refer to pages 15-16 of the Racher Testimony, specifically, the proposal to amortize Columbia's estimated rate case expenses over a two-year period based on it having been approximately two years since its last rate case.

a. Prior to 2007, Columbia had gone five years since its previous rate case in 2002. Prior to its 2002 rate case, Columbia had gone eight years between rate cases. Explain whether there are any overriding reasons for why only the period between Columbia's most recent general rate case and its current rate case should be the basis for the period over which its rate case expenses will be amortized.

b. One of the benefits of adopting an SFV rate design cited in the Prepared Direct Testimony of Mark P. Balmert ("Balmert Testimony") is less frequent rate cases. Explain whether any consideration was given to this benefit prior to proposing two years as the amortization period for Columbia's rate case expenses.

Response:

a. With the increased expenditures for the Accelerated Main Replacement Program, declining usage per customer, and other increased costs, it is anticipated that Columbia will be filing rate cases more frequently. While Columbia has included several proposals to mitigate the need for frequent rate cases in its application, approval of those proposals is not assured.

b. Please see the response to a. above.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 025:

Refer to Schedule C-2.2 in Volume 6 of 8 of Columbia's application.

a. Provide a detailed explanation for why Account 870, Supervision and Engineering, increased by roughly $250,000 (50 percent) from 2007 to 2008.

b. Provide a detailed explanation for why Account 878, Meters and House Regulator Expense, increased by roughly $270,000 (20 percent) from 2007 to 2008.

c. Provide a detailed explanation for why Account 887, Mains, increased by roughly $240,000 (20 percent) from 2007 to 2008.

d. Provide a detailed explanation for why Account 903, Customer Records and Collections - Utility Services, increased by roughly $1.7 million (181 percent) from 2007 to 2008.

e. Provide a detailed explanation for why Account 91 0, Miscellaneous Customer Account Expense, increased by nearly $480,000 (2000 percent) from 2007 to 2008.

f. Provide a detailed explanation for why Account 920, Administrative and General Salaries, increased by roughly $735,000 (280 percent) from 2007 to 2008. Refer to Schedule D-2.1, at Tab D in Volume 6 of Columbia's application.

Response:

a. Account 870 for 2008 increased over the 2007 level by $250,000 due primarily to the change in account classification of NiSource Corporate Services charges from FERC account 923 to the specific functional account. The change started January 1, 2008, and increased the account by approximately $400,000. This increase was partially offset by a decrease in labor of $96,000, temporary employees of $11,000 and permits and zoning fees of $17,000.

b. Account 878, Meters and House Regulator Expensed by $270,000 due to an increase in labor of $213,000, an increase in M&S of $17,600, and vehicle cost of $41,000.

c. Account 887, Mains, increased by roughly $240,000 due to an increase in labor of $65,500, leak repair activity of $84,000, and Corrosion maintenance of $76,000.

d. Account 903, Customer Records and Collections – Utility Services, increased by roughly $1.7 million due to the change in account classification of NiSource Corporate Services charges from FERC account 923 to the specific functional account. This includes both support and postage costs for billing. The change started January 1, 2008.

e. Account 910, Miscellaneous Customer Account Expense, increased by roughly $480,000 due to the change in account classification of NiSource Corporate Services charges from FERC account 923 to the specific functional account. The change started January 1, 2008.

f. Account 920, Administrative and General Salaries, increased by roughly $735,000 due to two reasons. First, the 2007 level included a credit adjustment of approximately $470,000 reflecting the deferral of severance costs which is being amortized in accordance with the settlement agreement in Kentucky's last general rate case 2007-0008. Second, 2008 incentive compensation was higher than the 2007 level by over $220,000.

PSC Case No. 2009-00141
Staff Set 2 DR No. 026
Respondent(s): James Racher

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 026:

Refer to Schedule D-2.1, at Tab D in Volume 6 of Columbia's application.

a. For all adjustments in this schedule that eliminate unbilled revenues and unbilled expenses, provide the amount of the unbilled portion for each schedule and the rationale for the elimination.

b. Refer to page 1 of 6. Explain why the amount recorded on Columbia's books for Public Utility Revenue is shown as zero when revenue was realized during the test year for this service as indicated on Schedule M-2.1, page 3 of 6, and normalized on M-2.2, page 20 of 38. Are these sales recorded per book in Account 483, Sales for Resale? If no, state the account in which they are recorded.

c. Refer to page 3 of 6. Provide a detailed breakdown of the $16,545,195 shown as "Per Books Other Gas Department Revenue'' and explain why it differs significantly from the normalized amount of $683,915.

d. Refer to page 4 of 6. Explain why "Purchase Gas Expense" of $390,527 would be included in "Total Annualized Gas Cost Revenue".

e. Refer to page 5 of 6.

(1) Identify where in this adjustment the removal for the uncollectible expense related to the expected gas cost which Columbia is proposing to recover through a separate surcharge is found.

(2) Given that the jurisdictional percentage is 100 percent, explain why line 12 shows (31,301) rather than (70,761).

Response:

a. Unbilled sales revenue of $4,721,004 and unbilled gas cost expense of $4,703,999 on the company's books for the test year 12 months ending December 31, 2008 are shown on Schedule M-2.1 page 3, line 24 as a part of reconciling the rate schedules to the books.

Unbilled transportation revenue of $69,009 on the company's books for the test year 12 months ending December 31, 2008 are shown on Schedule M-2.1 page 5, line 32 as a part of reconciling the rate schedules to the books.

Unbilled revenues represent the revenue generated from volumes of gas which have been supplied to the customer in the current calendar period, but will not be billed until the customer's meter is read in the subsequent calendar period. This unbilled revenue and related gas cost expense on Columbia's books is estimated to record revenues and off-setting gas cost expense in the calendar month the revenues are earned to conform to GAAP rules.

Columbia has eliminated unbilled revenue and gas cost expense through its annualization of revenues in Schedule M-2.2 by calculating revenue using actual billed volumes for the 12 monthly billing cycles during the test year normalized for weather. Using actual meter readings (billed volumes) in lieu of estimates on Columbia's books (unbilled volumes), increases the accuracy of the true revenue generated during the test year for rate making purposes.

b. The Public Utility Revenue shown on Schedule M-2.1, page 3 of 6, and normalized on M-2.2, page 20 of 38 are sales recorded per book in Account 483 (Sales for Resale).

Columbia intended to separately identify the annualization adjustment to Public Utility Revenue on Schedule D-2.1, Sheet 1 from all other "Other Gas Department Revenue" shown on Schedule D-2.1 Sheet 6. The annualized Public Utility Revenue is shown on Sheet 1 however the per books Public Utility Revenue of $243,259 was not identified on Sheet 1 but instead was included in all other per books "Other Gas Department Revenue" shown on Sheet 6 of $16,545,195. The chart below summarizes the two adjustments how they were filed and how they were intended to be filed. Note the end result is no net change in the total adjustment to revenue for annualization but simply a change in presentation.

	As Filed	As Intended	Difference
Annualized Public Utility Revenue	$211,101	$211,101	$0
Per Books Public Utility Revenue	$0	$243,259	$243,259
Adjustment	$211,101	($32,158)	($243,259)
Adjusted Other Gas Department Revenue	$683,915	$683,915	$0
Per Books Other Gas Department Revenue	$16,545,195	$16,301,936	($243,259)
Adjustment	($15,861,280)	($15,618,021)	$243,259
Total of two adjustments	($15,650,179)	($15,650,179)	$0

c. The normalized amount of $683,915 excludes off system sales, unbilled, and sales for resale revenues. Normalization of sales for resale revenues (Public Utility Revenue) is identified separately on page 1 of 6.

Account	Description	Amount
483	Sales for Resale	243,259
487	Forfeited Discounts	192,713
488	Misc. Service Revenue	147,314
495	Off System Sales	10,897,017
495	Unbilled	4,721,004
495	Other	343,888
	Total	16,545,195

Account	Description	Amount
487	Forfeited Discounts	192,713
488	Misc. Service Revenue	147,314
495	Other	343,888
	Total	683,915

d. Gas cost expense per books (Line 5) includes purchased gas expense for procurement services (Line 2). Thus, the net effect on the adjustment by including this cost as part of annualized gas cost is zero.

e(1) Uncollectible expense related to the commodity expected gas cost which Columbia is proposing to recover through a separate surcharge is a rate design issue and not a cost of service issue and therefore no adjustment was made to the cost of service. Attachment MPB-6 attached to Columbia witness Balmert's testimony shows the details of eliminating revenues produced from the proposed Gas Cost Uncollectible Charge when designing base rates.

e(2) Uncollectible Accounts Expense Jurisdictional Amount of ($31,301) on line 12 is 100% of the sum of the annualization adjustment of uncollectible accounts expense of $39,460 shown on line 7 and annualized EAP recovery adjustment of (70,761) shown on line 10.

**COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF**

Data Request 027:

Refer to page 1 of the Prepared Direct Testimony of Paul R. Moul ("Moul Testimony"). In Columbia's last rate case, Case No. 2007-00008, Mr. Moul's cost of common equity recommendation was 11.5 percent. Provide a discussion of the differences in the basis of that recommendation and the 12.25 percent recommendation in the present case.

Response:

The primary contributor to the increase in the rate of return on common equity relates to the turmoil in the capital markets that has developed since the Company's last rate case. Today, we are in the worst financial crisis since the Great Depression. This has increased the cost of capital in both the debt and equity markets, which among other consequences have lead to the increase in the Company's cost of equity.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 028:

Refer to the Moul Testimony at page 4 and Attachment PRM-3.

a. Provide copies of the pages from the Value Line Investment Survey for all of the gas companies which were considered for the selection of the Gas Group.

b. On page 4, Columbia states that Laclede and Nicor were not selected for the Gas Group because they lack a weather normalization feature in their tariffs. Explain why this is reason for exclusion from the Gas Group.

c. On PRM-3, page 2 of 2, Laclede and Nicor are not selected for the Gas Group because they lack a decoupling mechanism in their tariffs. State whether Columbia has a decoupling mechanism in its tariff and explain why this is a reason for exclusion from the Gas Group.

d. Both NiSource and Atmos Energy have natural gas and pipeline storage operations, yet NiSource was rejected from the proxy group. Explain the differences between NiSource and Atmos.

e. For each of the gas companies followed by Value Line that were not included in the Gas Group, provide a more detailed explanation of the basis for their rejection as a proxy for Columbia.

f. If a capital pool capital financing arrangement with NiSource is used by Columbia, explain how the presence of NiSource's electric operations should be a factor in its exclusion from consideration as a proxy.

Response:

a. The Value Line pages for all companies in the industry group are attached in Attachment A.

b. Laclede and NICOR were not selected because there might be a risk implication associated with the lack of a WNA. Subsequent to assembling the proxy group, NICOR obtained decoupling feature to its tariff.

c. Laclede and NICOR were not selected because there might be a risk implication associated with the lack of decoupling. Subsequent to assembling the proxy group, NICOR obtained decoupling feature to its tariff.

d. The pipeline operations of NiSource represent 20.1% of its identifiable assets, while pipeline operations of Atmos represent 16.4%. Moreover, NiSource has 21.0% of its identifiable assets devoted to electric operations, while Atmos has none.

e. Two companies (Laclede and NICOR) we eliminated because they did not have a WNA/decoupling feature to their tariff, two companies (NiSource and UGI) were eliminated due to significant non-LDC business, and one company (Southwest) was eliminated due to its location. Failure to screen for variables such as these would result in a generic cost of equity that would lack any specific features that would be comparable to Columbia of Kentucky.

f. The risk features associated with the electric operations of NiSource are distinct from Columbia of Kentucky. For example, capacity issues, air quality issues, transmission obligations required by MISO, etc. do not exist for Columbia of Kentucky.

Staff DR Set 2-028 A

AGL RESOURCES NYSE-AGL

RECENT PRICE	30.34	P/E RATIO	10.8 (Trailing: 9.8 Median: 14.0)	RELATIVE P/E RATIO	0.68	DIV'D YLD	5.7%	VALUE LINE

TIMELINESS **3** Lowered 6/12/09

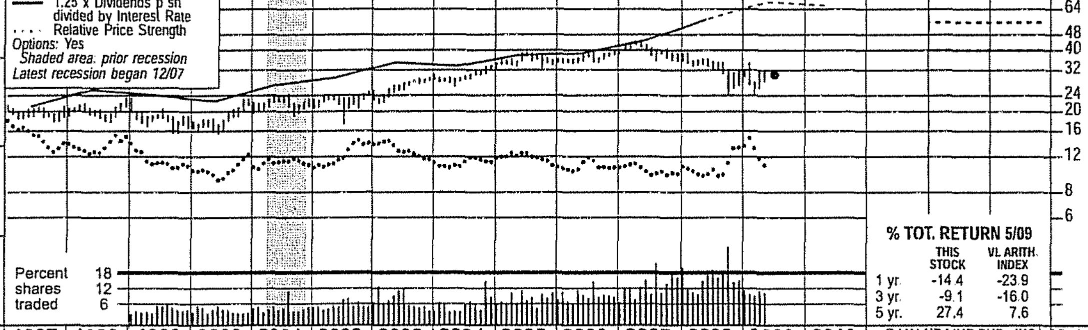
SAFETY **2** New 7/27/90

TECHNICAL **4** Lowered 6/5/09

BETA .75 (1.00 = Market)

High:	23.4	23.4	23.2	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	34.9
Low:	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	24.0

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+80%)	20%
Low	40	(+30%)	12%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	2	1	0	2	0
to Sell	0	1	0	0	3	1	0	1	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	131	92	107
to Sell	106	130	111
Hld's(000)	46762	48796	46113

Percent shares traded 18 12 6

% TOT. RETURN 5/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-14.4	-23.9
3 yr.	-9.1	-16.0
5 yr.	27.4	7.6

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
22.73	23.59	19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	*33.35*	*35.45*	Revenues per sh A	*38.80*
2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	*4.80*	*5.00*	"Cash Flow" per sh	*5.40*
1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	*2.80*	*2.95*	Earnings per sh A B	*3.30*
1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	*1.72*	*1.76*	Div'ds Decl'd per sh C■	*1.88*
2.49	2.37	2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	*5.00*	*5.20*	Cap'l Spending per sh	*5.60*
9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	*23.10*	*23.40*	Book Value per sh D	*23.55*
49.72	50.86	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	*78.00*	*79.00*	Common Shs Outst'g E	*85.00*
17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	*Value Line*		Relative P/E Ratio	*1.00*
5.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/09

Total Debt $2078.0 mill. *Due in 5 Yrs* $947.0 mill.

LT Debt $1675.0 mill. LT Interest $80.0 mill.

(Total interest coverage: 4.6x)

Leases, Uncapitalized Annual rentals $30.0 mill.

Pension Assets-12/08 $242.0 mill. **Oblig.** $442.0 mill.

Pfd Stock None

Common Stock 77,170,946 shs. as of 4/23/09

MARKET CAP: $2.3 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1068.6	607.4	1049.3	868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	*2600*	*2800*	Revenues ($mill) A	*3300*
52.1	71.1	82.3	103.0	132.4	153.0	193.0	212.0	211.0	207.6	*220*	*235*	Net Profit ($mill)	*280*
33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	40.5%	*36.0%*	*38.0%*	Income Tax Rate	*38.0%*
4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	*8.5%*	*8.4%*	Net Profit Margin	*8.5%*
45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	*48.0%*	*45.0%*	Long-Term Debt Ratio	*43.0%*
49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	*52.0%*	*55.0%*	Common Equity Ratio	*57.0%*
1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	*3475*	*3350*	Total Capital ($mill)	*3500*
1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	*4000*	*4150*	Net Plant ($mill)	*4400*
5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.4%	*7.5%*	*8.0%*	Return on Total Cap'l	*9.0%*
7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	*12.0%*	*12.5%*	Return on Shr. Equity	*14.0%*
7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	*12.0%*	*12.5%*	Return on Com Equity	*14.0%*
NMF	3.2%	4.2%	7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.1%	*5.0%*	*5.0%*	Retained to Com Eq	*6.0%*
101%	72%	65%	52%	53%	49%	52%	52%	58%	60%	*61%*	*59%*	All Div'ds to Net Prof	*57%*

CURRENT POSITION ($MILL.)	2007	2008	3/31/09
Cash Assets	21.0	16.0	21.0
Other	1790.0	2026.0	1410.0
Current Assets	1811.0	2042.0	1431.0
Accts Payable	172.0	202.0	193.0
Debt Due	580.0	866.0	403.0
Other	893.0	915.0	752.0
Current Liab.	1645.0	1983.0	1348.0
Fix. Chg. Cov.	391%	416%	473%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	4.0%	15.5%	2.0%
"Cash Flow"	6.0%	6.5%	2.5%
Earnings	7.0%	8.5%	3.5%
Dividends	4.0%	8.0%	2.5%
Book Value	7.0%	10.0%	1.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1044	436	434	707	2621
2007	973	467	369	685	2494
2008	1012	444	539	805	2800
2009	995	*445*	*460*	*700*	*2600*
2010	*1020*	*490*	*510*	*780*	*2800*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.41	.25	.46	.60	2.72
2007	1.29	.40	.17	.86	2.72
2008	1.16	.30	.28	.97	2.71
2009	1.55	*.30*	*.25*	*.70*	*2.80*
2010	*1.50*	*.35*	*.30*	*.80*	*2.95*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37	.37	1.48
2007	.41	.41	.41	.41	1.64
2008	.42	.42	.42	.42	1.68
2009	.43	.43			

BUSINESS: *AGL Resources Inc. is a public utility holding company.* Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Maryland. Engaged in nonregulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. Franklin Resources owns 7.7% of common stock; off./dir., less than 1.0% (3/09 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources turned in a solid performance in the first quarter, despite a challenging economic environment. Share earnings increased roughly 34%. The Distribution Operations segment posted healthy results, thanks to higher revenue from marketers in Georgia for the storage of natural gas inventory and increased pipeline replacement sales, offset slightly by a modest reduction in the customer base. Meanwhile, the Wholesale Services business posted a considerable increase in operating income, due to hedging gains and an increase in commercial activity. The Retail Energy unit also reported solid performance.

Growth may remain muted for the remainder of 2009, given weakness in the broader economy. Slower customer growth ought to hurt the performance of the utility operations, and we anticipate a return to more normal earnings at the Wholesale Services business in the coming quarters. Overall, the bottom line should increase modestly in the current year, due to the strong comparison in the first quarter. Share earnings growth may pick up in 2010, provided a more favorable economic climate and success at obtaining rate relief. On that note,

Elizabethtown Gas is seeking higher rates. The utility is requesting a $24.8 million (4.7%) rate hike, based on an 11.25% return on equity. Atlanta Gas Light plans to file a rate case in November, while Virginia Natural Gas and Chattanooga Gas intend to file applications in 2010. The company's focus on this matter is important, as it depends upon such approved revenue increases to help it cope with greater costs and to compensate it for investments made in this area. Nevertheless, it remains unclear what pressures the rate boards may face.

Shares of AGL Resources are ranked to track the broader market for the coming six to 12 months. Looking further out, we anticipate steady growth in earnings and dividends over the pull to 2012-2014. Moreover, this issue offers a healthy dividend yield and earns high marks for Safety, Price Stability, and Earnings Predictability. Overall, this equity features healthy total return potential for a utility.

Michael Napoli, CPA *June 12, 2009*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, ($0.83); '99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late July. (C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2008: $418 million, $5.44/share.
(E) In millions.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

ATMOS ENERGY CORP. NYSE-ATO

Staff DR Set 2-028 Attachment A

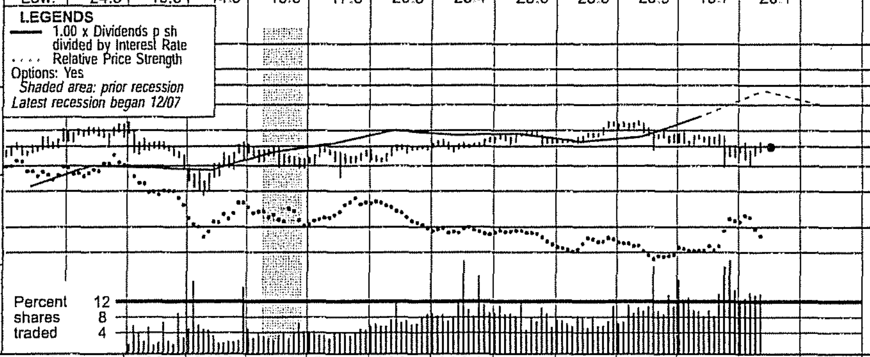
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
24.76	11.7	(Trailing: 11.3 / Median: 16.0)	0.74	5.4%

VALUE LINE

TIMELINESS 2 Raised 12/12/08
SAFETY 2 Raised 12/16/05
TECHNICAL 4 Lowered 6/5/09
BETA .65 (1.00 = Market)

High:	32.3	33.0	26.3	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	26.4
Low:	24.8	19.6	14.3	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.1

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+60%)	16%
Low	30	(+20%)	9%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	1
Options	0	0	0	0	0	0	0	1	0
to Sell	0	1	1	0	1	1	0	1	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	119	103	141
to Sell	89	119	103
Hld's(000)	58318	56301	53678

% TOT. RETURN 5/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-7.5	-23.9
3 yr.	3.0	-16.0
5 yr.	22.4	7.6

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
22.09	26.61	35.36	22.82	54.39	46.50	61.75	75.27	66.03	79.52	**73.25**	**80.65**	Revenues per sh A	**94.55**
2.62	3.01	3.03	3.39	3.23	2.91	3.90	4.26	4.14	4.19	**4.40**	**4.50**	"Cash Flow" per sh	**4.80**
.81	1.03	1.47	1.45	1.71	1.58	1.72	2.00	1.94	2.00	**2.05**	**2.15**	Earnings per sh A B	**2.50**
1.10	1.14	1.16	1.18	1.20	1.22	1.24	1.26	1.28	1.30	**1.32**	**1.34**	Div'ds Decl'd per sh C ■	**1.40**
3.53	2.36	2.77	3.17	3.10	3.03	4.14	5.20	4.39	5.20	**5.50**	**5.75**	Cap'l Spending per sh	**6.60**
12.09	12.28	14.31	13.75	16.66	18.05	19.90	20.16	22.01	22.60	**24.10**	**24.40**	Book Value per sh	**26.90**
31.25	31.95	40.79	41.68	51.48	62.80	80.54	81.74	89.33	90.81	**92.00**	**93.00**	Common Shs Outst'g D	**110.00**
33.0	18.9	15.6	15.2	13.4	15.9	16.1	13.5	15.9	13.6	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**14.0**
1.88	1.23	.80	.83	.76	.84	.86	.73	.84	.84			Relative P/E Ratio	**.95**
4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%			Avg Ann'l Div'd Yield	**4.0%**
690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	**6740**	**7500**	Revenues ($mill) A	**10400**
25.0	32.2	56.1	59.7	79.5	86.2	135.8	162.3	170.5	180.3	**190**	**200**	Net Profit ($mill)	**275**
35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	**35.0%**	**37.0%**	Income Tax Rate	**40.5%**
3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	**2.8%**	**2.7%**	Net Profit Margin	**2.6%**
50.0%	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	**50.0%**	**50.5%**	Long-Term Debt Ratio	**49.0%**
50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	**50.0%**	**49.5%**	Common Equity Ratio	**51.0%**
755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	**4430**	**4580**	Total Capital ($mill)	**5800**
965.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	**4360**	**4570**	Net Plant ($mill)	**5850**
5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.0%**
6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	**8.5%**	**9.0%**	Return on Shr. Equity	**9.5%**
6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	**8.5%**	**9.0%**	Return on Com Equity	**9.5%**
NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	**3.0%**	**3.5%**	Retained to Com Eq	**4.0%**
NMF	112%	79%	82%	70%	77%	73%	63%	65%	65%	**64%**	**62%**	All Div'ds to Net Prof	**56%**

CAPITAL STRUCTURE as of 3/31/09
Total Debt $2569.3 mill. **Due in 5 Yrs** $1360.0 mill.
LT Debt $2169.1 mill. **LT Interest** $115.0 mill.
(LT interest earned: 2.9x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $18.4 mill.
Pfd Stock None
Pension Assets-9/08 $341.4 mill. **Oblig.** $337.6 mill.
Common Stock 92,008,920 shs. as of 4/22/09
MARKET CAP: $2.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	3/31/09
Cash Assets	60.7	46.7	482.1
Other	1008.2	1238.4	996.5
Current Assets	1068.9	1285.1	1478.6
Accts Payable	355.3	395.4	472.1
Debt Due	154.4	351.3	400.2
Other	410.0	460.4	413.8
Current Liab.	919.7	1207.1	1286.1
Fix. Chg. Cov.	405%	450%	440%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	9.5%	14.5%	*4.0%*
"Cash Flow"	3.5%	5.5%	*2.5%*
Earnings	2.5%	5.0%	*4.0%*
Dividends	2.5%	1.5%	*1.5%*
Book Value	6.5%	7.5%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	2283.8	2033.8	863.2	971.6	6152.4
2007	1602.6	2075.6	1218.2	1002.0	5898.4
2008	1657.5	2484.0	1639.1	1440.7	7221.3
2009	1716.3	1821.4	**1700**	**1502.3**	**6740**
2010	**1740**	**2710**	**1620**	**1430**	**7500**

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.88	1.10	d.22	.25	2.00
2007	.97	1.20	d.15	d.05	1.94
2008	.82	1.24	d.07	.02	2.00
2009	.83	1.29	**d.06**	**d.01**	**2.05**
2010	**.90**	**1.35**	**d.06**	**d.04**	**2.15**

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315	.32	1.27
2007	.32	.32	.32	.325	1.29
2008	.325	.325	.325	.33	1.31
2009	.33	.33			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2008 gas volumes: 293 MMcf. Breakdown: 56%, residential; 32%, commercial; 7%, industrial; and 5% other. 2008 depreciation rate 3.5%. Has around 4,560 employees. Officers and directors own approximately 1.9% of common stock (12/08 Proxy). Chairman and Chief Executive Officer: Robert W. Best. Incorporated: Texas. Address: P.O. Box 650205, Dallas, Texas 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy's earnings in fiscal 2009 (which ends on September 30th) are running a bit ahead of the prior-year tally. The bread-and-butter natural gas utility is benefiting greatly from an increase in rates, primarily for the Mid-Tex, Louisiana, and West Texas divisions. But throughput here is being partially squeezed by diminished consumption from residential and commercial customers (caused by the recessionary environment). Meanwhile, the performance of the pipeline and storage segment is being aided nicely by expanded margins resulting from gains from the settlement of financial positions associated with storage and trading activities. What's more, the regulated transmission and storage operation is enjoying a rise in transportation fees on through-system deliveries, due to favorable market conditions. On the negative side, unrealized margins for the nonregulated marketing segment are down lately. That reflects greater volatility between current cash prices (used to value the company's physical inventory) and future natural gas prices.

At this juncture, share net may increase about 3%, to $2.05, this fiscal year. Assuming further expansion in operating margins, the bottom line stands to advance another 5%, to $2.15 a share, in fiscal 2010.

We continue to anticipate steady, albeit unspectacular, profit growth over the 2012-2014 time frame. The utility is one of the country's leading natural gas-only distributors, now serving 3.2 million customers across 12 states. Moreover, the unregulated segments, contributing between 15% and 35% to net income on a historical basis, possess healthy overall prospects. Lastly, management may resume its successful acquisition strategy. In the present corporate configuration, annual share-net gains may be in the mid-single-digit range over the 3- to 5-year period.

Total return potential looks decent, on a risk-adjusted basis. Too, the stock is timely. Dividend growth is steady, but unspectacular. The dividend yield is well above the group average, reflecting range-bound earnings of late. Meanwhile, coverage of the payout remains well in hand.

Frederick L. Harris, III *June 12, 2009*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '99, d23¢; '00, 12¢; '03, d17¢; '06, d18¢; '07, d2¢; Q2 '09, 12¢. Next egs. rpt. due early Aug. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	85

LACLEDE GROUP NYSE-LG

RECENT PRICE **33.05** | P/E RATIO **12.7** (Trailing: 10.7 Median: 15.0) | RELATIVE P/E RATIO **0.80** | DIV'D YLD **4.7%** | VALUE LINE

Staff DR Sel 2-028 A

TIMELINESS **3** Lowered 5/22/09
SAFETY **2** Raised 6/20/03
TECHNICAL **5** Lowered 5/29/09
BETA .60 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3	37.5	36.0	55.8	48.3
Low:	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9	29.1	28.8	31.9	29.3

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

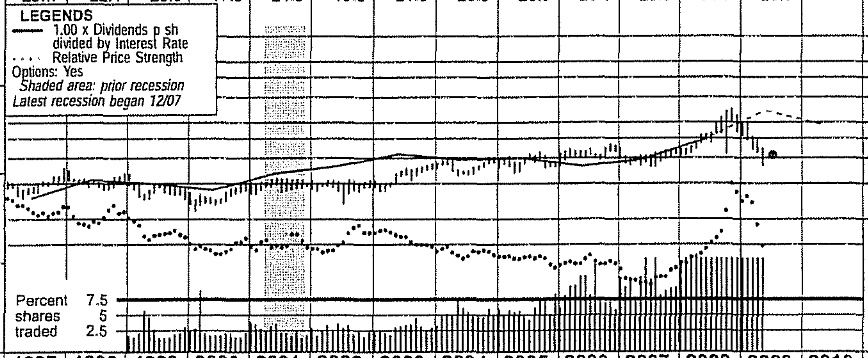
	Price	Gain	Ann'l Total Return
High	60	(+80%)	19%
Low	45	(+35%)	12%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	6	0	0	0	0
to Sell	0	2	0	0	6	0	0	0	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	97	82	73
to Sell	50	72	86
Hld's(000)	11750	11943	11494



% TOT. RETURN 5/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-19.4	-23.9
3 yr.	4.8	-16.0
5 yr.	41.8	7.6

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	*99.55*	*95.65*	Revenues per sh	*111.55*
2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	*4.90*	*4.50*	"Cash Flow" per sh	*5.40*
1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	*3.00*	*2.60*	Earnings per sh A B	*3.00*
1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	*1.53*	*1.57*	Div'ds Decl'd per sh C■	*1.70*
2.62	2.50	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	*2.65*	*2.70*	Cap'l Spending per sh	*3.45*
12.19	12.44	13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	*23.60*	*25.10*	Book Value per sh D	*28.05*
15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	*22.50*	*23.00*	Common Shs Outst'g E	*26.00*
13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.89	*Value Line*		Relative P/E Ratio	*1.15*
5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*

CAPITAL STRUCTURE as of 3/31/09
Total Debt $628.0 mill. **Due in 5 Yrs** $50.0 mill.
LT Debt $389.2 mill. **LT Interest** $25.0 mill.
(Total interest coverage: 3.0x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/08 $248.3 mill. **Oblig.** $308.7 mill.
Pfd Stock None
Common Stock 22,147,631 shs. as of 4/29/09

MARKET CAP: $725 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	*2240*	*2200*	Revenues ($mill) A	*2900*
26.9	26.0	30.5	22.4	34.6	36.1	40.1	50.5	49.8	57.6	*70.0*	*60.0*	Net Profit ($mill)	*80.0*
35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	*31.5%*	*31.5%*	Income Tax Rate	*35.0%*
5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	*3.1%*	*2.7%*	Net Profit Margin	*2.8%*
41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*47.0%*
57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	*55.0%*	*55.0%*	Common Equity Ratio	*53.0%*
488.6	519.2	574.1	546.6	605.0	737.4	707.9	798.9	784.5	876.1	*965*	*1050*	Total Capital ($mill)	*1375*
519.4	575.4	602.5	594.4	621.2	646.9	679.5	763.8	793.8	823.2	*855*	*880*	Net Plant ($mill)	*980*
7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	*8.5%*	*7.0%*	Return on Total Cap'l	*7.0%*
9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	*13.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	*13.0%*	*10.5%*	Return on Com Equity	*11.0%*
1.0%	.2%	1.8%	NMF	3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	*6.5%*	*4.0%*	Retained to Com Eq	*5.0%*
89%	98%	83%	113%	74%	73%	72%	59%	63%	56%	*49%*	*60%*	All Div'ds to Net Prof	*55%*

CURRENT POSITION ($MILL.)

	2007	2008	3/31/09
Cash Assets	52.7	14.9	93.6
Other	414.6	547.0	408.4
Current Assets	467.3	561.9	502.0
Accts Payable	106.8	159.6	100.4
Debt Due	251.6	216.1	238.8
Other	115.3	103.5	90.0
Current Liab.	473.7	479.2	429.2
Fix. Chg. Cov.	282%	377%	375%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	11.5%	14.0%	*2.5%*
"Cash Flow"	2.0%	6.5%	*5.5%*
Earnings	3.5%	9.5%	*3.5%*
Dividends	1.0%	1.5%	*2.5%*
Book Value	3.5%	5.5%	*5.5%*

QUARTERLY REVENUES ($ mill.) A

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	689.2	708.8	330.6	269.0	1997.6
2007	539.6	700.8	457.9	323.3	2021.6
2008	504.0	747.7	505.5	451.8	2209.0
2009	674.3	659.1	*455.9*	*450.7*	*2240*
2010	*550*	*550*	*550*	*550*	*2200*

EARNINGS PER SHARE A B F

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	1.23	1.05	.13	d.04	2.37
2007	.89	.97	.43	.03	2.31
2008	.99	1.39	.41	d.14	2.64
2009	1.42	1.40	*.30*	*d.12*	*3.00*
2010	*1.03*	*1.21*	*.38*	*d.02*	*2.60*

QUARTERLY DIVIDENDS PAID C ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.34	.345	.345	.345	1.38
2006	.345	.355	.355	.355	1.41
2007	.365	.365	.365	.365	1.46
2008	.375	.375	.375	.375	1.50
2009	.385	.385			

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 630,000 customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Therms sold and transported in fiscal 2008: 1.08 mill. Revenue mix for regulated operations: residential, 62%; commercial and industrial, 24%; transportation, 1%; other, 13%. Has around 1,807 employees. Officers and directors own approximately 7.2% of common shares (1/09 proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Profits for Laclede Group's nonregulated gas marketing unit, Laclede Energy Resources, have been much higher in fiscal 2009 (which ends on September 30th) than the prior-year figure. That is attributable partly to a rise in volumes, made possible by significantly increased pipeline capacity. That division is also enjoying expanded margins on sales of natural gas. Increased shale production and falling natural gas prices have worked in the company's favor.

But the utility, Laclede Gas, has not fared as well lately, stemming partially from a rise in operational expenses. Additionally, last year's results included certain previously unrecognized tax benefits. In spite of this,

The bottom line ought to advance some 14%, to $3.00 a share, in fiscal 2009. Earnings may be lower next year, however, since the benefit of sharply lower natural gas prices may not be repeatable.

We anticipate a lackluster operating performance for the company over the next 3 to 5 years. It seems that customer growth for the natural gas distribution unit will remain moderate. That's because the service area is in a mature phase. Although we think the nonregulated segment has promising expansion opportunities, it has contributed only a small portion to Laclede Group's total profits on a historical basis. A major acquisition could help to offset this, but it appears that management has no such plans anytime soon. Consequently, annual earnings-per-share growth could range only between 4% and 5% over the 2012-2014 horizon.

This neutrally ranked stock has lost substantial ground in recent months. Investors apparently feel that the company's profit drivers have cooled off for the time being.

The dividend yield has moderate appeal. Additional increases in the payout will likely be moderate, though. That is mainly because of the regulated gas operation's unspectacular long-term demand prospects.

Total return possibilities over the next 3 to 5 years look unexciting, given that our projections assume minimal hikes in the distribution.

Frederick L. Harris, III *June 12, 2009*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '08: $340.4 mill., $15.48/sh.
(E) In millions.
(F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	80

NEW JERSEY RES. NYSE-NJR

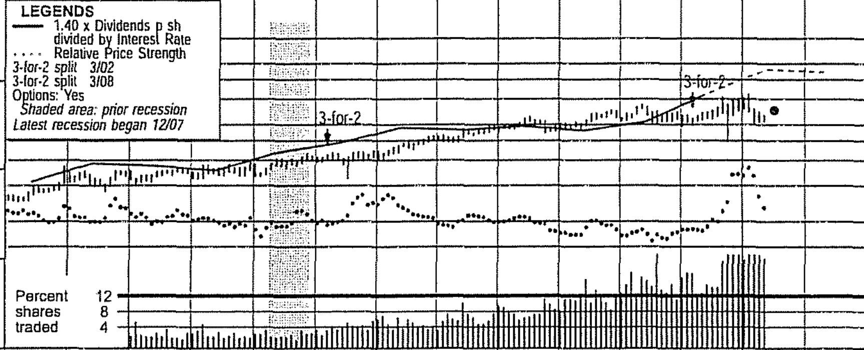
RECENT PRICE **35.24** | P/E RATIO **13.7** (Trailing: 17.6 Median: 15.0) | RELATIVE P/E RATIO **0.87** | DIV'D YLD **3.5%** | VALUE LINE

Staff DR Sel 2-028 A

TIMELINESS **3** Lowered 5/22/09
SAFETY **1** Raised 9/15/06
TECHNICAL **5** Lowered 6/12/09
BETA .65 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	17.9	18.3	19.8	21.7	22.4	26.4	29.7	32.9	35.4	37.6	41.1	42.4	
Low:	14.0	14.9	16.1	16.6	16.2	20.0	24.3	27.1	27.7	30.3	24.6	30.0	

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	10%
Low	35	(Nil)	4%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	1	2	3	0	0	1
to Sell	0	1	0	0	1	4	0	1	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	90	64	93
to Sell	62	88	73
Hld's(000)	26910	26312	24319

% TOT. RETURN 5/09

	THIS STOCK	VL ARITH INDEX
1 yr	3.4	-23.9
3 yr	22.5	-16.0
5 yr	49.3	7.6

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
12.02	12.81	11.36	13.48	17.31	17.73	22.65	29.42	51.22	44.11	62.29	60.89	76.19	79.63	72.62	90.74	*83.65*	*87.20*	Revenues per sh A	*91.10*
1.42	1.54	1.42	1.48	1.63	1.74	1.86	1.99	2.12	2.14	2.38	2.50	2.62	2.73	2.44	3.62	*3.40*	*3.60*	"Cash Flow" per sh	*3.80*
.76	.84	.86	.92	.99	1.04	1.11	1.20	1.30	1.39	1.59	1.70	1.77	1.87	1.55	2.70	*2.50*	*2.70*	Earnings per sh B	*2.90*
.68	.68	.68	.69	.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	*1.24*	*1.28*	Div'ds Decl'd per sh C ■	*1.40*
1.54	1.40	1.18	1.19	1.15	1.07	1.21	1.23	1.10	1.02	1.14	1.45	1.28	1.28	1.46	1.72	*1.75*	*1.75*	Cap'l Spending per sh	*1.80*
6.54	6.43	6.47	6.73	6.92	7.26	7.57	8.29	8.80	8.71	10.26	11.25	10.60	15.00	15.50	17.28	*18.80*	*20.75*	Book Value per sh D	*27.50*
37.84	38.93	40.03	40.69	40.23	40.07	39.92	39.59	40.00	41.50	40.85	41.61	41.32	41.44	41.61	42.06	*42.50*	*43.00*	Common Shs Outst'g E	*45.00*
15.1	13.0	11.8	13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.0*
.89	.85	.79	.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.77	*estimates*		Relative P/E Ratio	*.95*
5.8%	6.2%	6.7%	5.6%	5.3%	4.6%	4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%			Avg Ann'l Div'd Yield	*3.4%*
						904.3	1164.5	2048.4	1830.8	2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	*3555*	*3750*	Revenues ($mill) A	*4100*
						44.9	47.9	52.3	56.8	65.4	71.6	74.4	78.5	65.3	113.9	*105*	*115*	Net Profit ($mill)	*130*
						36.2%	37.8%	38.0%	38.7%	39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	*39.0%*	*39.0%*	Income Tax Rate	*40.0%*
						5.0%	4.1%	2.6%	3.1%	2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	*3.0%*	*3.1%*	Net Profit Margin	*3.2%*
						48.7%	47.0%	50.1%	50.6%	38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	*38.5%*	*37.0%*	Long-Term Debt Ratio	*32.0%*
						51.2%	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	*61.5%*	*63.0%*	Common Equity Ratio	*68.0%*
						590.4	620.1	706.2	732.4	676.8	783.8	755.3	954.0	1028.0	1182.1	*1300*	*1415*	Total Capital ($mill)	*1820*
						705.4	730.6	743.9	756.4	852.6	880.4	905.1	934.9	970.9	1017.3	*1040*	*1060*	Net Plant ($mill)	*1125*
						9.0%	9.0%	8.5%	8.7%	10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	*9.0%*	*9.0%*	Return on Total Cap'l	*8.0%*
						14.8%	14.6%	14.8%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	*13.5%*	*13.0%*	Return on Shr. Equity	*10.5%*
						14.8%	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	*13.5%*	*13.0%*	Return on Com Equity	*10.5%*
						5.0%	5.4%	6.1%	6.9%	7.7%	7.8%	8.5%	6.3%	3.6%	9.5%	*6.5%*	*7.0%*	Retained to Com Eq	*5.5%*
						67%	63%	59%	56%	51%	49%	50%	50%	64%	40%	*50%*	*47%*	All Div'ds to Net Prof	*48%*

CAPITAL STRUCTURE as of 3/31/09
Total Debt $474.9 mill. Due in 5 Yrs $175.6 mill.
LT Debt $459.0 mill. LT Interest $16.9 mill.
Incl. $8.8 mill. capitalized leases.
(LT interest earned: 4.8x; total interest coverage: 4.8x)
Pension Assets-9/08 $80.6 mill. Oblig. $102.4 mill.

Pfd Stock None

Common Stock 42,139,988 shs.
as of 5/6/09
MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	3/31/09
Cash Assets	5.1	42.6	83.3
Other	794.8	1067.1	699.9
Current Assets	799.9	1109.7	783.2
Accts Payable	64.4	61.7	48.0
Debt Due	260.8	238.3	15.9
Other	378.1	594.0	605.8
Current Liab.	703.3	894.0	669.7
Fix. Chg. Cov.	461%	450%	450%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	17.5%	9.0%	2.0%
"Cash Flow"	6.0%	6.0%	4.5%
Earnings	7.5%	7.5%	6.0%
Dividends	4.0%	5.0%	5.5%
Book Value	8.5%	11.5%	9.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	1164	1064	536.1	535.5	3299.6
2007	737.4	1029	662.2	593.2	3021.8
2008	811.1	1178	1000	827.1	3816.2
2009	801.3	937.5	*993.7*	*822.5*	*3555*
2010	*845*	*985*	*1040*	*880*	*3750*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.82	1.43	d.09	d.29	1.87
2007	.70	.19	.60	.06	1.55 F
2008	1.31	1.86	d.10	d.39	2.70
2009	.77	1.71	*d.10*	*.12*	*2.50*
2010	*.85*	*1.75*	*d.05*	*.15*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C E ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.227	.227	.227	.227	.91
2006	.24	.24	.24	.24	.96
2007	.253	.253	.253	.253	1.01
2008	.267	.28	.28	.28	1.11
2009	.31	.31			

BUSINESS: *New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 484,000 customers at 9/30/08 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2008 volume: 99.6 bill. cu. ft. (59% firm, 6% interruptible industrial and electric utility, 35% off-system and capacity release). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2008 dep. rate: 2.9%. Has 854 empls. Off./dir. own about 1.7% of common (12/08Proxy). Chrmn., CEO, & Pres.: Laurence M. Downes. Inc.: N.J. Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.*

New Jersey Resources continues to be impacted by the economic downturn. Due to consumers trimming expenses, NJR's top line declined 20% in the March period. A large portion of this downturn stems from difficult operating conditions at its wholesale energy subsidiary, NJR Energy Services. That unit has been tackling narrower storage spreads and an overall slowdown in contracted transportation capacity. On a brighter note, the New Jersey Natural Gas (NJNG) division was able to partially offset those negative results. NJNG added almost 3,150 new customers and has completed roughly 370 customer conversions year to date. Meantime, base rate hikes, as well as incentive programs, have been a boon toward that unit's bottom-line contributions.

We look for the June-period share loss to remain flat at $0.10. The continued addition of new accounts at NJNG, coupled with the rate-case increase, should help offset the temporary slowdown at the wholesale division. And, as that unit's capital projects (like Steckman Ridge discussed below) come on line, profitability should improve. Meantime, NJNG is accelerating 14 of its infrastructure programs to boost the safety and reliability of its distribution system. And we look for year-to-year comparisons to start improving in late 2009, assuming the economy begins to pick up.

Meanwhile, the Steckman Ridge storage facility is in the early stages of operation. Recently, the FERC gave NJR the go-ahead to place certain injection sites into commercial operation. Customers have begun storing their natural gas inventories in preparation for the upcoming winter season. As that storage facility becomes fully operational, we look for the wholesale energy unit to experience a perk-up in contributions to earnings.

These high-quality shares are appealing. The equity is ranked to keep pace with the broader markets in the coming six to 12 months. Moreover, a 17% pullback from the high reached earlier this year, may provide an attractive entry point to this stock's otherwise steady uptrend. And, like most utilities, this issue features a solid dividend yield.

Bryan Fong *June 12, 2009*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late July.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2008: $340.7 million, $8.09/share.
(E) In millions, adjusted for split.
(F) Restated.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	50

Staff DR Set 2-028 A

NICOR, INC. NYSE-GAS

RECENT PRICE 32.83 | P/E RATIO 12.4 (Trailing: 12.3; Median: 15.0) | RELATIVE P/E RATIO 0.78 | DIV'D YLD 5.7% | VALUE LINE

TIMELINESS 3 Raised 12/7/07

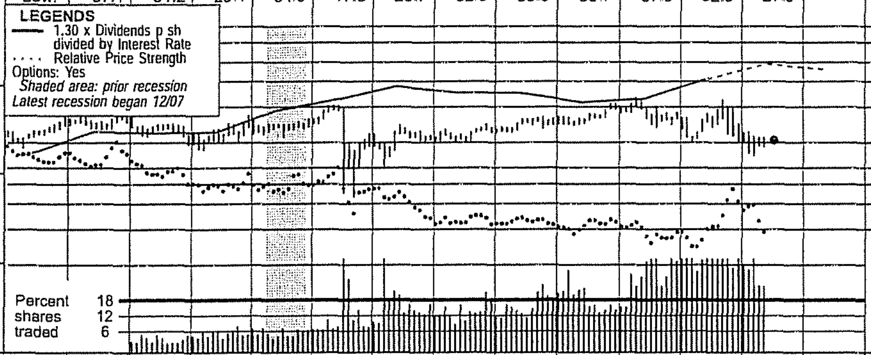
SAFETY 3 Lowered 6/17/05

TECHNICAL 4 Lowered 5/29/09

BETA .75 (1.00 = Market)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	44.4	42.9	43.9	42.4	49.0	39.3	39.7	43.0	49.9	53.7	52.0	36.3					
Low:	37.1	31.2	29.4	34.0	17.3	23.7	32.0	35.5	38.7	37.8	32.3	27.5					

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



Target Price Range 2012 | 2013 | 2014

120 100 80 64 48 32 24 20 16 12 8

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+70%)	*17%*
Low	40	(+20%)	*10%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	1	2
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	119	105	114
to Sell	90	125	126
Hld's(000)	32273	32539	27287

Percent shares traded 18 12 6

% TOT. RETURN 5/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-19.2	-23.9
3 yr.	-12.2	-16.0
5 yr.	19.2	7.6

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
31.02	31.23	29.42	37.39	41.33	30.84	34.45	50.52	57.30	43.11	60.46	62.12	76.00	65.92	69.20	83.68	*70.00*	*72.80*	Revenues per sh	*93.35*
3.80	4.11	4.19	4.97	5.29	5.21	5.59	6.16	6.41	6.03	5.37	6.00	6.19	6.82	6.96	6.85	*6.55*	*6.85*	"Cash Flow" per sh	*8.10*
1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.27	2.87	2.99	2.63	*2.65*	*2.85*	Earnings per sh A	*2.95*
1.22	1.25	1.28	1.32	1.40	1.48	1.54	1.66	1.76	1.84	1.86	1.86	1.86	1.86	1.86	1.86	*1.86*	*1.86*	Div'ds Decl'd per sh B■	*1.86*
2.62	3.34	3.12	2.42	2.34	2.87	3.28	3.48	4.18	4.37	4.12	4.32	4.57	4.17	3.77	5.54	*5.35*	*5.20*	Cap'l Spending per sh	*4.85*
13.05	13.26	13.67	14.74	15.43	15.97	16.80	15.56	16.39	16.55	17.13	16.99	18.36	19.43	20.58	21.55	*22.40*	*23.40*	Book Value per sh	*26.45*
53.96	51.54	50.30	49.49	48.22	47.51	46.89	45.49	44.40	44.01	44.04	44.10	44.18	44.90	45.90	45.13	*45.00*	*45.00*	Common Shs Outst'g C	*45.00*
14.1	12.5	13.1	12.5	14.2	17.6	14.6	11.9	12.8	13.1	15.8	15.9	17.3	15.0	15.0	15.1	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.84	.92	.81	.80	.93	*Value Line*		Relative P/E Ratio	*1.05*
4.4%	4.8%	5.0%	4.4%	3.9%	3.6%	4.1%	4.7%	4.6%	4.9%	5.6%	5.3%	4.7%	4.3%	4.2%	4.7%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*
						1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	3357.8	2960.0	3176.3	3776.6	*3150*	*3275*	Revenues ($mill)	*4200*
						121.9	136.4	136.3	128.0	93.1	98.1	101.1	128.3	135.2	119.5	*120*	*130*	Net Profit ($mill)	*135*
						34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	26.3%	26.6%	27.0%	*27.0%*	*27.0%*	Income Tax Rate	*27.0%*
						7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	4.3%	4.3%	3.2%	*3.8%*	*3.9%*	Net Profit Margin	*3.2%*
						35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	36.3%	30.9%	31.5%	*31%*	*30%*	Long-Term Debt Ratio	*26%*
						64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	69.0%	68.4%	*69%*	*70%*	Common Equity Ratio	*74%*
						1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	1370.7	1368.0	1421.1	*1455*	*1500*	Total Capital ($mill)	*1615*
						1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2659.1	2714.1	2757.3	2858.6	*2980*	*3100*	Net Plant ($mill)	*3415*
						10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	10.9%	11.2%	9.7%	*9.5%*	*10.0%*	Return on Total Cap'l	*9.5%*
						15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	*12.0%*	*12.0%*	Return on Shr. Equity	*11.0%*
						15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	*12.0%*	*12.0%*	Return on Com Equity	*11.0%*
						6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	5.2%	5.4%	3.6%	*3.5%*	*4.0%*	Retained to Com Eq	*4.0%*
						60%	56%	58%	63%	88%	84%	81%	65%	62%	71%	*70%*	*66%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 3/31/09
Total Debt $932.7 mill. Due in 5 Yrs $914.9 mill.
LT Debt $448.7 mill. LT Interest $5.0 mill.
(Total interest coverage: 5.1x)

Pension Assets-12/08 $306.6 mill. Oblig. $270.2 mill.

Pfd Stock $.6 mill. Pfd Div'd None

Common Stock 45,214,530 shares as of 4/24/09

MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	3/31/09
Cash Assets	91.9	95.5	106.4
Other	931.9	1243.4	991.9
Current Assets	1023.8	1338.9	1098.3
Accts Payable	564.5	411.3	259.4
Debt Due	350.0	789.9	484.0
Other	227.9	466.8	659.1
Current Liab.	1142.4	1668.0	1402.5
Fix. Chg. Cov.	543%	461%	570%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	6.5%	*4.0%*
"Cash Flow"	3.0%	3.0%	*3.0%*
Earnings	1.5%	1.0%	*.5%*
Dividends	3.0%	0.5%	*Nil*
Book Value	3.0%	4.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1319.4	451.3	351.1	838.2	2960.0
2007	1334.7	556.9	365.2	919.5	3176.3
2008	1595.7	699.8	440.3	1040.8	3776.6
2009	1110.8	*600*	*400*	*1039.2*	*3150*
2010	*1150*	*625*	*415*	*1085*	*3275*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.99	.19	.39	1.30	2.87
2007	1.04	.40	.32	1.22	2.98
2008	.91	.64	.03	1.05	2.63
2009	.96	*.44*	*.20*	*1.05*	*2.65*
2010	*1.05*	*.50*	*.30*	*1.00*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.465	.465	.465	.465	1.86
2006	.465	.465	.465	.465	1.86
2007	.465	.465	.465	.465	1.86
2008	.465	.465	.465	.465	1.86
2009	.465	.465			

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.2 million customers in northern and western Illinois. 2008 gas delivered: 498.1 Bcf, incl. 222.6 Bcf from transportation. 2008 gas sales (275.5 bcf): residential, 93%; commercial, 6%; industrial, 1%. Principal supplying pipelines: Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested oil and gas E&P, 6/93. Has about 3,900 employees. Officers/directors own about 2.2% of common stock (3/09 proxy). Chairman and Chief Executive Officer: Russ Strobel. Incorporated: Illinois. Address: 1844 Ferry Road, Naperville, Illinois 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor started 2009 on a relatively solid note. Earnings of $0.96 a share topped our March $0.90-a-share estimate. Results were bolstered by good performances in the company's non regulated operations, which offset weak results in the gas distribution business. Still, lower volumes due to the tough economic climate led to a year-over-year decline in revenue to $1.11 billion.

The Illinois Commerce Commission (ICC) approved a rate increase. The new base rate of $69 million with an authorized return on equity of 10.17% adds about $2.50 to the average residential customer's monthly bill. The new rate order also has an energy efficiency rider to fund numerous efficiency programs. The decision was lower than what Nicor originally sought, though. The company has been pressured by rising costs of late and was seeking a rate base about double what was approved. Even so, the new rate should provide a boost to results going forward.

We have raised our 2009 share-net estimate. In light of the good first-quarter showing, we have increased our bottom-line number by 6% to $2.65 a share. Furthermore, cost pressures should ease over the coming months. However, we expect the Gas Distribution segment to continue to struggle in the near term due to the difficult economic environment. Moreover, declining customer consumption will likely pressure earnings in the months ahead. Therefore, despite our upward earnings revision, near-term prospects remain uninspiring.

Long-term appeal is currently limited. The bottom line should grow at a modest clip thanks to the company's non-regulated operations and the new rate case. However, we do not foresee the board increasing the dividend payout over the coming years. All told, this issue has below-average total return potential over the 2012-2014 time frame.

This stock is ranked to track the broader market in the year ahead. Shares of GAS do not stand out for the long term, either. Thus, we recommend most investors stay on the sidelines. Still, income-oriented accounts may find this equity's yield (5.7%), which is above the industry average (4.8%), of interest.

Richard Gallagher *June 12, 2009*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢); '07 (13¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Next egs. report due late July. (B) Dividends historically paid mid February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	80

Staff DR Set 2-028 Attachment A

NISOURCE INC. NYSE-NI

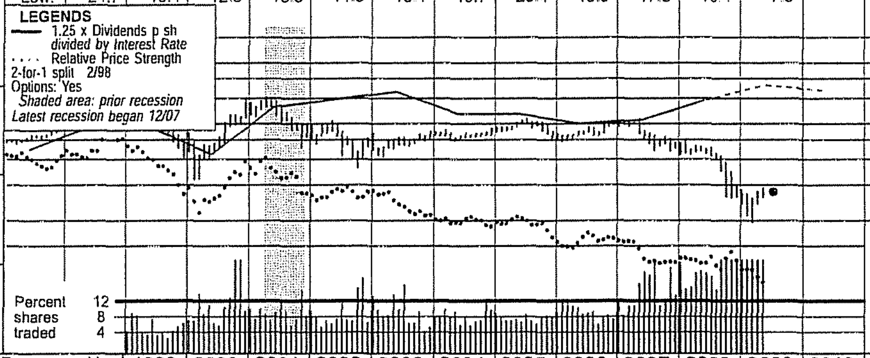
RECENT PRICE **11.10** | P/E RATIO **10.6** (Trailing: 8.7; Median: 16.0) | RELATIVE P/E RATIO **0.67** | DIV'D YLD **8.3%** | VALUE LINE

TIMELINESS **3** Raised 11/14/08
SAFETY **3** Lowered 1/4/02
TECHNICAL **3** Lowered 4/17/09
BETA .85 (1.00 = Market)

High:	33.8	30.9	31.5	32.6	25.0	22.0	22.8	25.5	24.8	25.4	19.8	11.6	
Low:	24.7	16.4	12.8	18.3	14.5	16.4	19.7	20.4	19.5	17.5	10.4	7.8	

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 2/98
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	20	(+80%)	21%
Low	15	(+35%)	14%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	2	0	0	2	5
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	1	1	5	0	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	147	138	154
to Sell	144	143	153
Hld's(000)	224075	207644	202113

Percent shares traded 12 8 4

% TOT. RETURN 5/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-36.4	-23.9
3 yr.	-42.3	-16.0
5 yr.	-32.7	7.6

NiSource acquired Columbia Energy on November 1, 2000, paying approximately $6 billion in cash and stock. Columbia shareholders who chose cash received $70 a share, plus a security with a face value of $2.60. Those who chose stock received $74 a share in NiSource common stock. Shareholders' selections were prorated to reflect a 30% stock portion of the transaction. In 2003, NiSource sold Columbia's exploration and production business.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
25.33	29.34	45.59	26.09	23.78	24.63	28.97	27.37	28.96	32.36	27.70	28.15	Revenues per sh	32.25
3.80	2.74	4.23	3.94	3.47	3.47	3.14	3.18	3.20	3.32	3.00	3.15	"Cash Flow" per sh	3.55
1.27	1.39	1.13	1.91	1.59	1.62	1.08	1.14	1.14	1.34	1.05	1.15	Earnings per sh A	1.30
1.04	.81	1.16	1.16	1.10	.92	.92	.92	.92	.92	.92	.92	Div'd Decl'd per sh B ■	.92
2.75	1.80	3.22	2.50	2.19	1.91	2.17	2.33	2.88	3.54	2.90	2.90	Cap'l Spending per sh	3.25
10.90	16.61	16.72	16.78	16.81	17.69	18.09	18.32	18.52	17.24	17.35	17.55	Book Value per sh C	18.35
124.14	205.55	207.49	248.86	262.63	270.63	272.62	273.65	274.18	274.26	275.5	276.0	Common Shs Outst'g D	279.0
19.6	14.9	23.4	10.8	12.2	13.0	21.4	19.2	18.8	12.1	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	14.0
1.12	.97	1.20	.59	.70	.69	1.14	1.04	1.00	.73			Relative P/E Ratio	.95
4.2%	3.9%	4.4%	5.6%	5.7%	4.4%	4.0%	4.2%	4.3%	5.7%			Avg Ann'l Div'd Yield	5.1%
3144.6	6030.7	9458.7	6492.3	6246.6	6666.2	7899.1	7488.0	7942.0	8872.0	7625	7775	Revenues ($mill)	9000
168.7	196.9	243.5	412.5	419.4	434.6	298.7	314.6	312.0	369.8	290	320	Net Profit ($mill)	360
34.9%	33.3%	44.7%	35.5%	35.3%	35.7%	33.3%	35.2%	35.6%	33.4%	36.5%	36.5%	Income Tax Rate	36.5%
3.4%	2.0%	1.8%	.6%	.6%	1.1%	2.1%	4.2%	6.6%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
51.8%	63.4%	63.3%	55.7%	57.1%	49.8%	51.2%	50.7%	52.4%	55.7%	58.0%	58.0%	Long-Term Debt Ratio	58.0%
35.5%	35.2%	35.8%	43.4%	42.1%	49.3%	48.0%	49.3%	47.6%	44.3%	42.0%	42.0%	Common Equity Ratio	42.0%
3813.3	9695.6	9683.8	9622.8	10490	9704.1	10285	10160	10671	10673	11300	11600	Total Capital ($mill)	12100
5230.4	9546.7	9554.7	10068	9304.9	9384.7	9554.3	9694.5	10032	10276	10900	11300	Net Plant ($mill)	12600
6.0%	2.7%	4.7%	6.7%	6.0%	6.4%	4.8%	4.8%	4.6%	5.2%	4.5%	4.5%	Return on Total Cap'l	5.0%
9.2%	5.5%	6.8%	9.7%	9.3%	8.9%	6.0%	6.3%	6.1%	7.8%	6.0%	6.5%	Return on Shr. Equity	7.0%
11.9%	5.5%	6.8%	9.7%	9.4%	9.0%	6.0%	6.3%	6.1%	7.8%	6.0%	6.5%	Return on Com Equity E	7.0%
2.6%	1.7%	NMF	3.9%	3.0%	3.9%	.9%	1.2%	1.2%	2.5%	1.0%	1.5%	Retained to Com Eq	2.0%
79%	71%	101%	60%	69%	57%	85%	80%	81%	68%	87%	79%	All Div'ds to Net Prof	71%

CAPITAL STRUCTURE as of 3/31/09
Total Debt $6887.9 mill. **Due in 5 Yrs** $3598.0 mill.
LT Debt $6451.9 mill. **LT Interest** $380 mill.
(LT interest earned: 2.5x)

Leases, Uncapitalized Annual rentals $45.3 mill.
Pension Assets-12/08 $1.44 bill. **Oblig.** $2.15 bill.

Pfd Stock None

Common Stock 274,592,165 shs. as of 4/30/09

MARKET CAP: $3.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	3/31/09
Cash Assets	36.0	20.6	135.2
Other	2418.9	3390.2	2497.2
Current Assets	2454.9	3410.8	2632.4
Accts Payable	719.9	693.3	531.6
Debt Due	1094.9	1632.8	436.0
Other	1577.8	2257.3	2310.4
Current Liab.	3392.6	4583.4	3278.0
Fix. Chg. Cov.	221%	245%	385%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	4.0%	-1.5%	1.5%
"Cash Flow"	-1.0%	-3.5%	1.5%
Earnings	-2.5%	-5.0%	1.0%
Dividends	--	-4.0%	Nil
Book Value	6.5%	1.5%	.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	2972	1311	1156	2049	7488
2007	2893	1577	1241	2228	7942
2008	3288	1790	1409	2385	8872
2009	2722	1625	1300	1978	7625
2010	2800	1650	1325	2000	7775

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.63	.08	.10	.33	1.14
2007	.76	.11	.03	.24	1.14
2008	.69	.08	.12	.45	1.34
2009	.62	.03	d.01	.41	1.05
2010	.65	.05	.10	.35	1.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.23	.23	.23	.23	.92
2006	.23	.23	.23	.23	.92
2007	.23	.23	.23	.23	.92
2008	.23	.23	.23	.23	.92
2009	.23	.23			

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 457,000 electric in Indiana, 3.3 million gas in IN, OH, PA, KY, VA, MD, MA. Acquired IWC Resources 3/97; Bay State Gas 2/99; Columbia Energy 11/00. Electric revenue breakdown, '08: residential, 27%; commercial, 27%; industrial, 39%; other, 7%. Generating sources, '08: coal, 82%; purchased & other, 18%. '08 reported deprec. rates: 2.9% electric, 2.8% gas. Has 7,981 employees. Chairman: Ian M. Rolland. President & CEO: Robert C. Skaggs, Jr. Inc.: Indiana. Address: 801 East 86th Ave., Merrillville, Indiana 46410. Tel.: 877-647-5990. Internet: www.nisource.com.

Shares of NiSource have risen nearly 40% in value since our March review. The company was able to ease liquidity concerns by securing capital. Indeed, NiSource raised $985 million in financing by way of $600 million of senior unsecured notes and a $385 million two-year term loan. Additionally, the company's cash balance has improved in recent months due to NI's reduced capital budget and the recent stimulus act.

The dividend payout appears safe, for now. Given NiSource's recent activity on the financing front, the annual $0.92-a-share payout will likely continue in the near term. However, the company is paying out a sizable amount of its earnings to shareholders. Thus, investors should be aware that the distribution could be reduced in the future. In fact, based on our cash flow projection, the payout may be difficult to maintain beyond 2009.

Share net will likely fall short of 2008's tally this year. Heavy financing costs coupled with lower volumes should lead to a year-over-year decline on the bottom line. Therefore, we look for earnings of $1.05 a share, which is at the midpoint of management's 2009 share-net guidance. For 2010, the bottom line should increase by about a dime, to $1.15 a share, thanks to better cost controls.

Prospects for the pull to 2012-2014 are somewhat ill-defined. The company suspended its multi-year outlook in late 2008. Furthermore, much of NI's growth potential remains tied to the pending electric rate case. The company requested an $85.7 million increase in its rate base at NIPSCO. Approval for the request is far from certain, given the difficult market conditions in Indiana. The decision will probably be determined late this year or early in 2010.

This stock is ranked to mirror the market over the coming six to 12 months. We recommend investors look elsewhere for now. NiSource's outlook remains clouded by liquidity concerns and the pending rate case. Additionally, income-oriented accounts should note that the company's ability to continue its sizable payout is questionable, given NI's limited earnings prospects.

Richard Gallagher *June 12, 2009*

(A) Dil. EPS. Excl. nonrec. gains (losses): '00, 24¢; '01, (10¢); '02, 9¢; '03, 1¢; '05, (4¢); gains (losses) on disc. ops.: '00, 7¢; '02, (25¢); '03, ($1.27); '04, 2¢; '05, 10¢; '06, (11¢); '07, 3¢; '08, ($1.14). Next egs. due early July. (B) Div'ds historically paid in mid-Feb., May, Aug., Nov. There were only 3 declarations in '00. ■ Div'd reinv. avail. (C) Incl. intang. In '08: $14.63/sh. (D) In mill., adj. for split. (E) Rate base: Fair val. Rate all'd on com. eq. in '87: 13.5%; earned on avg. com. eq., '08: 7.8%. Reg. Climate: Above Avg

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	10
Earnings Predictability	75

N.W. NAT'L GAS NYSE-NWN

RECENT PRICE 44.60 | P/E RATIO 15.6 (Trailing: 16.3 / Median: 16.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.7% | VALUE LINE

High:	30.8	27.9	27.5	26.8	30.7	31.3	34.1	39.6	43.7	52.8	55.2	45.7
Low:	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4	32.8	39.8	37.7	37.7

Target Price Range 2012 | 2013 | 2014

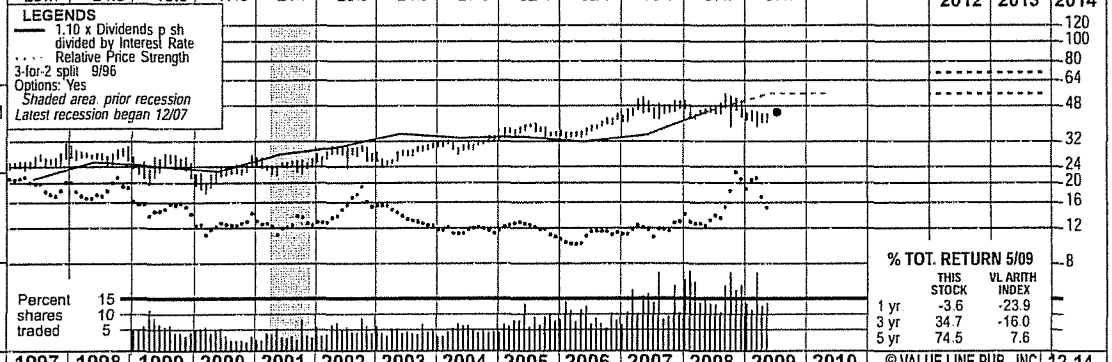
TIMELINESS 2 Raised 2/20/09

SAFETY 1 Raised 3/18/05

TECHNICAL 4 Lowered 5/29/09

BETA .60 (1.00 = Market)

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 9/96
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+55%)	14%
Low	55	(+25%)	9%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	2
Options	0	1	2	0	1	0	0	0	0
to Sell	0	1	2	0	2	0	1	0	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	78	65	82
to Sell	71	74	83
Hld's(000)	16947	16310	14907

% TOT. RETURN 5/09

	THIS STOCK	VL ARITH INDEX
1 yr	-3.6	-23.9
3 yr	34.7	-16.0
5 yr	74.5	7.6

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	*39.60*	*41.50*	Revenues per sh	*48.20*
3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	*5.60*	*5.85*	"Cash Flow" per sh	*6.75*
1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	*2.85*	*2.85*	Earnings per sh A	*3.45*
1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	*1.58*	*1.66*	Div'ds Decl'd per sh B■	*2.00*
3.61	4.23	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	*4.50*	*4.50*	Cap'l Spending per sh	*4.50*
13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	*24.90*	*26.10*	Book Value per sh	*30.50*
19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	*26.50*	*26.50*	Common Shs Outst'g C	*28.00*
12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.11	*Value Line*		Relative P/E Ratio	*1.20*
5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
455.8	532.1	650.3	641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	*1100*	*1125*	Revenues ($mill)	*1350*
44.9	47.8	50.2	43.8	46.0	50.6	58.1	65.2	74.5	68.5	*75.5*	*75.5*	Net Profit ($mill)	*96.5*
35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	*6.9%*	*6.7%*	Net Profit Margin	*7.2%*
46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	*47%*	*47%*	Long-Term Debt Ratio	*47%*
49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	*53%*	*53%*	Common Equity Ratio	*53%*
861.5	887.8	880.5	937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	*1180*	*1225*	Total Capital ($mill)	*1400*
895.9	934.0	965.0	995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.1	*1600*	*1660*	Net Plant ($mill)	*1900*
6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	7.7%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	10.9%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.0%*
9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	*11.0%*	*11.0%*	Return on Com Equity	*11.0%*
2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.5%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
74%	70%	67%	79%	72%	69%	63%	59%	52%	59%	*55%*	*58%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 3/31/09
Total Debt $675.6 mill. Due in 5 Yrs $173.8 mill.
LT Debt $587.0 mill. LT Interest $37.0 mill.

(Total interest coverage: 4.0x)

Pension Assets-12/08 $163 mill.
Oblig. $281 mill.
Pfd Stock None

Common Stock 26,504,188 shares
as of 4/20/09
MARKET CAP $1.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	3/31/09
Cash Assets	6.1	6.9	10.3
Other	268.8	474.1	405.2
Current Assets	274.9	481.0	415.5
Accts Payable	119.7	94.4	93.3
Debt Due	148.1	248.0	88.6
Other	122.1	208.9	220.8
Current Liab.	389.9	551.3	402.7
Fx. Chg. Cov.	408%	393%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	9.0%	9.0%	4.0%
"Cash Flow"	3.5%	6.5%	4.5%
Earnings	5.0%	8.0%	5.0%
Dividends	2.0%	3.0%	5.5%
Book Value	3.5%	3.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	390.4	171.0	114.9	336.9	1013.2
2007	394.1	183.2	124.2	331.7	1033.2
2008	387.7	191.3	109.7	349.2	1037.9
2009	437.4	*202*	*120*	*340.6*	*1100*
2010	*420*	*215*	*125*	*365*	*1125*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.48	.07	d.35	1.15	2.35
2007	1.77	.10	d.22	1.11	2.76
2008	1.62	.08	d.38	1.25	2.57
2009	1.72	*.13*	*d.31*	*1.31*	*2.85*
2010	*1.75*	*.11*	*d.33*	*1.32*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345	.355	1.39
2007	.355	.355	.355	.375	1.44
2008	.375	.375	.375	.395	1.52
2009	.395	.395			

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 665,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 55%; commercial, 28%; industrial, gas transportation, and other, 17%. Employs 1,117. Barclays Global owns 6.6% of shares; officers and directors, 1.4% (4/09 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural began 2009 reasonably well. The weather normalization and decoupling mechanisms in Oregon reduced pretax profits by $3.8 million, and the recession cut profits from industrial and commercial customers by 11%. But the company earned $8.4 million from its purchased gas cost-sharing arrangement in Oregon, which more than offset higher operating costs. Customer growth in the period fell to 1.2%, from rates in excess of 3% in recent years, but that was still well above the national average.

Profits arising from gas purchases should continue to boost earnings in 2009. Northwest charges rates in Oregon based on forecast gas costs that are approved by the public utility commission in October for the 12 months beginning November 1st. As spot gas costs are well below last fall's forecast, the company earned $0.19 a share from the gas cost-sharing mechanism in the first quarter, and we look for modest gains from that source through October, after which rates for next year's heating season will take effect. Moreover, operating costs should rise less than in the March period. Customer growth will probably remain positive, thanks to conversions from other fuels.

Assuming low profits from purchased gas costs, earnings will probably change little in 2010. Next year's results will likely benefit from better profits from commercial and industrial customers and a resumption of new home construction. But a decline in profits from the purchased gas mechanism in Oregon should offset the results of a stronger economy.

Two projects could significantly lift earnings by our 3- to 5-year horizon. Northwest plans to invest $160 million in Gill Ranch, a gas storage project near Fresno, CA, that should start up in late 2010 or early 2011. And the proposed Palomar Pipeline, a half-owned joint venture, would bring a second source of supply to Northwest's area, starting in 2011. The western part of that line would cost Northwest around $175 million. While both projects should be approved, for the time being we are excluding them from our forecasts.

These timely, high-quality shares offer worthwhile total-return potential.

Sigourney B. Romaine *June 12, 2009*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03); 1Q '09, 6¢. Next earnings report due early August.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.

(C) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	80

PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE 23.20 | P/E RATIO 14.8 (Trailing: 15.7 / Median: 18.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 3 Raised 6/15/07

SAFETY 2 New 7/27/90

TECHNICAL 5 Lowered 6/12/09

BETA .65 (1.00 = Market)

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+70%)	18%
Low	30	(+30%)	11%

Insider Decisions

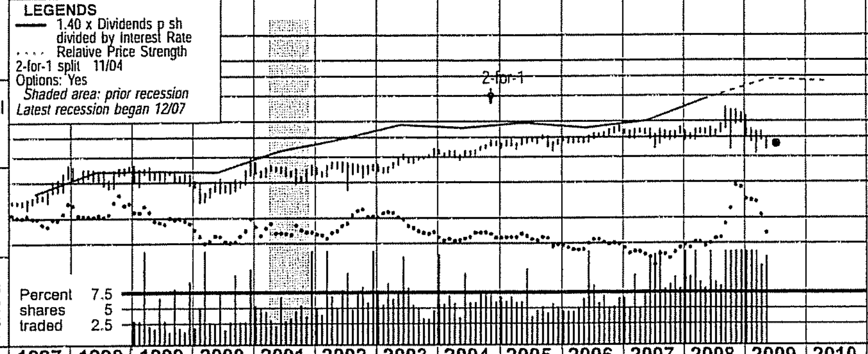
	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	1	1	0	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	97	82	112
to Sell	77	96	93
Hld's(000)	36688	35228	33160

High:	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0
Low:	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	20.7

Target Price Range 2012 | 2013 | 2014



% TOT. RETURN 5/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-13.1	-23.9
3 yr.	4.3	-16.0
5 yr.	33.6	7.6

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
10.57	10.82	8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	*29.25*	*30.15*	Revenues per sh A	*33.20*
1.14	1.13	1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	*2.80*	*2.90*	"Cash Flow" per sh	*3.20*
.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.27	1.40	1.49	*1.55*	*1.65*	Earnings per sh B	*2.00*
.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	*1.07*	*1.11*	Div'ds Decl'd per sh C■	*1.23*
1.58	1.95	1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	*2.40*	*2.10*	Cap'l Spending per sh	*2.25*
5.45	5.68	6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	*12.70*	*13.25*	Book Value per sh D	*15.05*
52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	*73.50*	*73.50*	Common Shs Outst'g E	*73.00*
15.4	15.7	13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.15	*Value Line*		Relative P/E Ratio	*1.50*
4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*
						686.5	830.4	1107.9	832.0	1220.8	1529.7	1761.1	1924.7	1711.3	2089.1	*2150*	*2215*	Revenues ($mill) A	*2420*
						58.2	64.0	65.5	62.2	74.4	95.2	101.3	97.2	104.4	110.0	*115*	*120*	Net Profit ($mill)	*145*
						39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.4%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	*5.3%*	*5.5%*	Net Profit Margin	*6.0%*
						46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	*47.5%*	*48.0%*	Long-Term Debt Ratio	*47.0%*
						53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	*52.5%*	*52.0%*	Common Equity Ratio	*53.0%*
						914.7	978.4	1069.4	1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	*1775*	*1870*	Total Capital ($mill)	*2075*
						1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	*2250*	*2300*	Net Plant ($mill)	*2450*
						8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.5%*
						11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	*12.5%*	*12.5%*	Return on Shr. Equity	*13.0%*
						11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	*12.5%*	*12.5%*	Return on Com Equity	*13.0%*
						3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	*4.0%*	*4.0%*	Retained to Com Eq	*5.0%*
						72%	71%	75%	83%	74%	66%	68%	74%	70%	69%	*69%*	*67%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 1/31/09
Total Debt $1271.9 mill. Due in 5 Yrs $150.0 mill.
LT Debt $793.9 mill. LT Interest $55.5 mill.
(LT interest earned: 4.0x; total interest coverage: 3.7x)

Pension Assets-10/08 $150.3 mill. Oblig. $143.5 mill.

Pfd Stock None

Common Stock 73,484,181 shs. as of 3/2/09
MARKET CAP: $1.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	1/31/09
Cash Assets	7.5	7.0	22.9
Other	427.8	593.8	782.7
Current Assets	435.3	600.8	805.6
Accts Payable	143.6	132.3	154.4
Debt Due	195.0	436.5	478.0
Other	75.9	112.7	204.2
Current Liab.	424.5	681.5	836.6
Fix. Chg. Cov.	309%	341%	350%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.5%	10.0%	*4.0%*
"Cash Flow"	5.0%	7.0%	*3.5%*
Earnings	4.5%	6.5%	*6.0%*
Dividends	5.0%	4.5%	*3.5%*
Book Value	5.5%	6.0%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2006	921.4	483.2	237.9	282.2	1924.7
2007	677.2	531.5	224.4	278.2	1711.3
2008	788.5	634.2	354.7	311.7	2089.1
2009	779.6	*660*	*372*	*338.4*	*2150*
2010	*830*	*670*	*375*	*340*	*2215*

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2006	.94	.57	d.16	d.08	1.27
2007	.94	.69	d.12	d.11	1.40
2008	1.12	.66	d.10	d.18	1.49
2009	1.10	*.68*	*d.10*	*d.13*	*1.55*
2010	*1.12*	*.70*	*d.08*	*d.09*	*1.65*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.215	.23	.23	.23	.91
2006	.23	.24	.24	.24	.95
2007	.24	.25	.25	.25	.99
2008	.25	.26	.26	.26	1.03
2009	.26	.27			

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 935,724 customers in North Carolina, South Carolina, and Tennessee. 2008 revenue mix: residential (39%), commercial (24%), industrial (12%), other (25%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 73.5% of revenues. '08 deprec. rate: 3.2%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,833 employees. Officers & directors own about 1.1% of common stock (1/09 proxy). Chairman, CEO, & President: Thomas E. Skains. Inc.: NC. Address: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas' top- and bottom-line results have been hurt by the difficult economy. Both measures recently registered low single-digit declines. This trend stems from the deepening recession that has caused a decrease in commercial and industrial margins. Too, as Americans try to save money across the board, natural gas volumes have been on a steady decline. On a brighter note, PNY's Southstar Energy unit has been contributing nicely, as that division experienced higher retail margins and lower operating expenses. Still, on balance, profitability has been impacted.

Consequently, we have trimmed a nickel off our 2009 earnings estimate. We continue to look for minimal growth (about 1%-1.5%) in additional customers this year, across the NC, SC, TN service areas. And management does have plans to cut costs wherever possible. But the tighter margins for the commercial and industrial businesses will likely continue to detract from PNY's more profitable Energy Services unit. However, earnings should still advance about 4% this year.

The company appears to be making solid decisions with regard to capital conservation and spending. Management has opted to hold off until 2011 on construction of the Robeson liquefied natural gas storage facility. That facility was expected to add extra capacity and profits during peak winter months. It is now tentatively planned for an in-service date of 2015. Furthermore, the deferral of pipeline infrastructure enhancement projects to serve the new gas-fired power generation markets in North Carolina will also help to conserve cash. These postponements should cut the capital expenditure budget by $70 million this year.

All told, shares of this natural gas distributor may appeal to income-oriented accounts. An approximate pullback of 35% from the stock's 52-week high provides a potentially attractive entry point to these normally stable shares. Meantime, a recent quarterly dividend hike of 4% sweetens the deal and places PNY as one of the higher-yielding equities in *The Value Line Investment Survey*. The shares are ranked to track the broader market in the coming year.

Bryan Fong *June 12, 2009*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early August.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2008: $16.3 million, 22¢/share.
(E) In millions, adjusted for stock split.
(F) Quarters may not add to total due to change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	90

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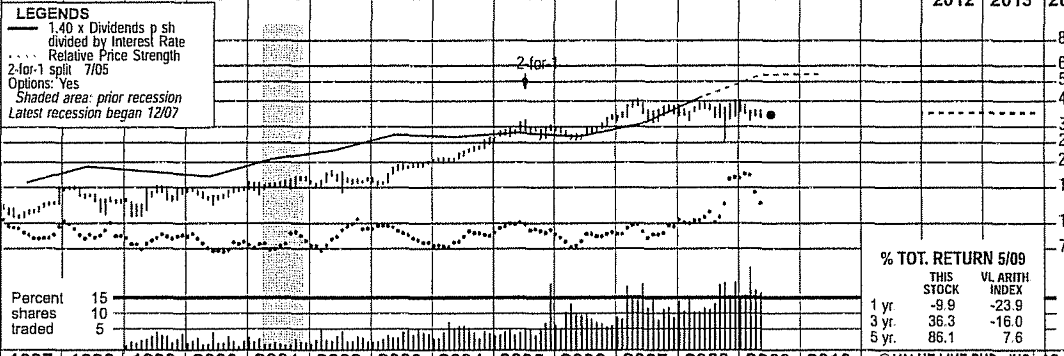
SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 34.15 | P/E RATIO 13.7 (Trailing: 14.1 Median: 14.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 2 Raised 12/26/08
SAFETY 2 Lowered 1/4/91
TECHNICAL 3 Lowered 5/15/09
BETA .65 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	15.4	15.4	15.1	17.0	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8
Low:	11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.0

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+45%)	13%
Low	35	(Nil)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	1	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	2	0	0	0	4

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	85	71	75
to Sell	58	59	69
Hld's(000)	17430	17041	16545

% TOT. RETURN 5/09

	THIS STOCK	VL ARITH INDEX
1 yr.	-9.9	-23.9
3 yr.	36.3	-16.0
5 yr.	86.1	7.6

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
17.03	17.45	16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	31.78	31.76	32.30	32.36	31.95	33.25	Revenues per sh	36.35
1.54	1.35	1.65	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.20	3.48	3.45	3.60	"Cash Flow" per sh	4.20
.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	2.27	2.50	2.65	Earnings per sh A	3.10
.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	1.20	1.28	Div'ds Decl'd per sh B ■	1.50
1.87	1.93	2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	2.51	1.88	2.08	2.25	2.40	Cap'l Spending per sh	2.90
7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.25	17.33	18.85	20.15	Book Value per sh C	22.75
19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.98	29.33	29.61	29.73	30.50	31.00	Common Shs Outst'g D	33.00
15.8	16.1	12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	Bold figures are		Avg Ann'l P/E Ratio	14.0
.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.91	.95	Value Line		Relative P/E Ratio	.95
5.9%	7.4%	7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	estimates		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 3/31/09
Total Debt $472.5 mill. Due in 5 Yrs $204.8 mill.
LT Debt $332.7 mill. LT Interest $15.0 mill.
(Total interest coverage: 5.8x)

Pension Assets-12/08 $88.3 mill. Oblig. $142.7 mill.

Pfd Stock none

Common Stock 29,796,232 common shs. as of 5/4/09

MARKET CAP: $1.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
392.5	515.9	837.3	505.1	696.8	819.1	921.0	931.4	956.4	962.0	975	1030	Revenues ($mill)	1200
22.0	24.7	26.8	29.4	34.6	43.0	48.6	72.0	61.8	67.7	75.0	80.0	Net Profit ($mill)	100
42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	41.5%	41.3%	41.9%	47.7%	40.0%	40.0%	Income Tax Rate	40.0%
5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	7.0%	7.7%	7.8%	Net Profit Margin	8.3%
53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	38.0%	39.0%	Long-Term Debt Ratio	38.0%
37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	62.0%	61.0%	Common Equity Ratio	62.0%
405.9	443.5	516.2	512.5	608.4	675.0	710.3	801.1	839.0	848.0	925	1025	Total Capital ($mill)	1210
533.3	562.2	607.0	666.6	748.3	799.9	877.3	920.0	948.9	982.6	1040	1100	Net Plant ($mill)	1260
7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	8.3%	10.1%	8.6%	8.5%	9.0%	8.5%	Return on Total Cap'l	9.0%
11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	12.4%	16.3%	12.8%	13.1%	13.0%	13.0%	Return on Shr. Equity	13.5%
14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.0%	13.0%	Return on Com Equity	13.5%
4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	6.7%	6.5%	6.5%	Retained to Com Eq	6.5%
72%	67%	76%	62%	57%	52%	50%	37%	48%	49%	49%	50%	All Div'ds to Net Prof	50%

CURRENT POSITION ($MILL.)	2007	2008	3/31/09
Cash Assets	11.7	5.8	6.7
Other	316.6	429.3	359.9
Current Assets	328.3	435.1	366.6
Accts Payable	101.2	120.2	96.1
Debt Due	118.4	237.6	139.8
Other	108.7	142.1	160.0
Current Liab.	328.3	499.9	395.9
Fix. Chg. Cov.	476%	598%	672%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	6.0%	3.0%	2.0%
"Cash Flow"	8.5%	10.0%	3.5%
Earnings	11.5%	13.0%	5.5%
Dividends	3.5%	6.0%	7.0%
Book Value	9.0%	11.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	372.6	153.8	154.7	250.3	931.4
2007	368.4	171.7	156.2	260.1	956.4
2008	348.1	135.8	210.4	267.7	962.0
2009	362.2	165	175	272.8	975
2010	375	170	200	285	1030

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.06	.20	.51	.69	2.46
2007	1.30	.21	d.05	.63	2.09
2008	1.32	.26	.04	.67	2.27
2009	1.46	.30	.05	.69	2.50
2010	1.45	.35	.10	.75	2.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	--	.213	.213	.438	.86
2006	--	.225	.225	.470	.92
2007	--	.245	.245	.515	1.01
2008	--	.270	.270	.568	1.11
2009	--	.298			

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 340,136 customers in New Jersey's southern counties, which covers about 2,500 square miles and includes Atlantic City. Gas revenue mix '08: residential, 46%; commercial, 23%; cogeneration and electric generation, 6%; industrial, 25%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 602 employees. Off./dir. control 1.0% of com. shares; Barclays, 7.5%; Keeley Asset Management, 5.6% (3/09 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037 Tel.: 609-561-9000. Internet: www.sjindustries.com.

South Jersey Industries posted healthy results for the first quarter. The company's nonutility operations led the way. The Asset Management and Marketing segment benefited greatly from the increased value of pipeline capacity, which more than offset tighter margins for storage capacity. The on-site energy production business, Marina Energy, also registered higher earnings. The bottom line at utility South Jersey Gas was roughly unchanged from the prior-year period. Improved operating performance and lower interest costs offset significantly higher pension expense. Overall, the company's revenues and share earnings advanced roughly 4% and 11%, respectively, for the recent period. Looking forward, we expect solid share-net growth for 2009 and 2010.

Long-term prospects appear favorable for utility South Jersey Gas. Customer growth has continued at a decent clip, in spite of the slowdown in the new housing construction market. Natural gas remains the fuel of choice in SJG's markets, where the company continues to see interest in conversions from other fuel sources. Its recent gas main extension project in Cape May County will likely augment the customer base, as well. Meanwhile, healthy performance should continue at SJI's non-utility operations. Overall, the company should do well over the long haul as portions of southern New Jersey are developed for residential and commercial use.

South Jersey Gas has received regulatory approval for a major infrastructure investment plan. This accelerates into 2009 and 2010 roughly $100 million in capital spending and entails extensive infrastructure improvement projects. As part of the program, South Jersey Gas will file a full base rate case in 2010 to recover, and earn a return on, this investment.

This stock is favorably ranked for year-ahead performance. Looking further out, we anticipate further growth in dividends and share earnings over the pull to 2012-2014. In addition, South Jersey earns superior marks for Safety, Price Stability, and Earnings Predictability. However, from the current quotation, total return potential for the coming years is below average for a utility.

Michael Napoli, CPA — *June 12, 2009*

(A) Based on GAAP EPS through 2006, economic earnings thereafter. GAAP EPS: '07, $2.10; '08, $2.58. Excl. nonrecur. gain (loss): '01, $0.13; '08, $0.31. Excl gain (losses) from discont. ops.: '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02); '07, $0.01. Earnings may not sum due to rounding. Next egs. report due in August. (B) Div'ds paid early Apr., Jul., Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. regulatory assets. In 2008: $270.4 mill., $9.10 per shr. (D) In millions, adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	80

SOUTHWEST GAS NYSE-SWX

RECENT PRICE 21.92 | P/E RATIO 12.9 (Trailing: 15.7 Median: 19.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 4.4% | VALUE LINE

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TIMELINESS 3 Raised 5/23/08

SAFETY 3 Lowered 1/4/91

TECHNICAL 4 Lowered 6/12/09

BETA .75 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	26.9	29.5	23.0	24.7	25.3	23.6	26.2	28.1	39.4	39.9	33.3	26.4	
Low:	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5	26.0	26.5	21.1	17.1	

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

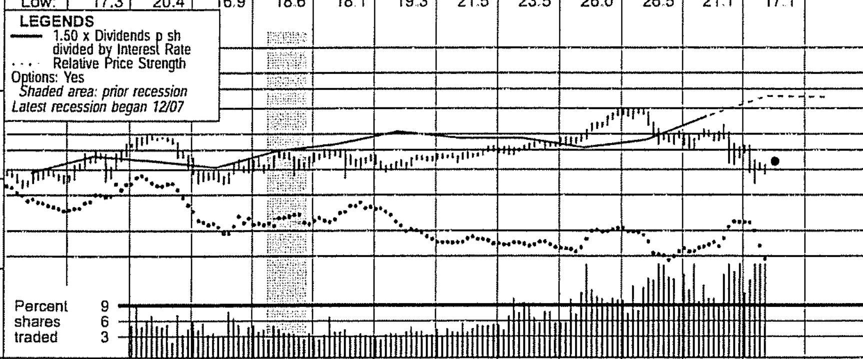
	Price	Gain	Ann'l Total Return
High	40	(+80%)	19%
Low	30	(+35%)	12%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	2	1	1	0	0	0	3
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	2	0	0	0	0	0	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	85	69	83
to Sell	65	74	75
Hld's(000)	34150	33669	32362



% TOT. RETURN 5/09

	THIS STOCK	VL ARITH INDEX
1 yr.	-30.8	-23.9
3 yr.	-21.9	-16.0
5 yr.	7.1	7.6

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
25.68	28.16	23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	*40.65*	*43.50*	Revenues per sh	*54.00*
3.24	5.09	2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	*6.05*	*6.40*	"Cash Flow" per sh	*7.50*
.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	*1.70*	*1.90*	Earnings per sh A	*2.35*
.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	*.95*	*1.00*	Div'ds Decl'd per sh B■†	*1.15*
5.43	6.64	6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	*6.00*	*6.50*	Cap'l Spending per sh	*8.00*
15.96	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	*25.25*	*26.65*	Book Value per sh	*28.00*
21.00	21.28	24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	*45.50*	*46.00*	Common Shs Outst'g C	*50.00*
26.5	14.0	NMF	69.3	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
1.57	.92	NMF	4.34	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.22	*Value Line*		Relative P/E Ratio	*1.00*
4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*
						936.9	1034.1	1396.7	1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	*1850*	*2000*	Revenues ($mill)	*2700*
						39.3	38.3	37.2	38.6	38.5	58.9	48.1	80.5	83.2	61.0	*75.0*	*85.0*	Net Profit ($mill)	*115*
						35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	*38.0%*	*38.0%*	Income Tax Rate	*36.0%*
						4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	*4.1%*	*4.3%*	Net Profit Margin	*4.3%*
						60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	*51.0%*	*50.5%*	Long-Term Debt Ratio	*49.0%*
						35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	*49.0%*	*49.5%*	Common Equity Ratio	*51.0%*
						1424.7	1489.9	1417.6	1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	*2350*	*2475*	Total Capital ($mill)	*2750*
						1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	*3050*	*3150*	Net Plant ($mill)	*3600*
						4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
						7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	*6.5%*	*7.0%*	Return on Shr. Equity	*8.0%*
						7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	*6.5%*	*7.0%*	Return on Com Equity	*8.0%*
						2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	*3.0%*	*3.0%*	Retained to Com Eq	*4.0%*
						64%	67%	71%	70%	72%	49%	65%	42%	44%	63%	*58%*	*54%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 3/31/09

Total Debt $1252.1 mill. **Due in 5 Yrs** $566.0 mill.
LT Debt $1247.1 mill. **LT Interest** $85.0 mill.
(Total interest coverage: 2.2x)
Leases, Uncapitalized Annual rentals $6.0 mill.
Pension Assets-12/08 $342.9 mill.
Oblig. $558.9 mill.

Pfd Stock None

Common Stock 44,708,482 shs.
as of 5/1/09

MARKET CAP: $975 million (Small Cap)

CURRENT POSITION ($MILL.)	2007	2008	3/31/09
Cash Assets	32.0	26.4	23.8
Other	470.5	411.7	305.7
Current Assets	502.5	438.1	329.5
Accts Payable	220.7	191.4	116.1
Debt Due	47.1	62.8	5.0
Other	260.1	255.7	279.4
Current Liab.	527.9	509.9	400.5
Fix. Chg. Cov.	229%	224%	230%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	6.0%	4.5%	*1.5%*
"Cash Flow"	4.5%	3.5%	*4.0%*
Earnings	7.0%	9.0%	*5.0%*
Dividends	0.5%	1.0%	*5.0%*
Book Value	4.5%	5.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	676.9	430.9	351.8	565.1	2024.7
2007	793.7	426.6	371.5	560.3	2152.1
2008	813.6	447.3	374.4	509.4	2144.7
2009	689.9	*380*	*310*	*470.1*	*1850*
2010	*750*	*425*	*325*	*500*	*2000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.11	.02	d.26	1.11	1.98
2007	1.17	d.01	d.22	1.01	1.95
2008	1.14	d.06	d.38	.71	1.39
2009	1.12	*d.05*	*d.30*	*.93*	*1.70*
2010	*1.15*	*Nil*	*d.30*	*1.05*	*1.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.205	.205	.205	.205	.82
2006	.205	.205	.205	.205	.82
2007	.205	.215	.215	.215	.85
2008	.215	.225	.225	.225	.89
2009	.225	.238			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.8 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2008 margin mix: residential and small commercial, 86%; large commercial and industrial, 5%; transportation, 9%. Total throughput: 2.4 billion therms. Sold PriMerit Bank, 7/96. Has 4,732 employees. Off. & Dir. own 2.0% of common stock; T. Rowe Price Associates, Inc., 7.0%; Barclays Global Investors, 6.8%; GAMCO Investors, Inc., 6.4% (3/09 Proxy). Chairman: James J. Kropid. CEO: Jeffrey W. Shaw. Inc.: CA. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89146. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas reported lower revenues for the first quarter. Warmer-than-normal temperatures and customers' conservation efforts resulted in lower heating demand for the period, hurting the performance of the utility business. The company's construction services subsidiary also posted lower revenues in the recent interim. This was partially offset by recently granted rate relief (discussed below). Expenses also declined significantly, and share earnings came in just slightly below the prior-year figure.

Weakness may well persist in the near term. Customer growth for the utility business will likely remain modest, owing to the prolonged housing slump in the Southwest. This should also continue to hurt the performance of the construction services unit. Thus, we anticipate unimpressive results in the second and third quarters. Losses are common during these periods, though, given the seasonal nature of the business. Performance may well improve from the fourth quarter onward, assuming a more favorable operating environment by that time.

The company has filed a general rate case with the state of Nevada. Southwest is seeking higher rates to recover increased operating costs in Nevada. The request asks that the new rates become effective at the beginning of November. The company is also looking to implement a rate structure that will allow it to more aggressively pursue customer conservation opportunities. This follows recent rate case settlements in California and Arizona. Southwest's focus on procuring rate relief and improving rate design is important, as such approved revenue increases help it to cope with higher expenses.

The stock is not without risk. Warmer-than-normal temperatures during the winter can hurt profitability at the company. Moreover, Southwest will probably incur greater operating expenses as it continues to expand. Furthermore, insufficient, or lagging, rate relief may hurt performance. Still,

At the present quotation, the stock features good total return potential for a utility. This is based on a well-covered dividend payout and the steady growth we envision out to 2012-2014.

Michael Napoli, CPA *June 12, 2009*

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Incl. asset writedown: '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Totals may not sum due to rounding. Next egs. report due early August. (B) Dividends historically paid early March, June, September, December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	65

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UGI CORP. NYSE-UGI

RECENT PRICE 24.93 | P/E RATIO 10.8 (Trailing: 10.1 Median: 14.0) | RELATIVE P/E RATIO 0.68 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 2 Lowered 5/29/09

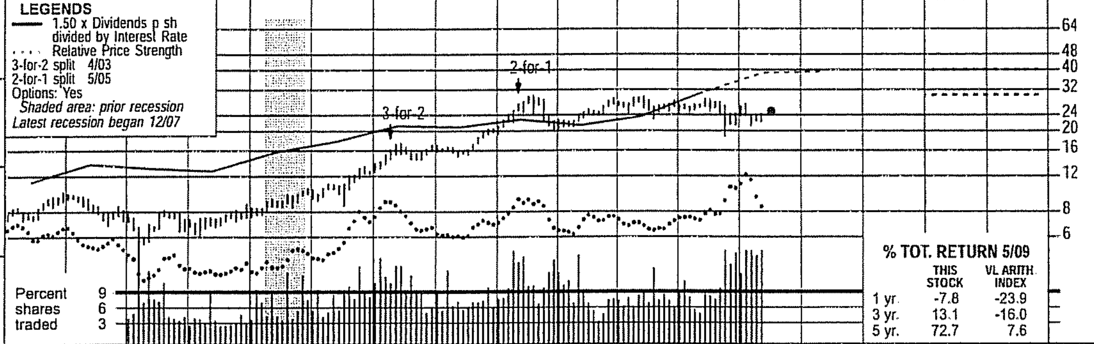
SAFETY 2 Raised 9/17/04

TECHNICAL 4 Lowered 6/12/09

BETA .70 (1.00 = Market)

	High:	Low:
1993	9.9	6.8
1994	8.2	5.0
1995	8.8	6.1
1996	10.5	7.5
1997	13.5	8.6
1998	17.5	12.5
1999	20.7	14.9
2000	30.0	19.2
2001	29.0	20.2
2002	29.6	22.8
2003	28.9	18.7
2004	27.4	21.1

Target Price Range 2012 2013 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+60%)	15%
Low	30	(+20%)	8%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	3	0	0	0	0	0	0	1
to Sell	0	3	0	0	0	0	0	3	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	121	121	115
to Sell	84	104	110
Hld's(000)	78717	79151	79392

% TOT. RETURN 5/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-7.8	-23.9
3 yr.	13.1	-16.0
5 yr.	72.7	7.6

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
5.32	7.84	8.89	15.67	16.66	14.46	16.91	21.75	30.14	26.64	35.44	36.95	46.65	49.51	51.36	61.90	61.75	63.95	Revenues per sh A	68.45
.44	.82	.82	1.21	1.36	1.29	1.62	1.74	1.99	2.03	2.38	2.44	3.13	3.08	3.39	3.72	4.15	4.15	"Cash Flow" per sh	4.75
.14	.39	.20	.35	.49	.41	.45	.53	.70	.90	1.15	1.22	1.72	1.61	1.79	1.99	2.40	2.35	Earnings per sh B	2.80
.33	.45	.46	.47	.48	.48	.49	.51	.53	.54	.57	.60	.65	.68	.72	.76	.80	.86	Div'ds Decl'd per sh C ■	.98
.43	.50	.70	.63	.70	.69	.86	.88	.95	1.14	1.18	1.31	1.51	1.82	2.09	2.16	3.05	2.05	Cap'l Spending per sh	2.25
4.33	4.38	3.85	3.80	3.82	3.69	3.05	3.05	3.12	3.82	6.67	8.14	9.52	10.43	12.40	13.20	14.80	16.35	Book Value per sh D	21.90
95.83	97.18	98.75	99.41	98.59	99.60	81.81	80.98	81.89	83.11	85.40	102.42	104.80	105.45	106.65	107.40	108.5	109.5	Common Shs Outst'g E	111.0
56.6	18.7	33.9	21.0	16.2	21.7	15.9	13.6	12.1	11.4	12.6	13.4	13.8	14.0	15.1	13.3	Bold figures are	Value Line	Avg Ann'l P/E Ratio	13.0
3.34	1.23	2.27	1.32	.93	1.13	.91	.88	.62	.62	.72	.71	.73	.76	.80	.84	estimates		Relative P/E Ratio	.85
4.2%	6.2%	6.8%	6.4%	6.0%	5.5%	6.9%	7.0%	6.2%	5.3%	3.9%	3.7%	2.7%	3.0%	2.7%	2.9%			Avg Ann'l Div'd Yield	2.7%

CAPITAL STRUCTURE as of 3/31/09
Total Debt $2263.5 mill. Due in 5 Yrs $824.8 mill.

LT Debt $2057.9 mill. LT Interest $120.0 mill.
(Total interest coverage: 3.6x)

Leases, Uncapitalized Annual rentals $71.2 mill.
Pension Assets-9/08 $244.7 mill. Oblig. $310.9 mill.
Minority interests in AmeriGas $89.8 mill.
Pfd Stock None

Common Stock 108,267,638 shares as of 4/30/09
MARKET CAP: $2.7 bill. (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1383.6	1761.7	2468.1	2213.7	3026.1	3784.7	4888.7	5221.0	5476.9	6648.2	6700	7000	Revenues ($mill) A	7600
44.5	45.0	59.1	77.1	100.1	117.5	182.0	176.2	191.8	215.5	260	260	Net Profit ($mill)	315
44.8%	46.6%	45.3%	37.8%	37.7%	36.5%	39.5%	30.5%	23.8%	30.6%	30.0%	33.0%	Income Tax Rate	33.0%
3.2%	2.6%	2.4%	3.5%	3.3%	3.1%	3.7%	3.4%	3.5%	3.2%	3.9%	3.7%	Net Profit Margin	4.1%
78.6%	79.4%	81.3%	77.0%	67.0%	65.0%	58.3%	64.1%	60.7%	58.4%	57.0%	54.0%	Long-Term Debt Ratio	46.0%
19.8%	19.1%	17.4%	21.7%	33.0%	35.0%	41.7%	35.9%	39.3%	41.6%	43.0%	46.0%	Common Equity Ratio	54.0%
1258.8	1296.9	1472.5	1464.3	1728.3	2381.4	2390.1	3064.6	3360.7	3405.0	3710	3900	Total Capital ($mill)	4530
1084.1	1073.2	1268.0	1271.9	1336.8	1781.9	1802.7	2214.7	2397.4	2449.5	2335	2450	Net Plant ($mill)	2820
6.7%	6.4%	7.1%	8.2%	8.3%	6.9%	9.8%	7.5%	7.4%	7.9%	8.5%	8.5%	Return on Total Cap'l	8.5%
16.5%	16.8%	21.4%	22.9%	17.6%	14.1%	18.2%	16.0%	14.5%	15.2%	16.5%	14.5%	Return on Shr. Equity	13.0%
17.2%	17.6%	22.5%	23.8%	17.6%	14.1%	18.2%	16.0%	14.5%	15.2%	16.5%	14.5%	Return on Com Equity	13.0%
NMF	.9%	5.8%	9.7%	9.2%	7.3%	11.5%	9.4%	8.7%	9.5%	11.0%	9.5%	Retained to Com Eq	8.5%
111%	95%	75%	60%	48%	48%	37%	41%	40%	38%	33%	36%	All Div'ds to Net Prof	35%

CURRENT POSITION ($MILL.)	2007	2008	3/31/09
Cash Assets	264.6	315.5	338.5
Other	909.0	1023.1	1161.1
Current Assets	1173.6	1338.6	1499.6
Accts Payable	420.8	461.8	428.8
Debt Due	213.6	218.2	205.6
Other	423.1	504.2	649.1
Current Liab.	1057.5	1184.2	1283.5
Fix. Chg. Cov.	361%	435%	1092%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	13.5%	12.0%	4.0%
"Cash Flow"	10.0%	10.0%	5.5%
Earnings	16.0%	14.5%	7.5%
Dividends	4.0%	6.0%	5.5%
Book Value	12.5%	21.5%	10.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	1577.9	1845.5	919.1	878.5	5221.0
2007	1463.2	2002.1	1076.8	934.8	5476.9
2008	1764.7	2361.5	1332.8	1189.2	6648.2
2009	1778.5	2137.8	1425	1358.7	6700
2010	1825	2500	1450	1225	7000

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.54	.98	.13	d.04	1.61
2007	.58	1.12	.11	d.02	1.79
2008	.74	1.17	.14	d.06	1.99
2009	.95	1.45	.08	d.08	2.40
2010	.85	1.30	.20	Nil	2.35

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.156	.156	.169	.169	.65
2006	.169	.169	.176	.176	.69
2007	.176	.176	.185	.185	.72
2008	.185	.185	.193	.193	.76
2009	.193	.193	.20		

BUSINESS: UGI Corp. operates six business segments: AmeriGas Propane (accounted for 20% of net income in 2008), International Propane (24%), Gas Utility (28%), Electric Utility (6%), Energy Services (21%), and Corp. & Other (1%). UGI Utilities distributes natural gas and electricity to nearly 484,000 customers in eastern PA; 44%-owned AmeriGas Partners is the largest U.S. propane marketer, serving about 1.3 million users in 46 states. Acquired remaining 80% interest in Antargaz (3/04). About 9,500 employees. Barclays Bank PLC owns 12.7% of common stock; Wellington Mgt Co., 10.7%; officers/ directors, 3.0% (12/08 proxy). Chairman and CEO: Lon Greenberg. Inc.: PA. Address: 460 N. Gulph Road., King of Prussia, PA 19406. Tele: 610-337-1000. Web: www.ugicorp.com.

UGI registered a better-than-expected showing in the March period (fiscal year ends September 30, 2009). Second-quarter share net came in at $1.45, which easily topped our $1.20 estimate. The company reported good results in all its segments except the electric business. The most notable performance was in the propane division, which posted wider margins thanks to lower costs.

Management raised its guidance for fiscal 2009. UGI expects share net to come in between $2.40 and $2.50 for the full year, thanks to its strong start to the year. The earnings outlook, adjusted for a one-time gain in the first quarter, is $2.30-$2.40 a share. Accordingly, we look for $2.40 a share on the bottom line. The company's diversified stream of income should support the share-net advance we foresee. Investors should note we expect earnings growth to ebb in the second half of the year due to the recessionary environment and lower volume.

The company awaits a decision on two rate cases in Pennsylvania. UGI filed these cases in January with the Pennsylvania Public Utility Commission. It requested revenue increases of $38.1 million for Penn Natural Gas and $19.6 million for Central Penn Gas. The proposed hikes also include programs for assistance and conservation aimed at helping customers. Management expects a decision by the end of this fiscal year.

The quarterly dividend was recently boosted to $0.20 a share. The board raised the payout roughly 4%, which will be payable on July 1, 2009. Still, income-oriented investors should note UGI's yield (3.1%) is below average compared to its peers in the Natural Gas Utility sector (4.8%).

This stock remains favorably ranked in our momentum-based system. Indeed, these shares should perform well relative to the broader market in the year ahead. On point, UGI's finances appear to be in order, which will probably help weather the challenges arising from the current economic environment. However, investors with a long-term view may want to look elsewhere. This equity has below-average total return potential over the 2012-2014 time frame.

Richard Gallagher *June 12, 2009*

(A) Fiscal year ends Sept. 30; fiscal '93 contains 9 mos.; calendar years prior to '93.
(B) Diluted earnings. Excludes nonrecur. items: '94, 8¢; '95, d15¢; '96, 2¢; '97, 4¢; '98, d1¢; '99, 13¢; '01, d1¢; '03, 22¢; '04, d6¢; '05, 3¢; '06, 5¢; '07, 12¢; Q1 '09, 10¢. Quarterly earnings may not sum due to rounding or change in share count. Next egs. rept. due late July. (C) Dividends historically paid in early Jan., April, July, and Oct. ■ Div. reinvest. plan available. (D) Incl. intang. At 9/08: $1644.7 mill., $15.31/sh. (E) In mill., adjusted for stock splits.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	85

WGL HOLDINGS NYSE-WGL

RECENT PRICE 31.01 | P/E RATIO 12.4 (Trailing: 12.4 / Median: 15.0) | RELATIVE P/E RATIO 0.78 | DIV'D YLD 4.8% | VALUE LINE

High:	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5		
Low:	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.6		

Target Price Range 2012 | 2013 | 2014

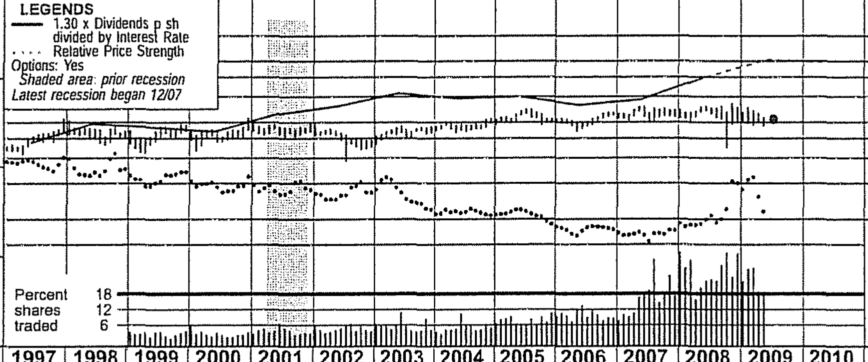
TIMELINESS 3 Lowered 6/5/09

SAFETY 1 Raised 4/2/93

TECHNICAL 4 Lowered 6/5/09

BETA .65 (1.00 = Market)

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+45%)	13%
Low	35	(+15%)	8%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	2	0	4	0	0	1	0
to Sell	0	0	2	0	4	0	0	4	1

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	95	83	94
to Sell	100	119	95
Hld's(000)	34195	32939	31580

Percent shares traded 18 12 6

% TOT. RETURN 5/09

	THIS STOCK	VL ARITH INDEX
1 yr.	-10.9	-23.9
3 yr.	17.6	-16.0
5 yr.	34.4	7.6

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
21.55	21.69	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	*54.00*	*55.10*	Revenues per sh A	*58.45*
2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.89	3.89	4.34	*4.40*	*4.45*	"Cash Flow" per sh	*4.75*
1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.10	2.44	*2.50*	*2.55*	Earnings per sh B	*2.75*
1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	*1.45*	*1.50*	Div'ds Decl'd per sh C■	*1.60*
2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	*3.00*	*3.00*	Cap'l Spending per sh	*2.50*
11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	*22.05*	*23.10*	Book Value per sh D	*26.50*
41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	*50.00*	*50.00*	Common Shs Outst'g E	*50.00*
15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.82	.85	*Value Line*		Relative P/E Ratio	*1.00*
5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 3/31/09
Total Debt $837.4 mill. Due in 5 Yrs $264.5 mill.
LT Debt $655.8 mill. LT Interest $37.4 mill.
(LT interest earned: 5.9x; total interest coverage: 5.2x)
Pension Assets-9/08 $588.2 mill. Oblig. $590.5 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 50,141,229 shs. as of 4/30/09

MARKET CAP: $1.6 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	*2700*	*2755*	Revenues ($mill) A	*2925*
68.8	84.6	89.9	55.7	112.3	98.0	104.8	96.0	102.9	122.9	*125*	*130*	Net Profit ($mill)	*140*
36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	*37.0%*	*37.0%*	Income Tax Rate	*38.0%*
7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	*4.7%*	*4.7%*	Net Profit Margin	*4.8%*
41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	*36.5%*	*35.5%*	Long-Term Debt Ratio	*34.0%*
56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	*62.0%*	*63.0%*	Common Equity Ratio	*64.5%*
1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	*1780*	*1835*	Total Capital ($mill)	*2050*
1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	*2325*	*2420*	Net Plant ($mill)	*2720*
7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	*11.5%*	*11.0%*	Return on Shr. Equity	*10.5%*
9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	*12.0%*	*11.5%*	Return on Com Equity	*11.0%*
1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
82%	69%	67%	112%	56%	65%	62%	69%	66%	57%	*57%*	*58%*	All Div'ds to Net Prof	*58%*

CURRENT POSITION ($MILL.)	2007	2008	3/31/09
Cash Assets	4.9	6.2	24.4
Other	568.8	736.1	794.6
Current Assets	573.7	742.3	819.0
Accts Payable	216.9	243.1	280.3
Debt Due	205.4	347.0	181.6
Other	134.8	158.4	220.5
Current Liab.	557.1	748.5	682.4
Fix. Chg. Cov.	432%	490%	500%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	9.0%	*1.5%*
"Cash Flow"	3.5%	4.0%	*3.0%*
Earnings	2.0%	4.0%	*4.0%*
Dividends	1.5%	1.5%	*2.5%*
Book Value	4.0%	4.5%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	902.9	1064.5	346.9	323.6	2637.9
2007	732.9	1119.9	467.5	325.7	2646.0
2008	751.6	1020.0	464.7	391.9	2628.2
2009	821.5	1040.9	*469.5*	*368.1*	*2700*
2010	*830*	*1050*	*485*	*390*	*2755*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.93	1.17	d.01	d.15	1.94
2007	.92	1.27	.22	d.31	2.10
2008	.96	1.66	.06	d.24	2.44
2009	1.03	1.65	*.06*	*d.24*	*2.50*
2010	*1.04*	*1.66*	*.07*	*d.22*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.325	.333	.333	.333	1.32
2006	.333	.338	.338	.338	1.34
2007	.34	.34	.34	.34	1.36
2008	.34	.36	.36	.36	1.42
2009	.36	.37			

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,053,032 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century Inv. own 7.1% of common stock; Off./dir. less than 1% (1/09 proxy). Chrmn. & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Addr.: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings has posted solid top- and bottom-line results so far this year. The regulated utility business contributed nicely to revenues as a result of about 10,500 new customer meters. However, the rise in accounts was partially offset by an overall decrease in natural gas consumption patterns and higher uncollectible accounts. Meanwhile, the retail energy marketing segment registered a slight uptick in its operating earnings during the first six months of fiscal 2009. That unit benefited from additional electric sales to larger commercial customers. And the design-build energy systems segment, while still a relatively small portion of WGL's business mix, has been making nice strides in boosting its contribution to net income, as well as racking up a backlog of approximately $40 million.

We look for annual earnings advances to remain moderate for the foreseeable future. Should this be the case, WGL would be faring better than most companies in this industry. This will likely stem from having a large portion of its utility business within the Greater DC Metro area. That territory benefits from the large federal government presence that exhibits a greater resistance to the recessionary environment. Not only has that area not been hit as hard by the economic downturn, it is expected to lead the way in our country's recovery.

A recent dividend hike should appeal to income-oriented accounts. The board of directors increased the annual dividend by 5% to $1.47 a share, or $0.37 on a quarterly basis, starting in May.

Investments in alternative energy could bear fruit down the road. The retail energy marketing segment's initial investment in solar power is anticipated to be modestly accretive to earnings this year. And while the company's solar operations only make up a minute portion of its business mix, this should provide valuable experience into greener energy.

These neutrally ranked shares are suitable for income-focused investors, as they offer an above-average dividend yield, owing to the board's recent hike. And WGL is in line with other utilities in the *Value Line* universe for total return potential over the pull to 2012-2014.

Bryan Fong *June 12, 2009*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late July.
(C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '08: $291.3 million, $5.81/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	75

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 029:

Refer to the Moul Testimony, Appendix F, Flotation Costs.

a. Provide a description of how firms operating in non-regulated competitive markets treat and recover flotation costs when the firm raises additional capital through the equity markets.

b. Provide a description of how firms operating in non-regulated competitive markets treat and recover flotation costs when the firm raises additional capital through the bond markets.

c. Provide a step-by-step description of how Columbia acquires additional capital through its parent company, beginning with how the parent acquires capital.

Response:

a. Although these firms incur transaction costs when they raise additional capital, the absence of a cost of service pricing model in the competitive market does not have the same implications for non-regulated competitive firms. That is to say, they cannot adjust their prices to recover any particular cost, including flotation costs, because their prices are determined by competitive markets. Further, many of these companies raise common equity infrequently because they are not as capital intensive as public utilities.

b. See response (a) above. The cost of raising debt capital is treated the same as the cost of raising equity capital for non-regulated competitive firms.

c. Columbia acquires its debt capital via inter-company note issuances to NiSource Finance Corp. using a standardized methodology. This methodology is described as follows:

The Notes will be unsecured and will be dated the date of their issue. The Notes will be issued with maturities of up to thirty years; will bear an interest rate that corresponds to the pricing being offered companies with financial profiles similar to NiSource Finance Corp.; and will reflect market conditions at the time of issuance. The interest rate of the Notes will be determined by the corresponding applicable Treasury yield (as reported in the Federal Reserve Statistical Release, H.15 Selected Interest Rates (Daily)) effective on the date a Note is issued, plus the yield spread on corresponding maturities for companies with a credit risk profile equivalent to that of NiSource Finance Corp. (as reported by Reuters Corporate Spreads) effective on the date a Note is issued. For maturities not specifically referenced in the Statistical Release or Reuters, an interest rate will be calculated based upon a simple linear interpolation method.

PSC Case No. 2009-00141
Staff Set 2 DR No. 030
Respondent(s): Paul R. Moul

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 030:

Refer to the Moul Testimony at pages 7-8. Since Columbia does not profit from the sale of gas, provide further explanation of why its risk profile is strongly influenced by the sale and delivery of gas to its largest customers.

Response:

The risk is three-fold. First, the magnitude of the cost of purchased gas overwhelms all other costs for a natural gas utility. Second, natural gas utilities generally incur significant risks in acquiring the gas commodity, but cannot profit from innovative procurement practices. Third, the potential exists for regulatory disallowances. So, even a small proportion of the cost of purchased gas that might be disallowed could have significant financial consequences due to the magnitude of this expense.

**COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF**

Data Request 031:

Refer to the Moul Testimony at pages 9-10. For each company in the Gas Group that has operations in more than one state, provide a state-by-state breakout of where weather normalization mechanisms are in the companies' tariffs. Refer to the Moul Testimony at pages 13-14.

Response:

Please refer to the Microsoft Excel spreadsheet that is attached in Attachment A.

AGL Resources, Inc.

Weather Normalization Adjustment Rider (TN)	For residential, multi-family and C&I General Service customers from November - April annually. Implemented in 1991, it uses predetermined factors as determined in a rate case of a Weighted Average Non-Gas Base Rate, a Heat Sensitive Factor, and a Base Load factor for each customer class in CCF along with the difference between Normal and Actual Degree Days to calculate an adjustment.
Interruptible Margin Credit Rider (TN)	Interruptible Margin Credit Rider applies to firm customers and recovers 90% of fiscal year annual gross margin losses resulting from negotiated rate contracts and 50% of gross margin losses resulting from off-system sales transactions.
Performance-Based Ratemaking Mechanism (PBRM) (TN)	The PBRM is a trigger for a reporting mechanism, not a cost-sharing mechanism. Commencing each July 1, an annual index is created that establishes predetermined monthly benchmark indices against which actual commodity gas costs are compared. Annual reporting required if there is a minimum 1% overrun deviation at the end of the plan year, and monthly reporting required if there is a deviation of over 2% for any month.
Rider B - Weather Normalization Clause (WNC) (NJ)	Applicable October - May annually to residential, multi-family and general service customers. Uses three factors: 1) Degree Days - Takes difference in degree days from a monthly list of degree day factors determined in each rate case with a 0.5% deadband; 2) Consumption Factor - Takes difference in number of customers and therms per degree day, using a monthly listing of baseline values for each updated annually; 3) Margin Revenue Factor - Weighted average of tail block margin of Distribution Charges, set at $.2242/therm in most recent rate case.
Rider C - On-System Margin Sharing Credit (OSMC) (NJ)	Monthly per therm credit for all full-service and residential transportation customers to reflect system margin over-recovery. One rate for all classes and period months set annually on July 31, utilizing an annual program period of July 1 - June 30.
Rider D - Societal Benefits Charge (SBC) including NJ Clean Energy Program (NJ)	Monthly per therm charge, applicable to all service classes except special contracts, that has 4 specified components representing charges for: 1) New Jersey Clean Energy Program (CEP); 2) Remediation Adjustment Charge (RAC) for costs incurred in manufactured gas plant remediation; 3) Energy Education Charge (EEC); and 4) Universal Service Fund Lifeline (USF). Each component is a per therm charge (same per month), determined annually. Each of the CEP, the RAC and the EEC have annual recovery periods of October 1 - September 30 of expenses incurred for the previous 12 months ended June 30, with annual filing by July 31.
Rider B - Energy Conservation Cost Recovery Adjustment (ECCR) (FL)	Per therm charge applied monthly and determined annually for each of 9 rate classes to recover conservation expenditures. Each rate class has a different charge that is the same each month. Annual program period commencing each January 1.
Rider C - Competitive Rate Adjustment (CRA) (FL)	Per therm adjustment to recover the difference in annual revenues from special contracts compared to tariff rates. Annual adjustment period January 1 - December 31 to recover or refund amounts of the annual determination period of 12 months ended September 30. Adjustment rate is the same per class and therm over the adjustment period, using sales forecasts and annual true-ups.
Rider B, the Experimental Weather Normalization Adjustment Rider, was filed and effected as of October 3, 2002. (VA)	First WNA approved in the State of Virginia - filed in April, 2002 and effective October 3, 2002. For residential, multi-family and general service customers from November - May annually. Uses predetermined (@ each rate case) factors of a Weighted Average Non-Gas Base Rate and a Customer Usage Per Degree Day rate that are multiplied by the number of bills issued in that billing cycle and the difference between Normal and Actual Degree Days. This product is divided by the aggregate volume of gas billed in that cycle for each customer class in CCF to calculate an adjustment.
Straight Fixed Variable Rates (SFV) (GA)	SFV is a method of determining demand and commodity rates whereby all costs classified as fixed are assigned to the demand component. Required through SB 215, Georgia's 1997 Natural Gas Competition and Deregulation Act; Effective July, 1998.

AGL Resources, Inc. (cont'd)

Pipeline Replacement Program (PRP) Cost Recovery Rider (GA)	Recovers costs of replacing bare steel and cast iron pipe. Approved in September, 1998 and applicable to 6 Firm distribution rate class schedules, until June, 2005 was equal to a forecast amount of associated costs for a year divided by the estimated number of customers in those rate classes. A Stipulation Agreement was reached on June 10, 2005 in a general rate case 18638-U whereby each class pays a fixed monthly charge depending on their classification. A specific scheduled monthly per customer charge was set for residential and small service classes, with the General G-11 service class paying 3x and the General - Conditional G-12 service class paying 12x the residential and small service amount of $1.29 through 9/30/07, and $1.95 after.
Social Responsibility Cost Rider (SRC) (GA)	Senior citizens at least 65 with a maximum annual income of $12,000 receive a maximum $14 monthly credit. The SRC rider recovers $10.50 of that amount, and is charged to remaining residential customers during the following month as a per customer charge.

	2007	2006	2005	2004	2003	2002	2001
Weather Normalization Adjustment Rider (TN)	X	X	X	X	X	X	X
Interruptible Margin Credit Rider (TN)	X	X	X	X			
Performance-Based Ratemaking Mechanism	X	X	X	X			
Rider B - Weather Normalization Clause (WNC)	X	X	X	X	X	X	X
Rider C - On-System Margin Sharing Credit (OSMC) (NJ)	X	X	X	X	X	X	X
Rider D - Societal Benefits Charge (SBC) including NJ Clean Energy Program (NJ)	X	X	X	X	X	X	X
Rider B - Energy Conservation Cost Recovery Adjustment	X	X	X	X			
Rider C - Competitive Rate Adjustment (CRA) (FL)	X	X	X	X			
Rider B, the Experimental Weather Normalization Adjustment Rider, was filed and effected as of October 3,	X	X	X	X	X	X	
Straight Fixed Variable Rates (SFV) (GA)	X	X	X	X	X	X	X
Pipeline Replacement Program (PRP) Cost Recovery Rider (GA)	X	X	X	X	X	X	X
Social Responsibility Cost Rider (SRC) (GA)	X	X	X	X	X	X	

Atmos Energy Corp.

Weather Normalization Adjustment Rider (TX) (LA) (KN) (TN) (GA) (KY) (MS)	WNA in the Mississippi Valley subsidiary is applicable to the non-gas charge billing components for November - May. Total usage is adjusted by a Normalized Consumption formula in which estimated daily Baseload (Non-Heating) Consumption, equal to either the most recent actual non-heating period use or a set factor depending on customer class, is multiplied by the number of billing days in the period and added to the product of Actual less Baseload Consumption multiplied by the ratio of Normal Heating Degree Days to Actual. Variations of the WNA are also in effect in Texas, Kansas, Tennessee, Georgia, Louisiana and Kentucky.
Gas Reliability Infrastructure Program (GRIP) (TX)	Gas Reliability Infrastructure Program (GRIP) allows natural gas utilities the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. Natural gas utilities that enter the program will be required to file a complete rate case at least once every five years.
Rate Stabilization Clause (RSC)	Return stabilization mechanisms approved in LA & MS.
Performance Based Rate Program	In February 2006, the KPSC approved the company's request to continue the performance-based ratemaking mechanism for an additional fiveyear period. Under the performance-based mechanism, the company and customers jointly share in any actual gas cost savings achieved when compared to pre-determined benchmarks. Rates are also subject to WNA.

	2007	2006	2005	2004	2003	2002	2001
Weather Normalization Adjustment Rider	X	X	X	X	X	X	X
Gas Reliability Infrastructure Program (GRIP) (TX)	X	X	X				
Rate Stabilization Clause (RSC)	X	X	X	X	X	X	X
Performance Based Rate Program	X	X	X	X	X	X	X

New Jersey Resources Corp.

Weather Normalization Clause	Effective during the Winter Period (8 months: October 1-May 31) and updated annually using as a basis normal Degree Days from the 20 yr. weighted average of the NOAA First Order Weather Observation Stations at 3 locations (Newark, Philadelphia, Atlantic City airports). Stabilizes revenues and minimizes customer bill volatility, but diminishes upside earnings potential.
Clean Energy Program Clause	Recovery of funds expended under a state-sponsored Clean Energy Program. Per therm charge, determined annually and recovered over 12 month period commencing October 1, to recover estimated forward year expenses and any over/under recovery of previous year's expenses. Same charge applicable to 16 different rate classes. Uses a forward estimate of both costs and therm sales for an annual period, with true-up over the next year. Interim filings to adjust the charge is allowed if actual collections indicate a large divergence of forecast vs. actual.
Societal Benefits Charge (SBC) that is inclusive of the NJ Clean Energy Program (NJ)	Monthly per therm charge, applicable to all service classes except special contracts, and includes components for: 1) New Jersey Clean Energy Program (CEP); 2) Remediation Adjustment Charge (RAC) for costs incurred in manufactured gas plant remediation; 3) Energy Education Charge (EEC); and 4) Universal Service Fund Lifeline (USF).
Conservation Incentive Program (CIP)	The CIP is a three-year pilot program, designed to decouple the link between customer usage and NJNG's utility gross margin to allow NJNG to encourage its customers to conserve energy. For the term of the pilot the existing WNC would be suspended and replaced with the CIP tracking mechanism, which addresses utility gross margin variations related to both weather and customer usage in comparison to established benchmarks. Recovery of such utility gross margin variations is subject to additional conditions including an earnings test and an evaluation of Basic Gas Supply Service (BGSS)-related savings achieved.

	2007	2006	2005	2004	2003	2002	2001
Weather Normalization Clause	X	X	X	X	X	X	X
Clean Energy Program Clause	X	X	X	X	X	X	X
Societal Benefits Charge (SBC) that is inclusive of the NJ Clean Energy Program (NJ)	X	X	X	X	X	X	X
Conservation Incentive Program (CIP)	X	X					

Northwest Natural Gas

Distribution Margin Normalization	A "conservation tariff," which is a rate mechanism designed to adjust margins for changes in average consumption patterns due to residential and commercial customers' conservation efforts. The tariff is a partial decoupling mechanism that is intended to break the link between earnings and the quantity of gas consumed by customers, removing any incentive for the utility to discourage customers' conservation efforts.
'Weather Normalization	In November 2003, the OPUC authorized, and the company implemented, a weather normalization mechanism in Oregon that helps stabilize utility margins by adjusting residential and commercial customer billings based on temperature variances from average weather. The current normalization mechanism is applied to residential and commercial customers' bills between December 1 and May 15 for each heating season. The mechanism adjusts the margin component of customers' rates to reflect "average" weather using the 25-year average temperature for each day of the billing period.

	2007	2006	2005	2004	2003	2002	2001
Distribution Margin Normalization	X	X	X	X	X	X	
'Weather Normalization	X	X	X	X	X		

Piedmont Natural Gas Co.

Weather Normalization Adjustment (WNA)	Implemented in South Carolina and Tennessee in 1993. Implemented in North Carolina in 1991 but discontinued in favor of a Customer Utilization Tracker in 2005. WNA mechanisms partially offset weather impacts. Affects bills rendered November - March. In NC and TN, adjustments made directly to customers' bills. In SC, adjustments calculated per individual customer, recorded in a deferred account and applied to base rates for all customers in the class. Utilizes 30-year historical normal data.
Customer Utilization Tracker (CTU)	Replaced the WNA mechanism in NC in 2005 as part of a general rate case. CTU is a 3 year experimental rider revenue decoupling mechanism effective to November 1, 2008. To gain the CUT, Piedmont agreed to a $500K annual contribution for conservation programs, to be chosen jointly with NC Attorney General and Public Staff. Rates are adjusted twice yearly to reflect margin true-up - April 1 (for under/overrecovery to most recent Jan. 31) and November 1 (for under/overrecovery to most recent August 31).
Revenue decoupling mechanism (NC)	Effective in North Carolina as of November 1, 2005.
Uncollectible Expense - Gas Component Recovery	Effective in North Carolina as of November 1, 2005.
Pipeline Integrity Management Regulations (USDOT)	In both of their NC entities - Piedmont Natural Gas and North Carolina Natural Gas, effective December 2004, received approval from the North Carolina Utilities Commission to segregate O&M and payroll compliance costs of PIM compliance (estimated at $3MM annually over several years) into a deferred account and postpone and lengthen recovery, after a prudence review, until the next general rate case for each entity. Continued per the 2005 rate case.
Rate Stabilization Mechanism	On February 16, 2005, the Natural Gas Rate Stabilization Act of 2005 became effective in South Carolina. The law provides electing natural gas utilities, including Piedmont, with a mechanism for the regular, periodic and more frequent (annual) adjustment of rates which is intended to: (1) encourage investment by natural gas utilities, (2) enhance economic development efforts, (3) reduce the cost of rate adjustment proceedings and (4) result in smaller but more frequent rate changes for customers. If the utility elects to operate under the Act, the annual filing will provide that the utility's rate of return on equity will remain within a 50-basis points band above or below the current allowed rate of return on equity.

	2007	2006	2005	2004	2003	2002	2001
Weather Normalization Adjustment (WNA)			X	X	X	X	X
Customer Utilization Tracker (CTU)	X	X	X				
Revenue decoupling mechanism (NC)	X	X	X				
Uncollectible Expense - Gas Component Recovery	X	X	X				
Pipeline Integrity Management Regulations (USDOT)	X	X	X	X			
Rate Stabilization Mechanism	X	X					

South Jersey Industries, Inc.

Temperature Adjustment Clause (TAC)	Through September 30, 2006, SJG's tariff included a TAC to mitigate the effect of variations in heating season temperatures from historical norms. Each TAC year ran from November 1 through May 31 of the following year. Once the TAC year ended, the net earnings impact was filed with the BPU for future recovery. As a result, the cash inflows or outflows generally would not begin until the next TAC year. Because of the timing delay between the earnings impact and the recovery, the net result can be either a regulatory asset or liability.
New Jersey Clean Energy Program (NJCEP)	This mechanism recovers costs associated with SJG's energy efficiency and renewable energy programs. NJCEP adjustments affect revenue and cash flows but do not directly affect earnings as related costs are deferred and recovered through rates on an on-going basis.
Remediation Adjustment Clause (RAC)	Remediation Adjustment Charge (RAC) for costs incurred in manufactured gas plant remediation
Universal Service Fund Lifeline (USF)	The USF is a statewide program through which funds for the USF and Lifeline Credit and Tenants Assistance Programs are collected from customers of all New Jersey electric and gas utilities.
Conservation Incentive Program (CIP)	The primary purpose of the CUA is to promote conservation efforts, without negatively impacting financial stability and to base SJG's profit margin on the number of customers rather than the amount of natural gas distributed to customers. In October 2006, the BPU approved the CUA as a 3-year pilot program and renamed it the Conservation Incentive Program. Each CIP year begins October 1 and ends September 30 of the subsequent year. On a monthly basis during the CIP year, SJG records adjustments to earnings based on weather and customer usage factors, as incurred. Subsequent to each year, SJG will make filings with the BPU to review and approve amounts recorded under the CIP. BPU approved cash inflows or outflows generally will not begin until the next CIP year.

	2007	2006	2005	2004	2003	2002	2001
Temperature Adjustment Clause (TAC)	X	X	X	X	X	X	X
New Jersey Clean Energy Program (NJCEP)	X	X	X	X	X	X	X
Remediation Adjustment Clause (RAC)	X	X	X	X	X	X	X
Universal Service Fund Lifeline (USF)	X	X	X	X	X		
Conservation Incentive Program (CIP)	X	X					

WGL Holdings, Inc.

Revenue Normalization Adjustment (RNA) Clause (MD)	RNA in effect within state of Maryland since 1999 (BG&E), implemented at WGL October 1, 2005. Columbia Gas of Maryland and Chesapeake Utilities has a WNA in lieu of the RNA. Compares target or recent base rate determination of revenue against actual revenues, adjusted for growth. Adjustments to the monthly Distribution Charge for each of 6 applicable rate classes. Monthly computation comprised of a current factor and a reconciliation factor that has a 2 month

	2007	2006	2005	2004	2003	2002	2001
Revenue Normalization Adjustment (RNA) Clause	X	X	X				

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 032:

Refer to the Moul Testimony at pages 13-14.

a. Provide a detailed explanation, including ratings agency reports, of why NiSource's ratings are so low.

b. Provide an explanation of specifically how Columbia's actions have contributed to the low ratings attributable to the parent.

Response:

Attached are the current Moody's (Attachment A and B), Standard and Poor's (Attachment C and D) and Fitch (Attachment E) reports which detail their rationale for our ratings.

Because the rating agencies themselves determine these credit ratings, NiSource can not provide any further elaboration regarding these ratings as that information is solely determined by the rating agencies.

Staff DR Set 2-032 Attachment A

Moody's Investors Services

Global Credit Research
Credit Opinion
29 OCT 2008

Credit Opinion: NiSource Inc.

NiSource Inc.

Merrillville, Indiana, United States

Ratings

Category	Moody's Rating
Outlook	Negative
Preferred Shelf	(P)Ba2
NiSource Finance Corporation	
Outlook	Negative
Issuer Rating	Baa3
Senior Unsecured	Baa3
Bkd Commercial Paper	P-3
NiSource Capital Markets, Inc.	
Outlook	Negative
Bkd Senior Unsecured	Baa3
Northern Indiana Public Service Company	
Outlook	Negative
Issuer Rating	Baa2
Senior Unsecured	Baa2
Bay State Gas Company	
Outlook	Negative
Senior Unsecured	Baa2

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Opinion

Corporate Profile

NiSource Inc. (Baa3 senior unsecured, negative outlook) is a holding company with regulated natural gas and electric utility subsidiaries in nine U.S. states and an interstate gas pipeline system that runs from the Gulf Coast through the Midwest to New England.

The company has three segments: Gas Distribution (LDC), Transmission and Storage (Pipelines), and Electric. Each segment accounts for roughly one-third of operating income. The LDCs account for half of NiSource's assets, and the Pipelines and Electric subsidiaries each account for about a quarter. The company is one the largest gas companies in the U.S., ranking as the third-largest LDC, the fourth-largest gas pipeline, and among the largest gas storage systems. The Electric operations are medium-sized relative to the industry.

Two of NiSource's utility subsidiaries are rated: Bay State Gas Company (Baa2 senior unsecured) holds 1% of the group's consolidated debt and Northern Indiana Public Service Company, or NIPSCO (Baa2 senior unsecured) holds 7%. NiSource's Electric operations are conducted through NIPSCO, a combination electric and gas utility. The majority of NiSource's debt is issued through finance vehicles that are guaranteed by the holding company.

Rating Rationale

NiSource's Baa3 rating results from its sizable portfolio of regulated subsidiaries, which are estimated to be of Baa quality overall. The subsidiaries support more than $6 billion of debt at the holding company level.

NiSource management has maintained a public commitment to an investment-grade credit rating. The company has superior position in terms of the scale and diversity of its assets relative to many other diversified gas companies. It is virtually all rate-regulated and has jurisdictional diversity, resulting in lower business risk that allows it to support higher leverage than its peers.

As a regulated company, NiSource is exposed to regulatory risk. It currently has active rate cases in critical jurisdictions, particularly for its NIPSCO subsidiary in Indiana.

Profitability and leverage metrics are weaker than most of its peers'. NiSource has experienced margin erosion from a secular decline in demand, the cyclical downturn in the economy and higher commodity prices. Furthermore, negative free cash flows arising from an expected doubling of capital spending - mostly debt-financed - are expected to pressure financial metrics during the next few years.

Moody's applies its diversified natural gas rating framework in evaluating NiSource as a consolidated whole. Each of NiSource's parts -- LDC, pipeline, electric -- is also assessed according to Moody's rating frameworks for those industries.

Management Strategy & Financial Policy

NiSource's Baa3 rating is supported by the management's longstanding public commitment to investment-grade ratings. Since acquiring Columbia Energy eight years ago, the company has been financially constrained and has managed to conserve cash flow while restructuring its operations and balance sheet.

The company has recently been struggling to stanch eroding profitability. Net revenues have been flat-to-down due to customer attrition and decline in usage at its LDCs, while expenses have steadily risen from personnel-related costs. The long-term plan NiSource initiated last year seeks to address these issues. NiSource's negative outlook indicates significant execution risk and increased financial risk from this plan.

According to the company, the long-term plan is designed to increase earnings meaningfully starting in 2011 through rounds of rate filings and a capital investment program of more than $1 billion a year. In the interim, earnings are expected to remain flat. The plan also includes a partial IPO of a pipeline MLP in 2008, which has not yet been implemented due to unfavorable market conditions.

The long-term plan will result in large funding gaps that will likely be predominantly debt financed. Future financing activity could reintroduce some of the balance sheet complexity that the company has reduced over the past several years. Project financings related to pipeline projects will add to off-balance-sheet obligations. If launched, an MLP will introduce high payouts and other risks that come with that corporate finance model, although the MLP at the outset will be too small to have a rating impact.

Ongoing rate cases have brought regulatory risk to the fore after more than a decade's hiatus. NiSource has filed for rate cases for NIPSCO's electric operations and it is awaiting a final order at its LDC subsidiary Columbia of Ohio (COH). Columbia of Pennsylvania (CPA) recently finished its rate case. With favorable rate settlements in hand for COH and CPA, NiSource's regulatory risk will then be concentrated on the outcome of the NIPSCO rate case. NiSource's electric segment accounts for about one-third of consolidated operating income.

Financial Strength

Derived virtually all from regulated rates, NiSource's net revenues (total revenue minus cost of sales) have limited volatility outside of rate cases. For the same reason, there is little upside potential to revenues because the company's service territories are mature with little organic growth (historically, about 1% customer growth per year).

LDCs, the company's largest and least-profitable segment, have been persistently affected by declining sales volumes and warmer-than-normal weather (the majority of its subsidiaries lack weather normalization). As a result, top-line margins have been flat for several years. By contrast, operating expenses have been growing steadily (driven by compensation and pensions), and account for much of the erosion of the bottom line.

These factors have resulted in declining profitability (ROE decreasing from 9.4% in 2003 to 5.6% for the last 12 months ended June 2008). Further erosion is likely at least through the rest of 2008 and into 2009 while NiSource goes through rate proceedings and completes pipeline projects. In 2009, the company will have its first full year of new rates at Columbia of Ohio and Columbia of Pennsylvania, and the Millennium Pipeline will be fully operational. In 2010, NiSource would have its first full year of benefit from the Eastern Market Expansion project and, in 2011, the first full year of new rates for NIPSCO-electric.

Cash Flow

Until fairly recently, NiSource managed its operations close to maintenance mode, so that over time, it stayed about free cash flow neutral. Common dividends have been kept flat. Capital expenditures were in the $500 million range until 2006, when the company began some pipeline expansions. NiSource's long-term plan entails doubling annual capital expenditures to over $1 billion annually. Most of the incremental $500 million in annual spending will be on pipeline and storage projects.

Some of this increase is more maintenance spending, but most of it will be spent on pipeline and storage projects. Because of the lag in incremental cash flow as discussed in the next section, the increase in capital expenditures would result in negative free cash flow, at least for the next few years. According to the long-term plan, this funding deficit would be financed mostly with debt.

Capitalization

NiSource has over $6 billion of long-term debt, which compares to less than $5 billion of book equity. It is weakly capitalized in terms of cash flow coverage. Retained cash flow/debt has generally been slightly below 10% for a few years (9.8% in the last 12 months ended June 2008, at a seasonal low in heating demand), and this metric will be vulnerable to further compression in the near term due to the lag in cash flow and increased debt financing, as described above. The company is also highly leveraged on a tangible net worth basis net of almost $4 billion of goodwill, most of which resulted from the Columbia acquisition. Debt/book capitalization (net goodwill, after Moody's standard adjustments) was 73% at June 30, 2008 at a seasonal low.

Contingent Obligations

In May 2008, the Supreme Court of Appeals of West Virginia denied the company's appeal of a $404 million verdict in the Tawney class action lawsuit relating to a royalty dispute against NiSource's former E&P subsidiary. The company has entered into a preliminary settlement of $338 million for its share of the litigation, subject to final approval in November 2008. Although a credit-negative event, this litigation was already incorporated in the negative outlook.

Liquidity Profile

NiSource's liquidity position is adequate, though less robust than before, as the company proceeds on a capital spending cycle that will put it in a negative free cash flow position for an extended period at a time when the ability to tap the financial markets is extraordinarily uncertain.

The primary source of NiSource's alternate liquidity is NiSource Finance's drawn $1.5 billion committed revolver due on July 7, 2011. This base facility does not require the company to represent and warrant as to a general financial material adverse change at each borrowing. The sole financial covenant is a debt-to-capitalization ratio of 70%. The company has sufficient headroom under this covenant with a ratio of 56.8% as of December 31, 2007, around the last seasonal peak.

NiSource Finance also has in place a $500 million six-month facility expiring on March 23, 2009, as additional liquidity insurance for the settlement of the Tawney litigation.

Moody's satisfactory assessment of NiSource's near-term liquidity is subject to its renewing its receivables sales programs at COH, expiring on June 26, 2009, and NIPSCO, expiring December 19, 2008.

NiSource faces some financing risk on the horizon. Although the company has no scheduled debt maturities for the rest of 2008, NiSource Finance has sizable debt maturities over the next two years ($450 million of floating-rate notes on November 23, 2009, and $1 billion due on November 15, 2010). Additionally, there are small medium-term notes due during 2009 at NIPSCO and at NiSource Capital Markets. Furthermore, NiSource may need to permanently finance the Tawney obligation. Moody's will closely monitor NiSource's success in meeting its external financing requirements, particularly while the financial markets remain unfavorable.

Rating Outlook

The negative outlook indicates the risk of erosion in the company's already weak credit metrics over the next 12 months or so. If rate cases (particularly for NIPSCO) and pipeline projects (particularly the Millennium and Eastern Market Expansion) are executed in line with NiSource's long-term plan, the company should be able to sustain retained cash flow/debt at least in the 8% range and EBIT/interest in the low 2x range, and the outlook could be restored to stable.

What Could Change the Rating - Up

A rating upgrade is unlikely, given the downward pressure indicated by the negative outlook. Even if the company were to execute fully on its long-term plan, it is not expected to lift credit metrics sufficiently to warrant an upgrade (EBIT/interest in the 3x range, retained cash flow/debt in the 10% range).

What Could Change the Rating - Down

The rating could come under pressure if NiSource does not generate enough incremental revenues from its rate cases and pipeline projects, and EBIT/interest falls below 2x and retained cash flow/debt falls below 6%.

Rating Factors

NiSource Inc.

Diversified Natural Gas Transmission and Distribution	**Aaa**	**Aa**	**A**	**Baa**	**Ba**	**B**	**Caa**
Factor 1: Scale (10% weighting)							
a) Net Profit After-Tax Before Unusual Items (US$MM) (5%)				X			
b) Total Assets (US$B) (5%)	X						
Factor 2: Quality of Diversification (20% weighting)							
a) Scale of Unregulated Exposure (10%)	X						
b) Degree of Business Risk (10%)		X					
Factor 3: Management Strategy & Financial Policy (10% weighting)							
a) Management Strategy & Financial Policy (10%)				X			
Factor 4: Financial Strength (60% weighting)							
a) EBIT/Interest Expense (15%)						X	
b) Debt to Book Capitalization (excluding goodwill) (15%)						X	
c) Retained Cash Flow/Debt (15%)					X		
d) Return on Equity (15%)						X	
Rating:							
a) Methodology Model Implied Senior Unsecured Rating			**Baa3**				
b) Actual Senior Unsecured Equivalent Rating			**Baa3**				

Staff DR Set 2-032 Attachment A

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Moody's Investors Services

Global Credit Research
Announcement
4 FEB 2009

Announcement: Northern Indiana Public Service Company

Moody's affirms NiSource with negative outlook

New York, February 04, 2009 -- Moody's Investors Service affirmed that the ratings of NiSource Inc.'s subsidiaries (including its guaranteed primary financing vehicle NiSource Finance Corporation, rated Baa3 senior unsecured) and negative outlook are not impacted by the company's announcement of its updated long-range financial plan. In Moody's assessment, the company's weaker earnings outlook could be mitigated by a reduction in capital expenditures to reduce incremental debt, subject to the company successfully implementing its cost control and cash management initiatives.

"The plan metrics appear sufficient to maintain the company's ratings for now," says Moody's Vice President Mihoko Manabe. "However, they are low in the range that Moody's would expect for its current ratings and business risk profile and are vulnerable to shortfalls from the plan."

The latest iteration of NiSource's plan includes adjustments reflecting more difficult economic and financial market conditions than what was assumed previously. Capital expenditures for the next few years are expected to be about $800 million annually, down from $1 billion previously. The cuts are mostly on deferrable expenditures in the company's gas distribution segment and growth projects in its pipeline segment. The latter and increased pension obligations --- both non-cash expense and cash contributions --- contribute to the reduced earnings outlook. While less external debt financing would be required, borrowing rates will be higher.

With the rate cases for two of its largest gas distribution subsidiaries and some longstanding overhangs on its credit resolved, the critical issue at hand for NiSource is the rate case at its subsidiary Northern Indiana Public Service Company (NIPSCO, Baa2 senior unsecured). Moody's could stabilize outlook or initiate rating review in late 2009 or early 2010, whenever the credit impact of the NIPSCO's rate case can be reasonably assessed. Moody's notes that in changing the outlook to negative in December 2007, Moody's took an 18 to 24 months' view to allow time for certain rate cases and pipeline projects to be completed.

NiSource's near-term liquidity resources -- which should benefit from a reduction in the capital budget and lower natural gas prices -- appear sufficient for now. The company has obtained $265 million of commitments to-date on a two-year term loan, which would help replace the $500 million revolver that expires in March 2009. The company will implement a dividend reinvestment program which will mitigate its high payout rate and contribute modestly to retained earnings.

Additionally, NiSource is preparing new indentures for up to $350 million in secured bonds that could be issued by some of its larger operating subsidiaries, which would provide another option in refinancing the $417 million of debt that matures in November. At $350 million, the secured bonds would be about 5% of total debt at year-end 2008 and well below the 10% of net tangible assets limitation on liens test

Staff DR Set 2-032 Attachment B

under the holding company-level indenture. Given the magnitude of NiSource's total debt (roughly $6 billion), this incremental subsidiary borrowing as currently contemplated would not significantly affect the structural subordination of about 90% of consolidated debt at the holding company level.

The last rating action was on May 23, 2008 when Moody's commented that NiSource's ratings and negative outlook were not impacted by an adverse development in the Tawney class action lawsuit.

The principal methodology used in rating NiSource was Diversified Natural Gas Transmission and Distribution Companies, which can be found at www.moodys.com in the Credit Policy & Methodologies directory, in the Ratings Methodologies subdirectory. Other methodologies and factors that may have been considered in the process of rating NiSource can also be found in the Credit Policy & Methodologies directory.

Headquartered in Merrillville, Indiana, NiSource Inc. is a diversified natural gas and electric distribution and transmission company.

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Staff DR Set 2-032 Attachment B

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STANDARD & POOR'S

RATINGSDIRECT®

March 5, 2009

Research Update:

NiSource Finance's $600 Million Notes Rated 'BBB-'; NiSource Inc.'s Outlook Revised To Stable

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Research Update:

NiSource Finance's $600 Million Notes Rated 'BBB-'; NiSource Inc.'s Outlook Revised To Stable

Rationale

On March 5, 2009, Standard & Poor's Ratings Services assigned its 'BBB-' rating to NiSource Finance Corp.'s $600 million senior unsecured notes due 2016, which are unconditionally guaranteed by parent NiSource Inc. At the same time, we affirmed NiSource Inc.'s 'BBB-' corporate credit rating and revised the outlook to stable from negative. NiSource will use the proceeds to repay floating-rates notes at NiSource Finance and for general corporate purposes. As of Dec. 31, 2008, NiSource's total reported debt totaled about $7.6 billion.

The outlook revision to stable reflects the company's improved liquidity position due to the $600 million NiSource Finance note issuance and the recently executed $265 million two-year bank loan. These actions have enabled NiSource to raise sufficient funds to the point where it should have an adequate liquidity cushion and meet debt maturities of about $429 million in 2009, as well as meet expected cash payments under the Tawney legal settlement and fund remaining amounts under an approximately $800 million capital program. These recent financings have come at substantially higher interest rates than the existing debt, however, which may place long-term pressure on the company's financial profile and could notably hamper interest coverage ratios over the next several years. The company continues to project a liquidity shortfall in 2010 due to significant debt maturities of about $943 million, which, when coupled with expected capital expenditures and dividend payments, will substantially exceed cash flow estimates and require refinancing. These risks will continue to weigh on the rating. However, management's commitment to easing liquidity concerns and NiSource's demonstrated access to capital markets under difficult market conditions suggests that these financings are manageable.

The ratings on NiSource Inc. are based on the consolidated financial and business risk profiles of its various subsidiaries, which include Columbia Energy Group (CEG; not rated), Northern Indiana Public Service Co. (NIPSCO; BBB-/Stable/--), and Bay State Gas Co.(BBB-/Stable/--). Merrillville, Ind.-based NiSource is involved in regulated gas distribution (35% of consolidated cash flow), gas transmission and storage (32%), and vertically integrated electric operations (33%).

The stand-alone financial profiles of NiSource's utility subsidiaries are much stronger than the consolidated financial profile, where substantial acquisition-related debt is held. Nevertheless, we view the default risk as the same throughout the organization, due to the absence of regulatory mechanisms or other structural barriers that sufficiently restrict subsidiary cash flow to the holding company. NiSource recently curtailed its aggressive capital-spending program to $800 million from $1 billion, but nonetheless is likely to still result in negative free cash flow for 2009 and increased debt levels, reversing years of deleveraging. Initiatives to improve regulatory design at the gas distribution companies, several pipeline expansions, and the inclusion of the Sugar Creek power plant into rate base will improve and further stabilize cash in the longer term.

NiSource's business strategy, which centers almost exclusively on regulated businesses, as well as a diverse service area that encompasses nine states, historically responsive ratemaking principles, and competitive gas distribution and pipeline cost structures support the company's excellent business position. NIPSCO's high electric rates, heavy dependence on the industrial sector, and the pursuit of a more aggressive financial policy somewhat temper NiSource's strengths. Standard & Poor's business risk profile on NiSource is excellent, based on our expectations that the regulatory environment will likely improve in the near term as regulators contemplate more supportive rate-design mechanisms. These include "decoupling" rates from profits to reduce revenue sensitivity to fluctuations in weather and customer conservation efforts. NIPSCO's pending rate case will also influence future performance. Although the process is still in its early stages, we do not anticipate that a result that is not markedly different than the company's expectations to dramatically influence consolidated cash flow metrics given the cash flow diversity from other business lines.

We characterize the company's financial risk profile as aggressive due to its high debt leverage, weak cash flow metrics, and a constrained liquidity position. While NiSource had improved its balance sheet after the debt-financed acquisitions of Bay State and CEG, a more aggressive growth plan, which includes capital spending of about $800 million in 2009 after $1.3 billion in 2008, reversed some of this improvement. Also, the company has further delayed the $300 million master limited partnership IPO as announced earlier and will now likely fund this gap with debt. While recent external financings have been positive from a liquidity perspective, NiSource's already weak financial profile will be hurt even more if it continues to incur high interest rates on its borrowings, which could further pressure credit metrics.

For the next several years, we expect funds from operations (FFO) to total debt to remain weak, at around 12%, despite adequate FFO interest coverage of 3x. However, the higher interest rates the company is experiencing will likely pressure interest coverage ratios. Despite the many growth initiatives in the company's strategic plan, we don't expect cash flow to improve from current levels for several years due to the financing and operating costs of buying the Sugar Creek power plant, weakness in the local economy, and the regulatory lag in implementing a series of rate cases.

Liquidity

We project NiSource's liquidity position to remain adequate in 2009 given recent capital markets issuances, but it will likely be tight again in 2010 due to substantial debt maturities of about $943 million. For 2009, in addition to capital spending of $800 million, other projected uses of cash include dividends of about $254 million, debt maturities of $429 million, and payments associated with the Tawney settlement (about $232 million after-tax).

The company's pension and postretirement plans are also significantly underfunded (about $1.2 billion as of Dec. 31, 2008) so cash contributions to the plans are expected to total about $100 million more in 2009 than in 2008. Given these uses of cash and projected cash from operations of about $950 million and expected improvements in working capital of about $230 million, NiSource is able to meet its 2009 debt maturities via the $865 million of funds sourced from the NiSource Finance debt issue and bank loan. As of Dec. 31, 2008, NiSource had about $770 million of available credit facility capacity and unrestricted cash to provide liquidity support too. However, NiSource has about $933 million of debt maturities in 2010, resulting in nearly 20% of its adjusted debt balance coming due in the next two years. In 2010, while payments under the Tawney settlement will not occur and excess liquidity from the recent financings could be used to reduce debt, uses of cash (capital spending, dividends, and debt maturities) could total about $2 billion while cash from operations is expected to be about half this figure. This could create a significant liquidity shortfall next year that could affect ratings unless the company refinances the debt, albeit at potentially higher interest rates. The company only has $27 million of debt maturities in 2011, but the bank loan is also due that year.

Funding vehicle NiSource Finance has a $1.5 billion, five-year revolving credit facility that terminates in July 2011. As of Dec. 31, 2008, the company had about $750 million available under the facilities and $20 million in unrestricted cash.

Outlook

The stable outlook reflects our expectation for the company to maintain an adequate liquidity position throughout 2009. We also expect NiSource to continue the stable operating and financial performance of its regulated subsidiaries while executing on its capital expenditure program without material construction cost overruns or completion delays. We could revise the outlook to negative if the company's liquidity position deteriorates and a slight shortfall in the company's sources and uses of cash is expected in advance of the 2010 debt maturities (assuming they're refinanced), or an increase in borrowing costs creates further weakness in key credit metrics, which have no cushion to withstand any further degradation. We could lower the rating if the company can't get the required funds for the 2010 debt maturities well in advance of their refinancing need or if key credit metrics decline, specifically an FFO to debt ratio of about 10% to 11%. While an outlook revision to positive or higher ratings are not currently contemplated, credit quality could improve if cash flow metrics considerably improve, specifically FFO to debt of more than 15% on a sustained basis. The company can accomplish this by paying down debt with increased equity sales, asset dispositions, or higher internally generated cash flow, but management is not specifically contemplating any of these strategies at this time.

Ratings List

Ratings Affirmed; CreditWatch/Outlook Action

	To	From
NiSource Inc.		
NiSource Finance Corp.		
Northern Indiana Public Service Co.		
NiSource Capital Markets Inc.		
Bay State Gas Co.		
Corporate Credit Rating	BBB-/Stable/--	BBB-/Negative/--

New Rating

NiSource Finance Corp.	
Senior Unsecured (1 issue)	BBB-

Ratings Affirmed

Bay State Gas Co.	
Senior Unsecured (1 issue)	BBB-
NiSource Capital Markets Inc.	
Senior Unsecured (3 issues)	BBB-
NiSource Finance Corp.	
Senior Unsecured (8 issues)	BBB-
Northern Indiana Public Service Co.	
Senior Unsecured (1 issue)	AA-/Watch Dev
Senior Unsecured (3 issues)	BBB-

Complete ratings information is available to RatingsDirect subscribers at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; select your preferred country or region, then Ratings in the left navigation bar, followed by Find a Rating.

STANDARD &POOR'S

RATINGSDIRECT®

March 10, 2009

Summary:

NiSource Inc.

Primary Credit Analyst:
William Ferara, New York (1) 212-438-1776; bill_ferara@standardandpoors.com

Table Of Contents

Summary:
NiSource Inc.

Credit Rating: BBB-/Stable/NR

Rationale

The ratings on NiSource Inc. are based on the consolidated financial and business risk profiles of its various subsidiaries, which include Columbia Energy Group (CEG; not rated), Northern Indiana Public Service Co. (NIPSCO; BBB-/Stable/--), and Bay State Gas Co. (BBB-/Stable/--). Merrillville, Ind.-based NiSource is involved in regulated gas distribution (35% of consolidated cash flow), gas transmission and storage (32%), and vertically integrated electric operations (33%).

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FII Fitch Downgrades NiSource & Subs' IDRs to 'BBB-'; Outlook Stable
Feb 4 2009 15:51:55

FITCH DOWNGRADES NISOURCE & SUBSIDIARIES' IDRS TO 'BBB-'; OUTLOOK STABLE

Fitch Ratings-New York-04 February 2009: Fitch Ratings has downgraded the outstanding ratings for NiSource Inc. (NI) and its subsidiaries as follows:

NI

--Issuer Default Rating (IDR) to 'BBB-' from 'BBB'.

NiSource Capital Markets, Inc. (NI Capital Markets)

--IDR to 'BBB-' from 'BBB';

--Senior unsecured debt to 'BBB-' from 'BBB'.

NiSource Finance Corp. (NI Finance)

--IDR to 'BBB-' from 'BBB';

--Senior unsecured debt to 'BBB-' from 'BBB';

--Short-term IDR to 'F3' from 'F2';

--Commercial paper (CP) to 'F3' from 'F2'

Northern Indiana Public Service Co. (NIPSCO)

--IDR to 'BBB-' from 'BBB';

--Senior unsecured debt to 'BBB' from 'BBB+'.

Jasper County (IN)

Michigan City (IN)

--Senior unsecured pollution control revenue bonds to 'BBB' from 'BBB+'.

Approximately $6.2 billion of outstanding long-term debt is affected. The Rating Outlook for NI and its subsidiaries is Stable.

The rating action reflects Fitch's expectation that NI will experience challenging operating and financial conditions and a potential weakening in credit metrics in 2009. The unfavorable economic and capital market environment could continue for the full year and beyond. At NIPSCO the recessionary U.S. economy will contribute to weakening industrial demand and lower margins. Steel and steel related businesses, NIPSCO's largest industrial customer category, have been particularly hard hit in recent months. Fitch notes that domestic steel production has been declining since August and is currently at less than

50% capacity utilization. Also contributing to weakening financial results are increasing electric operating costs, primarily the result of the mid-2008 purchase of the $330 million Sugar Creek gas-fired electric generation plant. Future earnings will also be affected by increasing pension costs which could be $100 million greater in 2009 than 2008 and higher interest expenses. Based on current conditions Fitch expects NI's consolidated 2009 credit measures to be generally consistent with a 'BBB-' rating.

Planned capital spending at NI's operating subsidiaries, while reduced to $800 million in 2009 from in excess of $1 billion, is expected to be relatively large over the next several years. In addition to companywide maintenance and growth spending, NIPSCO must address its long-term capacity shortfall which could result in the future purchase or construction of new electric generation. At the same time, debt maturities will be significant with nearly $1.4 billion of NI Finance long-term debt maturing by the end of 2010. In addition, NI Finance's seasonal $500 million short-term revolving credit facility matures on March 23, 2009. The once planned monetization of Columbia Gulf through a MLP dropdown is now impractical. Given limited capital market and bank liquidity and depressed equity values, financing costs are expected to be up significantly. NI Finance has recently received written commitments from a syndicate of banks for $265 million of unsecured two-year term debt maturing in April 2011. While the term debt will provide a temporary liquidity cushion, the issuance of additional long-term debt is anticipated in each of the next several years. NI's inability to maintain adequate liquidity and address its refinancing and capital spending needs in a timely fashion would likely result in a negative rating action.

Favorable rating considerations include the low business risk and stable operating performance generated by NI's geographically diverse mix of regulated operations and the positive effect of increased natural gas utility rates in Ohio and Pennsylvania. Virtually 100% of NI's earnings now come from its utility and pipeline subsidiaries. With the sale of the Whiting Clean Energy co-generation facility to BP Alternative Energy North America Inc. in mid-2008, NI completed the divestiture of its higher risk and least profitable businesses. Growth initiatives have modest risk and are complementary to existing core operations. Current pipeline and storage expansion projects have favorable locational and contractual characteristics. Furthermore, working capital is reduced with lower natural gas prices.

Regulatory mechanisms have generally provided timely cost recovery and supported relatively stable operating results. On Dec. 3, 2008, the Public Utilities Commission of Ohio approved Columbia Gas of Ohio's settled rate case. This will result in a $47.1 million annual increase in revenues and was its first base rate increase in fourteen years. On Oct. 23, 2008, the Pennsylvania Public Utility Commission approved Columbia Gas of Pennsylvania's $41.5 million rate case settlement. The new rates in Ohio and Pennsylvania became effective in the fourth quarter of 2008.

On Aug. 29, 2008, NIPSCO filed its first full rate case with the Indiana Utility Regulatory Commission in twenty years. The filing was modified on Dec. 22, 2008. NIPSCO is requesting among other things the inclusion of Sugar Creek in rate base. The base rate increase, if fully approved, would result in an $85.7 million increase in revenues. The rate case also proposes a new tracker to recover any MISO charges currently being deferred, recovery of purchase power energy and capacity costs and a sharing with customers of off-system sales and transmission revenues. The rate case review is expected to take between 12 to 18 months with new rates expected to be effective in late 2009 or early 2010. The inclusion of Sugar Creek in rate base and a reasonable revenue increase would be viewed favorably by Fitch.

Contact: Ralph Pellecchia +1-212-908-0586, New York or Karen Anderson +1-312-368-3165, Chicago.

Media Relations: Cindy Stoller, New York, Tel: +1 212 908 0526, Email: cindy.stoller@fitchratings.com.

Provider ID: 00305518
-0- Feb/04/2009 20:51 GMT

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 033:

Refer to the Moul Testimony, Attachments PRM-7, PRM-8, and PRM-9. Provide a spreadsheet showing the underlying data for each company in the Gas Group used to construct the graphs in each exhibit.

Response:

Please refer to the Microsoft Excel spreadsheets that are attached in Attachment A.

Monthly Dividend Yields for
Combination Group
for the Twelve Months Ending February 2009

Company	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	12-Month Average	6-Month Average	3-Month Average
AGL Resources Inc. (NYSE:AGL)	4.93%	4.99%	4.72%	4.89%	4.91%	5.09%	5.39%	5.59%	5.59%	5.40%	5.65%	6.22%			
Atmos Energy Corp. (NYSE:ATO	5.13%	4.74%	4.75%	4.74%	4.96%	4.73%	4.91%	5.50%	5.30%	5.60%	5.43%	6.05%			
New Jersey Resources Corp. (NY	3.61%	3.53%	3.39%	3.44%	3.30%	3.12%	3.13%	3.35%	3.11%	3.16%	3.11%	3.56%			
Northwest Natural Gas Co. (NYSE	3.47%	3.34%	3.30%	3.26%	3.32%	3.09%	2.90%	3.11%	3.17%	3.59%	3.68%	3.87%			
Piedmont Natural Gas Co. Inc. (N	3.97%	3.97%	3.88%	3.98%	3.90%	3.63%	3.26%	3.17%	3.11%	3.29%	4.19%	4.51%			
South Jersey industries, Inc. (NYS	3.08%	2.97%	2.84%	2.90%	2.91%	3.05%	3.03%	3.51%	3.07%	2.99%	3.21%	3.32%			
WGL Holdings Inc. (NYSE:WGL)	4.32%	4.34%	4.09%	4.13%	4.12%	4.44%	4.42%	4.42%	3.96%	4.39%	4.44%	4.71%			
Average	**4.07%**	**3.98%**	**3.85%**	**3.91%**	**3.92%**	**3.88%**	**3.86%**	**4.09%**	**3.90%**	**4.06%**	**4.24%**	**4.61%**	**4.03%**	**4.13%**	**4.30%**

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: http://finance.yahoo.com/
http://ccbn.aol.com Event Calendar - Split/Dividend data provided by FT Interactive Data

Month-End Closing Prices

	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09
AGL Resources Inc. (NYSE:AGL)	$ 34.320	$ 34.000	$ 35.700	$ 34.580	$ 34.560	$ 33.060	$ 31.380	$ 30.400	$ 30.110	$ 31.350	$ 30.830	$ 27.740
Atmos Energy Corp. (NYSE:ATO)	$ 25.500	$ 27.680	$ 27.390	$ 27.570	$ 26.470	$ 27.540	$ 26.620	$ 24.270	$ 24.930	$ 23.700	$ 24.550	$ 21.830
New Jersey Resources Corp. (NY	$ 31.050	$ 31.850	$ 33.310	$ 32.650	$ 34.090	$ 36.180	$ 35.890	$ 37.240	$ 40.160	$ 39.350	$ 40.090	$ 35.070
Northwest Natural Gas Co. (NYSE	$ 43.440	$ 44.870	$ 45.590	$ 46.260	$ 45.250	$ 48.730	$ 52.000	$ 50.880	$ 49.950	$ 44.230	$ 42.940	$ 40.950
Piedmont Natural Gas Co. Inc. (N	$ 26.260	$ 26.290	$ 27.030	$ 26.160	$ 26.780	$ 28.850	$ 31.960	$ 32.920	$ 33.600	$ 31.670	$ 25.910	$ 24.140
South Jersey Industries, Inc. (NYS	$ 35.110	$ 36.510	$ 38.250	$ 37.360	$ 37.300	$ 35.670	$ 35.700	$ 34.070	$ 39.000	$ 39.850	$ 37.300	$ 36.060
WGL Holdings Inc. (NYSE:WGL)	$ 32.060	$ 32.800	$ 34.890	$ 34.740	$ 34.530	$ 32.200	$ 32.450	$ 32.190	$ 36.100	$ 32.690	$ 32.100	$ 30.360

Quarterly Dividend Payment

	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09
AGL Resources Inc. (NYSE:AGL)	$ 0.420	$ 0.420	$ 0.420	$ 0.420	$ 0.420	$ 0.420	$ 0.420	$ 0.420	$ 0.420	$ 0.420	$ 0.430	$ 0.430
Atmos Energy Corp. (NYSE:ATO)	$ 0.325	$ 0.325	$ 0.325	$ 0.325	$ 0.325	$ 0.325	$ 0.325	$ 0.330	$ 0.330	$ 0.330	$ 0.330	$ 0.330
New Jersey Resources Corp. (NY	$ 0.280	$ 0.280	$ 0.280	$ 0.280	$ 0.280	$ 0.280	$ 0.280	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310
Northwest Natural Gas Co. (NYSE	$ 0.375	$ 0.375	$ 0.375	$ 0.375	$ 0.375	$ 0.375	$ 0.375	$ 0.395	$ 0.395	$ 0.395	$ 0.395	$ 0.395
Piedmont Natural Gas Co. Inc. (N	$ 0.260	$ 0.260	$ 0.260	$ 0.260	$ 0.260	$ 0.260	$ 0.260	$ 0.260	$ 0.260	$ 0.260	$ 0.270	$ 0.270
South Jersey Industries, Inc. (NYS	$ 0.270	$ 0.270	$ 0.270	$ 0.270	$ 0.270	$ 0.270	$ 0.270	$ 0.298	$ 0.298	$ 0.298	$ 0.298	$ 0.298
WGL Holdings Inc. (NYSE:WGL)	$ 0.343	$ 0.355	$ 0.355	$ 0.355	$ 0.355	$ 0.355	$ 0.355	$ 0.355	$ 0.355	$ 0.355	$ 0.355	$ 0.355

Ex-Dividend Dates

	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09
AGL Resources Inc. (NYSE:AGL)	13-Feb-08	13-Feb-08	14-May-08	14-May-08	14-May-08	13-Aug-08	13-Aug-08	13-Aug-08	12-Nov-08	12-Nov-08	12-Nov-08	11-Feb-09
Atmos Energy Corp. (NYSE:ATO)	21-Feb-08	21-Feb-08	22-May-08	22-May-08	22-May-08	21-Aug-08	21-Aug-08	21-Aug-08	21-Nov-08	21-Nov-08	21-Nov-08	23-Feb-09
New Jersey Resources Corp. (NY	12-Mar-08	12-Mar-08	12-Mar-08	11-Jun-08	11-Jun-08	11-Jun-08	11-Sep-08	11-Sep-08	11-Sep-08	11-Dec-08	11-Dec-08	11-Dec-08
Northwest Natural Gas Co. (NYSE	29-Jan-08	28-Apr-08	28-Apr-08	28-Apr-08	29-Jul-08	29-Jul-08	29-Jul-08	29-Oct-08	29-Oct-08	29-Oct-08	28-Jan-09	28-Jan-09
Piedmont Natural Gas Co. Inc. (N	20-Mar-08	20-Mar-08	20-Mar-08	23-Jun-08	23-Jun-08	23-Jun-08	23-Sep-08	23-Sep-08	23-Sep-08	23-Dec-08	23-Dec-08	23-Dec-08
South Jersey Industries, Inc. (NYS	06-Mar-08	06-Mar-08	06-Mar-08	06-Jun-08	06-Jun-08	06-Jun-08	08-Sep-08	08-Sep-08	08-Sep-08	08-Dec-08	08-Dec-08	08-Dec-08
WGL Holdings Inc. (NYSE:WGL)	08-Jan-08	08-Apr-08	08-Apr-08	08-Apr-08	08-Jul-08	08-Jul-08	08-Jul-08	08-Oct-08	08-Oct-08	08-Oct-08	07-Jan-09	07-Jan-09

Days from Ex-Dividend Date

	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09
AGL Resources Inc. (NYSE:AGL)	47	77	17	47	78	18	48	79	18	49	80	17
Atmos Energy Corp. (NYSE:ATO)	39	69	9	39	70	10	40	71	9	40	71	5
New Jersey Resources Corp. (NY	19	49	80	19	50	81	19	50	80	20	51	79
Northwest Natural Gas Co. (NYSE	62	2	33	63	2	33	63	2	32	63	3	31
Piedmont Natural Gas Co. Inc. (N'	11	41	72	7	38	69	7	38	68	8	39	67
South Jersey Industries, Inc. (NYS	25	55	86	24	55	86	22	53	83	23	54	82
WGL Holdings Inc. (NYSE:WGL)	83	22	53	83	23	54	84	23	53	84	24	52

Adjusted Prices

	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09
AGL Resources Inc. (NYSE:AGL)	$34.103	$33.645	$35.622	$34.363	$34.200	$32.977	$31.158	$30.035	$30.027	$31.124	$30.452	$27.660
Atmos Energy Corp. (NYSE:ATO)	$25.361	$27.434	$27.358	$27.431	$26.220	$27.504	$26.477	$24.013	$24.897	$23.555	$24.293	$21.812
New Jersey Resources Corp. (NY	$30.992	$31.699	$33.064	$32.592	$33.936	$35.931	$35.832	$37.070	$39.887	$39.282	$39.916	$34.801
Northwest Natural Gas Co. (NYSE	$43.185	$44.862	$45.454	$46.000	$45.242	$48.594	$51.740	$50.871	$49.811	$43.957	$42.927	$40.815
Piedmont Natural Gas Co. Inc. (N	$26.229	$26.173	$26.824	$26.140	$26.671	$28.653	$31.940	$32.811	$33.406	$31.647	$25.794	$23.941
South Jersey Industries, Inc. (NYS	$35.036	$36.347	$37.995	$37.289	$37.137	$35.415	$35.635	$33.897	$38.729	$39.775	$37.123	$35.792
WGL Holdings Inc. (NYSE:WGL)	$31.748	$32.714	$34.683	$34.416	$34.440	$31.989	$32.122	$32.100	$35.893	$32.362	$32.006	$30.157

PSC Case No. 2009-00141
Staff Set 2 DR No. 034
Respondent(s): Paul R. Moul

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 034:

Refer to the Moul Testimony at pages 20-22, Attachments PRM-5 and PRM-6, and Schedules J-1 .I and J-2 in Volume 6 of 8 of Columbia's application.

a. The testimony indicates that Mr. Moul developed a hypothetical capital structure of 45 percent long-term debt and 55 percent common equity using averages for the Gas Group, excluding short-term debt. He acknowledges that short term debt for gas utilities fluctuates greatly over the course of their fiscal years and states that short-term debt for gas utility is usually stated on an average basis. Explain why Mr. Moul concluded that a short-term debt average should not be part of his hypothetical structure.

b. The testimony states that in his analysis, to develop capital structure ratios, Mr. Moul began with Columbia's rate base. Attachment PRM-5 appears to show that Mr. Moul began with Columbia's capitalization and adjusted it to equal the proposed rate base. Provide clarification of whether this is an accurate characterization.

c. Columbia's proposed rate base is greater than its capitalization. Explain whether this indicates that a portion of the rate base has been supported with funds other than those supplied by investors.

d. Schedules J-1.1 and J-2 reflect a cost rate for short-term debt of 3.24 percent based on the average rate of the NiSource Money Pool in the last three months of the test year. Provide the calculation of the average rate for the money pool using the last three months of the test year and the months of 2009 for which information is currently available.

Response:

a. The hypothetical capital structure ratios were established based upon the permanent capital of the Company vis-à-vis the proxy group (i.e., the Gas Group). Such ratios can be determined with a higher degree of reliability than short-term debt, which is cyclical/seasonal in nature. Moreover, the average amount of short-term debt is more company-specific due to the unique nature of its operations. It was for this reason that the actual average amount of short-term debt was used for the Company, and the hypothetical permanent capital structure ratios were layered over it.
b. That is correct.
c. Mr. Moul has not investigated that possibility.
d. Please see the excel file attached in Attachment A. Formulas have been left intact.

Staff DR Set 2-034 Attachment A

NISOURCE INC. AND SUBSIDIARIES
OPERATING COMPANIES MONEY POOL RATES
FOR 2008 AND YEAR TO DATE 2009

		AVERAGE DAILY BALANCES			MONTHLY INTEREST ACCRUALS			MONTHLY RATES *		
MONTH	DAYS	S-T DEBT $	INVESTMENT $	COMPOSITE $	S-T DEBT $	INVESTMENT $	COMPOSITE $	S-T DEBT %	INVEST %	COMPOSITE %
OCT	31	1,264,235,483.87	6,971,133.99	1,271,206,617.86	4,381,924.36	13,683.45	4,395,607.81	4.08%	2.31%	4.07%
NOV	30	1,424,990,000.00	3,780,167.06	1,428,770,167.06	4,337,034.98	8,934.05	4,345,969.03	3.70%	2.88%	3.70%
DEC	31	1,303,554,838.71	14,318,252.10	1,317,873,090.81	2,133,015.40	31,143.40	2,164,158.80	1.93%	2.56%	1.93%
JAN	31	1,071,161,290.32	86,367,654.34	1,157,528,944.66	946,354.76	119,186.38	1,065,541.14	1.04%	1.62%	1.08%
FEB	28	844,417,857.14	53,256,313.32	897,674,170.46	669,630.64	53,437.25	723,067.89	1.03%	1.31%	1.05%
MAR	31	220,272,580.65	43,382,308.82	263,654,889.47	308,926.29	26,189.66	335,115.95	1.65%	0.71%	1.50%
APR	30	-	70,296,814.31	70,296,814.31	-	23,606.17	23,606.17	0.00%	0.41%	0.41%
MAY	31	-	442,681,918.73	442,681,918.73	-	141,940.03	141,940.03	0.00%	0.38%	0.38%

* Assumes 365 day yield no matter if actual days are 366.

PSC Case No. 2009-00141
Staff Set 2 DR No. 035
Respondent(s): Paul R. Moul

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 035:

Refer to the Moul Testimony at page 44, and page 2 of Attachment PRM-12. Provide an explanation of why using either the various range median values or the average of the geometric mean and median values to obtain a midpoint estimate provides a meaningful calculation of risk differentials.

Response:

The procedure employed provides a comprehensive process to analyze the data to take into account widely recognized measures of central tendency. The mode of the data series was ignored because it is an unusual measure of central tendency.

PSC Case No. 2009-00141
Staff Set 2 DR No. 036
Respondent(s): Paul R. Moul

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 036:

Refer to the Moul Testimony at page 48. Provide copies of industry literature commonly available to investors, such as Ibbotsons, which prescribes how and why Betas need to be unleveraged and then re-leveraged for use in Capital Asset Pricing Model analyses.

Response:

Please refer to the article that is attached in Attachment A.

The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stocks

Robert S. Hamada

The Journal of Finance, Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May, 1972), pp. 435-452.

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THE EFFECT OF THE FIRM'S CAPITAL STRUCTURE ON THE SYSTEMATIC RISK OF COMMON STOCKS

ROBERT S. HAMADA*

I. INTRODUCTION

ONLY RECENTLY has there been an interest in relating the issues historically associated with corporation finance to those historically associated with investment and portfolio analyses. In fact, rigorous theoretical attempts in this direction were made only since the capital asset pricing model of Sharpe [13], Lintner [6], and Mossin [11], itself an extension of the Markowitz [7] portfolio theory. This study is one of the first empirical works consciously attempting to show and test the relationships between the two fields. In addition, differences in the observed systematic or nondiversifiable risk of common stocks, β, have never really been analyzed before by investigating some of the underlying differences in the firms.

In the capital asset pricing model, it was demonstrated that the efficient set of portfolios to any individual investor will always be some combination of lending at the risk-free rate and the "market portfolio," or borrowing at the risk-free rate and the "market portfolio." At the same time, the Modigliani and Miller (MM) propositions [9, 10] on the effect of corporate leverage are well known to the students of corporation finance. In order for their propositions to hold, personal leverage is required to be a perfect substitute for corporate leverage. If this is true, then corporate borrowing could substitute for personal borrowing in the capital asset pricing model as well.

Both in the pricing model and the MM theory, borrowing, from whatever source, while maintaining a fixed amount of equity, increases the risk to the investor. Therefore, in the mean-standard deviation version of the capital asset pricing model, the covariance of the asset's rate of return with the market portfolio's rate of return (which measures the nondiversifiable risk of the asset—the proxy β will be used to measure this) should be greater for the stock of a firm with a higher debt-equity ratio than for the stock of another firm in the same risk-class with a lower debt-equity ratio.[1]

This study, then, has a number of purposes. First, we shall attempt to link empirically corporation finance issues with portfolio and security analyses through the effect of a firm's leverage on the systematic risk of its common

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1. This very quick summary of the theoretical relationship between what is known as corporation finance and the modern investment and portfolio analyses centered around the capital asset pricing model is more thoroughly presented in [5], along with the necessary assumptions required for this relationship.

stock. Then, we shall attempt to test the MM theory, or at least provide another piece of evidence on this long-standing controversial issue. This test will not rely on an explicit valuation model, such as the MM study of the electric utility industry [8] and the Brown study of the railroad industry [2]. A procedure using systematic risk measures (β s) has been worked out in this paper for this purpose.

If the MM theory is validated by this procedure, then the final purpose of this study is to demonstrate a method for estimating the cost of capital of individual firms to be used by them for scale-changing or nondiversifying investment projects. The primary component of any firm's cost of capital is the capitalization rate for the firm if the firm had no debt and preferred stock in its capital structure. Since most firms do have fixed commitment obligations, this capitalization rate (we shall call it $E(R_A)$; MM denote it ρ^τ) is unobservable. But if the MM theory and the capital asset pricing model are correct, then it is possible to estimate $E(R_A)$ from the systematic risk approach for individual firms, even if these firms are members of a one-firm risk-class.[2]

With this statement of the purposes for this study, we shall, in Section II, discuss the alternative general procedures that are possible for estimating the effect of leverage on systematic risk and select the most feasible ones. The results are presented in Section III. And finally, tests of the MM versus the traditional theories of corporation finance are presented in Section IV.

II. Some Possible Procedures and the Selected Estimating Relationships

There are at least four general procedures that can be used to estimate the effect of the firm's capital structure on the systematic risk of common stocks. The first is the MM valuation model approach. By estimating ρ^τ with an explicit valuation model as they have for the electric utility industry, it is possible to relate this ρ^τ with the use of the capital asset pricing model to a nonleveraged systematic risk measure, ${}_A\beta$. Then the difference between the observed common stock's systematic risk (which we shall denote ${}_B\beta$) and ${}_A\beta$ would be due solely to leverage. But the difficulties of this approach for all firms are many.

The MM valuation model approach requires the specification, in advance, of risk-classes. All firms in a risk-class are then assumed to have the same ρ^τ—the capitalization rate for an all-common equity firm. Unfortunately, there must be enough firms in a risk-class so that a cross-section analysis will yield statistically significant coefficients. There may not be many more risk-classes (with enough observations) now that the electric utility and railroad industries have been studied. In addition, the MM approach requires estimating expected asset earnings and estimating the capitalized growth potential implicit in stock prices. If it is possible to consider growth and expected earnings without having

2. It is, in fact, this last purpose of making applicable and practical some of the implications of the capital asset pricing model for corporation finance issues that provided the initial motivation for this paper. In this context, if one is familiar with the fair rate of return literature for regulated utilities, for example, an industry where debt is so prevalent, adjusting correctly for leverage is not frequently done and can be very critical.

to specify their exact magnitude at a specific point in time, considerable difficulty and possible measurement errors will be avoided.

The second approach is to run a regression between the observed systematic risk of a stock and a number of accounting and leverage variables in an attempt to explain this observed systematic risk. Unfortunately, without a theory, we do not know which variables to include and which variables to exclude and whether the relationship is linear, multiplicative, exponential, curvilinear, etc. Therefore, this method will also not be used.

A third approach is to measure the systematic risk before and after a new debt issue. The difference can then be attributed to the debt issue directly. An attractive feature of this procedure is that a good estimate of the market value of the incremental debt issue can be obtained. A number of disadvantages, unfortunately, are associated with this direct approach. The difference in the [illegible] reason the debt was issued. It may be used to finance a new investment project, in which case the project's characteristics will also be reflected in the new systematic risk measure. In addition, the new debt issue may have been anticipated by the market if the firm had some long-run target leverage ratio which this issue will help maintain; conversely, the market may not fully consider the new debt issue if it believes the increase in leverage is only temporary. For these reasons, this seemingly attractive procedure will not be employed.

The last approach, which will be used in this study, is to assume the validity of the MM theory from the outset. Then the observed rate of return of a stock can be adjusted to what *it would have been* over the same time period had the firm no debt and preferred stock in its capital structure. The difference between the observed systematic risk, ${}_B\beta$, and the systematic risk for this adjusted rate of return time series, ${}_A\beta$, can be attributed to leverage, if the MM theory is correct. The final step, then, is to test the MM theory.

To discuss this more specifically, consider the following relationship for the dollar return to the common shareholder from period $t-1$ to t:

$$(X - I)_t(1 - \tau)_t - p_t + \Delta G_t = d_t + cg_t \tag{1}$$

where X_t represents earnings before taxes, interest, and preferred dividends and is assumed to be unaffected by fixed commitment obligations; I_t represents interest and other fixed charges paid during the period; τ is the corporation income tax rate; p_t is the preferred dividends paid; ΔG_t represents the change in capitalized growth over the period; and d_t and cg_t are common shareholder dividends and capital gains during the period, respectively.

Equation (1) relates the corporation finance types of variables with the market holding period return important to the investors. The first term on the left-hand-side of (1) is profits after taxes and after interest which is the earnings the common and preferred shareholders receive on their investment for the period. Subtracting out p_t leaves us with the earnings the common shareholder would receive from currently-held assets.

To this must be added any change in capitalized growth since we are trying to explain the common shareholder's market holding period dollar return. ΔG_t

must be added for growth firms to the current period's profits from existing assets since capitalized growth opportunities of the firm—future earnings from new assets over and above the firm's cost of capital which are already reflected in the stock price at $(t-1)$—should change over the period and would accrue to the common shareholder. Assuming shareholders at the start of the period estimated these growth opportunities on average correctly, the expected value of ΔG_t would not be zero, but should be positive. For example, consider growth opportunities five years from now which yield more than the going rate of return and are reflected in today's stock price. These growth opportunities will become one year closer to fruition at time t than at time $t-1$ so that their present value would become larger. ΔG_t then represents this increase in the present value of these future opportunities simply because it is now four years away rather than five.[3]

Since the systematic risk of a common stock is:

$$_B\beta = \frac{\text{cov}\,(R_{B_t}, R_{M_t})}{\sigma^2(R_{M_t})} \tag{2}$$

where R_{B_t} is the common shareholder's rate of return and R_{M_t} is the rate of return on the market portfolio, then substitution of (1) into (2) yields:

$$_B\beta = \frac{\text{cov}\left[\dfrac{(X-I)(1-\tau)_t - p_t + \Delta G_t}{S_{B_{t-1}}}, R_{M_t}\right]}{\sigma^2(R_{M_t})} \tag{2a}$$

where $S_{B_{t-1}}$ denotes the market value of the common stock at the beginning of the period.

The systematic risk for the same firm over the same period *if* there were no debt and preferred stock in its capital structure is:

$$_A\beta = \frac{\text{cov}(R_{A_t}, R_{M_t})}{\sigma^2(R_{M_t})}$$

$$= \frac{\text{cov}\left[\dfrac{X(1-\tau)_t + \Delta G_t}{S_{A_{t-1}}}, R_{M_t}\right]}{\sigma^2(R_{M_t})} \tag{3}$$

where R_{A_t} and $S_{A_{t-1}}$ represent the rate of return and the market value, respectively, to the common shareholder if the firm had no debt and preferred stock. From (3), we can obtain:

$$_A\beta S_{A_{t-1}} = \frac{\text{cov}\,[X(1-\tau)_t + \Delta G_t, R_{M_t}]}{\sigma^2(R_{M_t})} \tag{3a}$$

3. Continual awareness of the difficulties of estimating capitalized growth, or changes in growth, especially in conjunction with leverage considerations, for purposes such as valuation or cost of capital is a characteristic common to students of corporation finance. This is the reason for the emphasis on growth in this paper and for presenting a method to neutralize for differences in growth when comparing rates of return.

Next, by expanding and rearranging (2a), we have:

$$_{B}\beta S_{B_{t-1}} = \frac{\text{cov}\,[X(1-\tau)_t + \Delta G_t, R_{M_t}]}{\sigma^2(R_{M_t})} - \frac{\text{cov}\,[I(1-\tau)_t, R_{M_t}]}{\sigma^2(R_{M_t})} - \frac{\text{cov}\,(p_t, R_{M_t})}{\sigma^2(R_{M_t})} \tag{2b}$$

If we assume as an empirical approximation that interest and preferred dividends have negligible covariance with the market, at least relative to the (pure equity) common stock's covariance, then substitution of the LHS of (3a) into the RHS of (2b) yields:[4]

$$_{B}\beta S_{B_{t-1}} = {}_{A}\beta S_{A_{t-1}} \tag{4}$$

or

$$_{A}\beta = \left(\frac{S_B}{S_A}\right)_{t-1} {}_{B}\beta \tag{4a}$$

Because $S_{A_{t-1}}$, the market value of common stock *if* the firm had no debt and preferred stock, is not observable since most firms do have debt and/or preferred stock, a theory is required in order to measure what this quantity *would have been* at $t-1$. The MM theory [10] will be employed for this purpose, that is:

$$S_{A_{t-1}} = (V - \tau D)_{t-1}. \tag{5}$$

Equation (5) indicates that if the Federal government tax subsidy for debt financing, τD, where D is the market value of debt, is subtracted from the observed market value of the firm, V_{t-1} (where V_{t-1} is the sum of S_B, D and the observed market value of preferred), then the market value of an unleveraged firm is obtained. Underlying (5) is the assumption that the firm is near its target leverage ratio so that no more or no less debt subsidy is capitalized already into the observed stock price. The conditions under which this MM relationship hold are discussed carefully in [4].

It is at this point that problems in obtaining satisfactory estimates of $_{A}\beta$ develop, since (4) theoretically holds only for the next period. As a practical matter, the accepted, and seemingly acceptable, method of obtaining estimates of a stock's systematic risk, $_{B}\beta$, is to run a least squares regression between a stock's and market portfolio's *historical* rates of return. Using past data for $_{B}\beta$, it is not clear which *period's* ratio of market values to apply in (4a) to estimate the firm's systematic risk, $_{A}\beta$. There would be no problem if the market value ratios of debt to equity and preferred stock to equity remained relatively stable over the past for each firm, but a cursory look at these data reveals that this is not true for the large majority of firms in our sample. Should we use the market value ratio required in (4a) that was observed at the start of our regression period, at the end of our regression period, or some kind of average over the period? In addition, since these different observed ratios will give us different estimates for $_{A}\beta$, it is not clear, without some criterion, how we should select from among the various estimates.

4. This general method of arriving at (4) was suggested by the comments of William Sharpe, one of the discussants of this paper at the annual meeting. A much more cumbersome and less general derivation of (4) was in the earlier version.

It is for this purpose—to obtain a standard—that a more cumbersome and more data demanding approach to obtain estimates of ${}_A\beta$ is suggested. Given the large fluctuations in market leverage ratios, intuitively it would appear that the firm's risk is more stable than the common stock's risk. In that event, a leverage-free rate of return time series for each firm should be derived and the market model applied to this time series directly. In this manner, the beta coefficient would give us a *direct* estimate of ${}_A\beta$ which can then be used as a criterion to determine if any of the market value ratios discussed above can be applied to (4a) successfully.

For this purpose, the "would-have-been" rate of return for the common stock if the firm had no debt and preferred is:

$$R_{A_t} = \frac{X_t(1-\tau)_t + \Delta G_t}{S_{A_{t-1}}}. \tag{6}$$

The numerator of (6) can be rearranged to be:

$$X_t(1-\tau)_t + \Delta G_t \equiv [(X-I)_t(1-\tau)_t - p_t + \Delta G_t] + p_t + I_t(1-\tau)_t.$$

Substituting (1):

$$X_t(1-\tau)_t + \Delta G_t = [d_t + cg_t] + p_t + I_t(1-\tau)_t.$$

Therefore, (6) can be written as:

$$R_{A_t} = \frac{d_t + cg_t + p_t + I_t(1-\tau)_t}{S_{A_{t-1}}}. \tag{7}$$

Since $S_{A_{t-1}}$ is unobservable for the firms with leverage, the MM theory, equation (5), will be employed; then:

$$R_{A_t} = \frac{d_t + cg_t + p_t + I_t(1-\tau)_t}{(V-\tau D)_{t-1}}. \tag{8}$$

The observed rate of return on the common stock is, of course:

$$R_{B_t} = \frac{(X-I)_t(1-\tau)_t - p_t + \Delta G_t}{S_{B_{t-1}}} = \frac{d_t + cg_t}{S_{B_{t-1}}}. \tag{9}$$

Equation (8) is the rate of return to the common shareholder of the same firm and over the same period of time as (9). However, in (8) there are the underlying assumptions that the firm never had any debt and preferred stock and that the MM theory is correct; (9) incorporates the exact amount of debt and preferred stock that the firm actually did have over this time period and no leverage assumption is being made. Both (8) and (9) are now in forms where they can be measured with available data. One can note that it is unnecessary to estimate the change in growth, or earnings from current assets, since these should be captured in the market holding period return, $d_t + cg_t$.

Using CRSP data for (9) and both CRSP and Compustat data for the components of (8), a time series of yearly R_{A_t} and R_{B_t} for $t = 1948\text{-}1967$ were derived for 304 different firms. These 304 firms represent an exhaustive sample of the firms with complete data on both tapes for all the years.

A number of "market model" [1, 12] variants were then applied to these data. For each of the 304 firms, the following regressions were run:

$$R_{Ait} = {}_{A}\alpha_i + {}_{A}\beta_i R_{Mt} + {}_{A}\epsilon_{it} \qquad (10a)$$

$$R_{Bit} = {}_{B}\alpha_i + {}_{B}\beta_i R_{Mt} + {}_{B}\epsilon_{it} \qquad (10b)$$

$$\ln(1 + R_{Ait}) = {}_{AC}\alpha_i + {}_{AC}\beta_i \ln(1 + R_{M_t}) + {}_{AC}\epsilon_{it} \qquad (10c)$$

$$\ln(1 + R_{Bit}) = {}_{BC}\alpha_i + {}_{BC}\beta_i \ln(1 + R_{M_t}) + {}_{BC}\epsilon_{it} \qquad (10d)$$

$$i = 1, 2, \ldots, 304$$
$$t = 1948\text{-}1967$$

where R_{Mt} is the observed NYSE arithmetic stock market rate of return with dividends reinvested, α_i and β_i are constants for each firm-regression, and the usual conditions are assumed for the properties of the disturbance terms, ϵ_{it}. Equations (10c) and (10d) are the continuously-compounded rate of return versions of (10a) and (10b), respectively.[5]

III. The Results

An abbreviated table of the regression results for each of the four variants, equations (10a)-(10d), summarized across the 304 firms is shown in Table 1.

The first column designated "mean" is the average of the statistic (indicated by the rows) over all 304 firms. Therefore, the mean ${}_{A}\hat{\alpha}$ of 0.0221 is the intercept term of equation (10a) averaged over 304 different firm-regressions. The second and third columns give the deviation measures indicated, of the 304 point estimates of, say, ${}_{A}\hat{\alpha}$. The mean standard error of estimate in the last column is the average over 304 firms of the individual standard errors of estimate.

The major conclusion drawn from Table 1 is the following mean β comparisons:

$${}_{B}\hat{\beta} > {}_{A}\hat{\beta}, \text{ i.e., } 0.9190 > 0.7030$$
$${}_{BC}\hat{\beta} > {}_{AC}\hat{\beta}, \text{ i.e., } 0.9183 > 0.7263.$$

The directional results of these betas, assuming the validity of the MM theory, are not imperceptible and clearly are not negligible differences from the investor's point of view. This is obtained in spite of all the measurement and data problems associated with estimating a time series of the RHS of (8) for

5. Because the R_{M_t} used in equations (10) is defined as the observed stock market return, and since adjusting for capital structure is the major purpose of this exercise, it was decided that the same four regressions should be replicated on a leverage-adjusted stock market rate of return. The major reason for this additional adjustment is the belief that the rates of return over time and their relationship with the market are more stable when we can abstract from all changes in leverage and get at the underlying risk of all firms.

For the 221 firms (out of the total 304) whose fiscal years coincide with the calendar year, average values for the components of the RHS of (8) were obtained for each year so that R_{M_t} could be adjusted in the same way as for the individual firms—a yearly time series of stock market rates of return, if all the firms on the NYSE had no debt and no preferred in their capital structure, was derived. The results, when using this adjusted market portfolio rate of return time series, were not very different from the results of equations (10), and so will not be reported here separately.

TABLE 1
SUMMARY RESULTS OVER 304 FIRMS OF EQUATIONS (10a)-(10d)

	Mean	Mean Absolute Deviation*	Standard Deviation	Mean Standard Error of Estimate
${}_A\hat{\alpha}$	0.0221	0.0431	0.0537	0.0558
${}_A\hat{\beta}$	0.7030	0.2660	0.3485	0.2130
${}_A\hat{R}^2$	0.3799	0.1577	0.1896	
${}_A\hat{\rho}$	0.0314			
${}_B\hat{\alpha}$	0.0187	0.0571	0.0714	0.0720
${}_B\hat{\beta}$	0.9190	0.3550	0.4478	0.2746
${}_B\hat{R}^2$	0.3864	0.1578	0.1905	
${}_B\hat{\rho}$	0.0281			
${}_{AO}\hat{\alpha}$	0.0058	0.0427	0.0535	0.0461
${}_{AO}\hat{\beta}$	0.7263	0.2700	0.3442	0.2081
${}_{AO}\hat{R}^2$	0.3933	0.1586	0.1909	
${}_{AO}\hat{\rho}$	0.0268			
${}_{BO}\hat{\alpha}$	−0.0052	0.0580	0.0729	0.0574
${}_{BO}\hat{\beta}$	0.9183	0.3426	0.4216	0.2591
${}_{BO}\hat{R}^2$	0.4012	0.1602	0.1922	
${}_{BO}\hat{\rho}$	0.0262			

* Defined as: $\dfrac{\sum_{i=1}^{N} |x_i - \bar{x}|}{N}$, where $N = 304$. $\hat{\rho}$ = first order serial correlation coefficient.

each firm. One of the reasons for the "traditional" theory position on leverage is precisely this point—that small and reasonable amounts of leverage cannot be discerned by the market. In fact, if the MM theory is correct, leverage has explained as much as, roughly, 21 to 24 per cent of the value of the mean β.

We can also note that if the covariance between the asset and market rates of return, as well as the market variance, was constant over time, then the systematic risk from the market model is related to the expected rate of return by the capital asset pricing model. That is:

$$E(R_{A_t}) = R_{F_t} + {}_A\beta[E(R_{M_t}) - R_{F_t}] \tag{11a}$$

$$E(R_{B_t}) = R_{F_t} + {}_B\beta[E(R_{M_t}) - R_{F_t}] \tag{11b}$$

Equation (11a) indicates the relationship between the expected rate of return for the common stock shareholder of a debt-free and preferred-free firm, to the systematic risk, ${}_A\beta$, as obtained in regressions (10a) or (10c). The LHS of (11a) is the important $\rho\tau$ for the MM cost of capital. The MM theory [9, 10] also predicts that shareholder expected yield must be higher (for the same real firm) when the firm has debt than when it does not. Financial risk is greater, therefore, shareholders require more expected return. Thus, $E(R_{B_t})$ must be greater than $E(R_{A_t})$. In order for this MM prediction to be true, from (11a) and (11b) it can be observed that ${}_B\beta$ must be greater than ${}_A\beta$, which is what we obtained.

Using the results underlying Table 1, namely the firm and stock betas, as the criterion for selecting among the possible observed market value ratios that can be used, if any, for (4), the following cross-section regressions were run:

$$({}_{B}\beta)_{i} = a_{1} + b_{1}\left(\frac{S_{A}}{S_{B}}\,{}_{A}\beta\right)_{i} + u_{1i} \qquad i = 1, 2, \ldots, 102 \tag{12a}$$

$$({}_{BO}\beta)_{i} = a_{2} + b_{2}\left(\frac{S_{A}}{S_{B}}\,{}_{AO}\beta\right)_{i} + u_{2i} \qquad i = 1, 2, \ldots, 102 \tag{12b}$$

$$({}_{A}\beta)_{i} = a_{3} + b_{3}\left(\frac{S_{B}}{S_{A}}\,{}_{B}\beta\right)_{i} + u_{3i} \qquad i = 1, 2, \ldots, 102 \tag{13a}$$

$$({}_{AO}\beta)_{i} = a_{4} + b_{4}\left(\frac{S_{B}}{S_{A}}\,{}_{BO}\beta\right)_{i} + u_{4i} \qquad i = 1, 2, \ldots, 102 \tag{13b}$$

Because the preferred stock market values were not as reliable as debt, only the 102 firms (out of 304) that did not have preferred in any of the years were used. The test for the adequacy of this alternative approach, equation (4), to adjust the systematic risk of common stocks for the underlying firm's capital structure, is whether the intercept term, a, is equal to zero, and the slope coefficient, b, is equal to one in the above regressions (as well as, of course, a high R^2)—these requirements are implied by (4). The results of this test would also indicate whether future "market model" studies that only use common stock rates of return without adjusting, or even noting, for the firm's debt-equity ratio will be adequate. The total firm's systematic risk may be stable (as long as the firm stays in the same risk-class), whereas the common stock's systematic risk may not be stable merely because of unanticipated capital structure changes—the data underlying Table 3 indicate that there were very few firms which did not have major changes in their capital structure over the twenty years studied.

The results of these regressions, when using the average S_A and average S_B over the twenty years for each firm, are shown in the first column panel of Table 2. These regressions were then replicated twice, first using the December 31, 1947 values of S_{A_i} and S_{B_i} instead of the twenty-year average for each firm, and then substituting the December 31, 1966 values of S_{A_i} and S_{B_i} for the 1947 values. These results are in the second and third panels of Table 2.[6]

From the first panel of Table 2, it appears that this alternative approach via (4a) for adjusting the systematic risk for the firm's leverage is quite

6. The point should be made that we are not merely regressing a variable on itself in (12) and (13). (12a) and (12b) can be interpreted as correlating the ${}_{B}\beta_{i}$ obtained from (10b) and (10d)—the LHS variable in (12a) and (12b)—against the ${}_{B}\beta_{i}$ obtained from rearranging (4)—the RHS variable in (12a) and (12b)—to determine whether the use of (4) is as good a means of obtaining ${}_{B}\beta_{i}$ as the direct way via the equations (10). We would be regressing a variable on itself only if the ${}_{A}\beta_{i}$ were calculated using (4a), and then the ${}_{A}\beta_{i}$ thus obtained, inserted into (12a) and (12b).

Instead, we are obtaining ${}_{A}\beta_{i}$ using the MM model in *each* of the twenty years so that a leverage-adjusted 20 year time series of R_{A_i} is derived. Of course, if there were no data nor measurement problems, and if the debt-to-equity ratio were perfectly stable over this twenty year period for each firm, then we should obtain perfect correlation in (12a) and (12b), with $a = 0$ and $b = 1$, as (4) would be an identity.

TABLE 2

RESULTS FOR THE EQUATIONS (12a), (12b), (13a), AND (13b)*

	Using 20-Year Average for $\left(\frac{S_A}{S_B}\right)_i$			Using 1947 Value for $\left(\frac{S_A}{S_B}\right)_i$			Using 1966 Value for $\left(\frac{S_A}{S_B}\right)_i$		
	a	b	R^2	a	b	R^2	a	b	R^2
Eq. (12a)	−0.022 (0.021)	1.062 (0.021)	0.962	0.150 (0.048)	0.842 (0.045)	0.781	0.085 (0.041)	0.905 (0.038)	0.849
	constant suppressed	1.042 (0.009)	0.962	constant suppressed	0.966 (0.021)	0.781	constant suppressed	0.976 (0.017)	0.849
Eq. (12b)	−0.003 (0.013)	1.016 (0.013)	0.984	0.159 (0.047)	0.816 (0.044)	0.773	0.124 (0.037)	0.843 (0.034)	0.859
	constant suppressed	1.014 (0.005)	0.984	constant suppressed	0.952 (0.019)	0.773	constant suppressed	0.947 (0.015)	0.859

	Using 20-Year Average for $\left(\frac{S_B}{S_A}\right)_i$			Using 1947 Value for $\left(\frac{S_B}{S_A}\right)_i$			Using 1966 Value for $\left(\frac{S_B}{S_A}\right)_i$		
	a	b	R^2	a	b	R^2	a	b	R^2
Eq. (13a)	0.030 (0.016)	0.931 (0.017)	0.969	0.112 (0.028)	0.843 (0.030)	0.888	0.080 (0.027)	0.898 (0.030)	0.902
	constant suppressed	0.960 (0.007)	0.969	constant suppressed	0.948 (0.015)	0.888	constant suppressed	0.976 (0.014)	0.902
Eq. (13b)	0.007 (0.010)	0.979 (0.011)	0.988	0.119 (0.026)	0.852 (0.028)	0.902	0.063 (0.026)	0.942 (0.029)	0.911
	constant suppressed	1.004 (0.012)	0.911	constant suppressed	0.967 (0.013)	0.902	constant suppressed	1.005 (0.012)	0.911

* Standard error in parentheses.

satisfactory (at least with respect to our sample of firms and years) only if long-run averages of S_A and S_B are used. The second and third panels indicate that the equations (8) and (10) procedure is markedly superior when only one year's market value ratio is used as the adjustment factor. The annual debt-to-equity ratio is much too unstable for this latter procedure.

Thus, when forecasting systematic risk is the primary objective—for example, for portfolio decisions or for estimating the firm's cost of capital to apply to prospective projects—a long-run forecasted leverage adjustment is required. Assuming the firm's risk is more stable than the common stock's risk,[7] and if there is some reason to believe that a better forecast of the firm's future leverage can be obtained than using simply a past year's (or an average of past years') leverage, it should be possible to improve the usual extrapolation forecast of a stock's systematic risk by forecasting the total firm's systematic risk first, and then using the independent leverage estimate as an adjustment.

IV. Tests of the MM vs. Traditional Theories of Corporation Finance

To determine if the difference, ${}_B\beta - {}_A\beta$, found in this study is indeed the correct effect of leverage, some confirmation of the MM theory (since it was assumed to be correct up to this point) from the systematic risk approach is needed. Since a direct test by this approach seems impossible, an indirect, inferential test is suggested.

The MM theory [9, 10] predicts that for firms in the same risk-class, the capitalization rate if all the firms were financed with only common equity, $E(R_A)$, would be the same—regardless of the actual amount of debt and preferred each individual firm had. This would imply, from (11a), that if $E(R_A)$ must be the same for all firms in a risk-class, so must ${}_A\beta$. And if these firms had different ratios of fixed commitment obligations to common equity, this difference in financial risk would cause their observed ${}_B\beta$s to be different.

The major competing theory of corporation finance is what is now known as the "traditional theory," which has contrary implications. This theory predicts that the capitalization rate for common equity, $E(R_B)$, (sometimes called the required or expected stock yield, or expected earnings-price ratio) is constant, as debt is increased, up to some critical leverage point (this point being a function of gambler's ruin and bankruptcy costs).[8] The clear implication of this constant, horizontal, equity yield (or their initial downward sloping cost of capital curve) is that changes in market or covariability risk are assumed not to be discernible to the shareholders as debt is increased. Then the traditional theory is saying that the ${}_B\beta$s, a measure of this covariability risk, would be the same for all firms in a given risk-class irregardless of differences in leverage, as long as the critical leverage point is not reached.

Since there will always be unavoidable errors in estimating the β's of indi-

7. A faint, but possible, empirical indication of this point may be obtained from Table 1. The ratio of the mean point estimate to the mean standard error of estimate is less for the firm β than for the stock β in both the discrete and continuously compounded cases.

8. This interpretation of the traditional theory can be found in [9, especially their figure 2, page 275, and their equation (13) and footnote 24 where reference is made to Durand and Graham and Dodd].

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TABLE 3

INDUSTRY MARKET VALUE RATIOS OF PREFERRED STOCK (P) AND DEBT (D) TO COMMON STOCK (S)

Industry Number	Industry	Number of Firms		P/S			D/S			$\frac{P+D}{S}$		
20	Food and Kindred Products	30	Mean*		0.22			0.81			1.04	
			ROM**	0.00		1.18	0.00		3.55	0.00		4.13
			ROCR***	0.00		2.52	0.00		8.10	0.00		10.01
28	Chemicals and Allied Products	30	Mean		0.07			0.25			0.33	
			ROM	0.00		0.51	0.00		0.90	0.00		1.20
			ROCR	0.00		1.54	0.00		2.07	0.00		2.92
29	Petroleum and Coal Products	18	Mean		0.06			0.22			0.27	
			ROM	0.00		0.26	0.00		0.55	0.03		0.57
			ROCR	0.00		0.83	0.00		1.54	0.00		2.30
33	Primary Metals	21	Mean		0.14			0.54			0.68	
			ROM	0.00		1.31	0.00		1.95	0.00		3.04
			ROCR	0.00		4.69	0.00		6.20	0.00		7.49
35	Machinery, except Electrical	28	Mean		0.07			0.33			0.40	
			ROM	0.00		0.49	0.00		1.92	0.00		2.32
			ROCR	0.00		1.28	0.00		6.92	0.00		7.62

TABLE 3 (*Continued*)

Industry Number	Industry	Number of Firms		P/S			D/S			$\frac{P+D}{S}$		
36	Electrical Machinery & Equipment	13	Mean		0.06			0.35			0.41	
			ROM	0.00		0.29	0.00		1.31	0.01		1.33
			ROCR	0.00		1.13	0.00		2.53	0.00		2.53
37	Transportation Equipment	24	Mean		0.08			0.38			0.47	
			ROM	0.00		0.54	0.00		0.93	0.00		1.32
			ROCR	0.00		2.33	0.00		3.76	0.00		6.09
49	Utilities	27	Mean		0.25			1.03			1.28	
			ROM	0.00		0.53	0.49		2.64	0.52		3.12
			ROCR	0.00		3.12	0.12		16.40	0.12		19.52
53	Dep't Stores, Order Houses & Vending Mach. Operators	17	Mean		0.13			0.49			0.62	
			ROM	0.00		0.38	0.01		1.52	0.01		1.87
			ROCR	0.00		1.09	0.00		3.19	0.00		3.66

* "Mean" refers to the average ratio over 20 years and over all firms in the industry.
** "Range of Means" (ROM) refers to the lowest firm's mean (over 20 years) ratio and the highest firm's mean (over 20 years) ratio in the industry.
*** "Range of Company Ranges" (ROCR) refers to the lowest and highest ratio in the industry, regardless of the year.

vidual firms and in specifying a risk-class, we would not expect to find a set of firms with identical systematic risk. But by specifying reasonable a priori risk-classes, if the individual firms had closer or less scattered ${}_A\beta$s than ${}_B\beta$s, then this would support the MM theory and contradict the traditional theory. If, instead, the ${}_B\beta$s were not discernibly more diverse than the ${}_A\beta$s, and the leverage ratio differed considerably among firms, then this would indicate support for the traditional theory.[9]

In order to test this implication, risk-classes must be first specified. The SEC two-digit industry classification was used for this purpose. Requiring enough firms for statistical reasons in any given industry, nine risk-classes were specified that had at least 13 firms; these nine classes are listed in Table 3 with their various leverage ratios.[10] It is clear from this table that our first requirement is met—that there is a considerable range of leverage ratios among firms in a risk-class and also over the twenty-year period.

Three tests will be performed to distinguish between the MM and traditional theories. The first is simply to calculate the standard deviation of the unbiased β estimates in a risk-class. The second is a chi-square test of the distribution of β's in an industry compared to the distribution of the β's in the total sample. Finally, an analysis of variance test on the estimated variance of the β's between industries, as opposed to within industries, is performed. In all tests, only the point estimate of β (which should be unbiased) for each stock and firm is used.[11]

The first test is reported in Table 4. If we compare the standard deviation of ${}_{AC}\beta$ with the standard deviation of ${}_{BC}\beta$ by industries (or risk-classes), we can note that $\sigma({}_{AC}\beta)$ is less than $\sigma({}_{BC}\beta)$ for eight out of the nine classes. The probability of obtaining this is only 0.0195, given a 50% probability that $\sigma({}_{AC}\beta)$ can be larger or smaller than $\sigma({}_{BC}\beta)$. These results indicate that the systematic risk of the firms in a given risk-class, if they were all financed only with common equity, is much less diverse than their observed stock's systematic risk. This supports the MM theory, at least in contrast to the traditional theory.[12]

9. The traditional theory also implies that $E(R_A)$ is equal to $E(R_B)$ for all firms. Unfortunately, we do not have a functional relationship between these traditional theory capitalization rates and the measured βs of this study. Clearly, since the ${}_A\beta$s were obtained assuming the validity of the MM theory, they would not be applicable for the traditional theory. In fact, no relationship between the ${}_A\beta$ and ${}_B\beta$ for a given firm, or for firms in a given risk-class, can be specified as was done for the capitalization rates.

10. The tenth largest industry had only eight firms. For our purpose of testing the uniformity of firm βs relative to stock βs within a risk-class, the use of the two-digit industry classification as a proxy does not seem as critical as, for instance, its use for the purpose of performing an MM valuation model study [8] wherein the ρ^{τ} must be pre-specified to be exactly the same for all firms in the industry.

11. Since these βs are estimated in the market model regressions with error, precise testing should incorporate the errors in the β estimation. Unfortunately, to do this is extremely difficult and more importantly, requires the normality assumption for the market model disturbance term. Since there is considerable evidence that is contrary to this required assumption [see 3], our tests will ignore the β measurement error entirely. But ignoring this is partially corrected in our first and third tests since means and variances of these point estimate βs must be calculated, and this procedure will "average out" the individual measurement errors by the factor 1/N.

12. Of course, there could always be another theory, as yet not formulated, which could be even

TABLE 4
MEAN AND STANDARD DEVIATION OF INDUSTRY β'S

Industry Number	Industry	Number of Firms		$_A\beta$	$_B\beta$	$_{A\sigma}\beta$	$_{B\sigma}\beta$
20	Food & Kindred Products	30	Mean β	0.515	0.815	0.528	0.806
			σ(β)	0.232	0.448	0.227	0.424
28	Chemicals & Allied Products	30	Mean β	0.747	0.928	0.785	0.946
			σ(β)	0.237	0.391	0.216	0.329
29	Petroleum & Coal Products	18	Mean β	0.633	0.747	0.656	0.756
			σ(β)	0.144	0.188	0.148	0.176
33	Primary Metals	21	Mean β	1.036	1.399	1.106	1.436
			σ(β)	0.223	0.272	0.197	0.268
35	Machinery, except Electrical	28	Mean β	0.878	1.037	0.917	1.068
			σ(β)	0.262	0.240	0.271	0.259
36	Electrical Machinery and Equipment	13	Mean β	0.940	1.234	0.951	1.164
			σ(β)	0.320	0.505	0.283	0.363
37	Transportation Equipment	24	Mean β	0.860	1.062	0.875	1.048
			σ(β)	0.225	0.313	0.225	0.289
49	Utilities	27	Mean β	0.160	0.255	0.166	0.254
			σ(β)	0.086	0.133	0.098	0.147
53	Department Stores, etc.	17	Mean β	0.652	0.901	0.692	0.923
			σ(β)	0.187	0.282	0.198	0.279

Our second test, the chi-square test, requires us to rank our 300 $_A\beta$s into ten equal categories, each with 30 $_A\beta$s (four miscellaneous firms were taken out randomly). By noting the value of the highest and lowest $_A\beta$ for each of the ten categories, a distribution of the number of $_A\beta$s in each category, by risk-class, can be obtained. This was then repeated for the other three betas. To test whether the distribution for each of the four β's and for each of the risk-classes follows the expected uniform distribution, a chi-square test was performed.[13]

Even with just casual inspection of these distributions of the betas by risk-class, it is clear that two industries, primary metals and utilities, are so highly skewed that they greatly exaggerate our results.[14] Eliminating these

more strongly supported than the MM theory. If we compare $\sigma(_A\beta)$ to $\sigma(_B\beta)$ by risk-classes in Table 4, precisely the same results are obtained as those reported above for the continuously-compounded betas.

13. By risk-classes, seven of the nine chi-square values of $_A\beta$ are larger than those of $_B\beta$, as are eight out of nine for the continuously-compounded betas. This would occur by chance with probabilities of 0.0898 and 0.0195, respectively, if there were a 50% chance that either the firm or stock chi-square value could be larger. Nevertheless, if we inspect the individual chi-square values by risk-class, we note that most of them are large so that the probabilities of obtaining these values are highly unlikely. For all four βs, the distributions for most of the risk-classes are nonuniform.

14. Primary metals have extremely large betas; utilities have extremely small betas.

two industries, and also two miscellaneous firms so that an even 250 firms are in the sample, new upper and lower values of the β's were obtained for each of the ten class intervals and for each of the four β's.

In Table 5, the chi-square values are presented; for the total of all risk-classes, the probability of obtaining a chi-square value less than 120.63 is over 99.95% (for ${}_{A}\beta$), whereas the probability of obtaining a chi-square value less than 99.75 is between 99.5% and 99.9% (for ${}_{B}\beta$). More sharply contrasting results are obtained when ${}_{AC}\beta$ is compared to ${}_{BC}\beta$. For ${}_{AC}\beta$, the probability of obtaining less than 128.47 is over 99.95%, whereas for ${}_{BC}\beta$, the probability of obtaining less than 78.65 is only 90.0%. By abstracting from financial risk, the underlying systematic risk is much less scattered when grouped into risk-classes than when leverage is assumed not to affect the systematic risk. The null hypothesis that the β's in a risk-class come from the same distribution as all β's is rejected for ${}_{AC}\beta$, but not for ${}_{BC}\beta$ (at the 90% level). Although this, in itself, does not tell us *how* a risk-class differs from the total market, an inspection of the distributions of the betas by risk-class underlying Table 5 does indicate more clustering of the ${}_{AC}\beta$s than the ${}_{BC}\beta$s so that the MM theory is again favored over the traditional theory.

The analysis of variance test is our last comparison of the implications of the two theories. The ratio of the estimated variance between industries to the estimated variance within the industries (the F-statistic) when the seven

TABLE 5
CHI-SQUARE RESULTS FOR ALL β'S AND ALL INDUSTRIES
(EXCEPT UTILITIES AND PRIMARY METALS)

Industry		${}_{A}\beta$	${}_{B}\beta$	${}_{AC}\beta$	${}_{BC}\beta$
Food and Kindred	Chi-Square	18.67	11.33	26.00	9.33
	$P\{\chi^2 < \}^* =$	95-97.5%	70-75%	99.5-99.9%	50-60%
Chemicals	Chi-Square	9.33	10.67	12.00	7.33
	$P\{\chi^2 < \} =$	50-60%	60-70%	75-80%	30-40%
Petroleum	Chi-Square	17.56	25.33	18.67	22.00
	$P\{\chi^2 < \} =$	95-97.5%	99.5-99.9%	95-97.5%	99-99.5%
Machinery	Chi-Square	19.14	12.00	24.86	9.14
	$P\{\chi^2 < \} =$	97.5-98%	75-80%	99.5-99.9%	50-60%
Electrical Machinery	Chi-Square	13.92	7.77	12.38	9.31
	$P\{\chi^2 < \} =$	80-90%	40-50%	80-90%	50-60%
Transportation Equipment	Chi-Square	15.17	16.83	13.50	6.83
	$P\{\chi^2 < \} =$	90-95%	90-95%	80-90%	30-40%
Dep't Stores	Chi-Square	14.18	3.59	14.18	3.59
	$P\{\chi^2 < \} =$	80-90%	5-10%	80-90%	5-10%
Miscellaneous	Chi-Square	12.67	12.22	6.89	11.11
	$P\{\chi^2 < \} =$	80-90%	80-90%	30-40%	70-75%
Total	Chi-Square	120.63	99.75	128.47	78.65
	$P\{\chi^2 < \} =$	over 99.95%	99.5-99.90%	over 99.95%	90.0%

* Example: $P\{\chi^2 < 18.67\} = 95\text{-}97.5\%$ for 9 degrees of freedom.

industries are considered (again, the two obviously skewed industries, primary metals and utilities, were eliminated) is less for $_B\beta$ (F = 3.90) than for $_A\beta$ (F = 9.99), and less for $_{BC}\beta$ (F = 4.18) than for $_{AC}\beta$ (F = 10.83). The probability of obtaining these F-statistics for $_A\beta$ and $_{AC}\beta$ is less than 0.001, but for $_B\beta$ and $_{BC}\beta$ greater than or equal to 0.001. These results are consistent with the results obtained from our two previous tests. The MM theory is more compatible with the data than the traditional theory.[15]

V. Conclusions

This study attempted to tie together some of the notions associated with the field of corporation finance with those associated with security and portfolio analyses. Specifically, if the MM corporate tax leverage propositions are correct, then approximately 21 to 24% of the observed systematic risk of common stocks (when averaged over 304 firms) can be explained merely by the added financial risk taken on by the underlying firm with its use of debt and preferred stock. Corporate leverage does count considerably.

To determine whether the MM theory is correct, a number of tests on a contrasting implication of the MM and "traditional" theories of corporation finance were performed. The data confirmed MM's position, at least vis-à-vis our interpretation of the traditional theory's position. This should provide another piece of evidence on this controversial topic.

Finally, if the MM theory and the capital asset pricing model are correct, and if the adjustments made in equations (8) or (4a) result in accurate measures of the systematic risk of a leverage-free firm, the possibility is greater, without resorting to a fullblown risk-class study of the type MM did for the electric utility industry [8], of estimating the cost of capital for individual firms.

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15. All of our tests, it should be emphasized, although consistent, are only inferential. Aside from assuming that the two-digit SEC industry classification is a good proxy for risk-classes and that the errors in estimating the individual βs can be safely ignored, the tests rely on the two theories exhausting all the reasonable theories on leverage. But there is always the use of another line of reasoning. If the results of the MM electric utility study [8] are correct, and if these results can be generalized to all firms and to all risk-classes, then it can be claimed that the MM theory is universally valid. Then our result in Section III does indicate the correct effect of the firm's capital structure on the systematic risk of common stocks.

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COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 037:

Explain how Columbia's required return on equity will be affected if the Commission approves Columbia's SFV Rate Design proposal.

Response:

The gas distribution companies in the proxy group already have various forms of regulatory mechanisms that are intended to stabilize revenue, which enhance their ability to cover their fixed costs. Many of these mechanisms are intended to address the same issues as the Company's proposal of straight fixed variable rate design. As such, the market prices of these companies' common stocks reflect the expectations of investors related to a regulatory mechanism that adjust revenues for conservation, abnormal weather, and other items such as infrastructure investment. The trend in the industry is to stabilize the recovery of fixed costs, which are unaffected by usage, through margin reconciliations or other means.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 038:

Refer to page 5 of the Balmert Testimony where Mr. Balmert discusses how test year billings are adjusted. Explain the difference between discontinued service (Attrition) bills shown in column 6 on Sheet 1 of Workpaper WPM-B and bills of customers who have chosen to discontinue service (Finalled Bills) shown in column 7.

Response:

Attrition bills shown in column 6 on Sheet 1 of Workpaper WPM-B were bills sent to customers during the test year who are no longer customers and Columbia is no longer serving the premises where those customers were provided service. It is a routine occurrence for a customer to request a final bill when moving from a premise. The account status code of a customer who is issued a final bill is "inactive".

Bill counts in column 1 of Workpaper WPM-B are bills sent to customers with an account status code of "active" including customers with initial bills and are used to determine customer counts. Final bill counts in column 7 are the number of bills sent to customers who are coded inactive and receive their final invoice when terminating service and are not included in customer counts

Columbia bills customers a monthly customer charge on all bills including both initial and final bills. Columbia includes these final bill counts in the determination of its revenue recovery from the customer charge because in fact Columbia does bill a customer charge to these accounts and that final bills are considered a normal part of business.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 039:

Refer to page 10 of the Balmert Testimony. Mr. Balmert states that for residential and small commercial rate schedules, the Ogive method was used to create the bill frequencies. Explain why the Ogive method was used and whether this means that Columbia's billing system is not able to provide the actual bill frequency.

Response:

The basis of the OGIVE method is the use of an actual bill frequency by customer class for residential and small commercial customers billed out of Columbia's DIS billing system. This actual bill frequency was created by the DIS billing system. Columbia creates monthly bill frequencies by rate schedule by applying the OGIVE method to this actual bill frequency.

Billing determinants coming from the DIS billing system into Columbia's Revenue Pricing System are in aggregate by rate schedule by customer class by month and not on a customer by customer basis. Billing determinants pulled from Columbia's GMB (large Commercial and all industrial customers on sales or Choice transportation service) and GTS (all non-Choice transportation service customers) billing systems are on a customer by customer basis and an actual bill frequency is developed within the Revenue Pricing System to determine usage by rate block.

Columbia continues to use the OGIVE method to determine usage by rate block for its DIS billed customers for three reasons: 1) The customer group that it billed in DIS have a predictable distribution curve that proves to be highly accurate to within a minimum of 0.5% of actual billings using the OGIVE method; 2) OGIVE has been an accepted method by both this commission and the commissions in Ohio, Maryland, Pennsylvania, Virginia, and New Hampshire where NiSource has used the method in rate filings going back to the 1950's; and, 3) there are only a few residential customers still being billed under a declining rate block structure.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 040:

Refer to pages 14 and 15 of the Balmert Testimony where he discusses how Annualized Test Year Revenues at current and proposed rates were developed. Provide calculations showing how Current Revenue Less Gas Cost Revenue of $24,154,350.48 in column (K) in Schedule M-2.2 was derived for General Service - Residential; and how Proposed Revenue Less Gas Cost Revenue of $32,222,134.30 was derived in Schedule M-2.3 column (F) for General Service - Residential.

Response:

Please see the attached spreadsheet.

Columbia Gas of Kentucky, Inc.
PSC Data Request Set 2 No. 40

Calculation showing General Service Residential Current Revenue Less Gas Cost Revenue at Current Rates

Line No.	Rate Code (1)	Class/ Description (2)	Customer Bills (3)	Sales [1] (4) (Mcf)	Most Current Rates (5) ($/Mcf)	Current Revenue Less Gas Cost Revenue (6) ($)	
1	GSR	General Service - Residential					
2		RESIDENTIAL					
3		Customer Charge:	1,185,131		9.30	11,021,718.30	(6 = 3 x 5)
4		Commodity Charge:					
5		All Gas Consumed		6,825,692.4	1.8715	12,774,283.33	(6 = 4 x 5)
6		Gas Cost Uncollectible Charge			0.0000	0.00	
7		EAP Recovery			0.0525	358,348.85	(6 = 4 x 5)
8		**Total**				**24,154,350.48**	(sum of column 6)

Calculation showing General Service Residential Current Revenue Less Gas Cost Revenue at Proposed Rates

Line No.	Rate Code (1)	Class/ Description (2)	Customer Bills (3)	Sales [1] (4) (Mcf)	Most Current Rates (5) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (6) ($)	
1	GSR	General Service - Residential					
3		Customer Charge:	1,185,131		17.92	21,237,547.52	(6 = 3 x 5)
4		Commodity Charge:					
5		All Gas Consumed		6,825,692.4	1.4604	9,968,241.18	(6 = 4 x 5)
6		Gas Cost Uncollectible Charge			0.0964	657,996.75	(6 = 4 x 5)
7		EAP Recovery			0.0525	358,348.85	(6 = 4 x 5)
8		**Total**				**32,222,134.30**	(sum of column 6)

PSC Case No. 2009-00141
Staff Set 2 DR No. 041
Respondent(s): Mark Balmert

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 041:

On page 15 of his testimony, Mr. Balmert discusses the development of Schedule N, the Typical Bill Comparison. Explain how typical bills for residential customers using proposed rates were calculated in column D of pages 1 and 2 of Schedule N.

Response:

Amounts in column D are proposed base revenue excluding gas cost for the respective levels of consumption in column B. For example, the proposed bill excluding gas costs for the average monthly use of 6 Mcf (page 1, line 4, column D) is $27.65. This amount is calculated by (6 Mcf x ($1.4604/Mcf + $.0525/Mcf + $.0124/Mcf + $.0964/Mcf)) + $17.92. The $1.4604/Mcf is the proposed base rate delivery charge, $.0525/Mcf is the last Commission-approved energy assistance program rider, $.0124/Mcf is the last Commission-approved research and development rider, $.0964/Mcf is the proposed Gas Cost Uncollectible Charge, and the $17.92 is the proposed customer charge for the first year rates are in effect.

Similarly, on page 2 for the second year rates are in effect, the calculation for the average monthly bill excluding gas costs for 6 Mcf is $27.50. This is calculated in the same manner, but the volumetric base rate delivery charge reduced to zero and the customer charge is increased to $26.53. The calculation is: (6 Mcf x ($.0525/Mcf + $.0124/Mcf + $.0964/Mcf)) + $26.53 = $27.50.

PSC Case No. 2009-00141
Staff Set 2 DR No. 042
Respondent(s): Mark Balmert

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 042:

Refer to pages 27-29 of the Balmert Testimony. Mr. Balmert explains the allocations of the proposed increase to Columbia's customer classes. Explain why Columbia proposes to implement the full $331.50 customer charge calculated in the cost-of-service study for its IUS customers, while it proposes a gradual phasing in of higher customer charges for all other customer classes.

Response:

Using both the Customer/Demand and Demand/Commodity class cost of service studies shown under Tab 39 in volume 5 of 8 of the filing as a guide, the goal of migrating all classes of customers toward earning the proposed return on rate base of 9.00%, and the goal of recovering through the customer charge the cost of service based on the customer based costs study (Attachment MPB-7) I assigned 0.09% of the revenue requirement in this case to the IUS class. This amounted to a 4.79% increase in revenue for the IUS class.

The increase in revenue creates a 6.41% return based on the Demand/Commodity study and a 11.22% return based on the Customer/Demand study with an average of 8.82% to achieve the first goal of achieving a return on rate base of 9%.

The 4.79% increase in revenue was more than enough to justify an increase in the customer charge to the customer based cost study of $331.50. The remainder of the IUS increased revenue requirement was applied to the volumetric delivery charge.

With an overall increase of 4.79% and the fact that IUS only has two customers, each customer on average for the year will not experience greater than a 5% increase and therefore their was no need for a gradual phasing of higher customer charges for the IUS class.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 043:

Refer to page 30 of the Balmert Testimony. Mr. Balmert states that, in the event the Commission does not approve Columbia's request to make the Late Payment Penalty applicable to residential customers, its proposed base rates in Attachment MPB-6 would have to be redesigned to exclude the proposed late-payment penalty revenue contribution. Provide work papers showing the effect of removing residential late-payment penalty revenues from the calculation of base rates. Include Attachment MPB-6 along with any other attachment or exhibit that would be affected.

Response:

Please see attached revised Schedule M-2.3 (Annualized test Year Revenue at Proposed Rates), Schedule M (Revenues at Present and Proposed Rates), Attachment MPB-6 (Rate Design) to Direct Testimony of Mark Balmert, and Schedule N (Bill Comparison) for sales rate schedules GSR, GSO, and IUS and transportation rate schedules GTR, GTO and GDS reflecting the elimination of Columbia's proposed residential late-payment penalty revenues.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)		Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1		**Sales Service**								
2	GSR	General Service - Residential		1,185,131	6,825,692.4		32,424,108.15	51.00	69,092,388.75	101,516,496.90
3	G1C	LG&E Commercial		48	6,675.8		10,867.78	0.02	67,575.12	78,442.90
4	G1R	LG&E Residential		281	2,390.1		8,641.00	0.01	24,193.55	32,834.55
5	IN3	Inland Gas General Service - Residential		120	1,480.4		592.16	0.00	0.00	592.16
6	IN3	Inland Gas General Service - Commercial		12	56.4		22.56	0.00	0.00	22.56
7	IN4	Inland Gas General Service - Residential		12	112.2		61.71	0.00	0.00	61.71
8	IN5	Inland Gas General Service - Residential		60	721.2		432.72	0.00	0.00	432.72
9	LG2	LG&E Residential		12	633.9		221.87	0.00	0.00	221.87
10	LG2	LG&E Commercial		12	938.2		328.37	0.00	0.00	328.37
11	LG3	LG&E Residential		12	482.8		176.07	0.00	0.00	176.07
12	LG4	LG&E Residential		12	266.5		106.60	0.00	0.00	106.60
13	GSO	General Service - Commercial		133,374	4,029,933.7		11,437,498.18	17.99	40,792,600.88	52,230,099.06
14	GSO	General Service - Industrial		522	155,474.1		300,208.80	0.47	1,573,771.03	1,873,979.83
15	GST	General Service - Trans Fallback - Comm	[3]	0	0.0		0.00	0.00	0.00	0.00
16	GST	General Service - Trans Fallback - Ind	[3]	0	0.0		0.00	0.00	0.00	0.00
17	IST	Interruptible Service - Commercial	[3]	0	0.0		0.00	0.00	0.00	0.00
18	IST	Interruptible Service - Industrial	[3]	0	0.0		0.00	0.00	0.00	0.00
19	IUS	Intrastate Utility Service - Wholesale		24	19,134.0		27,365.53	0.04	193,682.00	221,047.53
20		**Transportation Service**								
21	GTR	GTS Choice - Residential		310,965	1,995,520.2		8,647,722.18	13.60	0.00	8,647,722.18
22	GTO	GTS Choice - Commercial		38,712	1,417,583.7		3,646,809.11	5.74	0.00	3,646,809.11
23	GTO	GTS Choice - Industrial		96	34,057.4		61,923.81	0.10	0.00	61,923.81

[1] Reflects Normalized Volumes.
[2] See Schedule M-2.3 Pages 3 through 38 for detail.
[3] Customers are included under Transportation Rate Schedules

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1		**Transportation Service**							
2	DS	GTS Delivery Service - Commercial	312	1,463,233.4		1,011,516.90	1.59	0.00	1,011,516.90
3	DS	GTS Delivery Service - Industrial	538	6,668,558.0		3,472,910.69	5.46	0.00	3,472,910.69
4	GDS	GTS Grandfathered Delivery Service - Commercia	204	243,928.7		435,968.37	0.69	0.00	435,968.37
5	GDS	GTS Grandfathered Delivery Service - Industrial	109	157,300.0		277,739.09	0.44	0.00	277,739.09
6	DS3	GTS Main Line Service - Industrial	17	213,976.0		22,709.44	0.04	0.00	22,709.44
7	FX1	GTS Flex Rate - Commercial	12	305,721.5		45,563.63	0.07	0.00	45,563.63
8	FX2	GTS Flex Rate - Industrial	12	5,202.2		7,998.72	0.01	0.00	7,998.72
9	FX4	GTS Flex Rate - Industrial	12	52,333.0		24,247.47	0.04	0.00	24,247.47
10	FX5	GTS Flex Rate - Industrial	36	5,633,272.0		492,547.14	0.77	0.00	492,547.14
11	FX6	GTS Flex Rate - Industrial	12	346,158.0		32,771.16	0.05	0.00	32,771.16
12	FX7	GTS Flex Rate - Industrial	12	519,685.0		197,160.49	0.31	0.00	197,160.49
13	FX8	GTS Flex Rate - Industrial	12	29,145.0		23,172.81	0.04	0.00	23,172.81
14	SAS	GTS Special Agency Service	12	50,508.9		35,750.42	0.06	0.00	35,750.42
15	SC2	GTS Special Rate - Industrial	12	671,369.0		163,828.56	0.26	0.00	163,828.56
16	SC3	GTS Special Rate - Industrial	12	4,145,865.0		761,882.06	1.20	0.00	761,882.06
17	Total Sales and Transportation		1,670,729	34,997,408.7		63,572,853.55	100.00	111,744,211.33	175,317,064.88
18		**Other Gas Department Revenue**							
19		Acct. 487 Forfeited Discounts							167,537.00
20		Acct. 488 Miscellaneous Service Revenue							293,159.00
21		Acct. 495 Non-Traditional Sales							0.00
22		Acct. 495 Prior Yr. Rate Refund - Net.							0.00
23		Acct. 495 Other Gas Revenues - Other							343,888.00
24	Total Other Gas Department Revenue								804,584.00
25	Total Gross Revenue								176,121,648.88

[1] Reflects Normalized Volumes.
[2] See Schedule M-2.3 Pages 3 through 38 for detail.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GSR	General Service - Residential							
2		**RESIDENTIAL**							
3		Customer Delivery Charge:	1,185,131		18.00	21,332,358.00	65.8	0.00	21,332,358.00
4		Commodity Charge:							
5		All Gas Consumed		6,825,692.4	1.4761	10,075,404.55	31.1	69,092,388.75	79,167,793.30
6		Gas Cost Uncollectible Charge			0.0964	657,996.75	2.0	0.00	657,996.75
7		EAP Recovery			0.0525	358,348.85	1.1	0.00	358,348.85
8		Total	1,185,131	6,825,692.4		32,424,108.15	100.0	69,092,388.75	101,516,496.90

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	G1C	LG&E Commercial							
2		COMMERCIAL							
3		Customer Charge:	48		16.50	792.00	7.3	0.00	792.00
4		Commodity Charge:							
5		All Gas Consumed		6,675.8	1.5093	10,075.78	92.7	67,575.12	77,650.90
6		Total	48	6,675.8		10,867.78	100.0	67,575.12	78,442.90

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	G1R	LG&E Residential							
2		RESIDENTIAL							
3		Customer Charge:	281		8.50	2,388.50	27.6	0.00	2,388.50
4		Commodity Charge:							
5		All Gas Consumed		2,390.1	2.6160	6,252.50	72.4	24,193.55	30,446.05
6		Total	281	2,390.1		8,641.00	100.0	24,193.55	32,834.55

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IN3	Inland Gas General Service - Residential							
2		**RESIDENTIAL**							
3		Customer Charge:	120		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		1,480.4	0.4000	592.16	100.0	0.00	592.16
6		Total	120	1,480.4		592.16	100.0	0.00	592.16

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IN3	Inland Gas General Service - Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	12		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		56.4	0.4000	22.56	100.0	0.00	22.56
6		Total	12	56.4		22.56	100.0	0.00	22.56

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IN4	Inland Gas General Service - Residential							
2		**RESIDENTIAL**							
3		Customer Charge:	12		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		112.2	0.5500	61.71	100.0	0.00	61.71
6		Total	12	112.2		61.71	100.0	0.00	61.71

[1] Reflects Normalized Volumes.

Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IN5	Inland Gas General Service - Residential							
2		**RESIDENTIAL**							
3		Customer Charge:	60		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		721.2	0.6000	432.72	100.0	0.00	432.72
6		Total	60	721.2		432.72	100.0	0.00	432.72

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	LG2	LG&E Residential							
2		**RESIDENTIAL**							
3		Customer Charge:	12		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		633.9	0.3500	221.87	100.0	0.00	221.87
6		Total	12	633.9		221.87	100.0	0.00	221.87

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	LG2	LG&E Commercial							
2		COMMERCIAL							
3		Customer Charge:	12		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		938.2	0.3500	328.37	100.0	0.00	328.37
6		Total	12	938.2		328.37	100.0	0.00	328.37

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	LG3	LG&E Residential							
2		**RESIDENTIAL**							
3		Customer Charge:	12		1.20	14.40	8.2	0.00	14.40
4		Commodity Charge:							
5		First 2 Mcf		20.9	0.0000	0.00	0.0	0.00	0.00
6		Over 2 Mcf		461.9	0.3500	161.67	91.8	0.00	161.67
7		Total	12	482.8		176.07	100.0	0.00	176.07

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	LG4	LG&E Residential							
2		RESIDENTIAL							
3		Customer Charge:	12		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		266.5	0.4000	106.60	100.0	0.00	106.60
6		Total	12	266.5		106.60	100.0	0.00	106.60

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GSO	General Service - Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	133,374		28.45	3,794,490.30	33.2	0.00	3,794,490.30
4		Commodity Charge:							
5		First 50 Mcf		1,525,963.6	1.8715	2,855,840.88	25.0	15,446,413.94	18,302,254.82
6		Next 350 Mcf		1,586,648.3	1.8153	2,880,242.66	25.2	16,060,688.75	18,940,931.41
7		Next 600 Mcf		461,089.8	1.7296	797,500.92	7.0	4,667,335.39	5,464,836.31
8		Over 1,000 Mcf		456,232.0	1.5802	720,937.81	6.2	4,618,162.80	5,339,100.61
9		Gas Cost Uncollectible Charge			0.0964	388,485.61	3.4	0.00	388,485.61
10		Total	133,374	4,029,933.7		11,437,498.18	100.0	40,792,600.88	52,230,099.06

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Co' 'ia Gas of Kentucky, Inc.
Case No. 2009-00141
Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GSO	General Service - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	522		28.45	14,850.90	4.9	0.00	14,850.90
4		Commodity Charge:							
5		First 50 Mcf		14,708.0	1.8715	27,526.02	9.2	148,880.26	176,406.28
6		Next 350 Mcf		61,807.5	1.8153	112,199.15	37.4	625,640.24	737,839.39
7		Next 600 Mcf		39,321.6	1.7296	68,010.64	22.7	398,028.96	466,039.60
8		Over 1,000 Mcf		39,637.0	1.5802	62,634.39	20.8	401,221.57	463,855.96
9		Gas Cost Uncollectible Charge			0.0964	14,987.70	5.0	0.00	14,987.70
10		Total	522	155,474.1		300,208.80	100.0	1,573,771.03	1,873,979.83

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GST	General Service - Trans Fallback - Comm							
2		COMMERCIAL							
3		Customer Charge:	0		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		0.0	0.0000	0.00	0.0	0.00	0.00
6		Total	0	0.0		0.00	0.0	0.00	0.00

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

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Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GST	General Service - Trans Fallback - Ind							
2		**INDUSTRIAL**							
3		Customer Charge:	0		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		0.0	0.0000	0.00	0.0	0.00	0.00
6		Total	0	0.0		0.00	0.0	0.00	0.00

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
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Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IST	Interruptible Service - Commercial							
2		COMMERCIAL							
3		Customer Charge:	0		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		0.0	0.0000	0.00	0.0	0.00	0.00
6		Total	0	0.0		0.00	0.0	0.00	0.00

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Columbia Gas of Kentucky, Inc.
Case No. 2009-00141
Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IST	Interruptible Service - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	0		0.00	0.00	0.0	0.00	0.00
4		Commodity Charge:							
5		All Gas Consumed		0.0	0.0000	0.00	0.0	0.00	0.00
6		Total	0	0.0		0.00	0.0	0.00	0.00

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Co' ia Gas of Kentucky, Inc.
Case No. 2009-00141
Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	IUS	Intrastate Utility Service - Wholesale							
2		**WHOLESALE**							
3		Customer Charge:	24		331.50	7,956.00	29.1	0.00	7,956.00
4		Commodity Charge:							
5		All Gas Consumed		19,134.0	0.9180	17,565.01	64.2	193,682.00	211,247.01
6		Gas Cost Uncollectible Charge			0.0964	1,844.52	6.7	0.00	1,844.52
7		Total	24	19,134.0		27,365.53	100.0	193,682.00	221,047.53

[1] Reflects Normalized Volumes.
[2] Reflects Gas Cost Adjustment Rate of $10.1224/Mcf as of March 1, 2009.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GTR	GTS Choice - Residential							
2		**RESIDENTIAL**							
3		Customer Delivery Charge:	310,965		18.00	5,597,370.00	64.7	0.00	5,597,370.00
4		Commodity Charge:							
5		All Gas Consumed		1,995,520.2	1.4761	2,945,587.37	34.1	0.00	2,945,587.37
6		EAP Recovery			0.0525	104,764.81	1.2	0.00	104,764.81
7		Total	310,965	1,995,520.2		8,647,722.18	100.0	0.00	8,647,722.18

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
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Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GTO	GTS Choice - Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	38,712		28.45	1,101,356.40	30.2	0.00	1,101,356.40
3		Commodity Charge:							
4		First 50 Mcf		494,625.5	1.8715	925,691.62	25.4	0.00	925,691.62
5		Next 350 Mcf		568,367.4	1.8153	1,031,757.34	28.3	0.00	1,031,757.34
6		Next 600 Mcf		185,270.2	1.7296	320,443.34	8.8	0.00	320,443.34
7		Over 1,000 Mcf		169,320.6	1.5802	267,560.41	7.3	0.00	267,560.41
8		Total	38,712	1,417,583.7		3,646,809.11	100.0	0.00	3,646,809.11

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Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GTO	GTS Choice - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	96		28.45	2,731.20	4.4	0.00	2,731.20
4		Commodity Charge:							
5		First 50 Mcf		3,306.3	1.8715	6,187.74	10.0	0.00	6,187.74
6		Next 350 Mcf		12,616.5	1.8153	22,902.73	37.0	0.00	22,902.73
7		Next 600 Mcf		9,677.7	1.7296	16,738.55	27.0	0.00	16,738.55
8		Over 1,000 Mcf		8,456.9	1.5802	13,363.59	21.6	0.00	13,363.59
9		Total	96	34,057.4		61,923.81	100.0	0.00	61,923.81

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Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	DS	GTS Delivery Service - Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	312		622.20	194,126.40	19.2	0.00	194,126.40
4		Administrative Charge:	312		55.90	17,440.80	1.7	0.00	17,440.80
5		Commodity Charge:							
6		First 30,000 Mcf		1,463,233.4	0.5467	799,949.70	79.1	0.00	799,949.70
7		Over 30,000 Mcf		0.0	0.2905	0.00	0.0	0.00	0.00
8		Total	312	1,463,233.4		1,011,516.90	100.0	0.00	1,011,516.90

[1] Reflects Normalized Volumes.

Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	DS	GTS Delivery Service - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	538		622.20	334,743.60	9.6	0.00	334,743.60
4		Administrative Charge:	538		55.90	30,074.20	0.9	0.00	30,074.20
5		Commodity Charge:							
6		First 30,000 Mcf		4,570,167.0	0.5467	2,498,510.30	71.9	0.00	2,498,510.30
7		Over 30,000 Mcf		2,098,391.0	0.2905	609,582.59	17.6	0.00	609,582.59
8		Total	538	6,668,558.0		3,472,910.69	100.0	0.00	3,472,910.69

[1] Reflects Normalized Volumes.

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Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GDS	GTS Grandfathered Delivery Service - Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	204		28.45	5,803.80	1.3	0.00	5,803.80
4		Administrative Charge:	204		55.90	11,403.60	2.6	0.00	11,403.60
5		Commodity Charge:							
6		First 50 Mcf		10,200.0	1.8715	19,089.30	17.1	0.00	19,089.30
7		Next 350 Mcf		69,538.6	1.8153	126,233.42	29.0	0.00	126,233.42
8		Next 600 Mcf		93,608.1	1.7296	161,904.57	37.1	0.00	161,904.57
9		Over 1,000 Mcf		70,582.0	1.5802	111,533.68	12.9	0.00	111,533.68
10		Total	204	243,928.7		435,968.37	100.0	0.00	435,968.37

[1] Reflects Normalized Volumes.

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Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	GDS	GTS Grandfathered Delivery Service - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	109		28.45	3,101.05	1.1	0.00	3,101.05
4		Administrative Charge:	109		55.90	6,093.10	2.2	0.00	6,093.10
5		Commodity Charge:							
6		First 50 Mcf		20,585.0	1.8715	38,524.83	41.1	0.00	38,524.83
7		Next 350 Mcf		28,309.0	1.8153	51,389.33	18.5	0.00	51,389.33
8		Next 600 Mcf		49,047.0	1.7296	84,831.69	30.5	0.00	84,831.69
9		Over 1,000 Mcf		59,359.0	1.5802	93,799.09	6.6	0.00	93,799.09
10		Total	109	157,300.0		277,739.09	100.0	0.00	277,739.09

[1] Reflects Normalized Volumes.

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Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	DS3	GTS Main Line Service - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	17		200.00	3,400.00	0.0	0.00	3,400.00
4		Administrative Charge:	17		55.90	950.30	4.2	0.00	950.30
5		Commodity Charge:							
6		All Gas Consumed		213,976.0	0.0858	18,359.14	95.8	0.00	18,359.14
7		Total	17	213,976.0		22,709.44	100.0	0.00	22,709.44

[1] Reflects Normalized Volumes.

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Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX1	GTS Flex Rate - Commercial							
2		**COMMERCIAL**							
3		Customer Charge:	12		547.37	6,568.44	14.4	0.00	6,568.44
4		Administrative Charge:	12		65.00	780.00	1.7	0.00	780.00
5		Commodity Charge:							
6		Rate Schedule FX1		305,721.5	0.1250	38,215.19	83.9	0.00	38,215.19
7		Total	12	305,721.5		45,563.63	100.0	0.00	45,563.63

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX2	GTS Flex Rate - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	12		547.37	6,568.44	82.1	0.00	6,568.44
4		Administrative Charge:	12		65.00	780.00	9.8	0.00	780.00
5		Commodity Charge:							
6		All Gas Consumed		5,202.2	0.1250	650.28	8.1	0.00	650.28
7		Total	12	5,202.2		7,998.72	100.0	0.00	7,998.72

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX4	GTS Flex Rate - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	12		547.37	6,568.44	27.1	0.00	6,568.44
4		Administrative Charge:	12		55.90	670.80	2.8	0.00	670.80
5		Commodity Charge:							
6		All Gas Consumed		52,333.0	0.3250	17,008.23	70.1	0.00	17,008.23
7		Total	12	52,333.0		24,247.47	100.0	0.00	24,247.47

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
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Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX5	GTS Flex Rate - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	36		200.00	7,200.00	1.5	0.00	7,200.00
4		Administrative Charge:	36		55.90	2,012.40	0.4	0.00	2,012.40
5		Commodity Charge:							
6		All Gas Consumed		5,633,272.0	0.0858	483,334.74	98.1	0.00	483,334.74
7		Total	36	5,633,272.0		492,547.14	100.0	0.00	492,547.14

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX6	GTS Flex Rate - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	12		200.00	2,400.00	7.3	0.00	2,400.00
4		Administrative Charge:	12		55.90	670.80	2.0	0.00	670.80
5		Commodity Charge:							
6		All Gas Consumed		346,158.0	0.0858	29,700.36	90.7	0.00	29,700.36
7		Total	12	346,158.0		32,771.16	100.0	0.00	32,771.16

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX7	GTS Flex Rate - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	12		547.37	6,568.44	0.0	0.00	6,568.44
4		Administrative Charge:	12		55.90	670.80	0.3	0.00	670.80
5		Commodity Charge:							
6		First 25,000 Mcf		300,000.0	0.4500	135,000.00	68.5	0.00	135,000.00
7		Over 25,000 Mcf		219,685.0	0.2500	54,921.25	31.2	0.00	54,921.25
8		Total	12	519,685.0		197,160.49	100.0	0.00	197,160.49

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	FX8	GTS Flex Rate - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	12		547.37	6,568.44	0.0	0.00	6,568.44
4		Administrative Charge:	12		55.90	670.80	2.9	0.00	670.80
5		Commodity Charge:							
6		First 30,000		29,145.0	0.5467	15,933.57	68.8	0.00	15,933.57
7		Over 30,000		0.0	0.2905	0.00	28.3	0.00	0.00
8		Total	12	29,145.0		23,172.81	100.0	0.00	23,172.81

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	SAS	GTS Special Agency Service							
2		**INDUSTRIAL**							
3		Customer Charge:	12		622.20	7,466.40	20.9	0.00	7,466.40
4		Administrative Charge:	12		55.90	670.80	1.9	0.00	670.80
5		Commodity Charge:							
6		First 30,000		50,508.9	0.5467	27,613.22	77.2	0.00	27,613.22
7		Over 30,000		0.0	0.2905	0.00	0.0	0.00	0.00
8		Total	12	50,508.9		35,750.42	100.0	0.00	35,750.42

[1] Reflects Normalized Volumes.

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	SC2	GTS Special Rate - Industrial							
2		**INDUSTRIAL**							
3		Customer Charge:	12		200.00	2,400.00	1.5	0.00	2,400.00
4		Administrative Charge:	12		25.00	300.00	0.2	0.00	300.00
5		Commodity Charge:							
6		All Gas Consumed		671,369.0	0.2400	161,128.56	98.3	0.00	161,128.56
7		Total	12	671,369.0		163,828.56	100.0	0.00	163,828.56

[1] Reflects Normalized Volumes.

Co' ia Gas of Kentucky, Inc.
Case No. 2009-00141
Annualized Test Year Revenues at Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Proposed Annualized

Line No.	Rate Code (A)	Class/ Description (B)	Customer Bills (C)	Sales [1] (D) (Mcf)	Proposed Rates (E) ($/Mcf)	Proposed Revenue Less Gas Cost Revenue (F) ($)	% of Rev To Total Less Gas Cost Revenue (G) (%)	Gas Cost Revenue [2] (H) ($)	Proposed Total Revenue (F + H) (I) ($)
1	SC3	GTS Special Rate - Industrial							
2		INDUSTRIAL							
3		Customer Charge:	12		200.00	2,400.00	0.3	0.00	2,400.00
4		Administrative Charge:	12		25.00	300.00	0.0	0.00	300.00
5		Commodity Charge:							
6		First 150,000 Mcf		1,693,997.0	0.2600	440,439.22	57.8	0.00	440,439.22
		Over 150,000 Mcf		2,451,868.0	0.1300	318,742.84	41.9	0.00	318,742.84
7		Total	12	4,145,865.0		761,882.06	100.0	0.00	761,882.06

[1] Reflects Normalized Volumes.

Columbia Gas of Kentucky, Inc.
Case No. 2009-00141
Revenues At Present and Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Line No.	Rate Classification (A)	Revenue At Present Rates (B) ($)	Revenue At Proposed Rates (C) ($)	Revenue Change (D=C-B) ($)	% Of Revenue Change (E=D/B) (%)
1	Sales Service				
2	General Service - Residential	93,246,739.23	101,516,496.90	8,269,757.67	8.87
3	LG&E Commercial	78,442.90	78,442.90	0.00	0.00
4	LG&E Residential	32,834.55	32,834.55	0.00	0.00
5	Inland Gas General Service - Residential	592.16	592.16	0.00	0.00
6	Inland Gas General Service - Commercial	22.56	22.56	0.00	0.00
7	Inland Gas General Service - Residential	61.71	61.71	0.00	0.00
8	Inland Gas General Service - Residential	432.72	432.72	0.00	0.00
9	LG&E Residential	221.87	221.87	0.00	0.00
10	LG&E Commercial	328.37	328.37	0.00	0.00
11	LG&E Residential	176.07	176.07	0.00	0.00
12	LG&E Residential	106.60	106.60	0.00	0.00
13	General Service - Commercial	51,242,764.19	52,230,099.06	987,334.87	1.93
14	General Service - Industrial	1,856,648.35	1,873,979.83	17,331.48	0.93
15	General Service - Trans Fallback - Comm	0.00	0.00	0.00	0.00
16	General Service - Trans Fallback - Ind	0.00	0.00	0.00	0.00
17	Interruptible Service - Commercial	0.00	0.00	0.00	0.00
18	Interruptible Service - Industrial	0.00	0.00	0.00	0.00
19	Intrastate Utility Service - Wholesale	211,100.63	221,047.53	9,946.90	4.71
20	Transportation Service				
21	GTS Choice - Residential	6,731,355.36	8,647,722.18	1,916,366.82	28.47
22	GTS Choice - Commercial	3,472,992.23	3,646,809.11	173,816.88	5.00
23	GTS Choice - Industrial	61,492.77	61,923.81	431.04	0.70
24	GTS Delivery Service - Commercial	988,169.94	1,011,516.90	23,346.96	2.36
25	GTS Delivery Service - Industrial	3,432,652.15	3,472,910.69	40,258.54	1.17
26	GTS Grandfathered Delivery Service - Comm	435,052.41	435,968.37	915.96	0.21
27	GTS Grandfathered Delivery Service - Indust	277,249.68	277,739.09	489.41	0.18
28	GTS Main Line Service - Industrial	22,709.44	22,709.44	0.00	0.00
29	GTS Flex Rate - Commercial	45,563.63	45,563.63	0.00	0.00
30	GTS Flex Rate - Industrial	7,998.72	7,998.72	0.00	0.00
31	GTS Flex Rate - Industrial	24,247.47	24,247.47	0.00	0.00
32	GTS Flex Rate - Industrial	492,547.14	492,547.14	0.00	0.00
33	GTS Flex Rate - Industrial	32,771.16	32,771.16	0.00	0.00
34	GTS Flex Rate - Industrial	197,160.49	197,160.49	0.00	0.00
35	GTS Flex Rate - Industrial	23,172.81	23,172.81	0.00	0.00
36	GTS Special Agency Service	30,684.02	35,750.42	5,066.40	16.51
37	GTS Special Rate - Industrial	163,828.56	163,828.56	0.00	0.00
38	GTS Special Rate - Industrial	761,882.06	761,882.06	0.00	0.00
39	Total Sales and Transportation	163,872,001.95	175,317,064.88	11,445,062.93	6.98

Columbia Gas of Kentucky, Inc.
Case No. 2009-00141
Revenues At Present and Proposed Rates
For the 12 Months Ended December 31, 2008
(Gas Service)

Data: X Base Period _ Forecasted Period
Type of Filing: X Original _ Update _ Revised
Work Paper Reference No(s):

Line No.	Rate Classification (A)	Revenue At Present Rates (B) ($)	Revenue At Proposed Rates (C) ($)	Revenue Change (D=C-B) ($)	% Of Revenue Change (E=D/B) (%)
1	Other Gas Department Revenue				
2	Acct. 487 Forfeited Discounts	192,713.00	167,537.00	(25,176.00)	(13.06)
3	Acct. 488 Miscellaneous Service Revenue	147,314.00	293,159.00	145,845.00	99.00
4	Acct. 495 Non-Traditional Sales	0.00	0.00	0.00	0.00
5	Acct. 495 Prior Yr. Rate Refund - Net.	0.00	0.00	0.00	0.00
6	Acct. 495 Other Gas Revenues - Other	343,888.00	343,888.00	0.00	0.00
7	Total Other Gas Departnemt Revenue	683,915.00	804,584.00	120,669.00	17.64
8	Total Gross Revenue	164,555,916.95	176,121,648.88	11,565,731.93	7.03

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

PSC Data Request Set 2 No. 43
Attachment MPB-6
Sheet 1 of 4

Line No.	DESCRIPTION	Adjusted Volumes (1) MCF	Revenue @ Current Rates (2) $	Proposed Increase (3) $	Revenue @ Proposed Rates (4) $	Proposed Increase (5=3/2) %
	Gas Service Revenues					
1	GSR/GTR Residential	8,821,212.6	$99,978,095	$10,186,105	$110,164,200	10.19%
2	GSO/GTO/GDS	6,038,277.6	57,346,200	1,179,986	58,526,186	2.06%
3	DS/SAS	8,182,300.3	4,451,506	68,670	4,520,176	1.54%
4	IUS	19,134.0	211,101	10,301	221,402	4.88%
5	IN3	1,536.8	615	0	615	0.00%
6	IN4	112.2	62	0	62	0.00%
7	IN5	721.2	433	0	433	0.00%
5	G1C	6,675.8	78,443	0	78,443	0.00%
6	G1R	2,390.1	32,835	0	32,835	0.00%
7	LG2 Residential	633.9	222	0	222	0.00%
8	LG2 Commercial	938.2	328	0	328	0.00%
9	LG3 Residential	482.8	176	0	176	0.00%
10	LG4 Residential	266.5	107	0	107	0.00%
11	DS3	213,976.0	22,709	0	22,709	0.00%
12	FX1	305,721.5	45,564	0	45,564	0.00%
13	FX2	5,202.2	7,999	0	7,999	0.00%
14	FX4	52,333.0	24,247	0	24,247	0.00%
15	FX5	5,633,272.0	492,547	0	492,547	0.00%
16	FX6	346,158.0	32,771	0	32,771	0.00%
17	FX7	519,685.0	197,160	0	197,160	0.00%
18	FX8	29,145.0	23,173	0	23,173	0.00%
19	SC2	671,369.0	163,829	0	163,829	0.00%
20	SC3	4,145,865.0	761,882	0	761,882	0.00%
21	Other Gas Department Revenue					
22	Acct. 487 Forfeited Discounts		192,713	(25,176)	167,537	
23	Acct. 488 Miscellaneous Service Revenue		147,314	145,845	293,159	
24	Acct. 495 Non-Traditional Sales		0	0	0	
25	Acct. 495 Prior Yr. Rate Refund - Net.		0	0	0	
26	Acct. 495 Other Gas Revenues - Other		343,888	0	343,888	
27	Total Gas Service Revenues	34,997,408.7	$164,555,917	$11,565,731	$176,121,648	7.03%

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.		Bills	Mcf	Proposed Rate	Proposed Revenue ($)	Current Rev Revenue ($)	Pct. Of Current Rev	Current Rate	Proposed Inc. (Dec.)
1	GSR/GTR Rate Design								
2	Total Revenue @ Proposed Rates				110,164,200				
3 Less:	Gas Cost Revenue				69,092,389				
4 Less:	Gas Cost Uncollectible Charge [1]		6,825,692	0.0964	657,997	0			657,997
5 Less:	EAP Revenue				463,114				
6 Less:	Administrative Charge Revenue				0				
7 Less:	Customer Delivery Charge Revenue	1,496,096		**18.00**	26,929,728	13,913,693		9.30	13,016,035
8	Net Volumetric Base Revenue				13,020,972				
9	All Gas Consumed		8,821,212.6	**1.4761**	13,020,992	16,508,899		1.8715	(3,487,907)
10	Total					30,422,592			10,186,125
11	GSO/GTO/GDS Rate Design								
12	Total Revenue @ Proposed Rates				58,526,186				
13 Less:	Gas Cost Revenue				42,366,372				
14 Less:	Gas Cost Uncollectible Charge [1]		4,185,408	0.0964	403,473	0			403,473
15 Less:	EAP Revenue				0				
16 Less:	Administrative Charge Revenue	313		**55.90**	17,497	17,497		55.90	0
17 Less:	Customer Charge Revenue	173,017		**28.45**	4,922,000	4,145,487		23.96	776,513
18	Net Volumetric Base Revenue				10,816,844				1,179,986
19 Less:	First 50 Mcf		2,069,388.4	**1.8715**	3,872,860	3,872,860	0.358039785	1.8715	(0)
20	Next 350 Mcf		2,327,287.3	**1.8153**	4,224,725	4,224,725	0.390569074	1.8153	0
21	Next 600 Mcf		838,014.4	**1.7296**	1,449,430	1,449,430	0.133997472	1.7296	0
22	Over 1,000 Mcf		803,587.5	**1.5802**	1,269,829	1,269,829	0.117393669	1.5802	0
23	Total		6,038,277.6		10,816,844	10,816,844	1.000000000		1,179,986

[1] See MPB-6 Sheet 3.

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.			Bills	Mcf	Proposed Rate	Proposed Revenue ($)	Current Rev Revenue ($)	Pct. Of Current Rev	Current Rate	Proposed Inc. (Dec.)
1		DS/SAS Rate Design								
2		Total Revenue @ Proposed Rates				4,520,176				
3	Less:	Gas Cost Revenue				0				
4	Less:	Gas Cost Uncollectible Charge [1]		0	0.0964	0	0			0
5	Less:	EAP Revenue				0				
6	Less:	Customer Charge Revenue	862		**622.20**	536,334	467,665		547.37	68,670
7	Less:	Administrative Charge Revenue	862		**55.90**	48,186	48,186		55.90	0
8		Net Volumetric Base Revenue				3,935,656				68,670
9		First 30,000 Mcf		6,083,909.3	**0.5467**	3,326,073	3,326,073	0.845112830	0.5467	(0)
10		Over 30,000 Mcf		2,098,391.0	**0.2905**	609,583	609,583	0.154887170	0.2905	0
11		Total		8,182,300.3		3,935,656	3,935,656	1.000000000		68,670
12		DS3 (Mainline) Customer Charge Rate Design Change								
13		Total Revenue @ Proposed Rates				22,709				
14	Less:	Gas Cost Revenue				0				
15	Less:	Gas Cost Uncollectible Charge [1]		0	0.0964	0	0			0
16	Less:	EAP Revenue				0				
17	Less:	Customer Charge Revenue	17		**200.00**	3,400	3,400		200.00	0
18	Less:	Administrative Charge Revenue	17		**55.90**	950	950		55.90	(0)
19		Net Volumetric Base Revenue				18,359				(0)
20		All Gas Consumed		213,976.0	**0.0858**	18,359	18,359		0.0858	(0)
21		Total								(1)
22		IUS Rate Design								
23		Total Revenue @ Proposed Rates				221,402				
24	Less:	Gas Cost Revenue				193,682				
25	Less:	Gas Cost Uncollectible Charge [1]		19,134	0.0964	1,845	0			1,845
26	Less:	EAP Revenue				0				
27	Less:	Administrative Charge Revenue				0				
28	Less:	Customer Charge Revenue	24		**331.50**	7,956	6,120		255.00	1,836
29		Net Volumetric Base Revenue				17,919				3,681
30		All Gas Consumed		19,134.0	**0.9180**	17,565	11,299		0.5905	6,266
31		Total		19,134.0		17,565	11,299			9,947

[1] Gas Cost Uncollectible Charge to GCA Customers

Expected Gas Cost Commodity Rate as of March 1, 2009 ($/Mcf)	6.8373
Uncollectible Expense Accrual Rate (See Schedule D-2.1 Sheet 5)	1.410552%
Proposed Rate / Mcf	**0.0964**

Columbia Gas of Kentucky, Inc.
Schedule of Additional Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2008

Line No.			Reference	Detail ($)	Amount ($)
1		**Change in Forfeited Discounts Revenue**			
2		Test Year Forfeited Discounts (Account 487)	Schedule M-2.1		192,713.00
3		Test Year Revenue Subject to Late Payment Penalties:			
4	G1C	LG&E Commercial	Schedule M-2.1	76,888.46	
5	GSO	General Service - Commercial	Schedule M-2.1	59,683,440.58	
6	GSO	General Service - Industrial	Schedule M-2.1	2,355,847.53	
7	IUS	Intrastate Utility Service - Wholesale	Schedule M-2.1	254,639.38	
8	GTO	GTS Choice - Commercial	Schedule M-2.1	3,595,137.38	
9	GTO	GTS Choice - Industrial	Schedule M-2.1	64,589.67	
10	DS	GTS Delivery Service - Commercial	Schedule M-2.1	1,020,173.08	
11	DS	GTS Delivery Service - Industrial	Schedule M-2.1	3,435,275.12	
12	GDS	GTS Grandfathered Delivery Service - Commercial	Schedule M-2.1	434,838.25	
13	GDS	GTS Grandfathered Delivery Service - Industrial	Schedule M-2.1	204,801.06	
14	DS3	GTS Main Line Service - Industrial	Schedule M-2.1	22,709.43	
15	FX1	GTS Flex Rate - Commercial	Schedule M-2.1	136,239.48	
16	FX2	GTS Flex Rate - Industrial	Schedule M-2.1	8,079.95	
17	FX4	GTS Flex Rate - Industrial	Schedule M-2.1	24,257.89	
18	FX5	GTS Flex Rate - Industrial	Schedule M-2.1	492,547.14	
19	FX6	GTS Flex Rate - Industrial	Schedule M-2.1	32,771.16	
20	FX7	GTS Flex Rate - Industrial	Schedule M-2.1	197,160.49	
21	FX8	GTS Flex Rate - Industrial	Schedule M-2.1	20,647.13	
22	SAS	GTS Special Agency Service	Schedule M-2.1	31,680.71	
23	SC2	GTS Special Rate - Industrial	Schedule M-2.1	157,598.52	
24	SC3	GTS Special Rate - Industrial	Schedule M-2.1	719,002.12	
25	Total				72,968,324.53
26		Ration of Late Payment Penalties to Total Revenue	Line 2 / Line 25		0.002641050
27		Proposed Revenue Subject to Late Payment Penalties:			
28		GSR/GTR Residential	MPB-6 Page 1	0	
29		GSO/GTO/GDS	MPB-6 Page 1	58,526,186	
30		DS/SAS	MPB-6 Page 1	4,520,176	
31		IUS	MPB-6 Page 1	221,402	
32		G1C	MPB-6 Page 1	615	
33		G1R	MPB-6 Page 1	62	
34		DS3	MPB-6 Page 1	433	
35		FX1	MPB-6 Page 1	78,443	
36		FX2	MPB-6 Page 1	32,835	
37		FX4	MPB-6 Page 1	222	
38		FX5	MPB-6 Page 1	328	
39		FX6	MPB-6 Page 1	176	
40		FX7	MPB-6 Page 1	107	
41		FX8	MPB-6 Page 1	22,709	
42		SC2	MPB-6 Page 1	7,999	
43		SC3	MPB-6 Page 1	24,247	
44	Total				63,435,939
45		Proposed Forfeited Discounts (Account 487)	Line 26 x Line 45		167,537
46		**Proposed Adjustment to Account 487 Revenue**	**Line 46 - Line 2**		**(25,176)**

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED SALES SERVICE RATES
TYPICAL BILL COMPARISON
12 Months Ending December 31, 2008

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

PSC Data Request Set 2 No. 43
Schedule N

Witness: M. P. Balmert

Line No.	Rate Code	Level of Demand (A)	Level of Use (MCF) (B)	Current Bill ($) (C)	Proposed Step 1 Bill ($) (D)	Increase (D - C) ($) (E)	Increase (E/C) (%) (F)	Gas Cost ($) (G)	Total Current Bill ($) (H) (C + G)	Total Proposed Step 1 Bill ($) (I) (D + G)	Percent Increase (%) (J) (I - H) / H
1	GSR	Not	1	$11.23	$19.64	$8.41	74.9%	$10.12	$21.35	$29.76	39.4%
2	General	Applicable	3	$15.10	$22.91	$7.81	51.7%	$30.37	$45.47	$53.28	17.2%
3	Service		5	$18.98	$26.19	$7.21	38.0%	$50.61	$69.59	$76.80	10.4%
4	Residential		6	$20.92	$27.83	$6.91	33.0%	$60.73	$81.65	$88.56	8.5%
5			8	$24.79	$31.10	$6.31	25.5%	$80.98	$105.77	$112.08	6.0%
6			10	$28.67	$34.37	$5.70	19.9%	$101.22	$129.89	$135.59	4.4%
7			12	$32.54	$37.65	$5.11	15.7%	$121.47	$154.01	$159.12	3.3%
8			16	$40.28	$44.20	$3.92	9.7%	$161.96	$202.24	$206.16	1.9%
9			20	$48.03	$50.75	$2.72	5.7%	$202.45	$250.48	$253.20	1.1%
10			30	$67.40	$67.12	-$0.28	-0.4%	$303.67	$371.07	$370.79	-0.1%
11			40	$86.76	$83.49	-$3.27	-3.8%	$404.90	$491.66	$488.39	-0.7%
12			50	$106.13	$99.88	-$6.25	-5.9%	$506.12	$612.25	$606.00	-1.0%

Average monthly bill = 6

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED SALES SERVICE RATES
TYPICAL BILL COMPARISON
12 Months Ending December 31, 2008

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Witness: M. P. Balmert

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

Line No.	Rate Code	Level of Demand (A)	Level of Use (MCF) (B)	Current Bill ($) (C)	Proposed Bill ($) (D)	Increase (D - C) ($) (E)	Increase (E/C) (%) (F)	Gas Cost ($) (G)	Total Current Bill ($) (H) (C + G)	Total Proposed Bill ($) (I) (D + G)	Percent Increase (%) (J) (I - H) / H
1	GSO	Not	10	$42.80	$48.25	$5.45	12.7%	$101.22	$144.02	$149.47	3.8%
2	General	Applicable	30	$80.48	$87.86	$7.38	9.2%	$303.67	$384.15	$391.53	1.9%
3	Service		30	$80.48	$87.86	$7.38	9.2%	$303.67	$384.15	$391.53	1.9%
4	Commercial &		50	$118.16	$127.47	$9.31	7.9%	$506.12	$624.28	$633.59	1.5%
5	Industrial		70	$154.72	$165.96	$11.24	7.3%	$708.57	$863.29	$874.53	1.3%
6			100	$209.55	$223.68	$14.13	6.7%	$1,012.24	$1,221.79	$1,235.92	1.2%
7			150	$300.93	$319.88	$18.95	6.3%	$1,518.36	$1,819.29	$1,838.24	1.0%
8			200	$392.32	$416.09	$23.77	6.1%	$2,024.48	$2,416.80	$2,440.57	1.0%
9			250	$483.70	$512.29	$28.59	5.9%	$2,530.60	$3,014.30	$3,042.89	0.9%
10			298	$571.43	$604.65	$33.22	5.8%	$3,016.48	$3,587.91	$3,621.13	0.9%
11			300	$575.09	$608.50	$33.41	5.8%	$3,036.72	$3,611.81	$3,645.22	0.9%
12			350	$666.47	$704.70	$38.23	5.7%	$3,542.84	$4,209.31	$4,247.54	0.9%
13			400	$757.86	$800.91	$43.05	5.7%	$4,048.96	$4,806.82	$4,849.87	0.9%
14			450	$844.96	$892.83	$47.87	5.7%	$4,555.08	$5,400.04	$5,447.91	0.9%
15			500	$932.06	$984.75	$52.69	5.7%	$5,061.20	$5,993.26	$6,045.95	0.9%
16			700	$1,280.46	$1,352.43	$71.97	5.6%	$7,085.68	$8,366.14	$8,438.11	0.9%
17			1,000	$1,803.06	$1,903.95	$100.89	5.6%	$10,122.40	$11,925.46	$12,026.35	0.8%
18			1,200	$2,121.58	$2,241.75	$120.17	5.7%	$12,146.88	$14,268.46	$14,388.63	0.8%

Average monthly bill = 30 (Commercial)
Average monthly bill = 298 (Industrial)

COLUMBIA GAS OF KENTUCKY, INC.
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TYPICAL BILL COMPARISON
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Work Paper Reference No(s):

Line No.	Rate Code	Level of Demand (A)	Level of Use (MCF) (B)	Current Bill ($) (C)	Proposed Bill ($) (D)	Increase (D - C) ($) (E)	Increase (E/C) (%) (F)	Gas Cost ($) (G)	Total Current Bill ($) (H) (C + G)	Total Proposed Bill ($) (I) (D + G)	Percent Increase (%) (J) (I - H) / H
1	IUS	Not	500	$556.45	$844.90	$288.45	51.8%	$5,061.20	$5,617.65	$5,906.10	5.1%
2	Intrastate	Applicable	797	$735.51	$1,149.86	$414.35	56.3%	$8,067.55	$8,803.06	$9,217.41	4.7%
3	Utility		1,000	$857.90	$1,358.30	$500.40	58.3%	$10,122.40	$10,980.30	$11,480.70	4.6%
4	Service		2,000	$1,460.80	$2,385.10	$924.30	63.3%	$20,244.80	$21,705.60	$22,629.90	4.3%
5	Wholesale		3,000	$2,063.70	$3,411.90	$1,348.20	65.3%	$30,367.20	$32,430.90	$33,779.10	4.2%
6			4,000	$2,666.60	$4,438.70	$1,772.10	66.5%	$40,489.60	$43,156.20	$44,928.30	4.1%
7			5,000	$3,269.50	$5,465.50	$2,196.00	67.2%	$50,612.00	$53,881.50	$56,077.50	4.1%
8			6,000	$3,872.40	$6,492.30	$2,619.90	67.7%	$60,734.40	$64,606.80	$67,226.70	4.1%
9			7,000	$4,475.30	$7,519.10	$3,043.80	68.0%	$70,856.80	$75,332.10	$78,375.90	4.0%
10			8,000	$5,078.20	$8,545.90	$3,467.70	68.3%	$80,979.20	$86,057.40	$89,525.10	4.0%
11			10,000	$6,284.00	$10,599.50	$4,315.50	68.7%	$101,224.00	$107,508.00	$111,823.50	4.0%
12			15,000	$9,298.50	$15,733.50	$6,435.00	69.2%	$151,836.00	$161,134.50	$167,569.50	4.0%
13			20,000	$12,313.00	$20,867.50	$8,554.50	69.5%	$202,448.00	$214,761.00	$223,315.50	4.0%
14			30,000	$18,342.00	$31,135.50	$12,793.50	69.7%	$303,672.00	$322,014.00	$334,807.50	4.0%
15			40,000	$24,371.00	$41,403.50	$17,032.50	69.9%	$404,896.00	$429,267.00	$446,299.50	4.0%

Average monthly bill = 797

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED TRANSPORTATION SERVICE RATES
TYPICAL BILL COMPARISON
As of December 31, 2008

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				Monthly Customer Charge				Transportation Commodity Charge						
Line No.	Rate Code	Level of Demand (A)	Monthly Transp Volume (MCF) (B)	Current Monthly Customer Charge ($) (C)	Proposed Step 1 Monthly Customer Charge ($) (D)	Dollar Increase (Decrease) (D - C) ($) (E)	Percent Increase (Decrease) (E/C) (%) (F)	Current Commodity Charge ($) (G)	Proposed Step 1 Commodity Charge ($) (H)	Dollar Increase (Decrease) (H - G) ($) (I)	Percent Increase (Decrease) (I/G) (%) (J)	Total Current Bill (C + G) ($) (K)	Total Proposed Step 1 Bill (D + H) ($) (L)	Percent Increase (Decrease) (L - K)/K (%) (M)
1	GTR	Not	1	$9.30	$18.00	$8.70	93.5%	$1.93	$1.54	-$0.39	-20.2%	$11.23	$19.54	74.0%
2	GTS	Applicable	3	$9.30	$18.00	$8.70	93.5%	$5.81	$4.63	-$1.18	-20.3%	$15.11	$22.63	49.8%
3	Choice		6	$9.30	$18.00	$8.70	93.5%	$11.62	$9.25	-$2.37	-20.4%	$20.92	$27.25	30.3%
4	Residential		8	$9.30	$18.00	$8.70	93.5%	$15.49	$12.33	-$3.16	-20.4%	$24.79	$30.33	22.3%
5			10	$9.30	$18.00	$8.70	93.5%	$19.37	$15.41	-$3.96	-20.4%	$28.67	$33.41	16.5%
6			12	$9.30	$18.00	$8.70	93.5%	$23.24	$18.49	-$4.75	-20.4%	$32.54	$36.49	12.1%
7			16	$9.30	$18.00	$8.70	93.5%	$30.98	$24.66	-$6.32	-20.4%	$40.28	$42.66	5.9%
8			20	$9.30	$18.00	$8.70	93.5%	$38.73	$30.82	-$7.91	-20.4%	$48.03	$48.82	1.6%
9			30	$9.30	$18.00	$8.70	93.5%	$58.10	$46.23	-$11.87	-20.4%	$67.40	$64.23	-4.7%
10			40	$9.30	$18.00	$8.70	93.5%	$77.46	$61.64	-$15.82	-20.4%	$86.76	$79.64	-8.2%
11			50	$9.30	$18.00	$8.70	93.5%	$96.83	$77.06	-$19.77	-20.4%	$106.13	$95.06	-10.4%

Average monthly bill = 6

COLUMBIA GAS OF KENTUCKY, INC.
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Work Paper Reference No(s):

				Monthly Customer Charge				Transportation Commodity Charge						
Line No.	Rate Code	Level of Demand (A)	Monthly Transp Volume (MCF) (B)	Current Monthly Customer Charge ($) (C)	Proposed Monthly Customer Charge ($) (D)	Dollar Increase (Decrease) (D - C) ($) (E)	Percent Increase (Decrease) (E/C) (%) (F)	Current Commodity Charge ($) (G)	Proposed Commodity Charge ($) (H)	Dollar Increase (Decrease) (H - G) ($) (I)	Percent Increase (Decrease) (I/G) (%) (J)	Total Current Bill (C + G) ($) (K)	Total Proposed Bill (D + H) ($) (L)	Percent Increase (Decrease) (L - K)/K (%) (M)
1	GTO	Not	10	$23.96	$28.45	$4.49	18.7%	$18.84	$18.84	$0.00	0.0%	$42.80	$47.29	10.5%
2	GTS	Applicable	30	$23.96	$28.45	$4.49	18.7%	$56.52	$56.52	$0.00	0.0%	$80.48	$84.97	5.6%
3	Choice		37	$23.96	$28.45	$4.49	18.7%	$69.71	$69.71	$0.00	0.0%	$93.67	$98.16	4.8%
4	Commercial		50	$23.96	$28.45	$4.49	18.7%	$94.20	$94.20	$0.00	0.0%	$118.16	$122.65	3.8%
5	and		70	$23.96	$28.45	$4.49	18.7%	$130.76	$130.76	$0.00	0.0%	$154.72	$159.21	2.9%
6	Industrial		100	$23.96	$28.45	$4.49	18.7%	$185.59	$185.59	$0.00	0.0%	$209.55	$214.04	2.1%
7			150	$23.96	$28.45	$4.49	18.7%	$276.97	$276.97	$0.00	0.0%	$300.93	$305.42	1.5%
8			200	$23.96	$28.45	$4.49	18.7%	$368.36	$368.36	$0.00	0.0%	$392.32	$396.81	1.1%
9			250	$23.96	$28.45	$4.49	18.7%	$459.74	$459.74	$0.00	0.0%	$483.70	$488.19	0.9%
10			300	$23.96	$28.45	$4.49	18.7%	$551.13	$551.13	$0.00	0.0%	$575.09	$579.58	0.8%
11			350	$23.96	$28.45	$4.49	18.7%	$642.51	$642.51	$0.00	0.0%	$666.47	$670.96	0.7%
12			400	$23.96	$28.45	$4.49	18.7%	$733.90	$733.90	$0.00	0.0%	$757.86	$762.35	0.6%
13			450	$23.96	$28.45	$4.49	18.7%	$821.00	$821.00	$0.00	0.0%	$844.96	$849.45	0.5%
14			355	$23.96	$28.45	$4.49	18.7%	$655.51	$655.51	$0.00	0.0%	$679.47	$683.96	0.7%
15			500	$23.96	$28.45	$4.49	18.7%	$908.10	$908.10	$0.00	0.0%	$932.06	$936.55	0.5%
16			700	$23.96	$28.45	$4.49	18.7%	$1,256.50	$1,256.50	$0.00	0.0%	$1,280.46	$1,284.95	0.4%
17			1,000	$23.96	$28.45	$4.49	18.7%	$1,779.10	$1,779.10	$0.00	0.0%	$1,803.06	$1,807.55	0.2%
18			1,200	$23.96	$28.45	$4.49	18.7%	$2,097.62	$2,097.62	$0.00	0.0%	$2,121.58	$2,126.07	0.2%

Average monthly bill = 37 (Commercial)
Average monthly bill = 355 (Industrial)

COLUMBIA GAS OF KENTUCKY, INC.
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				Monthly Customer Charge				Monthly Administrative Charge				Transportation Commodity Charge						
Line No.	Rate Code	Level of Demand (A)	Monthly Transp Volume (MCF) (B)	Current Monthly Customer Charge ($) (C)	Proposed Monthly Customer Charge ($) (D)	Dollar Increase (Decrease) (D - C) ($) (E)	Percent Increase (Decrease) (E/C) (%) (F)	Current Monthly Administrative Charge ($) (G)	Proposed Monthly Administrative Charge ($) (H)	Dollar Increase (Decrease) (H - G) ($) (I)	Percent Increase (Decrease) (I/G) (%) (J)	Current Commodity Charge ($) (K)	Proposed Commodity Charge ($) (L)	Dollar Increase (Decrease) (L - K) ($) (M)	Percent Increase (Decrease) (M/K) (%) (N)	Total Current Bill (C + G + K) ($) (O)	Total Proposed Bill (D + H + L) ($) (P)	Percent Increase (Decrease) (P - O)/O (%) (Q)
1	DS	Not	10	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$5.80	$5.80	$0.00	0.0%	$609.07	$683.90	12.3%
2	GTS	Applicable	150	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$86.99	$86.99	$0.00	0.0%	$690.26	$765.09	10.8%
3	Interruptible		300	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$173.97	$173.97	$0.00	0.0%	$777.24	$852.07	9.6%
4	Service		500	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$289.95	$289.95	$0.00	0.0%	$893.22	$968.05	8.4%
5	Commercial		1,000	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$579.90	$579.90	$0.00	0.0%	$1,183.17	$1,258.00	6.3%
6	and		3,000	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$1,739.70	$1,739.70	$0.00	0.0%	$2,342.97	$2,417.80	3.2%
7	Industrial		4,690	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$2,719.73	$2,719.73	$0.00	0.0%	$3,323.00	$3,397.83	2.3%
8			5,000	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$2,899.50	$2,899.50	$0.00	0.0%	$3,502.77	$3,577.60	2.1%
9			10,000	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$5,799.00	$5,799.00	$0.00	0.0%	$6,402.27	$6,477.10	1.2%
10			12,395	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$7,187.87	$7,187.87	$0.00	0.0%	$7,791.14	$7,865.97	1.0%
11			15,000	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$8,698.50	$8,698.50	$0.00	0.0%	$9,301.77	$9,376.60	0.8%
12			20,000	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$11,598.00	$11,598.00	$0.00	0.0%	$12,201.27	$12,276.10	0.6%
13			25,000	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$14,497.50	$14,497.50	$0.00	0.0%	$15,100.77	$15,175.60	0.5%
14			30,000	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$17,397.00	$17,397.00	$0.00	0.0%	$18,000.27	$18,075.10	0.4%
15			35,000	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$19,015.50	$19,015.50	$0.00	0.0%	$19,618.77	$19,693.60	0.4%
16			40,000	$547.37	$622.20	$74.83	13.7%	$55.90	$55.90	$0.00	0.0%	$20,634.00	$20,634.00	$0.00	0.0%	$21,237.27	$21,312.10	0.4%

Average monthly bill = 4,690 (Commercial)
Average monthly bill = 12,395 (Industrial)

Note: Customers electing Standby Service pay an additional $6.5482/Mcf per contracted volumes per month.

COLUMBIA GAS OF KENTUCKY, INC.
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Line No.	Rate Code	Level of Demand (A)	Monthly Transp Volume (MCF) (B)	Current Monthly Customer Charge ($) (C)	Proposed Monthly Customer Charge ($) (D)	Dollar Increase (Decrease) (D - C) ($) (E)	Percent Increase (Decrease) (E/C) (%) (F)	Current Monthly Administrative Charge ($) (G)	Proposed Monthly Administrative Charge ($) (H)	Dollar Increase (Decrease) (H - G) ($) (I)	Percent Increase (Decrease) (I/G) (%) (J)	Current Commodity Charge ($) (K)	Proposed Commodity Charge ($) (L)	Dollar Increase (Decrease) (L - K) ($) (M)	Percent Increase (Decrease) (M/K) (%) (N)	Total Current Bill (C + G + K) ($) (O)	Total Proposed Bill (D + H + L) ($) (P)	Percent Increase (Decrease) (P - O)/O (%) (Q)
1	GDS	Not	10	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$19.05	$19.05	$0.00	0.0%	$98.91	$103.40	4.5%
2	GTS	Applicable	30	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$57.14	$57.14	$0.00	0.0%	$137.00	$141.49	3.3%
3	General		50	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$95.24	$95.24	$0.00	0.0%	$175.10	$179.59	2.6%
4	Service		70	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$132.22	$132.22	$0.00	0.0%	$212.08	$216.57	2.1%
5	Commercial		100	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$187.67	$187.67	$0.00	0.0%	$267.53	$272.02	1.7%
6	and		150	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$280.09	$280.09	$0.00	0.0%	$359.95	$364.44	1.2%
7	Industrial		200	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$372.52	$372.52	$0.00	0.0%	$452.38	$456.87	1.0%
8			250	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$464.94	$464.94	$0.00	0.0%	$544.80	$549.29	0.8%
9			300	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$557.37	$557.37	$0.00	0.0%	$637.23	$641.72	0.7%
10			350	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$649.79	$649.79	$0.00	0.0%	$729.65	$734.14	0.6%
11			400	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$742.22	$742.22	$0.00	0.0%	$822.08	$826.57	0.5%
12			450	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$830.36	$830.36	$0.00	0.0%	$910.22	$914.71	0.5%
13			500	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$918.50	$918.50	$0.00	0.0%	$998.36	$1,002.85	0.4%
14			700	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$1,271.06	$1,271.06	$0.00	0.0%	$1,350.92	$1,355.41	0.3%
15			1000	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$1,799.90	$1,799.90	$0.00	0.0%	$1,879.76	$1,884.25	0.2%
16			1,196	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$2,116.13	$2,116.13	$0.00	0.0%	$2,195.99	$2,200.48	0.2%
17			1,200	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$2,122.58	$2,122.58	$0.00	0.0%	$2,202.44	$2,206.93	0.2%
18			1,443	$23.96	$28.45	$4.49	18.7%	$55.90	$55.90	$0.00	0.0%	$2,514.63	$2,514.63	$0.00	0.0%	$2,594.49	$2,598.98	0.2%

Average monthly bill = 1,196 (Commercial)
Average monthly bill = 1,443 (Industrial)

Note: Customers electing Standby Service pay an additional $6.5482/Mcf per contracted volumes per month.

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2009-00141
EFFECT OF PROPOSED TRANSPORTATION SERVICE RATES
TYPICAL BILL COMPARISON
As of December 31, 2008

Data: __ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original __ Update __Revised
Work Paper Reference No(s):

PSC Data Request Set 2 No. 43
Schedule N

Witness: M. P. Balmert

				Monthly Customer Charge				Monthly Administrative Charge				Transportation Commodity Charge						
Line No.	Rate Code	Level of Demand (A)	Monthly Transp Volume (MCF) (B)	Current Monthly Customer Charge ($) (C)	Proposed Monthly Customer Charge ($) (D)	Dollar Increase (Decrease) (D - C) ($) (E)	Percent Increase (Decrease) (E/C) (%) (F)	Current Monthly Administrative Charge ($) (G)	Proposed Monthly Administrative Charge ($) (H)	Dollar Increase (Decrease) (H - G) ($) (I)	Percent Increase (Decrease) (I/G) (%) (J)	Current Commodity Charge ($) (K)	Proposed Commodity Charge ($) (L)	Dollar Increase (Decrease) (L - K) ($) (M)	Percent Increase (Decrease) (M/K) (%) (N)	Total Current Bill (C + G + K) ($) (O)	Total Proposed Bill (D + H + L) ($) (P)	Percent Increase (Decrease) (P - O)/O (%) (Q)
1	SAS	Not	10	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$5.59	$5.59	$0.00	0.0%	$261.49	$683.69	161.5%
2	GTS	Applicable	150	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$83.87	$83.87	$0.00	0.0%	$339.77	$761.97	124.3%
3	Special		300	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$167.73	$167.73	$0.00	0.0%	$423.63	$845.83	99.7%
4	Rate		500	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$279.55	$279.55	$0.00	0.0%	$535.45	$957.65	78.8%
5	Industrial		1,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$559.10	$559.10	$0.00	0.0%	$815.00	$1,237.20	51.8%
6			3,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$1,677.30	$1,677.30	$0.00	0.0%	$1,933.20	$2,355.40	21.8%
7			4,209	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$2,353.25	$2,353.25	$0.00	0.0%	$2,609.15	$3,031.35	16.2%
8			5,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$2,795.50	$2,795.50	$0.00	0.0%	$3,051.40	$3,473.60	13.8%
9			10,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$5,591.00	$5,591.00	$0.00	0.0%	$5,846.90	$6,269.10	7.2%
10			15,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$8,386.50	$8,386.50	$0.00	0.0%	$8,642.40	$9,064.60	4.9%
11			20,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$11,182.00	$11,182.00	$0.00	0.0%	$11,437.90	$11,860.10	3.7%
12			25,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$13,977.50	$13,977.50	$0.00	0.0%	$14,233.40	$14,655.60	3.0%
13			30,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$16,773.00	$16,773.00	$0.00	0.0%	$17,028.90	$17,451.10	2.5%
14			35,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$18,287.50	$18,287.50	$0.00	0.0%	$18,543.40	$18,965.60	2.3%
15			40,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$19,802.00	$19,802.00	$0.00	0.0%	$20,057.90	$20,480.10	2.1%
16			45,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$21,316.50	$21,316.50	$0.00	0.0%	$21,572.40	$21,994.60	2.0%
17			50,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$22,831.00	$22,831.00	$0.00	0.0%	$23,086.90	$23,509.10	1.8%
18			55,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$24,345.50	$24,345.50	$0.00	0.0%	$24,601.40	$25,023.60	1.7%
19			60,000	$200.00	$622.20	$422.20	211.1%	$55.90	$55.90	$0.00	0.0%	$25,860.00	$25,860.00	$0.00	0.0%	$26,115.90	$26,538.10	1.6%

Average monthly bill = 4209

*SAS Monthly Gas Cost not included.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 044:

Refer to page 42 of the Balmert Testimony. The fourth rate objective achieved by the SFV rate design, as cited by Mr. Balmert, is alleviating the need for a decoupling mechanism which requires frequent controversial reconciliations and weather adjustments.

a. Explain whether Columbia is no longer interested in a rate stabilization or annual rate-review mechanism such as was set forth in the Joint Direct Testimony of Columbia, Delta Natural Gas, Inc., and Atmos Energy Corporation in Administrative Case No. 2008-00408.3

b. If Columbia were to move completely to an SFV rate design in Year 2 as proposed, would it propose to discontinue the use of its Weather Normalization Adjustment? Explain the response.

Response:

a. Columbia believes that the implementation of a SFV rate design is preferable to the implementation of a rate stabilization or annual rate-review mechanism such as was set forth in the Joint Direct Testimony of Columbia, Delta Natural Gas, Inc., and Atmos Energy Corporation in Administrative Case No. 2008-00408.3. However, in the absence of the implementation of a SFV rate design Columbia remains interested in such a mechanism. Even with the implementation of a SFV rate design Columbia remains interested in a rate stabilization or annual rate-review mechanism for Columbia's General Service commercial and industrial class.

b. The Weather Normalization Adjustment should be continued for residential customers not on the GSR/GTR rate schedules and for the General Service commercial customers. These rate schedules will continue to bill volumetric base rates as they do currently for recovery of delivery service under the proposed rate design, and therefore their usage and recovery of fixed costs will continue to be influenced by weather. The WNA will continue to allow Columbia a reasonable opportunity to recover fixed costs while mitigating the financial effects of colder than normal winters on customer bills.

PSC Case No. 2009-00141
Staff Set 2 DR No. 045
Respondent(s): Mark Balmert

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 045:

Refer to Attachment MPB-1, page 8. For Factor No. 16, Mr. Balmert states that, "individual installed meters for residential, small commercial, and small industrial customers were identified on Columbia's DIS and summarized by the four "pressure groups". Explain what is meant by "Columbia's DIS" and identify the four pressure groups.

Response:

DIS is the name of one of Columbia's billing systems. DIS stands for Distributive Information System. DIS bills Columbia's sales and Choice transportation customers whose meters are read on a monthly basis. DIS is also the repository of base data for all Columbia's customers including those billed by GMB (Gas Measurment billing) which bills daily read sales and Choice transportation customers and GTS (Gas Transportation System) which bills non-Choice transportation customers.

Meter information for all customers is stored in DIS even if DIS does not directly bill the customer.

The four pressure groups that meter information is identified under are:

0 – 500 CFH
501 – 1,000 CFH
1,001-1,500 CFH
Over 1,500 CFH

PSC Case No. 2009-00141
Staff Set 2 DR No. 046
Respondent(s): Mark Balmert

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 046:

Refer to Attachment MPB-2.

a. In column D heading, should the factor read D = C x .6132?
b. In column G heading, should the factor read G = F x .3868?

Response:

a. Yes
b. Yes

PSC Case No. 2009-00141
Staff Set 2 DR No. 047
Respondent(s): Mark Balmert

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 047:

Refer to Attachment MPB-6 of the Balmert Testimony. Provide an electronic version of this schedule with the formulas intact and unprotected.

Response:

Please see the file provided on compact disk.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 048:

Refer to Tab 39 in Volume 5 of 8 of the application.

a. Provide an electronic version of both cost-of-service studies with the formulas intact and unprotected.

b. Describe all differences in methodology between the cost-of-service studies filed in Columbia's most recent rate case and the current case.

Response:

a. Please see the files provided on compact disk.

b. There have been no changes in methodology for the studies since the last rate case.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 049:

Refer to Tab M of Volume 6 of 8 of the application.

a. Refer to Schedule M-2.1, page 1 of 6.

(1) Provide a general description of the rate schedules G1R and G1C, IN3-IN5, and LG2-LG4.

(2) Provide an explanation for the adjustment on Line 12 entitled "Rate Refund Normalization".

(3) On line 20, explain why the "Base Period Revenue Less Gas Cost Revenue" is a negative number.

b. Refer to Schedule M-2.1 , pages 2-5 of 6. Explain why adjustments are made to add estimated bills for December 2008 and actual bills for December 2007 and to subtract actual bills for December 2008 and estimated bills for December 2007. Include in the explanation the meaning of "GMB" that appears at the front of each of these adjustment titles.

c. Refer to Schedule M-2.1, page 4. Provide a general description of the rate schedules FXI -FX8.

d. Refer to Schedule M-2.1, page 6. Describe in detail the nature of the $10,897,017 amount recorded in Account 495, Non-Traditional Sales.

e. Refer to Schedule M-2.2. Column M appears to be the result of subtracting Column K from Column F. Explain what Column F contains and why it does not appear on this schedule.

f. Refer to Schedule M-2.2, page 21 of 38. Explain why the EAP Recovery rate charged to this rate class is .0549 as opposed to the .0525 charged to rate class GSR.

g. Provide an electronic version of Schedules M-2.2 and M-2.3 with the formulas intact and unprotected.

Response:

a.

(1) Rate schedules G1R, G1C, LG2-LG4, and IN3-IN5 are customers served under right-of-way contracts which Columbia has acquired over the years.

(2) As Columbia receives refunds from pipelines and suppliers, Columbia books a debit to revenue and a credit to a liability account on the financial statement in the month the refund is received. As Columbia refunds these dollars each month, the revenue account is credited the liability account is debited. These credits sum to make up the Rate Refund Normalization amount on Schedule M-2.1.

(3) During the test year, rate schedule G1C customers were billed less than Columbia's average gas cost rate, per their right-of-way contract. The agreement states that these customers will pay a rate for gas which is not to exceed the current rate for domestic use in the city of Louisville, KY.

b. Columbia must estimate current month revenues due to the timing lag of two billing systems, GMB (GMB for large volume sales and transportation customers) and GTS (GTS billing for non-Choice transportation customers). Therefore, each month, Columbia books the current month estimated revenue, the prior month's actual invoiced revenue, and the prior month's estimate is reversed. Schedule M-2.1 shows actual invoiced revenue for the test year 12 months ending December 2008. As estimated revenue is reversed and replaced by actual invoiced revenue on Columbia's books, the remaining pieces to reconcile Schedule M-2.1 to Columbia's financial statement is to add December 2008 estimated revenue, plus December 2007 actual invoiced revenue, and subtract December 2008 actual invoiced revenue and December 2007 estimated revenue.

c. Rate schedules FX1-FX8 are special contract customers with alternate fuel capabilities. These customers' rates are flexed off of Columbia's normal distribution rates.

d. The $10,897,017 is revenue from off system sales during the test year. The accounting for the off-system sales recognizes revenue in other gas department revenue equal to the gas costs. Any margin realized on the sale is credited to the Company's Gas Cost Adjustment Clause and the appropriate sharing level, if achieved, to below the line income. The off-system sales/Non-Traditional sales activity has a zero impact on Operating Income.

e. Column F contains proposed base revenue excluding gas cost which, is found on Schedule M-2.3 Annualized Test Year Revenue at Proposed Rates. Column M on Schedule M-2.2 is merely designed to show the increase on base revenue of proposed rates versus current rates.

f. When Schedule M-2.2 was originally prepared, the EAP of $.0549/Mcf was the last approved rate by the Commission. Subsequently, in March, a new EAP rate of $.0525/Mcf was approved and went into effect and Schedule M-2.2 was updated to reflect the new rate. The old rate of $.0549/Mcf was inadvertently left unchanged for rate schedule GTR customers.

g. Please see the file on compact disk.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 050:

Refer to Tab 39 in Volume 5 of 8 of the application.

a. Refer to page 1 of 28. On line 2, total company operating and maintenance is shown as $30,401,363. What accounts for the difference between this amount and the $30,219,684 that appears on page 3 of 28, line 3?

b. Refer to page 12 of either cost-of-service study. Provide this schedule using proposed rates. The total on line 11 of the requested schedule should equal line 1, Total Revenues, on page 1 of both studies.

c. Refer to page 27 of both cost-of-service studies. For Factor No. 8, explain why the percentages on line 16 do not correlate with the amounts on line 15. As Factor 8 allocations were made using the percentages as they appear on these pages, if corrections to the percentages on line 16 are necessary, update all affected schedules.

Response:

a. Total company operating expense is $181,679 higher at proposed rates due the increase in total revenue. This consists of uncollectible expense of $163,140 and Kentucky PSC fees of $18,539.

b. Please see the attachment.

c. Line 16 allocation percentages for factor 8 were not being referenced properly. The studies have been corrected and the change in returns is not material enough to warrant changes to rate design. Please see the revised studies provided on compact disk.

PSC Data Request Set 2 No. 50-b

COLUMBIA GAS OF KENTUCKY, INC.
OPERATING REVENUE @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED 12/31/2008

WITNESS: M. Balmert

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	GS-RES. (E) $	GS-OTHER (F) $	IUS (G) $	DS-ML/SC (H) $	DS/IS (I) $
1	OPERATING REVENUE								
2	480	RESIDENTIAL SALES		101,348,949	101,348,949	0	0	0	0
3	481.1	COMMERCIAL SALES		52,286,219	0	52,286,219	0	0	0
4	481.2	INDUSTRIAL SALES		2,094,076	0	1,873,891	220,185	0	0
5		TOTAL SALES REVENUE		155,729,244	101,348,949	54,160,110	220,185	0	0
6	487	FORFEITED DISCOUNTS		457,733	290,280	154,494	584	2	12,373
7	488/495	OTHER REVENUE	6	637,046	570,660	65,998	6	25	357
8	489	REVENUE FROM TRANSPORTATION		19,302,412	8,596,305	4,415,790	0	745,187	5,545,130
10		TOTAL OTHER GAS DEPT REVENUE		20,397,191	9,457,245	4,636,282	590	745,214	5,557,860
11		TOTAL OPERATING REVENUE		176,126,435	110,806,194	58,796,392	220,775	745,214	5,557,860

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 051:

Refer to page 12 of the Prepared Direct Testimony of John J. Spanos ("Spanos Testimony").

a. Explain why 1969 through 2008 was chosen as the historical period used to estimate the net salvage percentages used in Mr. Spanos' depreciation study.

b. Identify the other gas companies for which Mr. Spanos considered estimates and whether those estimates were developed by Mr. Spanos or his firm.

c. Provide a detailed explanation for why Mr. Spanos chose to use the equal life group procedure for determining the remaining life annual accrual for each vintage property group. If the equal life group procedure reflects a change from the method currently used by Columbia, identify and describe the current method.

Response:

a) The 1969 through 2008 period was chosen as the historical period for the net salvage analyses because those were the years of available data.

b) The attached schedule sets forth the other gas companies for which Mr. Spanos considered estimates. This group of gas companies was developed by Mr. Spanos or his firm.

c) Mr. Spanos chose to use the Equal Life Group for determining the remaining life annual accruals for each property group because it is the superior procedure for matching asset utilization to asset consumption. The Equal Life Group procedure is a change from the currently used procedure. The current procedure is the Average Service Life procedure.

PSC Case No. 2009-00141
Staff Set 1 DR No. 052
Respondent(s): John Spanos

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 052:

Refer to the question and answer beginning at the bottom of page 14 of the Spanos Testimony. The second sentence in the answer states that "historical data did not maintain a type pipe identifier, but historical balances were available by pipe type, therefore, separate life characteristics could not be accurately studied." Explain why having historical balances available "by pipe type" prevented an accurate study of separate life characteristics.

Response:

Having historical balances "by pipe type" does not prevent an accurate study of separate life characteristics, however, not having historical additions and retirements by vintage and transaction year does prevent any analyses. In order to conduct an actuarial life analyses by type pipe, the historical additions, retirements and balances must be available by vintage and transaction year.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 053:

Refer to the depreciation study performed by Mr. Spanos filed at Tab 32 in Volume 2 of 8 of Columbia's application.

a. Refer to pages 11-11 through 11-15. Provide general definitions of the terms "Experience Band" and "Placement Band" and explain why the periods of the two bands are 10 and 15 years, respectively.

b. Refer to page 11-25. Explain why statistical indications for the periods 1939 through 2008 and 1974 through 2008 are the bases for the survivor curve estimate for Accounts 376, Mains.

c. Refer to pages 11-25 through 11-27. Columbia's net salvage percent for Account 376, Mains, based on the period 1969 through 2008, is 12 percent negative net salvage while the range of estimates made by other gas companies for mains is negative 15 to negative 75 percent. Columbia's cost of removal for the most recent five years averaged 13 percent. With this set of facts, explain why it is appropriate to select negative 15 percent for Columbia's mains.

d. For all Columbia's plant accounts other than Account 376, Mains, provide the net salvage percent based on the period 1969 through 2008, the average cost of removal for the five most recent years, and the range of estimates made by other gas companies.

e. Identify the other gas companies from whom the range of estimates was developed and any of the estimates that were developed by Mr. Spanos or his firm.

Response:

a) An "Experience Band" is a period of time where transaction year data is analyzed for life characteristics. A "Placement Band" is the installation year or vintage year of the transactional data within the experience band. The 10-year experience band and 15-year placement band were determined as reasonable periods of time in order to illustrate how a life table is developed. Pages II-11 through II-19 describe the development of a life table.

b) The 1939 through 2008 experience band was selected for statistical indications for Account 376, Mains, because this is the overall period of historical data available to analyze. The 1974 through 2008 experience band was selected as a representative period of time to reflect current life characteristics of all mains.

c) As discussed on page II-27 of the Depreciation Study, the estimate of net salvage is more than a statistical exercise. There is a need to incorporate informed judgment. The most common industry average is negative 15 to negative 75 percent. The Company is in the process on retiring considerable amounts of cast iron and bare steel pipe which will require considerable amounts of labor hours. With this added information, the most appropriate estimate was negative 15 percent for mains.

d) The net salvage data that is available to analyze is set forth for all accounts on pages III-102 through III-131 of the depreciation study. A sample of other gas company estimates is set forth in response to AG-1-098.

e) See the attachment to AG-1-098.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 054:

Refer to page 4 of the Prepared Direct Testimony of June M. Konold ("Konold Testimony") regarding how Rider POM would work. Clarify whether the reference to Columbia having a fiscal year ending June 30th is correct.

Response:

The reference in question was never intended to imply that Columbia had a fiscal year ending June 30th for financial reporting purposes. Rather the intent was to clarify that the amounts included in Rider POM would be based on an accounting period covering the 12 consecutive months ending June 30th. However, as noted in Sheet 59 of the tariff, the first filing would be based on the eighteen month period ending June 30, 2010. Subsequent filings would be based on a twelve month period ending June 30th. For financial reporting purposes, Columbia's fiscal year ends December 31st.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 055:

Refer to the table on Page 5 of the Konold Testimony.

a. explain, generally, why the year-to-year percent of change has been so much greater for pension expense than for OPEB expense for the period 2004 to 2009.

b. The pension expense and OPEB expense amounts for calendar year 2009 are estimates. Provide workpapers, spreadsheets, calculations, etc. which show the derivation of these estimates. Include a narrative description which identifies all relevant assumptions.

c. Provide the same information shown in the table for 2004 through 2009 for the years 1999 through 2003.

Response:

a. During the period under consideration, the main driver of expense volatility has been asset returns. Because the pension plan is larger and better funded than the OPEB plans in aggregate, the dollar amount of pension assets is significantly greater than the dollar amount of OPEB assets. Therefore the asset return volatility has a relatively greater impact on pension expense than OPEB expense.

b. Please refer to Attachment A for a copy of the Columbia Energy Group actuarial report which includes narrative description identifying all relevant assumptions. The amounts derived from the actuarial report are not likely to change. However the amount of OPEB and pension expense allocated to capital is based on the estimated percentage of direct labor transferred to capital and that amount is subject to change.

c. Please refer to the table below for years 1999 through 2003.

Year	Pension Expense	Change from Prior Year	Percent of Change	OPEB Expense	Change from Prior Year	Percent of Change
1999	$ (173,000)			$ 887,141		
2000	$ (627,020)	$ (454,020)	262.4%	$ 912,228	$ 25,087	2.8%
2001	$ (126,000)	$ 501,020	79.9%	$ 879,978	$ (32,250)	3.5%
2002	$ 112,000	$ 238,000	188.9%	$ 857,533	$ (22,445)	2.6%
2003	$ 391,556	$ 279,556	249.6%	$ 697,269	$ (160,264)	18.7%

Preparation of this Actuarial Valuation

As of December 31, 2008

NiSource Inc.
Pension and Other Postretirement Benefit Plans

This report has been prepared to present to management the accounting and reporting requirements for the 2008 fiscal year for pension and postretirement benefits as set forth in FASB Statement of Financial Accounting Standard No. 87 as amended ("SFAS No. 87"), No. 88 as amended ("SFAS No. 88"), and No. 106 as amended ("SFAS No.106")—including the provisions of SFAS No. 132(R) and SFAS No. 158. Determinations for purposes other than financial accounting requirements may be significantly different from the results reported herein. Thus, the use of this report for purposes other than those expressed here may not be appropriate. The results as of other dates may also be significantly different from the results reported herein and the scope of this report does not include an analysis of the potential range of results as of other dates.

In conducting the valuation, we have relied on personnel, plan design, health care claim cost, and asset information supplied by NiSource (and its health plans). While we cannot verify the accuracy of all this information, the supplied information was reviewed for consistency and reasonability. As a result of this review, we have no reason to doubt the substantial accuracy or completeness of the information and believe that it has produced appropriate results. This information along with any adjustments or modifications is summarized in various sections of this report. In calculating 2008 expense, we have measured liabilities as of December 31, 2007. In calculating projected year-end disclosure results, we have measured liabilities as of December 31, 2008. Except as specifically noted elsewhere in this report, these projected results do not reflect changes in assumptions and other significant events between January 1, 2008 and the December 31, 2008 year-end measurement date.

This valuation has been conducted in accordance with generally accepted actuarial principles and practices, including the applicable Actuarial Standards of Practice as issued by the Actuarial Standards Board. In addition, the valuation results are based on our understanding of the requirements of SFAS No. 87, SFAS No. 88, and SFAS No. 106. The information in this report is not intended to supersede or supplant the advice and interpretations of the Company's auditors.

The actuarial assumptions and methods used in this valuation are described in later sections of this report. The economic assumptions used for purposes of compliance with SFAS No. 87, SFAS No. 88, and SFAS No. 106 were prescribed by NiSource. While the discount rate assumption was prescribed by NiSource, Hewitt Associates provided guidance with respect to this assumption, and it is our belief that it, as well as the non-prescribed assumptions are reasonable. Hewitt Associates selected the demographic assumptions and it is our belief that they represent reasonable expectations of anticipated plan experience. The actuarial cost method used is prescribed by SFAS No. 87 and SFAS No. 106.

The preparation of this report included both health care and pension actuaries familiar with the near-term and long-term aspects of pension and postretirement benefits. The undersigned are familiar with the necessary aspects of pension and postretirement valuations and meet the Qualification Standards of the American Academy of Actuaries necessary to render the actuarial opinions herein. All of the sections of this report are considered an integral part of the actuarial opinions.

Preparation of this Actuarial Valuation

To our knowledge, no associate of Hewitt Associates providing services to NiSource has any direct financial interest or indirect material interest in NiSource. Thus, we believe there is no relationship existing that might affect our capacity to prepare and certify this actuarial report for NiSource.

Hewitt Associates LLC

Nicholas J. Craig
Fellow of the Society of Actuaries
Enrolled Actuary

Anne K. Goepfert
Fellow of the Society of Actuaries
Enrolled Actuary

March 2009

About this Material

This report contains 2008 year-end disclosure information in revised FAS 158 format for the NiSource Inc. pension and postretirement health care and life insurance plans.

Actuarial Assumptions and Methods

The assumptions used to develop 2008 expense are fully documented in the 2008 FAS 87 and FAS 106 expense reports. The same assumptions were used to develop 2008 year-end liabilities with the following exceptions:

Discount Rate	6.92%
Health Care Trend Rate	9.00% in 2008 grading down to 5.00% in 2014
Mortality Rates	RP2000 Combined Healthy projected with Scale AA to 2009
Retirement Age	Updated for terminated vested participants
Health Care Claims	Updated based on experience through December 2007
Cash Balance Interest Crediting Rate	5.00%
Lump Sum Conversion Rate	5.00%
Payment form Election Percentage	Updated for NiSource and Columbia participants

All results shown reflect the impact of the sale of Northern Utilities and Granite to Unitil Service Corp.

Plan Provisions

The plan provisions used to develop 2008 expense are fully documented in the 2008 FAS 87 and FAS 106 expense reports. The same plan provisions were used to develop 2008 year-end liabilities with the following exceptions:

- The defined dollar retiree medical plan was extended to Lawrence union employees who retire on or after January 1, 2013.

- The current Final Average Pay pension option for Lawrence union employees will sunset in 2013, and all active employees at that time will be placed in the Account Balance 2011 pension option.

About this Material

Participant Data

2008 expense was developed from participant data as of January 1, 2007 as summarized in the 2008 FAS 87 and FAS 106 expense reports. 2008 year-end liabilities were developed from participant data as of January 1, 2008 as summarized below.

Pension

	January 1, 2008		
	[redacted]	Columbia	[redacted]
Number of Participants			
Actives		4,042	
Retirees & Beneficiaries		4,199	
Vested Terminations		3,132	
Total		11,373	
Characteristics of Active Participants			
Average Age	[redacted]	47.9	
Average Service		20.0	
Average Pay		$ 59,300	
Total Payroll ($ Millions)		$ 239.7	

Postretirement Welfare

	January 1, 2008		
	[redacted]	Columbia	[redacted]
Health Care Participants			
Actives		4,041	
Retirees & Surviving Spouses		2,314[2]	
Retirees' Spouses		1,526	
Total		7,881	
Life Insurance Participants			
Actives		2,966[5]	
Retirees		1,926	
Total		4,892	

Supplemental 2008 year-end FAS 87 and FAS 106 reports will be issued detailing the development of the disclosure information and the calculation of fiscal 2009 expense.

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[1] Excludes 33 retirees with post-65 supplement only.
[2] Excludes 3,684 retirees with post-65 supplement coverage only.
[3] Excludes 6 retirees with post-65 supplement only.
[4] Excludes 3 retirees with post-65 supplement only.
[5] 4,041 active employees, but eligibility is limited to those employees over age 45.

Columbia Energy Group
Disclosure under FAS 158 - Qualified Pension Plan

	2008	2007	2006
Accumulated Benefit Obligation at End of Year	$ 783,682,906	$ 763,212,594	$ 778,829,462
Change in Projected Benefit Obligation			
Benefit Obligation at Prior Year Measurement Date	$ 805,511,015	$ 853,386,552	$ 876,410,640
Adjustment for Change in Measurement Date	-	(1,837,351)	-
Benefit Obligation at Beginning of Year	$ 805,511,015	$ 851,549,201	$ 876,410,640
Service Cost	18,267,001	20,113,373	20,207,481
Interest Cost	49,427,905	47,621,878	46,533,335
Participant Contributions	-	-	-
Plan Amendments	-	(11,851,275)	112,505
Plan Merger	-	-	-
Divestitures	-	-	-
Curtailment (Gain)/Loss	-	-	-
Settlement (Gain)/Loss	-	-	-
Special Termination Benefits	-	-	-
Benefits Paid	(65,658,429)	(63,831,305)	(69,247,394)
Settlement Payments	-	-	-
Actuarial (Gain)/Loss	16,690,960	(38,090,857)	(20,630,015)
Benefit Obligation at End of Year	$ 824,238,452	$ 805,511,015	$ 853,386,552
Change in Plan Assets			
Fair Value of Plan Assets at Prior Year Measurement Date	$ 881,249,808	$ 827,699,253	$ 822,246,737
Adjustment for Change in Measurement Date	-	30,954,031	-
Fair Value of Plan Assets at Beginning of Year	$ 881,249,808	$ 858,653,284	$ 822,246,737
Actual Return on Plan Assets	(250,275,732)	86,427,829	74,699,910
Plan Merger	-	-	-
Divestitures	-	-	-
Employer Contributions	-	-	-
Participant Contributions	-	-	-
Benefits Paid	(65,658,429)	(63,831,305)	(69,247,394)
Settlement Payments	-	-	-
Administrative Expenses	-	-	-
Fair Value of Plan Assets at End of Year	$ 565,315,647	$ 881,249,808	$ 827,699,253
Funded Status	$ (258,922,805)	$ 75,738,793	$ (25,687,299)
Contribution Made After Measurement Date and Before Fiscal Year End	N/A	N/A	$ -
Net Amount Recognized at End of Year	$ (258,922,805)	$ 75,738,793	$ (25,687,299)
Amounts Recognized in the Statement of Financial Position Consist of:			
Noncurrent Assets	$ -	$ 75,738,793	$ -
Current Liabilities	-	-	-
Noncurrent Liabilities	(258,922,805)	-	(25,687,299)
Net Amount Recognized at End of Year	$ (258,922,805)	$ 75,738,793	$ (25,687,299)
Measurement Date	12/31/2008	12/31/2007	9/30/2006
Amounts Recognized in Accumulated Other Comprehensive Income			
Net Transition (Asset)/Obligation	$ -	$ -	$ -
Prior Service Cost	(27,751,829)	(30,471,742)	(20,786,644)
Net Actuarial (Gain)/Loss	329,433,122	(13,858,053)	68,678,707
	$ 301,681,293	$ (44,329,795)	$ 47,892,063

Columbia Energy Group
Disclosure under FAS 158 - Qualified Pension Plan

		2008		2007		2006
Components of Net Periodic Benefit Cost						
Service Cost	$	18,267,001	$	20,113,373	$	20,207,481
Interest Cost		49,427,905		47,621,878		46,533,335
Expected Return on Plan Assets		(76,324,483)		(73,903,796)		(71,270,706)
Amortization of Transitional (Asset)/Obligation		-		-		-
Amortization of Prior Service Cost		(2,719,913)		(1,732,942)		(1,741,596)
Recognized Actuarial (Gain)/Loss		-		-		424,739
Net Periodic Benefit Cost	$	(11,349,490)	$	(7,901,487)	$	(5,846,747)
Additional (Gain)/Loss Recognized due to:						
Curtailment	$	-	$	-	$	-
Divestitures		-		-		-
Special Termination Benefits		-		-		-
Settlement		-		-		-
Total Net Pension Cost	$	(11,349,490)	$	(7,901,487)	$	(5,846,747)
Adjustment to Retained Earnings for Measurement Date Change		N/A	$	(1,302,747)		N/A
Other Changes in Plan Assets and Projected Benefit Obligation Recognized in Other Comprehensive Income						
Adjustment for Change in Measurement Date	$	-	$	(31,488,635)		N/A
Curtailment (Gain)/Loss		-		-		N/A
Divesiture (Gain)/Loss		-		-		N/A
Prior Service Cost/(Credit)		-		(11,851,275)		N/A
Net Actuarial (Gain)/Loss		343,291,175		(50,614,890)		N/A
Less: Amortization of Transitional (Asset)/Obligation		-		-		N/A
Less: Amortization of Prior Service Cost		2,719,913		1,732,942		N/A
Less: Amortization of Net Actuarial (Gain)/Loss		-		-		N/A
Total Recognized in Other Comprehensive Income	$	346,011,088	$	(92,221,858)		N/A
Total Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	$	334,661,598	$	(100,123,345)		N/A

The estimated net actuarial loss, prior service cost, and transition obligation for the defined benefit pension plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost during the 2009 fiscal year are $20,932,990, $(2,719,913), and $0, respectively.

		2008		2007		2006
Weighted-Average Assumptions to Determine Benefit Obligations						
Discount Rate		6.92%		6.40%		5.85%
Rate of Compensation Increases		4.00%		4.00%		4.00%
Weighted-Average Assumptions to Determine Net Periodic Benefit Cost						
Discount Rate		6.40%		5.85%		5.50%
Expected Long-Term Rate of Return on Plan Assets		9.00%		9.00%		9.00%
Rate of Compensation Increases		4.00%		4.00%		4.00%
Expected Contributions for Fiscal 2009	$	0				

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Year(s)		Pension Benefits
2009	$	59,900,000
2010		61,950,000
2011		76,900,000
2012		70,900,000
2013		61,400,000
2014 - 2018		413,250,000

Columbia Energy Group
Disclosure under FAS 158 - Postretirement Medical and Life Benefits

		2008		2007		2006
Change in Projected Benefit Obligation						
Benefit Obligation at Prior Year Measurement Date	$	350,397,369	$	380,550,583	$	393,498,183
Adjustment for Change in Measurement Date		-		1,384,064		-
Benefit Obligation at Beginning of Year	$	350,397,369	$	381,934,647	$	393,498,183
Service Cost		4,347,606		5,237,470		4,885,133
Interest Cost		21,868,632		21,422,387		20,974,948
Estimated Participant Contributions		2,612,473		2,397,695		1,696,187
Plan Amendments		-		2,127,118		-
Plan Merger		-		-		-
Curtailment (Gain)/Loss		-		-		-
Settlement (Gain)/Loss		-		-		-
Special Termination Benefits		-		-		-
Estimated Benefits Paid		(23,622,505)		(18,794,514)		(26,889,129)
Estimated Benefits Paid by Incurred Subsidy		601,108		569,245		380,593
Settlement Payments		-		-		-
Actuarial (Gain)/Loss		(31,236,296)		(44,496,679)		(13,995,332)
Benefit Obligation at End of Year	$	324,968,387	$	350,397,369	$	380,550,583
Change in Plan Assets						
Fair Value of Plan Assets at Prior Year Measurement Date	$	274,294,787	$	227,304,061	$	206,122,970
Adjustment for Change in Measurement Date		-		11,439,486		-
Fair Value of Plan Assets at Beginning of Year	$	274,294,787	$	238,743,547	$	206,122,970
Actual Return on Plan Assets		(87,507,919)		26,049,896		20,452,974
Plan Merger		-		-		-
Estimated Employer Contributions		22,196,409		25,898,163		25,921,059
Estimated Participant Contributions		2,612,473		2,397,695		1,696,187
Estimated Benefits Paid		(23,622,505)		(18,794,514)		(26,889,129)
Settlement Payments		-		-		-
Administrative Expenses		-		-		-
Fair Value of Plan Assets at End of Year	$	187,973,245	$	274,294,787	$	227,304,061
Funded Status	$	(136,995,142)	$	(76,102,582)	$	(153,246,522)
~~Contribution Made After Measurement Date~~ and Before Fiscal Year End		N/A		N/A		4,536,372
Estimated Subsidy Incurred After Measurement Date and Before Fiscal Year End		N/A		N/A		(126,864)
Net Amount Recognized at End of Year	$	(136,995,142)	$	(76,102,582)	$	(148,837,014)
Amounts Recognized in the Statement of Financial Position Consist of:						
Noncurrent Assets	$	7,908,843	$	25,252,573	$	-
Current Liabilities		-		-		-
Noncurrent Liabilities		(144,903,985)		(101,355,155)		(148,837,014)
Net Amount Recognized at End of Year	$	(136,995,142)	$	(76,102,582)	$	(148,837,014)
Measurement Date		12/31/2008		12/31/2007		9/30/2006
Amounts Recognized in Accumulated Other Comprehensive Income						
Net Transition (Asset)/Obligation	$	-	$	-	$	-
Prior Service Cost		7,989,878		8,334,325		6,291,345
Net Actuarial (Gain)/Loss		77,870,818		(2,171,174)		58,642,658
	$	85,860,696	$	6,163,151	$	64,934,003
Effect of a 1% Increase in Assumed Health Care Cost Trend Rate for Medical Benefits						
Effect on Total of Service and Interest Cost	$	1,147,000	$	1,305,000	$	1,383,000
Effect on Postretirement Benefit Obligation	$	13,337,000	$	15,478,000	$	18,954,000
Effect of a 1% Decrease in Assumed Health Care Cost Trend Rate for Medical Benefits						
Effect on Total of Service and Interest Cost	$	(1,095,000)	$	(1,239,000)	$	(1,307,000)
Effect on Postretirement Benefit Obligation	$	(12,759,000)	$	(14,760,000)	$	(17,975,000)

Columbia Energy Group
Disclosure under FAS 158 - Postretirement Medical and Life Benefits

	2008	2007	2006
Components of Net Periodic Benefit Cost			
Service Cost	$ 4,347,606	$ 5,237,470	$ 4,885,133
Interest Cost	21,868,632	21,422,387	20,974,948
Expected Return on Plan Assets	(22,502,450)	(19,369,796)	(16,987,702)
Amortization of Transitional (Asset)/Obligation	-	-	-
Amortization of Prior Service Cost	344,447	67,311	67,311
Recognized Actuarial (Gain)/Loss	(476,264)	1,447,874	3,378,204
Net Periodic Benefit Cost	$ 3,581,971	$ 8,805,246	$ 12,317,894
Additional (Gain)/Loss Recognized due to:			
Curtailment	$ -	$ -	$ -
Special Termination Benefits	-	-	-
Settlement	-	-	-
Total Net Benefit Cost	$ 3,581,971	$ 8,805,246	$ 12,317,894
Adjustment to Retained Earnings for Measurement Date Change	N/A	$ 2,560,092	N/A
Other Changes in Plan Assets and Postretirement Benefit Obligation Recognized in Other Comprehensive Income			
Adjustment for Change in Measurement Date	$ -	$ (8,206,006)	N/A
Prior Service Cost/(Credit)	-	2,127,118	N/A
Net Actuarial (Gain)/Loss	78,774,073	(51,176,779)	N/A
Curtailment	-	-	N/A
RMBS Correction	791,655	-	N/A
Less:Amortization of Transitional (Asset)/Obligation	-	-	N/A
Less:Amortization of Prior Service Cost	(344,447)	(67,311)	N/A
Less:Amortization of Net Actuarial (Gain)/Loss	476,264	(1,447,874)	N/A
Total Recognized in Other Comprehensive Income	$ 79,697,545	$ (58,770,852)	N/A
Total Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	$ 83,279,516	$ (49,965,606)	N/A

The estimated net actuarial loss, prior service cost, and transition obligation for the postretirement benefit plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost during the 2009 fiscal year are $3,283,550, $913,118, $0, respectively, for health care and $519,799, ($256,496), $0, respectively, for life insurance.

	2008	2007	2006
Weighted-Average Assumptions to Determine Benefit Obligations			
Discount Rate	6.92%	6.40%	5.85%
Health Care Trend Rates			
Trend for Next Year	8.00%	9.00%	9.00%
Ultimate Trend	5.00%	5.00%	5.00%
Year Ultimate Trend Reached	2014	2012	2011
Weighted-Average Assumptions to Determine Net Periodic Benefit Cost[1]			
Discount Rate	6.40%	5.85%	5.50%
Expected Long-Term Rate of Return on Plan Assets	8.35%	8.35%	6.99%
Expected Contributions for Fiscal 2009	$ 20,102,000		

Estimated Future Benefit Payments

The following net benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Year(s)	Net Benefits	Subsidy Receipts
2009	$ 29,300,000	$ 780,000
2010	30,860,000	970,000
2011	32,080,000	1,160,000
2012	31,860,000	1,370,000
2013	31,350,000	1,600,000
2014 - 2018	151,380,000	8,440,000

[1] The expected long-term rate of return shown is for retiree medical. The retiree life insurance expected return is 7.50%.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 056:

The text on Page 8 of the Konold Testimony indicates that Columbia, with its Rider POM proposal, is seeking a long-term solution to the problem of volatility in pension and OPEB costs and accurately reflecting such costs in rates. Explain whether Columbia considered other approaches to addressing this problem such as 1) deferring the costs and for amortization and recovery in a subsequent rate case or 2) including an average representative amount for recovery in base rates. If these or other approaches were considered, explain why they were rejected in favor of the proposed rider.

Response:

Columbia did consider other approaches to addressing the problem of volatility in pension and OPEB costs. On April 23, 2009, Columbia filed an application in Case No. 2009-00168 requesting authority to defer the difference between Pension and OPEB expense calculated pursuant to SFAS No. 87 and SFAS No. 106 and annual Pension and OPEB expense included in base rates. This application requested that: (1) Pension and OPEB expense attributable to operation and maintenance expense be deferred and recognized as a regulatory asset or liability pursuant to the provisions of SFAS No. 71, and (2) the resulting assets or liabilities be collected from, or, returned to customers through the amortization of the asset or liability in Columbia's subsequent base rate case proceedings, in whatever manner deemed appropriate by the Commission.

The proposed rider was suggested as a long-term solution to the problem of volatility as it alleviates the difficulty of trying to determine a representative level of Pension and OPEB expense to include in base rates and it ensures that Columbia's customers pay no more or no less than the prudently incurred costs associated with its Pension and OPEB obligations. In addition, Rider POM would provide the Commission and Columbia with the ability to set rates on an annual basis to recover Pension and OPEB expense in a timely manner without having to incur the significant expense of filing a base rate proceeding. Utilizing an average representative amount for recovery in base rates was not considered because Columbia's customers or Columbia could be adversely impacted.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 057:

Refer to Page 9 of the Konold Testimony in which Ms. Konold states that, if Columbia is not authorized to defer pension and OPEB expenses as requested in Case No. 2009-00168,[4] the 2009 level of pension and OPEB expenses should be used for the purpose of calculating Columbia's base rates. Provide a schedule showing the base rates based on the proposed revenue allocation and rate design that would result if these expenses were included in Columbia's base rate revenue requirement.

Response:

The 2009 level of pension and OPEB expense is included in the calculation of Columbia's base rate revenue requirement as shown on Schedule D-2.4 and is used in the proposed revenue allocation and rate design.

[4] Case No. 2009-00168, Application of Columbia Gas of Kentucky, Inc. to Establish a Regulatory Asset Related to Pension and Other Post-Retirement Benefit Expenses (Filed April 23, 2009).

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 058:

Refer to Page 3 of the Efland testimony which states that normal weather is defined by a 20-year average (this is a change from 30-year averages proposed by Columbia in its past rate cases). The Commission has not approved averages less than 30 years, with the exception of one 25-year average. Explain why a 20-year average is proposed rather than a 25-year or 30-year average and provide weather normalized usage and adjustments for the test year using averages of both the 25-year and 30-year periods ending in 2008.

Response:

Columbia proposed normal weather based on a 20-year average in Case No. 2007-0008. The settlement in the case did not define the basis of normal weather. However, rates based on the increase from the settlement were developed using volumes normalized on the 20 year average proposed and were reflected in Attachment B, Proof of Revenue, included in the Order approving the Stipulation.

In the company's 2002 filing, Columbia's definition of normal HDD was a 30-year average ended 2000. For the 2007 filing, the normalization process was changed to incorporate more recent data and to reflect an averaging period with superior performance to the 30-year definition. For this current rate case, the averaging period has been updated from the previous filing to reflect twenty years ended December 2008.

An analysis of weather data has shown that a rolling 20-year average is a superior measure to a rolling 30 year average. As a predictor of one-year ahead weather, the 20-year average out performs the 30-year average in 69% of the most recent 29 years. The 25-year average out performs the 30-year average 55% of the most recent 29 years. Table 1, included in attachment A, shows that the 20-year average has consistently lower mean absolute error compared to both the 25-year and 30-year averages.

In an effort to best support rate design, the averages are analyzed over five years, representing a period of time that the rates are in effect. The three averages are used each year to predict each five year period for the 5-years ended 1984 through the five years ended 2008. In this analysis, the performance of the 20-year and 25-year averages were compared to the 30-year. The average with the smaller difference over the 5-year period was judged superior. In this analysis, the 20-year average out performs the 30-year average in 64% of the time or 16 of the 25 periods. The 25-year average out performs the 30-year average 56% or 14 of the 25 periods. When considering the most recent 12 periods, the 20-year average outperforms the 30-year average 67% or 8 out of the 12 periods. The 25-year average out performs the 30-year 50% or 6 of the 12 periods.

The 20-year measure performs better compared to the 30-year in both the year ahead analysis and the 5-year analysis. The 20-year is also a more dynamic measure compared to the 30-year. Whether the underlying data exhibit a cycle or a trend, the 20-year average will react more quickly to the change because it replaces 5% of the data each year, while the 30-year average replaces only 3% of the data each year. Columbia has chosen the 20-year average as both a better predictor and a more dynamic measure compared with the 30-year average.

Columbia Gas of Kentucky

	Annual Heating Degree Days				Absolute Error			Better 1-year predictor		Better 1-year predictor		Better 5-year predictor		Better 5-year predictor	
	Actual	20-yr Average	25-yr Average	30-yr Average	20-yr Average	25-yr Average	30-yr Average	20-yr Average	30-yr Average	25-yr Average	30-yr Average	20-yr Average	30-yr Average	25-yr Average	30-yr Average
1980	5141	4810	4815	4760	326	348	397	1		1			1	1	
1981	4887	4815	4832	4762	77	72	127	1		1			1		1
1982	4453	4789	4828	4764	362	379	309		1		1		1		1
1983	4806	4780	4807	4785	17	22	42	1		1			1		1
1984	4601	4781	4807	4790	179	206	184	1			1	1			1
1985	4720	4783	4787	4795	61	87	70	1			1	1			1
1986	4381	4744	4770	4792	402	406	414	1		1		1		1	
1987	4378	4733	4747	4786	366	392	414	1		1		1		1	
1988	5007	4734	4747	4776	274	260	221		1		1	1		1	
1989	4928	4732	4762	4787	194	181	152		1		1	1		1	
1990	3828	4679	4727	4740	904	934	959	1		1		1		1	
1991	4124	4663	4686	4717	555	603	616	1		1		1		1	
1992	4415	4645	4679	4699	248	271	302	1		1			1	1	
1993	4738	4671	4669	4691	93	59	39		1		1		1		1
1994	4476	4679	4649	4687	195	193	215	1		1		1		1	
1995	4815	4697	4646	4691	136	166	128		1		1	1		1	
1996	5050	4697	4670	4688	353	404	359	1			1		1	1	
1997	4896	4703	4675	4698	199	226	208	1			1		1	1	
1998	3934	4630	4664	4663	769	741	764		1	1			1	1	
1999	4203	4589	4659	4637	427	461	460	1			1	1			1
2000	4730	4569	4670	4632	141	71	93		1	1		1			1
2001	4258	4537	4638	4626	311	412	374	1			1	1			1
2002	4513	4540	4628	4617	24	125	113	1			1	1			1
2003	4672	4533	4599	4632	132	44	55		1	1		1			1
2004	4362	4521	4573	4634	171	237	270	1		1		1		1	
2005	4485	4510	4546	4635	36	88	149	1		1					
2006	4139	4498	4516	4604	371	407	496	1		1					
2007	4271	4492	4509	4588	227	245	333	1		1					
2008	4759	4480	4507	4567	267	250	171		1		1				
					Mean Absolute Error			Frequency of Lowest Absolute Error				Frequency of Lowest Absolute Error			
1980-2008					270	286	291	20	9	16	13	16	9	14	11
1993-2008					241	258	264	10	6	8	8	8	4	6	6
								Relative Frequency of Lowest Absolute Error				Relative Frequency of Lowest Absolute Error			
1980-2008								69%	31%	55%	45%	64%	36%	56%	44%
1993-2008								63%	38%	50%	50%	67%	33%	50%	50%

Residential

Normal = 1984 2008 25 year average

2008	Customers	Actual MCF	MCF/Cus Actual	NTS	TS Actual	TS Normal	Normal	HDD Actual	HDD Normal	Normal MCF	Billing Days	UPC per Day	Base UPC per Day 0.035
Jan	125,425	1,730,081	13.79	1.16	12.64	13.42	14.58	919	976	1,828,381	33.143		1.158
Feb	125,551	1,818,957	14.49	1.03	13.46	13.33	14.35	898	889	1,802,018	29.381		1.026
Mar	125,342	1,591,208	12.69	1.04	11.65	10.44	11.48	798	715	1,439,304	29.857		1.043
Apr	124,397	916,439	7.37	1.06	6.31	6.17	7.23	461	451	899,423	30.381		1.061
May	123,239	400,526	3.25	1.03	2.22	1.92	2.95	222	192	363,577	29.524		1.031
Jun	122,241	208,067	1.70	1.07	0.63	0.48	1.55	70	53	189,289	30.619		1.070
Jul	121,465	136,038	1.12	1.12	0.00	0.00	1.12	1	1	136,038	30.667	0.037	1.071
Aug	120,915	127,149	1.05	1.05	0.00	0.00	1.05	0	0	127,149	29.571	0.036	1.033
Sep	120,646	126,526	1.05	1.05	0.00	0.00	1.05	2	9	126,526	30.571	0.034	1.049
Oct	121,033	167,010	1.38	1.04	0.34	0.57	1.60	76	125	193,819	29.667		1.036
Nov	122,360	602,388	4.92	1.03	3.90	3.48	4.50	408	384	550,968	29.381		1.026
Dec	123,724	1,538,541	12.44	1.14	11.30	9.22	10.38	898	733	1,281,674	32.524		1.136
		9,362,930	75.25	12.81	62.45	59.02	71.83	4753	4508	8,938,167			

Residential

Normal = 1979 2008 30 year average

2008	Customers	Actual MCF	MCF/Cus Actual	NTS	TS Actual	TS Normal	Normal	HDD Actual	HDD Normal	Normal MCF	Billing Days	UPC per Day	Base UPC per Day 0.035
Jan	125,425	1,730,081	13.79	1.16	12.64	13.71	14.87	919	997	1,864,597	33.143		1.158
Feb	125,551	1,818,957	14.49	1.03	13.46	13.67	14.70	898	912	1,845,306	29.381		1.026
Mar	125,342	1,591,208	12.69	1.04	11.65	10.47	11.51	798	717	1,442,964	29.857		1.043
Apr	124,397	916,439	7.37	1.06	6.31	6.21	7.27	461	454	904,528	30.381		1.061
May	123,239	400,526	3.25	1.03	2.22	1.98	3.01	222	198	370,967	29.524		1.031
Jun	122,241	208,067	1.70	1.07	0.63	0.45	1.52	70	50	185,975	30.619		1.070
Jul	121,465	136,038	1.12	1.12	0.00	0.00	1.12	1	1	136,038	30.667	0.037	1.071
Aug	120,915	127,149	1.05	1.05	0.00	0.00	1.05	0	0	127,149	29.571	0.036	1.033
Sep	120,646	126,526	1.05	1.05	0.00	0.00	1.05	2	8	126,526	30.571	0.034	1.049
Oct	121,033	167,010	1.38	1.04	0.34	0.56	1.59	76	123	192,725	29.667		1.036
Nov	122,360	602,388	4.92	1.03	3.90	3.50	4.52	408	366	553,305	29.381		1.026
Dec	123,724	1,538,541	12.44	1.14	11.30	9.19	10.32	898	730	1,277,004	32.524		1.136
		9,362,930	75.25	12.81	62.45	59.73	72.53	4753	4556	9,027,085			

Commercial

Normal = 1984 2008 25 year average

2008	Customers	Actual MCF	MCF/Cus Actual	NTS	TS Actual	TS Normal	Normal	HDD Actual	HDD Normal	Normal MCF	Billing Days	UPC per Day	Base UPC per Day 0.586
Jan	14,529	1,258,517	86.62	19.42	67.20	71.37	90.79	919	976	1,319,076	33.143		19.419
Feb	14,539	1,263,087	86.88	17.21	69.66	68.96	86.18	898	889	1,252,936	29.381		17.215
Mar	14,525	1,099,344	75.69	17.49	58.19	52.14	69.63	798	715	1,011,430	29.857		17.494
Apr	14,427	651,987	45.19	17.80	27.39	26.80	44.60	461	451	643,415	30.381		17.801
May	14,308	394,761	27.59	17.30	10.29	8.90	26.20	222	192	374,862	29.524		17.299
Jun	14,206	275,135	19.37	17.94	1.43	1.08	19.02	70	53	270,211	30.619		17.940
Jul	14,107	263,457	18.68	18.68	0.00	0.00	18.68	1	1	263,457	30.667	0.609	17.968
Aug	14,067	239,247	17.01	17.01	0.00	0.00	17.01	0	0	239,247	29.571	0.575	17.008
Sep	14,020	255,754	18.24	18.24	0.00	0.00	18.24	2	9	255,754	30.571	0.597	17.912
Oct	14,049	328,346	23.37	17.38	5.99	9.85	27.23	76	125	382,595	29.667		17.382
Nov	14,233	600,360	42.18	17.21	24.97	22.27	39.49	408	384	562,039	29.381		17.215
Dec	14,360	1,140,741	79.44	19.06	60.38	49.29	68.34	898	733	981,420	32.524		19.056
		7,770,735	540.25	214.75	325.50	310.66	525.41	4753	4508	7,556,442			

Commercial

Normal = 1979 2008 30 year average

2008	Customers	Actual MCF	MCF/Cus Actual	NTS	TS Actual	TS Normal	Normal	HDD Actual	HDD Normal	Normal MCF	Billing Days	UPC per Day	Base UPC per Day 0.586
Jan	14,529	1,258,517	86.62	19.42	67.20	72.91	92.32	919	997	1,341,387	33.143		19.419
Feb	14,539	1,263,087	86.88	17.21	69.66	70.75	87.96	898	912	1,278,876	29.381		17.215
Mar	14,525	1,099,344	75.69	17.49	58.19	52.29	69.78	798	717	1,013,548	29.857		17.494
Apr	14,427	651,987	45.19	17.80	27.39	26.98	44.78	461	454	645,986	30.381		17.801
May	14,308	394,761	27.59	17.30	10.29	9.18	26.48	222	198	378,842	29.524		17.299
Jun	14,206	275,135	19.37	17.94	1.43	1.02	18.96	70	50	269,342	30.619		17.940
Jul	14,107	263,457	18.68	18.68	0.00	0.00	18.68	1	1	263,457	30.667	0.609	17.968
Aug	14,067	239,247	17.01	17.01	0.00	0.00	17.01	0	0	239,247	29.571	0.575	17.008
Sep	14,020	255,754	18.24	18.24	0.00	0.00	18.24	2	8	255,754	30.571	0.597	17.912
Oct	14,049	328,346	23.37	17.38	5.99	9.69	27.06	76	123	380,381	29.667		17.382
Nov	14,233	600,360	42.18	17.21	24.97	22.40	39.61	408	366	563,781	29.381		17.215
Dec	14,360	1,140,741	79.44	19.06	60.38	49.09	68.14	898	730	978,524	32.524		19.056
		7,770,735	540.25	214.75	325.50	314.29	529.03	4753	4556	7,609,125			

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 059:

Refer to Page 3 of the Efland Testimony. Is September included in calculation of the base load even if September contains Heating Degree Days?

Response:
Yes. September is included in the calculation of base load when total load per customer per day (Total Load/Customer/Day) is less than July and/or August. The procedure uses September billing data. This encompasses a portion of August through mid September and is one of the low usage months. September usually has very few or no heating degree days.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 060:

Refer to Workpaper WPM-C in Volume 8 of 8 in Columbia's application. Provide all calculations used in determining weather adjustments used to normalize volumes for all classes as found in column (2) of Sheet 1 of the workpaper.

Response:

The attached shows the development of normalized revenue by rate schedule by rate block shown on workpaper WPM-D column 2. The weather normalization adjustment in Workpaper WPM-D column 3 is the difference between actual physical flow volumes in column 1 and the normalized volumes in column 2. It is the weather normalization adjustment in column 3 that is transferred over to WPM-C column 2.

Columbia Gas of Kentucky Weather Normalization
Residential

Normal = 1989 2008 20 year average

	Customers	Actual MCF	MCF/Cus Actual	MCF/Cus NTS	MCF/Cus TS Actual	MCF/Cus TS Normal	MCF/Cus Normal	HDD Actual	HDD Normal	Normal MCF	Billling Days	UPC per Day	Base UPC per Day 0.035
Jan	125,425	1,730,081	13.79	1.16	12.64	13.25	14.41	919	964	1,807,686	33.143		1.158
Feb	125,551	1,818,957	14.49	1.03	13.46	13.04	14.07	898	870	1,766,259	29.381		1.026
Mar	125,342	1,591,208	12.69	1.04	11.65	10.32	11.37	798	707	1,424,662	29.857		1.043
Apr	124,397	916,439	7.37	1.06	6.31	6.20	7.26	461	453	902,826	30.381		1.061
May	123,239	400,526	3.25	1.03	2.22	1.92	2.95	222	192	363,577	29.524		1.031
Jun	122,241	208,067	1.70	1.07	0.63	0.48	1.55	70	53	189,289	30.619		1.070
Jul	121,465	136,038	1.12	1.12	0.00	0.00	1.12	1	1	136,038	30.667	0.037	1.071
Aug	120,915	127,149	1.05	1.05	0.00	0.00	1.05	0	0	127,149	29.571	0.036	1.033
Sep	120,646	126,526	1.05	1.05	0.00	0.00	1.05	2	7	126,526	30.571	0.034	1.049
Oct	121,033	167,010	1.38	1.04	0.34	0.53	1.57	76	118	189,990	29.667		1.036
Nov	122,360	602,388	4.92	1.03	3.90	3.51	4.53	408	367	554,474	29.381		1.026
Dec	123,724	1,538,541	12.44	1.14	11.30	9.21	10.35	898	732	1,280,118	32.524		1.136
		9,362,930	75.25	12.81	62.45	58.46	71.27	4753	4464	8,868,594			

Columbia Gas of Kentucky Weather Normalization
Commercial

Normal = 1989 2008 20 year average

		Actual	MCF/Cus					HDD	HDD	Normal	Billling	UPC	Base UPC per Day
	Customers	MCF	Actual	NTS	TS Actual	TS Normal	Normal	Actual	Normal	MCF	Days	per Day	0.586
Jan	14,529	1,258,517	86.62	19.42	67.20	70.49	89.91	919	964	1,306,327	33.143		19.419
Feb	14,539	1,263,087	86.88	17.21	69.66	67.49	84.70	898	870	1,231,507	29.381		17.215
Mar	14,525	1,099,344	75.69	17.49	58.19	51.56	69.05	798	707	1,002,956	29.857		17.494
Apr	14,427	651,987	45.19	17.80	27.39	26.92	44.72	461	453	645,129	30.381		17.801
May	14,308	394,761	27.59	17.30	10.29	8.90	26.20	222	192	374,862	29.524		17.299
Jun	14,206	275,135	19.37	17.94	1.43	1.08	19.02	70	53	270,211	30.619		17.940
Jul	14,107	263,457	18.68	18.68	0.00	0.00	18.68	1	1	263,457	30.667	0.609	17.968
Aug	14,067	239,247	17.01	17.01	0.00	0.00	17.01	0	0	239,247	29.571	0.575	17.008
Sep	14,020	255,754	18.24	18.24	0.00	0.00	18.24	2	7	255,754	30.571	0.597	17.912
Oct	14,049	328,346	23.37	17.38	5.99	9.30	26.68	76	118	374,845	29.667		17.382
Nov	14,233	600,360	42.18	17.21	24.97	22.46	39.67	408	367	564,651	29.381		17.215
Dec	14,360	1,140,741	79.44	19.06	60.38	49.22	68.28	898	732	980,455	32.524		19.056
		7,770,735	540.25	214.75	325.50	307.41	522.16	4753	4464	7,509,402			

Columbia Gas of Kentucky, Inc.
Development of Commercial Normalized Sales Volumes
For the Twelve Months Ended December 31, 2008

Physical Flow Volumes - Commercial

Month	DIS Billed Tariff (1)	GMB Billed Tariff (2)	Sub Total Tariff (3=1+2)	Choice DIS Billed (4)	Choice GMB Billed (5)	Choice Total (6 = 4+5)	Traditional Comm GTS (7)	Commercial Throughput (8=3+6+7)
January 2008	631,333.5	76,979.0	708,312.5	227,148.7	28,384.0	255,532.7	294,672.0	1,258,517.2
February	693,392.0	63,648.0	757,040.0	231,435.6	26,963.0	258,398.6	247,648.0	1,263,086.6
March	610,341.5	49,730.0	660,071.5	199,321.4	19,094.0	218,415.4	220,857.0	1,099,343.9
April	357,487.7	21,602.0	379,089.7	116,325.0	9,982.0	126,307.0	146,590.0	651,986.7
May	192,805.7	11,609.0	204,414.7	60,834.2	5,735.0	66,569.2	123,777.0	394,760.9
June	117,964.1	6,550.0	124,514.1	47,294.1	3,619.0	50,913.1	99,708.0	275,135.2
July	103,070.1	6,892.0	109,962.1	34,434.0	2,642.0	37,076.0	116,419.0	263,457.1
August	94,812.3	6,495.0	101,307.3	29,236.0	2,537.0	31,773.0	106,167.0	239,247.3
September	102,527.4	7,194.0	109,721.4	25,634.4	4,006.0	29,640.4	116,392.0	255,753.8
October	114,801.7	14,821.0	129,622.7	36,820.1	5,596.0	42,416.1	156,307.0	328,345.8
November	223,097.3	42,511.0	265,608.3	96,065.3	21,094.0	117,159.3	217,592.0	600,359.6
December	564,093.0	65,993.0	630,086.0	205,213.3	34,282.0	239,495.3	271,160.0	1,140,741.3
Totals	3,805,726.3	374,024.0	4,179,750.3	1,309,762.1	163,934.0	1,473,696.1	2,117,289.0	7,770,735.4

Percent of Total Commercial Throughput

Month	DIS Billed Tariff	GMB Billed Tariff	Choice DIS Billed	Choice GMB Billed	Traditional Comm GTS	Commercial Throughput
January 2008	50.1649%	6.1166%	18.0489%	2.2554%	23.4142%	100.0%
February	54.8966%	5.0391%	18.3230%	2.1347%	19.6066%	100.0%
March	55.5187%	4.5236%	18.1309%	1.7369%	20.0899%	100.0%
April	54.8305%	3.3133%	17.8416%	1.5310%	22.4836%	100.0%
May	48.8411%	2.9408%	15.4104%	1.4528%	31.3549%	100.0%
June	42.8750%	2.3806%	17.1894%	1.3154%	36.2396%	100.0%
July	39.1222%	2.6160%	13.0701%	1.0028%	44.1890%	100.0%
August	39.6294%	2.7148%	12.2200%	1.0604%	44.3754%	100.0%
September	40.0883%	2.8129%	10.0231%	1.5664%	45.5094%	100.0%
October	34.9637%	4.5138%	11.2138%	1.7043%	47.6044%	100.0%
November	37.1606%	7.0809%	16.0013%	3.5136%	36.2436%	100.0%
December	49.4497%	5.7851%	17.9895%	3.0052%	23.7705%	100.0%

Columbia Gas of Kentucky, Inc.
Development of Commercial Normalized Sales Volumes
For the Twelve Months Ended December 31, 2008

Normalized Physical Flow

Month	DIS Billed Tariff	GMB Billed Tariff	Sub Total Tariff	Choice DIS Billed	Choice GMB Billed	Choice Total	Traditional Comm GTS	Commercial Throughput
	(1)	(2)	(3=1+2)	(4)	(5)	(6 = 4+5)	(7)	(8=3+6+7)
January 2008	655,317.2	79,903.4	735,220.6	235,777.9	29,462.3	265,240.1	305,866.3	1,306,327.0
February	676,055.9	62,056.7	738,112.5	225,649.3	26,288.9	251,938.1	241,456.3	1,231,507.0
March	556,828.2	45,369.8	602,198.0	181,845.4	17,419.9	199,265.2	201,492.8	1,002,956.0
April	353,727.6	21,374.8	375,102.4	115,101.5	9,877.0	124,978.5	145,048.1	645,129.0
May	183,086.9	11,023.8	194,110.7	57,767.7	5,445.9	63,213.6	117,537.7	374,862.0
June	115,852.9	6,432.8	122,285.6	46,447.7	3,554.2	50,001.9	97,923.5	270,211.0
July	103,070.1	6,892.0	109,962.1	34,434.0	2,642.0	37,076.0	116,419.0	263,457.0
August	94,812.2	6,495.0	101,307.2	29,236.0	2,537.0	31,773.0	106,166.9	239,247.0
September	102,527.5	7,194.0	109,721.5	25,634.4	4,006.0	29,640.4	116,392.1	255,754.0
October	131,059.5	16,919.9	147,979.4	42,034.4	6,388.5	48,422.9	178,442.7	374,845.0
November	209,827.8	39,982.5	249,810.3	90,351.5	19,839.4	110,190.8	204,649.9	564,651.0
December	484,831.9	56,720.3	541,552.2	176,378.6	29,465.0	205,843.7	233,059.1	980,455.0
Totals	3,666,997.5	360,364.9	4,027,362.4	1,260,658.2	156,926.0	1,417,584.3	2,064,454.4	7,509,401.0

Columbia Gas of Kentucky, Inc.
Development of Residential Normalized Sales Volumes
For the Twelve Months Ended December 31, 2008

Physical Flow Volumes

Month	DIS Billed Res Tariff	Choice Res GTS	Residential Throughput
	(1)	(2)	(3=1+2)
January 2008	1,360,562.9	369,518.4	1,730,081.3
February	1,418,330.1	400,626.5	1,818,956.6
March	1,238,749.1	352,459.1	1,591,208.2
April	706,429.4	210,009.4	916,438.8
May	308,593.8	91,932.6	400,526.4
June	161,123.1	46,943.5	208,066.6
July	106,119.4	29,918.9	136,038.3
August	100,385.8	26,763.2	127,149.0
September	98,274.0	28,251.7	126,525.7
October	129,532.2	37,478.2	167,010.4
November	457,375.7	145,012.7	602,388.4
December	1,165,066.8	373,473.8	1,538,540.6
Totals	7,250,542.3	2,112,388.0	9,362,930.3

Percent of Total Residential Throughput

Month	DIS Billed Res Tariff	Choice Res GTS
January 2008	78.6416%	21.3584%
February	77.9749%	22.0251%
March	77.8496%	22.1504%
April	77.0842%	22.9158%
May	77.0471%	22.9529%
June	77.4382%	22.5618%
July	78.0070%	21.9930%
August	78.9513%	21.0487%
September	77.6712%	22.3288%
October	77.5594%	22.4406%
November	75.9270%	24.0730%
December	75.7255%	24.2745%

Columbia Gas of Kentucky, Inc.
Development of Residential Normalized Sales Volumes
For the Twelve Months Ended December 31, 2008

Normalized Physical Flow

Month	Total Throughput	DIS Billed Res Tariff	Choice Res GTS
January 2008	1,807,686.0	1,421,592.4	386,093.6
February	1,766,259.0	1,377,239.2	389,019.8
March	1,424,662.0	1,109,093.6	315,568.4
April	902,826.0	695,936.1	206,889.9
May	363,577.0	280,125.4	83,451.6
June	189,289.0	146,582.1	42,706.9
July	136,038.0	106,119.2	29,918.8
August	127,149.0	100,385.8	26,763.2
September	126,526.0	98,274.2	28,251.8
October	189,990.0	147,355.0	42,635.0
November	554,474.0	420,995.7	133,478.3
December	1,280,118.0	969,375.1	310,742.9
Totals	8,868,594.0	6,873,073.8	1,995,520.2

COLUMBIA GAS OF KENTUCKY, INC.
NORMALIZED VOLUMES
FOR THE TWELVE MONTHS ENDING 12/2008
TARIFF SALES

MCF	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	WHOLESALE	ELEC GEN	TOTAL
JAN	1421592.4	735220.6	23456.8	0.0	3368.0	0.0	2183637.8
FEB	1377239.2	738112.5	30124.4	0.0	2779.0	0.0	2148255.1
MAR	1109093.6	602198.0	17022.1	0.0	2194.0	443.0	1730950.7
APR	695936.1	375102.4	12708.6	0.0	1210.0	472.0	1085429.1
MAY	280125.4	194110.7	8485.1	0.0	904.0	0.0	483625.2
JUN	146582.1	122285.6	6408.8	0.0	673.0	0.0	275949.5
JUL	106119.2	109962.1	5956.2	0.0	670.0	344.0	223051.5
AUG	100385.8	101307.2	6081.1	0.0	664.0	0.0	208438.1
SEP	98274.2	109721.5	9074.8	0.0	549.0	320.0	217939.5
OCT	147355.0	147979.4	7288.1	0.0	1019.0	144.0	303785.5
NOV	420995.7	249810.3	13414.1	0.0	2373.0	0.0	686593.1
DEC	969375.1	541552.2	18849.0	0.0	2731.0	0.0	1532507.3
TOTAL	6873073.8	4027362.5	158869.1	0.0	19134.0	1723.0	11080162.4

COLUMBIA GAS OF KENTUCKY, INC.
NORMALIZED VOLUMES
FOR THE TWELVE MONTHS ENDING 12/2008
TRANSPORTATION

MCF	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	WHOLESALE	ELEC GEN	TOTAL
JAN	0.0	305866.3	2095592.0	0.0	0.0	0.0	2401458.3
FEB	0.0	241456.3	1945963.0	0.0	0.0	0.0	2187419.3
MAR	0.0	201492.8	1797089.0	0.0	0.0	0.0	1998581.8
APR	0.0	145048.1	1741943.0	0.0	0.0	0.0	1886991.1
MAY	0.0	117537.7	1414317.0	0.0	0.0	0.0	1531854.7
JUN	0.0	97923.5	1338283.0	0.0	0.0	0.0	1436206.5
JUL	0.0	116419.0	1361293.0	0.0	0.0	0.0	1477712.0
AUG	0.0	106166.9	1325746.0	0.0	0.0	0.0	1431912.9
SEP	0.0	116392.1	1451879.0	0.0	0.0	0.0	1568271.1
OCT	0.0	178442.7	1354775.0	0.0	0.0	0.0	1533217.7
NOV	0.0	204649.9	1254210.0	0.0	0.0	0.0	1458859.9
DEC	0.0	233059.1	1309183.0	0.0	0.0	0.0	1542242.1
TOTAL	0.0	2064454.4	18390273.0	0.0	0.0	0.0	20454727.4

COLUMBIA GAS OF KENTUCKY, INC.
NORMALIZED VOLUMES
FOR THE TWELVE MONTHS ENDING 12/2008
CHOICE

MCF	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	WHOLESALE	ELEC GEN	TOTAL
JAN	386093.6	265240.1	8269.8	0.0	0.0	0.0	659603.5
FEB	389019.8	251938.1	5850.6	0.0	0.0	0.0	646808.5
MAR	315568.4	199265.2	5064.6	0.0	0.0	0.0	519898.2
APR	206889.9	124978.5	2992.4	0.0	0.0	0.0	334860.8
MAY	83451.6	63213.6	1380.2	0.0	0.0	0.0	148045.4
JUN	42706.9	50001.9	671.8	0.0	0.0	0.0	93380.6
JUL	29918.8	37076.0	514.7	0.0	0.0	0.0	67509.5
AUG	26763.2	31773.0	370.1	0.0	0.0	0.0	58906.3
SEP	28251.8	29640.4	355.0	0.0	0.0	0.0	58247.2
OCT	42635.0	48422.9	509.4	0.0	0.0	0.0	91567.3
NOV	133478.3	110190.8	2725.8	0.0	0.0	0.0	246394.9
DEC	310742.9	205843.7	5353.0	0.0	0.0	0.0	521939.6
TOTAL	1995520.2	1417584.2	34057.4	0.0	0.0	0.0	3447161.8

COLUMBIA GAS OF KENTUCKY, INC.
ALLOCATION OF NORMALIZED TARIFF VOLUMES
BETWEEN GENERAL SERVICE AND SPECIAL RATE
FOR THE TWELVE MONTHS ENDING 12/2008
RESIDENTIAL

	NORMALIZED TOTAL CO (A)	ACTUAL SPEC. RATE (B)	ACTUAL GENERAL SERV. (C)	PERCENT SPEC. RATE (D=B/(B+C))	NORMALIZED SPEC. RATE (E=D*A)	NORMALIZED GENERAL SERVICE (F=A-E)
JAN	1421592.4	0.0	1360562.9	0.00000	0.0	1421592.4
FEB	1377239.2	0.0	1418330.1	0.00000	0.0	1377239.2
MAR	1109093.6	0.0	1238749.1	0.00000	0.0	1109093.6
APR	695936.1	0.0	706429.4	0.00000	0.0	695936.1
MAY	280125.4	0.0	308593.8	0.00000	0.0	280125.4
JUN	146582.1	0.0	161123.1	0.00000	0.0	146582.1
JUL	106119.2	0.0	106119.4	0.00000	0.0	106119.2
AUG	100385.8	0.0	100385.8	0.00000	0.0	100385.8
SEP	98274.2	0.0	98274.0	0.00000	0.0	98274.2
OCT	147355.0	0.0	129532.2	0.00000	0.0	147355.0
NOV	420995.7	0.0	457375.7	0.00000	0.0	420995.7
DEC	969375.1	0.0	1165066.8	0.00000	0.0	969375.1
TOTAL	6873073.8	0.0	7250542.3		0.0	6873073.8

COLUMBIA GAS OF KENTUCKY, INC.
ALLOCATION OF NORMALIZED TARIFF VOLUMES
BETWEEN GENERAL SERVICE AND SPECIAL RATE
FOR THE TWELVE MONTHS ENDING 12/2008
COMMERCIAL

	NORMALIZED TOTAL CO (A)	ACTUAL SPEC. RATE (B)	ACTUAL GENERAL SERV. (C)	PERCENT SPEC. RATE (D=B/(B+C))	NORMALIZED SPEC. RATE (E=D*A)	NORMALIZED GENERAL SERVICE (F=A-E)
JAN	735220.6	76979.0	631333.5	0.10868	79903.8	655316.8
FEB	738112.5	63648.0	693392.0	0.08407	62053.1	676059.4
MAR	602198.0	49730.0	610341.5	0.07534	45369.6	556828.4
APR	375102.4	21602.0	357487.7	0.05698	21373.3	353729.1
MAY	194110.7	11609.0	192805.7	0.05679	11023.5	183087.2
JUN	122285.6	6550.0	117964.1	0.05260	6432.2	115853.4
JUL	109962.1	6892.0	103070.1	0.06268	6892.4	103069.7
AUG	101307.2	6495.0	94812.3	0.06411	6494.8	94812.4
SEP	109721.5	7194.0	102527.4	0.06557	7194.4	102527.1
OCT	147979.4	14821.0	114801.7	0.11434	16920.0	131059.4
NOV	249810.3	42511.0	223097.3	0.16005	39982.1	209828.2
DEC	541552.2	65993.0	564093.0	0.10474	56722.2	484830.0
TOTAL	4027362.5	374024.0	3805726.3		360361.4	3667001.1

COLUMBIA GAS OF KENTUCKY, INC.
ALLOCATION OF NORMALIZED TARIFF VOLUMES
BETWEEN GENERAL SERVICE AND SPECIAL RATE
FOR THE TWELVE MONTHS ENDING 12/2008
INDUSTRIAL

	NORMALIZED TOTAL CO (A)	ACTUAL SPEC. RATE (B)	ACTUAL GENERAL SERV. (C)	PERCENT SPEC. RATE (D=B/(B+C))	NORMALIZED SPEC. RATE (E=D*A)	NORMALIZED GENERAL SERVICE (F=A-E)
JAN	23456.8	23456.8	0.0	1.00000	23456.8	0.0
FEB	30124.4	30124.4	0.0	1.00000	30124.4	0.0
MAR	17022.1	17022.1	0.0	1.00000	17022.1	0.0
APR	12708.6	12708.6	0.0	1.00000	12708.6	0.0
MAY	8485.1	8485.1	0.0	1.00000	8485.1	0.0
JUN	6408.8	6408.8	0.0	1.00000	6408.8	0.0
JUL	5956.2	5956.2	0.0	1.00000	5956.2	0.0
AUG	6081.1	6081.1	0.0	1.00000	6081.1	0.0
SEP	9074.8	9074.8	0.0	1.00000	9074.8	0.0
OCT	7288.1	7288.1	0.0	1.00000	7288.1	0.0
NOV	13414.1	13414.1	0.0	1.00000	13414.1	0.0
DEC	18849.0	18849.0	0.0	1.00000	18849.0	0.0
TOTAL	158869.1	158869.1	0.0		158869.1	0.0

COLUMBIA GAS OF KENTUCKY, INC.
ALLOCATION OF NORMALIZED TARIFF VOLUMES
BETWEEN GENERAL SERVICE AND SPECIAL RATE
FOR THE TWELVE MONTHS ENDING 12/2008
WHOLESALE

	NORMALIZED TOTAL CO (A)	ACTUAL SPEC. RATE (B)	ACTUAL GENERAL SERV. (C)	PERCENT SPEC. RATE (D=B/(B+C))	NORMALIZED SPEC. RATE (E=D*A)	NORMALIZED GENERAL SERVICE (F=A-E)
JAN	3368.0	3368.0	0.0	1.00000	3368.0	0.0
FEB	2779.0	2779.0	0.0	1.00000	2779.0	0.0
MAR	2194.0	2194.0	0.0	1.00000	2194.0	0.0
APR	1210.0	1210.0	0.0	1.00000	1210.0	0.0
MAY	904.0	904.0	0.0	1.00000	904.0	0.0
JUN	673.0	673.0	0.0	1.00000	673.0	0.0
JUL	670.0	670.0	0.0	1.00000	670.0	0.0
AUG	664.0	664.0	0.0	1.00000	664.0	0.0
SEP	549.0	549.0	0.0	1.00000	549.0	0.0
OCT	1019.0	1019.0	0.0	1.00000	1019.0	0.0
NOV	2373.0	2373.0	0.0	1.00000	2373.0	0.0
DEC	2731.0	2731.0	0.0	1.00000	2731.0	0.0
TOTAL	19134.0	19134.0	0.0		19134.0	0.0

COLUMBIA GAS OF KENTUCKY, INC.
ALLOCATION OF NORMALIZED TARIFF VOLUMES
BETWEEN GENERAL SERVICE AND SPECIAL RATE
FOR THE TWELVE MONTHS ENDING 12/2008
ELEC GEN

	NORMALIZED TOTAL CO (A)	ACTUAL SPEC. RATE (B)	ACTUAL GENERAL SERV. (C)	PERCENT SPEC. RATE (D=B/(B+C))	NORMALIZED SPEC. RATE (E=D*A)	NORMALIZED GENERAL SERVICE (F=A-E)
JAN	0.0	0.0	0.0	0.00000	0.0	0.0
FEB	0.0	0.0	0.0	0.00000	0.0	0.0
MAR	443.0	443.0	0.0	1.00000	443.0	0.0
APR	472.0	472.0	0.0	1.00000	472.0	0.0
MAY	0.0	0.0	0.0	0.00000	0.0	0.0
JUN	0.0	0.0	0.0	0.00000	0.0	0.0
JUL	344.0	344.0	0.0	1.00000	344.0	0.0
AUG	0.0	0.0	0.0	0.00000	0.0	0.0
SEP	320.0	320.0	0.0	1.00000	320.0	0.0
OCT	144.0	144.0	0.0	1.00000	144.0	0.0
NOV	0.0	0.0	0.0	0.00000	0.0	0.0
DEC	0.0	0.0	0.0	0.00000	0.0	0.0
TOTAL	1723.0	1723.0	0.0		1723.0	0.0

COLUMBIA GAS OF KENTUCKY, INC.
ALLOCATION OF NORMALIZED GTS VOLUMES
BETWEEN GENERAL SERVICE AND SPECIAL RATE
FOR THE TWELVE MONTHS ENDING 12/2008
COMMERCIAL

	NORMALIZED TOTAL CO (A)	ACTUAL SPEC. RATE (B)	ACTUAL GENERAL SERV. (C)	PERCENT SPEC. RATE (D=B/(B+C))	NORMALIZED SPEC. RATE (E=D*A)	NORMALIZED GENERAL SERVICE (F=A-E)
JAN	305866.3	294672.0	0.0	1.00000	305866.3	0.0
FEB	241456.3	247648.0	0.0	1.00000	241456.3	0.0
MAR	201492.8	220857.0	0.0	1.00000	201492.8	0.0
APR	145048.1	146590.0	0.0	1.00000	145048.1	0.0
MAY	117537.7	123777.0	0.0	1.00000	117537.7	0.0
JUN	97923.5	99708.0	0.0	1.00000	97923.5	0.0
JUL	116419.0	116419.0	0.0	1.00000	116419.0	0.0
AUG	106166.9	106167.0	0.0	1.00000	106166.9	0.0
SEP	116392.1	116392.0	0.0	1.00000	116392.1	0.0
OCT	178442.7	156307.0	0.0	1.00000	178442.7	0.0
NOV	204649.9	217592.0	0.0	1.00000	204649.9	0.0
DEC	233059.1	271160.0	0.0	1.00000	233059.1	0.0
TOTAL	2064454.4	2117289.0	0.0		2064454.4	0.0

COLUMBIA GAS OF KENTUCKY, INC.
ALLOCATION OF NORMALIZED GTS VOLUMES
BETWEEN GENERAL SERVICE AND SPECIAL RATE
FOR THE TWELVE MONTHS ENDING 12/2008
INDUSTRIAL

	NORMALIZED TOTAL CO (A)	ACTUAL SPEC. RATE (B)	ACTUAL GENERAL SERV. (C)	PERCENT SPEC. RATE (D=B/(B+C))	NORMALIZED SPEC. RATE (E=D*A)	NORMALIZED GENERAL SERVICE (F=A-E)
JAN	2095592.0	2095592.0	0.0	1.00000	2095592.0	0.0
FEB	1945963.0	1945963.0	0.0	1.00000	1945963.0	0.0
MAR	1797089.0	1797089.0	0.0	1.00000	1797089.0	0.0
APR	1741943.0	1741943.0	0.0	1.00000	1741943.0	0.0
MAY	1414317.0	1414317.0	0.0	1.00000	1414317.0	0.0
JUN	1338283.0	1338283.0	0.0	1.00000	1338283.0	0.0
JUL	1361293.0	1361293.0	0.0	1.00000	1361293.0	0.0
AUG	1325746.0	1325746.0	0.0	1.00000	1325746.0	0.0
SEP	1451879.0	1451879.0	0.0	1.00000	1451879.0	0.0
OCT	1354775.0	1354775.0	0.0	1.00000	1354775.0	0.0
NOV	1254210.0	1254210.0	0.0	1.00000	1254210.0	0.0
DEC	1309183.0	1309183.0	0.0	1.00000	1309183.0	0.0
TOTAL	18390273.0	18390273.0	0.0		18390273.0	0.0

COLUMBIA GAS OF KENTUCKY, INC.
ALLOCATION OF NORMALIZED CHOICE VOLUMES
BETWEEN GENERAL SERVICE AND SPECIAL RATE
FOR THE TWELVE MONTHS ENDING 12/2008
RESIDENTIAL

	NORMALIZED TOTAL CO (A)	ACTUAL SPEC. RATE (B)	ACTUAL GENERAL SERV. (C)	PERCENT SPEC. RATE (D=B/(B+C))	NORMALIZED SPEC. RATE (E=D*A)	NORMALIZED GENERAL SERVICE (F=A-E)
JAN	386093.6	0.0	369518.4	0.00000	0.0	386093.6
FEB	389019.8	0.0	400626.5	0.00000	0.0	389019.8
MAR	315568.4	0.0	352459.1	0.00000	0.0	315568.4
APR	206889.9	0.0	210009.4	0.00000	0.0	206889.9
MAY	83451.6	0.0	91932.6	0.00000	0.0	83451.6
JUN	42706.9	0.0	46943.5	0.00000	0.0	42706.9
JUL	29918.8	0.0	29918.9	0.00000	0.0	29918.8
AUG	26763.2	0.0	26763.2	0.00000	0.0	26763.2
SEP	28251.8	0.0	28251.7	0.00000	0.0	28251.8
OCT	42635.0	0.0	37478.2	0.00000	0.0	42635.0
NOV	133478.3	0.0	145012.7	0.00000	0.0	133478.3
DEC	310742.9	0.0	373473.8	0.00000	0.0	310742.9
TOTAL	1995520.2	0.0	2112388.0		0.0	1995520.2

COLUMBIA GAS OF KENTUCKY, INC.
ALLOCATION OF NORMALIZED CHOICE VOLUMES
BETWEEN GENERAL SERVICE AND SPECIAL RATE
FOR THE TWELVE MONTHS ENDING 12/2008
COMMERCIAL

	NORMALIZED TOTAL CO (A)	ACTUAL SPEC. RATE (B)	ACTUAL GENERAL SERV. (C)	PERCENT SPEC. RATE (D=B/(B+C))	NORMALIZED SPEC. RATE (E=D*A)	NORMALIZED GENERAL SERVICE (F=A-E)
JAN	265240.1	28384.0	227148.7	0.11108	29462.9	235777.2
FEB	251938.1	26963.0	231435.6	0.10435	26289.7	225648.4
MAR	199265.2	19094.0	199321.4	0.08742	17419.8	181845.4
APR	124978.5	9982.0	116325.0	0.07903	9877.1	115101.4
MAY	63213.6	5735.0	60834.2	0.08615	5445.9	57767.7
JUN	50001.9	3619.0	47294.1	0.07108	3554.1	46447.8
JUL	37076.0	2642.0	34434.0	0.07126	2642.0	34434.0
AUG	31773.0	2537.0	29236.0	0.07985	2537.1	29235.9
SEP	29640.4	4006.0	25634.4	0.13515	4005.9	25634.5
OCT	48422.9	5596.0	36820.1	0.13193	6388.4	42034.5
NOV	110190.8	21094.0	96065.3	0.18005	19839.9	90350.9
DEC	205843.7	34282.0	205213.3	0.14314	29464.5	176379.2
TOTAL	1417584.2	163934.0	1309762.1		156927.3	1260656.9

COLUMBIA GAS OF KENTUCKY, INC.
ALLOCATION OF NORMALIZED CHOICE VOLUMES
BETWEEN GENERAL SERVICE AND SPECIAL RATE
FOR THE TWELVE MONTHS ENDING 12/2008
INDUSTRIAL

	NORMALIZED TOTAL CO (A)	ACTUAL SPEC. RATE (B)	ACTUAL GENERAL SERV. (C)	PERCENT SPEC. RATE (D=B/(B+C))	NORMALIZED SPEC. RATE (E=D*A)	NORMALIZED GENERAL SERVICE (F=A-E)
JAN	8269.8	8269.8	0.0	1.00000	8269.8	0.0
FEB	5850.6	5850.6	0.0	1.00000	5850.6	0.0
MAR	5064.6	5064.6	0.0	1.00000	5064.6	0.0
APR	2992.4	2992.4	0.0	1.00000	2992.4	0.0
MAY	1380.2	1380.2	0.0	1.00000	1380.2	0.0
JUN	671.8	671.8	0.0	1.00000	671.8	0.0
JUL	514.7	514.7	0.0	1.00000	514.7	0.0
AUG	370.1	370.1	0.0	1.00000	370.1	0.0
SEP	355.0	355.0	0.0	1.00000	355.0	0.0
OCT	509.4	509.4	0.0	1.00000	509.4	0.0
NOV	2725.8	2725.8	0.0	1.00000	2725.8	0.0
DEC	5353.0	5353.0	0.0	1.00000	5353.0	0.0
TOTAL	34057.4	34057.4	0.0		34057.4	0.0

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
GSO - DIS BILLED TARIFF COMMERCIAL INDUSTRIAL SERVICE
COMMERCIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	8708.	203436.9
	N	350.	2210.	286587.5
	N	600.	227.	85342.3
	O	1000.	68.	78517.4
FEBRUARY	F	50.	8676.	206108.9
	N	350.	2243.	295508.2
	N	600.	238.	89887.0
	O	1000.	72.	83242.2
MARCH	F	50.	8992.	191717.5
	N	350.	1986.	240040.5
	N	600.	186.	66045.6
	O	1000.	51.	57833.4
APRIL	F	50.	9590.	154799.4
	N	350.	1442.	143043.2
	N	600.	93.	30007.9
	O	1000.	21.	25000.5
MAY	F	50.	10231.	106596.1
	N	350.	766.	59820.8
	N	600.	29.	8286.0
	O	1000.	6.	8001.8
JUNE	F	50.	10445.	78079.6
	N	350.	470.	30440.9
	N	600.	9.	3934.0
	O	1000.	5.	3249.9
JULY	F	50.	10434.	71936.5
	N	350.	397.	25141.4
	N	600.	6.	3488.6
	O	1000.	5.	2369.7
AUGUST	F	50.	10439.	67525.8
	N	350.	363.	22079.8
	N	600.	4.	3313.6
	O	1000.	5.	1789.1
SEPTEMBER	F	50.	10371.	71542.9
	N	350.	395.	25016.5
	N	600.	6.	3482.2
	O	1000.	5.	2348.6
OCTOBER	F	50.	10102.	84089.7
	N	350.	541.	37688.2
	N	600.	13.	4607.8
	O	1000.	5.	4427.8
NOVEMBER	F	50.	9855.	114719.2
	N	350.	885.	73162.4
	N	600.	40.	11100.5
	O	1000.	7.	10289.1
DECEMBER	F	50.	8871.	176944.7
	N	350.	1811.	207595.8
	N	600.	154.	53119.7
	O	1000.	40.	46023.7
TOTAL 12 MOS.	F	50.	116714.	1527497.2
	N	350.	13509.	1446125.2
	N	600.	1005.	362615.2
	O	1000.	290.	323093.2

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
GSR - DIS BILLED TARIFF RESIDENTIAL SERVICE
RESIDENTIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	100900.	1420401.5
FEBRUARY	0	0.	100102.	1376211.2
MARCH	0	0.	99785.	1108110.3
APRIL	0	0.	98695.	695317.5
MAY	0	0.	97680.	279841.5
JUNE	0	0.	96381.	146474.6
JULY	0	0.	95780.	106030.7
AUGUST	0	0.	95105.	100292.5
SEPTEMBER	0	0.	94848.	98189.4
OCTOBER	0	0.	95085.	147160.9
NOVEMBER	0	0.	95924.	420511.4
DECEMBER	0	0.	96436.	968444.9
TOTAL 12 MOS.	0	0.	1166721.	6866986.4

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
G1C - DIS BILLED TARIFF COMMERCIAL/INDUSTRIAL LG&E
COMMERCIAL

	RATE BLOCK	(MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	4.	1238.7
FEBRUARY	0	0.	4.	1145.0
MARCH	0	0.	4.	1054.6
APRIL	0	0.	4.	803.5
MAY	0	0.	4.	339.5
JUNE	0	0.	4.	132.8
JULY	0	0.	4.	120.1
AUGUST	0	0.	4.	83.5
SEPTEMBER	0	0.	4.	122.6
OCTOBER	0	0.	4.	208.8
NOVEMBER	0	0.	4.	459.4
DECEMBER	0	0.	4.	967.3
TOTAL 12 MOS.	0	0.	48.	6675.8

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
G1R - DIS BILLED TARIFF RESIDENTIAL LG&E
RESIDENTIAL

	RATE BLOCK	(MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	24.	510.1
FEBRUARY	0	0.	24.	432.5
MARCH	0	0.	24.	432.5
APRIL	0	0.	23.	237.2
MAY	0	0.	23.	109.3
JUNE	0	0.	24.	35.0
JULY	0	0.	23.	34.8
AUGUST	0	0.	23.	30.3
SEPTEMBER	0	0.	23.	33.6
OCTOBER	0	0.	23.	51.6
NOVEMBER	0	0.	23.	155.0
DECEMBER	0	0.	23.	328.2
TOTAL 12 MOS.	0	0.	280.	2390.1

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
IN3 - DIS BILLED TARIFF INLAND/CKY GENERAL SERVICE
RESIDENTIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	10.	313.8
FEBRUARY	0	0.	10.	261.6
MARCH	0	0.	10.	221.2
APRIL	0	0.	10.	145.9
MAY	0	0.	10.	67.5
JUNE	0	0.	10.	33.2
JULY	0	0.	10.	31.6
AUGUST	0	0.	10.	14.0
SEPTEMBER	0	0.	10.	23.1
OCTOBER	0	0.	10.	32.8
NOVEMBER	0	0.	10.	124.2
DECEMBER	0	0.	10.	211.5
TOTAL 12 MOS.	0	0.	120.	1480.4

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
IN3 - DIS BILLED TARIFF INLAND/CKY GENERAL SERVICE
COMMERCIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	14.0
FEBRUARY	0	0.	1.	13.0
MARCH	0	0.	1.	11.3
APRIL	0	0.	1.	7.6
MAY	0	0.	1.	0.0
JUNE	0	0.	1.	0.0
JULY	0	0.	1.	0.0
AUGUST	0	0.	1.	0.0
SEPTEMBER	0	0.	1.	0.0
OCTOBER	0	0.	1.	0.0
NOVEMBER	0	0.	1.	2.6
DECEMBER	0	0.	1.	7.9
TOTAL 12 MOS.	0	0.	12.	56.4

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
IN4 - DIS BILLED TARIFF INLAND/CKY GENERAL SERVICE
RESIDENTIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	21.6
FEBRUARY	0	0.	1.	17.4
MARCH	0	0.	1.	14.5
APRIL	0	0.	1.	10.0
MAY	0	0.	1.	6.2
JUNE	0	0.	1.	3.8
JULY	0	0.	1.	2.8
AUGUST	0	0.	1.	2.9
SEPTEMBER	0	0.	1.	3.0
OCTOBER	0	0.	1.	5.7
NOVEMBER	0	0.	1.	8.5
DECEMBER	0	0.	1.	15.8
TOTAL 12 MOS.	0	0.	12.	112.2

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
IN5 - DIS BILLED TARIFF INLAND/GENERAL SERVICE
RESIDENTIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	5.	151.9
FEBRUARY	0	0.	5.	129.8
MARCH	0	0.	5.	106.5
APRIL	0	0.	5.	72.8
MAY	0	0.	5.	31.6
JUNE	0	0.	5.	13.9
JULY	0	0.	5.	7.6
AUGUST	0	0.	5.	7.0
SEPTEMBER	0	0.	5.	8.4
OCTOBER	0	0.	5.	14.0
NOVEMBER	0	0.	5.	59.3
DECEMBER	0	0.	5.	118.4
TOTAL 12 MOS.	0	0.	60.	721.2

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
LG2 - DIS BILLED TARIFF RESIDENTIAL / COMMERCIAL
RESIDENTIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	125.3
FEBRUARY	0	0.	1.	129.4
MARCH	0	0.	1.	88.4
APRIL	0	0.	1.	47.9
MAY	0	0.	1.	26.8
JUNE	0	0.	1.	5.6
JULY	0	0.	1.	0.0
AUGUST	0	0.	1.	0.0
SEPTEMBER	0	0.	1.	4.9
OCTOBER	0	0.	1.	14.9
NOVEMBER	0	0.	1.	64.1
DECEMBER	0	0.	1.	126.6
TOTAL 12 MOS.	0	0.	12.	633.9

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
LG2 - DIS BILLED TARIFF RESIDENTIAL / COMMERCIAL
COMMERCIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	180.0
FEBRUARY	0	0.	1.	155.1
MARCH	0	0.	1.	125.5
APRIL	0	0.	1.	67.0
MAY	0	0.	1.	43.0
JUNE	0	0.	1.	16.2
JULY	0	0.	1.	13.4
AUGUST	0	0.	1.	20.6
SEPTEMBER	0	0.	1.	14.3
OCTOBER	0	0.	1.	37.1
NOVEMBER	0	0.	1.	95.0
DECEMBER	0	0.	1.	171.0
TOTAL 12 MOS.	0	0.	12.	938.2

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
LG3 - DIS BILLED TARIFF RESIDENTIAL
RESIDENTIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	2.	0.	1.9
	O	2.	1.	21.4
FEBRUARY	F	2.	0.	0.0
	O	2.	1.	0.0
MARCH	F	2.	0.	1.9
	O	2.	1.	72.9
APRIL	F	2.	0.	1.9
	O	2.	1.	75.5
MAY	F	2.	0.	1.9
	O	2.	1.	25.6
JUNE	F	2.	0.	1.9
	O	2.	1.	7.7
JULY	F	2.	0.	1.9
	O	2.	1.	6.7
AUGUST	F	2.	0.	1.9
	O	2.	1.	34.6
SEPTEMBER	F	2.	0.	1.9
	O	2.	1.	7.2
OCTOBER	F	2.	0.	1.9
	O	2.	1.	68.9
NOVEMBER	F	2.	0.	1.9
	O	2.	1.	52.4
DECEMBER	F	2.	0.	1.9
	O	2.	1.	89.0
TOTAL 12 MOS.	F	2.	1.	20.9
	O	2.	11.	461.9

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
LG4 - DIS BILLED TARIFF RESIDENTIAL
RESIDENTIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	44.9
FEBRUARY	0	0.	1.	57.3
MARCH	0	0.	1.	45.3
APRIL	0	0.	1.	27.3
MAY	0	0.	1.	15.0
JUNE	0	0.	1.	6.3
JULY	0	0.	1.	3.1
AUGUST	0	0.	1.	2.6
SEPTEMBER	0	0.	1.	2.7
OCTOBER	0	0.	1.	4.3
NOVEMBER	0	0.	1.	19.0
DECEMBER	0	0.	1.	38.7
TOTAL 12 MOS.	0	0.	12.	266.5

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
GTO - DIS BILLED GTS COMMERCIAL INDUSTRIAL CHOICE
COMMERCIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	2364.	63646.6
	N	350.	699.	102096.9
	N	600.	88.	35284.6
	O	1000.	29.	34749.1
FEBRUARY	F	50.	2377.	62432.8
	N	350.	686.	97865.3
	N	600.	84.	33203.5
	O	1000.	27.	32146.8
MARCH	F	50.	2470.	57197.8
	N	350.	622.	79585.0
	N	600.	63.	23545.0
	O	1000.	19.	21517.6
APRIL	F	50.	2652.	46983.4
	N	350.	452.	47905.7
	N	600.	33.	11001.6
	O	1000.	8.	9210.7
MAY	F	50.	2885.	32375.9
	N	350.	243.	19732.8
	N	600.	10.	2900.5
	O	1000.	2.	2758.5
JUNE	F	50.	2940.	28248.7
	N	350.	193.	14448.4
	N	600.	7.	1877.3
	O	1000.	1.	1873.4
JULY	F	50.	2982.	22931.8
	N	350.	143.	9305.5
	N	600.	4.	2196.7
	O	1000.	0.	0.0
AUGUST	F	50.	3004.	20496.5
	N	350.	113.	7093.2
	N	600.	3.	1646.2
	O	1000.	0.	0.0
SEPTEMBER	F	50.	3008.	18566.9
	N	350.	97.	5745.6
	N	600.	1.	726.3
	O	1000.	1.	595.7
OCTOBER	F	50.	3069.	26591.7
	N	350.	177.	12417.0
	N	600.	5.	1439.8
	O	1000.	1.	1586.0
NOVEMBER	F	50.	2906.	42618.6
	N	350.	378.	35290.3
	N	600.	22.	6708.9
	O	1000.	4.	5733.1
DECEMBER	F	50.	2649.	58477.6
	N	350.	620.	76637.9
	N	600.	61.	21884.2
	O	1000.	17.	19379.5
TOTAL 12 MOS.	F	50.	33306.	480568.3
	N	350.	4423.	508123.6
	N	600.	381.	142414.6
	O	1000.	109.	129550.4

COLUMBIA GAS OF KENTUCKY, INC.
BILL FREQUENCY ANALYSIS BY RATE BLOCK
FOR THE 12 MONTHS ENDED 12/2008
12 MONTHS ACTUAL, 0 MONTHS PROJECTED
DATA: ACTUAL NORMALIZED
GTR - DIS BILLED GTS RESIDENTIAL CHOICE
RESIDENTIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	24482.	386093.6
FEBRUARY	0	0.	25406.	389019.8
MARCH	0	0.	25514.	315568.4
APRIL	0	0.	25660.	206889.9
MAY	0	0.	25517.	83451.6
JUNE	0	0.	25817.	42706.9
JULY	0	0.	25643.	29918.8
AUGUST	0	0.	25768.	26763.2
SEPTEMBER	0	0.	25756.	28251.8
OCTOBER	0	0.	25906.	42635.0
NOVEMBER	0	0.	26394.	133478.3
DECEMBER	0	0.	27246.	310742.9
TOTAL 12 MOS.	0	0.	309109.	1995520.2

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
GSO - GMB BILLED COMMERCIAL INDUSTRIAL SERVICE
COMMERCIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	4.	2650.0
	N	350.	11.	16755.3
	N	600.	17.	21436.5
	O	1000.	25.	39061.9
FEBRUARY	F	50.	4.	2681.1
	N	350.	12.	16276.1
	N	600.	22.	17748.7
	O	1000.	19.	25347.2
MARCH	F	50.	7.	2601.2
	N	350.	13.	15314.4
	N	600.	26.	12846.0
	O	1000.	11.	14608.0
APRIL	F	50.	8.	2518.4
	N	350.	28.	11703.2
	N	600.	17.	5320.9
	O	1000.	4.	1830.6
MAY	F	50.	20.	2185.8
	N	350.	31.	6808.7
	N	600.	5.	1921.6
	O	1000.	1.	107.2
JUNE	F	50.	27.	1770.1
	N	350.	28.	3946.9
	N	600.	2.	715.3
	O	1000.	0.	0.0
JULY	F	50.	29.	1635.0
	N	350.	24.	3863.0
	N	600.	3.	1328.1
	O	1000.	1.	66.1
AUGUST	F	50.	30.	1635.0
	N	350.	23.	3820.0
	N	600.	3.	1036.0
	O	1000.	1.	4.0
SEPTEMBER	F	50.	27.	1768.0
	N	350.	26.	4126.0
	N	600.	3.	1291.1
	O	1000.	1.	9.1
OCTOBER	F	50.	16.	2347.7
	N	350.	29.	8736.6
	N	600.	9.	3837.3
	O	1000.	3.	1998.0
NOVEMBER	F	50.	6.	2628.0
	N	350.	19.	15082.3
	N	600.	22.	10476.2
	O	1000.	10.	11795.5
DECEMBER	F	50.	5.	2740.1
	N	350.	11.	16378.6
	N	600.	24.	16157.9
	O	1000.	17.	21445.2
TOTAL 12 MOS.	F	50.	183.	27160.4
	N	350.	255.	122811.1
	N	600.	153.	94115.6
	O	1000.	93.	116272.8

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
GSO - GMB BILLED COMMERCIAL INDUSTRIAL SERVICE
INDUSTRIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	14.	1670.0
	N	350.	14.	7573.9
	N	600.	9.	5853.6
	O	1000.	6.	8359.3
FEBRUARY	F	50.	15.	1618.4
	N	350.	11.	8027.9
	N	600.	11.	6230.4
	O	1000.	6.	9129.7
MARCH	F	50.	13.	1557.8
	N	350.	19.	6574.9
	N	600.	5.	4034.5
	O	1000.	5.	4854.9
APRIL	F	50.	16.	1432.9
	N	350.	17.	5129.2
	N	600.	4.	3624.1
	O	1000.	5.	2522.4
MAY	F	50.	24.	1102.4
	N	350.	10.	4224.2
	N	600.	7.	2384.7
	O	1000.	1.	773.8
JUNE	F	50.	27.	839.9
	N	350.	9.	3308.5
	N	600.	5.	1493.9
	O	1000.	1.	766.5
JULY	F	50.	28.	774.5
	N	350.	8.	3184.3
	N	600.	5.	1544.6
	O	1000.	1.	452.8
AUGUST	F	50.	28.	825.9
	N	350.	9.	3250.1
	N	600.	4.	1351.4
	O	1000.	1.	653.7
SEPTEMBER	F	50.	28.	770.5
	N	350.	8.	3475.7
	N	600.	4.	1830.9
	O	1000.	2.	2997.7
OCTOBER	F	50.	25.	942.6
	N	350.	11.	3653.6
	N	600.	5.	1990.0
	O	1000.	1.	701.9
NOVEMBER	F	50.	18.	1353.8
	N	350.	14.	5243.0
	N	600.	6.	3596.2
	O	1000.	4.	3221.1
DECEMBER	F	50.	16.	1569.3
	N	350.	11.	6804.2
	N	600.	11.	5272.3
	O	1000.	4.	5203.2
TOTAL 12 MOS.	F	50.	252.	14458.0
	N	350.	141.	60449.5
	N	600.	76.	39206.6
	O	1000.	37.	39637.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
GSO - GMB BILLED COMMERCIAL INDUSTRIAL SERVICE
ELEC GEN

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
FEBRUARY	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
MARCH	F	50.	0.	50.0
	N	350.	0.	350.0
	N	600.	1.	43.0
	O	1000.	0.	0.0
APRIL	F	50.	0.	50.0
	N	350.	0.	350.0
	N	600.	1.	72.0
	O	1000.	0.	0.0
MAY	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
JUNE	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
JULY	F	50.	0.	50.0
	N	350.	1.	294.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
AUGUST	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
SEPTEMBER	F	50.	0.	50.0
	N	350.	1.	270.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
OCTOBER	F	50.	0.	50.0
	N	350.	1.	94.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
NOVEMBER	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
DECEMBER	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
TOTAL 12 MOS.	F	50.	7.	250.0
	N	350.	3.	1358.0
	N	600.	2.	115.0
	O	1000.	0.	0.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
GSO - GMB BILLED COMMERCIAL INDUSTRIAL SERVICE
COMMERCIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	4.	2650.0
	N	350.	11.	16755.3
	N	600.	17.	21436.5
	O	1000.	25.	39061.9
FEBRUARY	F	50.	4.	2681.1
	N	350.	12.	16276.1
	N	600.	22.	17748.7
	O	1000.	19.	25347.2
MARCH	F	50.	7.	2601.2
	N	350.	13.	15314.4
	N	600.	26.	12846.0
	O	1000.	11.	14608.0
APRIL	F	50.	8.	2518.4
	N	350.	28.	11703.2
	N	600.	17.	5320.9
	O	1000.	4.	1830.6
MAY	F	50.	20.	2185.8
	N	350.	31.	6808.7
	N	600.	5.	1921.6
	O	1000.	1.	107.2
JUNE	F	50.	27.	1770.1
	N	350.	28.	3946.9
	N	600.	2.	715.3
	O	1000.	0.	0.0
JULY	F	50.	29.	1635.0
	N	350.	24.	3863.0
	N	600.	3.	1328.1
	O	1000.	1.	66.1
AUGUST	F	50.	30.	1635.0
	N	350.	23.	3820.0
	N	600.	3.	1036.0
	O	1000.	1.	4.0
SEPTEMBER	F	50.	27.	1768.0
	N	350.	26.	4126.0
	N	600.	3.	1291.1
	O	1000.	1.	9.1
OCTOBER	F	50.	16.	2347.7
	N	350.	29.	8736.6
	N	600.	9.	3837.3
	O	1000.	3.	1998.0
NOVEMBER	F	50.	6.	2628.0
	N	350.	19.	15082.3
	N	600.	22.	10476.2
	O	1000.	10.	11795.5
DECEMBER	F	50.	5.	2740.1
	N	350.	11.	16378.6
	N	600.	24.	16157.9
	O	1000.	17.	21445.2
TOTAL 12 MOS.	F	50.	183.	27160.4
	N	350.	255.	122811.1
	N	600.	153.	94115.6
	O	1000.	93.	116272.8

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
GSO - GMB BILLED COMMERCIAL INDUSTRIAL SERVICE
INDUSTRIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	14.	1670.0
	N	350.	14.	7573.9
	N	600.	9.	5853.6
	O	1000.	6.	8359.3
FEBRUARY	F	50.	15.	1618.4
	N	350.	11.	8027.9
	N	600.	11.	6230.4
	O	1000.	6.	9129.7
MARCH	F	50.	13.	1557.8
	N	350.	19.	6574.9
	N	600.	5.	4034.5
	O	1000.	5.	4854.9
APRIL	F	50.	16.	1432.9
	N	350.	17.	5129.2
	N	600.	4.	3624.1
	O	1000.	5.	2522.4
MAY	F	50.	24.	1102.4
	N	350.	10.	4224.2
	N	600.	7.	2384.7
	O	1000.	1.	773.8
JUNE	F	50.	27.	839.9
	N	350.	9.	3308.5
	N	600.	5.	1493.9
	O	1000.	1.	766.5
JULY	F	50.	28.	774.5
	N	350.	8.	3184.3
	N	600.	5.	1544.6
	O	1000.	1.	452.8
AUGUST	F	50.	28.	825.9
	N	350.	9.	3250.1
	N	600.	4.	1351.4
	O	1000.	1.	653.7
SEPTEMBER	F	50.	28.	770.5
	N	350.	8.	3475.7
	N	600.	4.	1830.9
	O	1000.	2.	2997.7
OCTOBER	F	50.	25.	942.6
	N	350.	11.	3653.6
	N	600.	5.	1990.0
	O	1000.	1.	701.9
NOVEMBER	F	50.	18.	1353.8
	N	350.	14.	5243.0
	N	600.	6.	3596.2
	O	1000.	4.	3221.1
DECEMBER	F	50.	16.	1569.3
	N	350.	11.	6804.2
	N	600.	11.	5272.3
	O	1000.	4.	5203.2
TOTAL 12 MOS.	F	50.	252.	14458.0
	N	350.	141.	60449.5
	N	600.	76.	39206.6
	O	1000.	37.	39637.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
GSO - GMB BILLED COMMERCIAL INDUSTRIAL SERVICE
ELEC GEN

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
FEBRUARY	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
MARCH	F	50.	0.	50.0
	N	350.	0.	350.0
	N	600.	1.	43.0
	O	1000.	0.	0.0
APRIL	F	50.	0.	50.0
	N	350.	0.	350.0
	N	600.	1.	72.0
	O	1000.	0.	0.0
MAY	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
JUNE	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
JULY	F	50.	0.	50.0
	N	350.	1.	294.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
AUGUST	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
SEPTEMBER	F	50.	0.	50.0
	N	350.	1.	270.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
OCTOBER	F	50.	0.	50.0
	N	350.	1.	94.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
NOVEMBER	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
DECEMBER	F	50.	1.	0.0
	N	350.	0.	0.0
	N	600.	0.	0.0
	O	1000.	0.	0.0
TOTAL 12 MOS.	F	50.	7.	250.0
	N	350.	3.	1358.0
	N	600.	2.	115.0
	O	1000.	0.	0.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
IUS - GMB BILLED INTRASTATE UTILITY SERVICE
WHOLESALE

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	2.	3368.0
FEBRUARY	0	0.	2.	2779.0
MARCH	0	0.	2.	2194.0
APRIL	0	0.	2.	1210.0
MAY	0	0.	2.	904.0
JUNE	0	0.	2.	673.0
JULY	0	0.	2.	670.0
AUGUST	0	0.	2.	664.0
SEPTEMBER	0	0.	2.	549.0
OCTOBER	0	0.	2.	1019.0
NOVEMBER	0	0.	2.	2373.0
DECEMBER	0	0.	2.	2731.0
TOTAL 12 MOS.	0	0.	24.	19134.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
GTO - CHOICE GMB BILLED COMMERCIAL INDUSTRIAL CHOICE
COMMERCIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	0.	1350.0
	N	350.	4.	8751.0
	N	600.	10.	9023.4
	O	1000.	13.	10338.6
FEBRUARY	F	50.	1.	1333.2
	N	350.	6.	8478.4
	N	600.	10.	8008.0
	O	1000.	10.	8470.0
MARCH	F	50.	1.	1331.0
	N	350.	13.	7462.5
	N	600.	7.	6506.5
	O	1000.	6.	2119.5
APRIL	F	50.	1.	1332.7
	N	350.	15.	5757.9
	N	600.	11.	2786.5
	O	1000.	0.	0.0
MAY	F	50.	10.	1136.8
	N	350.	12.	3121.3
	N	600.	4.	1044.4
	O	1000.	1.	143.3
JUNE	F	50.	12.	948.4
	N	350.	13.	2136.9
	N	600.	2.	468.9
	O	1000.	0.	0.0
JULY	F	50.	16.	809.0
	N	350.	10.	1617.0
	N	600.	1.	216.0
	O	1000.	0.	0.0
AUGUST	F	50.	14.	922.0
	N	350.	12.	1546.0
	N	600.	1.	69.0
	O	1000.	0.	0.0
SEPTEMBER	F	50.	12.	1025.0
	N	350.	13.	2450.0
	N	600.	2.	531.0
	O	1000.	0.	0.0
OCTOBER	F	50.	6.	1197.2
	N	350.	15.	3947.0
	N	600.	6.	1243.9
	O	1000.	0.	0.0
NOVEMBER	F	50.	1.	1336.7
	N	350.	13.	6955.0
	N	600.	8.	5544.8
	O	1000.	5.	6003.5
DECEMBER	F	50.	1.	1335.2
	N	350.	9.	8020.8
	N	600.	7.	7413.2
	O	1000.	10.	12695.3
TOTAL 12 MOS.	F	50.	75.	14057.2
	N	350.	135.	60243.8
	N	600.	69.	42855.6
	O	1000.	45.	39770.2

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
GTO - CHOICE GMB BILLED COMMERCIAL INDUSTRIAL CHOICE INDUSTRIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	1.	382.7
	N	350.	3.	1912.8
	N	600.	1.	2228.0
	O	1000.	3.	3746.3
FEBRUARY	F	50.	1.	391.4
	N	350.	3.	1812.1
	N	600.	2.	1910.5
	O	1000.	2.	1736.6
MARCH	F	50.	1.	379.3
	N	350.	4.	1637.5
	N	600.	0.	1800.0
	O	1000.	3.	1247.8
APRIL	F	50.	2.	353.6
	N	350.	3.	1320.8
	N	600.	3.	1318.0
	O	1000.	0.	0.0
MAY	F	50.	4.	307.7
	N	350.	2.	977.6
	N	600.	2.	94.9
	O	1000.	0.	0.0
JUNE	F	50.	6.	154.1
	N	350.	2.	517.7
	N	600.	0.	0.0
	O	1000.	0.	0.0
JULY	F	50.	6.	126.3
	N	350.	2.	388.4
	N	600.	0.	0.0
	O	1000.	0.	0.0
AUGUST	F	50.	6.	123.4
	N	350.	2.	246.7
	N	600.	0.	0.0
	O	1000.	0.	0.0
SEPTEMBER	F	50.	6.	136.4
	N	350.	2.	218.6
	N	600.	0.	0.0
	O	1000.	0.	0.0
OCTOBER	F	50.	5.	221.3
	N	350.	3.	288.1
	N	600.	0.	0.0
	O	1000.	0.	0.0
NOVEMBER	F	50.	2.	349.4
	N	350.	4.	1412.0
	N	600.	1.	661.4
	O	1000.	1.	303.0
DECEMBER	F	50.	1.	380.7
	N	350.	3.	1884.2
	N	600.	2.	1664.9
	O	1000.	2.	1423.2
TOTAL 12 MOS.	F	50.	41.	3306.3
	N	350.	33.	12616.5
	N	600.	11.	9677.7
	O	1000.	11.	8456.9

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
DS - GTS BILLEDGAS DISTRIBUTION SERVICE
COMMERCIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	30000.	26.	214059.1
	O	30000.	0.	0.0
FEBRUARY	F	30000.	26.	181353.6
	O	30000.	0.	0.0
MARCH	F	30000.	26.	149886.5
	O	30000.	0.	0.0
APRIL	F	30000.	26.	111283.9
	O	30000.	0.	0.0
MAY	F	30000.	26.	87418.4
	O	30000.	0.	0.0
JUNE	F	30000.	26.	69962.2
	O	30000.	0.	0.0
JULY	F	30000.	26.	70792.0
	O	30000.	0.	0.0
AUGUST	F	30000.	26.	72164.0
	O	30000.	0.	0.0
SEPTEMBER	F	30000.	26.	74665.0
	O	30000.	0.	0.0
OCTOBER	F	30000.	26.	121852.5
	O	30000.	0.	0.0
NOVEMBER	F	30000.	26.	142899.0
	O	30000.	0.	0.0
DECEMBER	F	30000.	27.	162757.2
	O	30000.	0.	0.0
TOTAL 12 MOS.	F	30000.	313.	1459093.4
	O	30000.	0.	0.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
DS - GTS BILLEDGAS DISTRIBUTION SERVICE
INDUSTRIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	30000.	39.	476221.0
	O	30000.	5.	360424.0
FEBRUARY	F	30000.	39.	445583.0
	O	30000.	5.	300410.0
MARCH	F	30000.	39.	419006.0
	O	30000.	5.	243600.0
APRIL	F	30000.	39.	373392.0
	O	30000.	5.	172788.0
MAY	F	30000.	39.	347683.0
	O	30000.	5.	154930.0
JUNE	F	30000.	40.	336822.0
	O	30000.	4.	96665.0
JULY	F	30000.	41.	301924.0
	O	30000.	3.	43102.0
AUGUST	F	30000.	41.	329207.0
	O	30000.	3.	91435.0
SEPTEMBER	F	30000.	39.	355636.0
	O	30000.	5.	108317.0
OCTOBER	F	30000.	40.	373839.0
	O	30000.	4.	162788.0
NOVEMBER	F	30000.	40.	397780.0
	O	30000.	4.	181885.0
DECEMBER	F	30000.	39.	397278.0
	O	30000.	5.	182047.0
TOTAL 12 MOS.	F	30000.	475.	4554371.0
	O	30000.	53.	2098391.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
DS3 - GTS BILLEDMAINLINE RATE
INDUSTRIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	22908.0
FEBRUARY	0	0.	1.	21227.0
MARCH	0	0.	1.	15530.0
APRIL	0	0.	1.	14599.0
MAY	0	0.	1.	14656.0
JUNE	0	0.	1.	12998.0
JULY	0	0.	1.	13937.0
AUGUST	0	0.	2.	17118.0
SEPTEMBER	0	0.	2.	17735.0
OCTOBER	0	0.	2.	19301.0
NOVEMBER	0	0.	2.	23146.0
DECEMBER	0	0.	2.	20821.0
TOTAL 12 MOS.	0	0.	17.	213976.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
FX1 - GTS BILLEDUK FLEX RATE
COMMERCIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	50083.0
FEBRUARY	0	0.	1.	24223.8
MARCH	0	0.	1.	22434.0
APRIL	0	0.	1.	7489.4
MAY	0	0.	1.	12311.5
JUNE	0	0.	1.	13677.7
JULY	0	0.	1.	31738.0
AUGUST	0	0.	1.	19971.0
SEPTEMBER	0	0.	1.	26607.0
OCTOBER	0	0.	1.	32144.5
NOVEMBER	0	0.	1.	31580.8
DECEMBER	0	0.	1.	33460.8
TOTAL 12 MOS.	0	0.	12.	305721.5

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
FX2 - GTS BILLEDAMERICAN STANDARD FLEX RATE
COMMERCIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	0.0
FEBRUARY	0	0.	1.	0.0
MARCH	0	0.	1.	0.0
APRIL	0	0.	1.	0.0
MAY	0	0.	1.	0.0
JUNE	0	0.	1.	0.0
JULY	0	0.	1.	1.0
AUGUST	0	0.	1.	0.0
SEPTEMBER	0	0.	1.	0.0
OCTOBER	0	0.	1.	194.1
NOVEMBER	0	0.	1.	1442.8
DECEMBER	0	0.	1.	3564.3
TOTAL 12 MOS.	0	0.	12.	5202.2

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
FX4 - GTS BILLEDMARTEK BIOSCIENCE
INDUSTRIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	6352.0
FEBRUARY	0	0.	1.	5118.0
MARCH	0	0.	1.	5927.0
APRIL	0	0.	1.	4229.0
MAY	0	0.	1.	4293.0
JUNE	0	0.	1.	4106.0
JULY	0	0.	1.	4340.0
AUGUST	0	0.	1.	3386.0
SEPTEMBER	0	0.	1.	2727.0
OCTOBER	0	0.	1.	3481.0
NOVEMBER	0	0.	1.	3720.0
DECEMBER	0	0.	1.	4654.0
TOTAL 12 MOS.	0	0.	12.	52333.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
FX5 - GTS BILLEDASHLAND / CALGON
INDUSTRIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	3.	682364.0
FEBRUARY	0	0.	3.	649235.0
MARCH	0	0.	3.	473677.0
APRIL	0	0.	3.	610250.0
MAY	0	0.	3.	448013.0
JUNE	0	0.	3.	450035.0
JULY	0	0.	3.	481146.0
AUGUST	0	0.	3.	345243.0
SEPTEMBER	0	0.	3.	410062.0
OCTOBER	0	0.	3.	306014.0
NOVEMBER	0	0.	3.	306161.0
DECEMBER	0	0.	3.	471072.0
TOTAL 12 MOS.	0	0.	36.	5633272.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
FX6 - GTS BILLEDMARKWEST HYDROCARBON
INDUSTRIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	29191.0
FEBRUARY	0	0.	1.	28176.0
MARCH	0	0.	1.	28138.0
APRIL	0	0.	1.	24587.0
MAY	0	0.	1.	27352.0
JUNE	0	0.	1.	25440.0
JULY	0	0.	1.	27658.0
AUGUST	0	0.	1.	27108.0
SEPTEMBER	0	0.	1.	28607.0
OCTOBER	0	0.	1.	31753.0
NOVEMBER	0	0.	1.	32034.0
DECEMBER	0	0.	1.	36114.0
TOTAL 12 MOS.	0	0.	12.	346158.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
FX7 - GTS BILLEDKES AQUISITIONS
INDUSTRIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	25000.	0.	25000.0
	O	25000.	1.	31500.0
FEBRUARY	F	25000.	0.	25000.0
	O	25000.	1.	20281.0
MARCH	F	25000.	0.	25000.0
	O	25000.	1.	19053.0
APRIL	F	25000.	0.	25000.0
	O	25000.	1.	25191.0
MAY	F	25000.	0.	25000.0
	O	25000.	1.	20654.0
JUNE	F	25000.	0.	25000.0
	O	25000.	1.	14255.0
JULY	F	25000.	0.	25000.0
	O	25000.	1.	19058.0
AUGUST	F	25000.	0.	25000.0
	O	25000.	1.	16814.0
SEPTEMBER	F	25000.	0.	25000.0
	O	25000.	1.	23812.0
OCTOBER	F	25000.	0.	25000.0
	O	25000.	1.	20775.0
NOVEMBER	F	25000.	0.	25000.0
	O	25000.	1.	5194.0
DECEMBER	F	25000.	0.	25000.0
	O	25000.	1.	3098.0
TOTAL 12 MOS.	F	25000.	0.	300000.0
	O	25000.	12.	219685.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
FX8 - GTS BILLEDSEKISUI
INDUSTRIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	30000.	1.	3353.0
	O	30000.	0.	0.0
FEBRUARY	F	30000.	1.	2978.0
	O	30000.	0.	0.0
MARCH	F	30000.	1.	2878.0
	O	30000.	0.	0.0
APRIL	F	30000.	1.	2247.0
	O	30000.	0.	0.0
MAY	F	30000.	1.	2092.0
	O	30000.	0.	0.0
JUNE	F	30000.	1.	1810.0
	O	30000.	0.	0.0
JULY	F	30000.	1.	1829.0
	O	30000.	0.	0.0
AUGUST	F	30000.	1.	2263.0
	O	30000.	0.	0.0
SEPTEMBER	F	30000.	1.	2243.0
	O	30000.	0.	0.0
OCTOBER	F	30000.	1.	2184.0
	O	30000.	0.	0.0
NOVEMBER	F	30000.	1.	2440.0
	O	30000.	0.	0.0
DECEMBER	F	30000.	1.	2828.0
	O	30000.	0.	0.0
TOTAL 12 MOS.	F	30000.	12.	29145.0
	O	30000.	0.	0.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
GDS - GTS BILLEDGRANDFATHERED DELIVERY SERVICE
COMMERCIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	0.	850.0
	N	350.	0.	5950.0
	N	600.	0.	10200.0
	O	1000.	17.	16008.0
FEBRUARY	F	50.	0.	850.0
	N	350.	0.	5950.0
	N	600.	3.	9633.6
	O	1000.	14.	11637.4
MARCH	F	50.	0.	850.0
	N	350.	0.	5950.0
	N	600.	5.	9062.9
	O	1000.	12.	7149.0
APRIL	F	50.	0.	850.0
	N	350.	0.	5950.0
	N	600.	4.	8964.6
	O	1000.	13.	5943.8
MAY	F	50.	0.	850.0
	N	350.	2.	5764.4
	N	600.	8.	7284.4
	O	1000.	7.	2432.3
JUNE	F	50.	0.	850.0
	N	350.	3.	5411.9
	N	600.	9.	5500.8
	O	1000.	5.	1074.3
JULY	F	50.	0.	850.0
	N	350.	3.	5523.0
	N	600.	9.	5013.0
	O	1000.	5.	1006.0
AUGUST	F	50.	0.	850.0
	N	350.	3.	5493.0
	N	600.	8.	5183.0
	O	1000.	6.	982.0
SEPTEMBER	F	50.	0.	850.0
	N	350.	2.	5699.0
	N	600.	10.	5646.0
	O	1000.	5.	1575.0
OCTOBER	F	50.	0.	850.0
	N	350.	1.	5947.3
	N	600.	5.	8980.4
	O	1000.	11.	5763.7
NOVEMBER	F	50.	0.	850.0
	N	350.	0.	5950.0
	N	600.	6.	8791.6
	O	1000.	11.	7059.9
DECEMBER	F	50.	0.	850.0
	N	350.	0.	5950.0
	N	600.	5.	9347.8
	O	1000.	12.	9950.6
TOTAL 12 MOS.	F	50.	0.	10200.0
	N	350.	14.	69538.6
	N	600.	72.	93608.1
	O	1000.	118.	70582.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
GDS - GTS BILLEDGRANDFATHERED DELIVERY SERVICE
INDUSTRIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	50.	2.	402.0
	N	350.	1.	2671.0
	N	600.	1.	4033.0
	O	1000.	6.	13425.0
FEBRUARY	F	50.	2.	400.0
	N	350.	1.	2602.0
	N	600.	0.	4200.0
	O	1000.	7.	12281.0
MARCH	F	50.	2.	400.0
	N	350.	1.	2603.0
	N	600.	0.	4200.0
	O	1000.	7.	5542.0
APRIL	F	50.	2.	400.0
	N	350.	3.	2122.0
	N	600.	2.	2606.0
	O	1000.	3.	381.0
MAY	F	50.	2.	377.0
	N	350.	2.	2018.0
	N	600.	4.	1276.0
	O	1000.	1.	70.0
JUNE	F	50.	2.	356.0
	N	350.	3.	1968.0
	N	600.	3.	1633.0
	O	1000.	1.	3493.0
JULY	F	50.	2.	352.0
	N	350.	4.	1826.0
	N	600.	3.	775.0
	O	1000.	0.	0.0
AUGUST	F	50.	2.	351.0
	N	350.	3.	2004.0
	N	600.	3.	1658.0
	O	1000.	1.	2059.0
SEPTEMBER	F	50.	1.	401.0
	N	350.	4.	2179.0
	N	600.	2.	1543.0
	O	1000.	2.	6178.0
OCTOBER	F	50.	0.	450.0
	N	350.	4.	2444.0
	N	600.	3.	2324.0
	O	1000.	2.	365.0
NOVEMBER	F	50.	0.	450.0
	N	350.	1.	3046.0
	N	600.	1.	4771.0
	O	1000.	7.	3779.0
DECEMBER	F	50.	0.	450.0
	N	350.	1.	2826.0
	N	600.	1.	4232.0
	O	1000.	7.	11786.0
TOTAL 12 MOS.	F	50.	17.	4789.0
	N	350.	28.	28309.0
	N	600.	23.	33251.0
	O	1000.	44.	59359.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
SAS - GTS BILLEDSPCL AGENCY SVC
COMMERCIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	30000.	1.	8716.0
	O	30000.	0.	0.0
FEBRUARY	F	30000.	1.	7807.8
	O	30000.	0.	0.0
MARCH	F	30000.	1.	6160.9
	O	30000.	0.	0.0
APRIL	F	30000.	1.	4566.5
	O	30000.	0.	0.0
MAY	F	30000.	1.	1476.6
	O	30000.	0.	0.0
JUNE	F	30000.	1.	1446.6
	O	30000.	0.	0.0
JULY	F	30000.	1.	1496.0
	O	30000.	0.	0.0
AUGUST	F	30000.	1.	1524.0
	O	30000.	0.	0.0
SEPTEMBER	F	30000.	1.	1350.0
	O	30000.	0.	0.0
OCTOBER	F	30000.	1.	2710.2
	O	30000.	0.	0.0
NOVEMBER	F	30000.	1.	6075.8
	O	30000.	0.	0.0
DECEMBER	F	30000.	1.	7178.5
	O	30000.	0.	0.0
TOTAL 12 MOS.	F	30000.	12.	50508.9
	O	30000.	0.	0.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
SC2 - GTS BILLEDAK STEEL (COKE)
INDUSTRIAL

	RATE BLOCK (MCF)		CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	0	0.	1.	81077.0
FEBRUARY	0	0.	1.	50814.0
MARCH	0	0.	1.	39668.0
APRIL	0	0.	1.	30551.0
MAY	0	0.	1.	35478.0
JUNE	0	0.	1.	34587.0
JULY	0	0.	1.	39327.0
AUGUST	0	0.	1.	66478.0
SEPTEMBER	0	0.	1.	58969.0
OCTOBER	0	0.	1.	55355.0
NOVEMBER	0	0.	1.	76085.0
DECEMBER	0	0.	1.	102980.0
TOTAL 12 MOS.	0	0.	12.	671369.0

COLUMBIA GAS OF KENTUCKY, INC. - NORMALIZED DATA
BILL FREQUENCY ANALYSIS BY RATE BLOCK
DATA: 12 MOS. ACTUAL 0 MOS. ESTIMATED
FOR THE 12 MONTHS ENDED 12/2008
SC3 - GTS BILLEDAK STEEL (MAIN)
INDUSTRIAL

		RATE BLOCK (MCF)	CUMULATIVE BILLS	CONSOLIDATED FACTOR MCF
JANUARY	F	150000.	0.	150000.0
	O	150000.	1.	206671.0
FEBRUARY	F	150000.	0.	150000.0
	O	150000.	1.	227658.0
MARCH	F	150000.	0.	150000.0
	O	150000.	1.	361867.0
APRIL	F	150000.	0.	150000.0
	O	150000.	1.	303600.0
MAY	F	150000.	0.	150000.0
	O	150000.	1.	180425.0
JUNE	F	150000.	0.	150000.0
	O	150000.	1.	179115.0
JULY	F	150000.	0.	150000.0
	O	150000.	1.	251019.0
AUGUST	F	150000.	0.	150000.0
	O	150000.	1.	245622.0
SEPTEMBER	F	150000.	0.	150000.0
	O	150000.	1.	258470.0
OCTOBER	F	150000.	0.	150000.0
	O	150000.	1.	198702.0
NOVEMBER	F	150000.	0.	150000.0
	O	150000.	1.	38719.0
DECEMBER	F	150000.	1.	43997.0
	O	150000.	0.	0.0
TOTAL 12 MOS.	F	150000.	1.	1693997.0
	O	150000.	11.	2451868.0

PSC Case No. 2009-00141
Staff Set 2 DR No. 061
Respondent(s): Erich Evans

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 061:

Refer to the Prepared Direct testimony of Erich A. Evans.

a. Describe the methodology that Columbia will use to determine the posted prices offered to potential Price Protection Service ("PPS") customers.

b. Explain how the proposed early termination fee will be charged. If a customer terminates after nine months, would he/she be charged $30 - $10 per each remaining month in the one-year term? If a customer terminates after three months, would he/she be charged only $60 as opposed to $90? Explain the response.

c. Explain how Columbia arrived at the $10 per month, maximum of $60, early termination fee.

d. Mr. Evans states on Page 3 of his testimony that Columbia will enter into financial hedges to control its risk associated with the PPS and Negotiated Sales Service ("NSS") pricing. Describe the types of hedging that will be used and explain how they will differ from Columbia's current hedging programs and whether Columbia anticipates requiring Commission approval to enter into these hedges.

e. On Page 4 of this testimony, Mr. Evans states that most customers who use 25,000 Mcf or less per year would be eligible for PPS and those using more than 25,000 Mcf per year would be eligible for NSS Explain why most, but not all, customers using less than 25,000 Mcf per year would be eligible for PPS.

f. One Page 5 of his testimony, Mr. Evans states that "{t}his approach of using Columbia's pooled supplies, and crediting the cost of the PPS and NSS volumes back to the GCA, helps to ensure that management of the PPS and NSS volumes and prices do not have a detrimental impact on the prices of its traditional GCA priced customers." Explain whether management of the PPS and NSS volumes and prices will have any impact on the prices of traditional Gas cost Adjustment ("GCA") priced customers? Explain the response.

g. On Pages 6-7 of his testimony, Mr. Evans discusses Columbia's proposal regarding the filing of the fixed-price changes with the Commission. What filings, if any, does Columbia propose to make regarding the index pricing option?

h. Mr. Evans states on Page 7 that it will take 30 days to implement a new fixed price. Explain why 30 days is required to implement the change.

i. On Page 15 of his testimony, Mr. Evans states that NSS customers will sign individual contracts. Explain whether Columbia proposes to file these contracts with the Commission.

Response:

a. Columbia will determine the posted prices based on the future cost of gas for the contract term and incorporate known risks for offering a fixed price. For instance, if Columbia was posting a price for a 1 year contract beginning July 1 then the price would be based on the value of NYMEX futures for 12 month beginning July 1. To that futures price Columbia would add (or subtract) amounts to compensate for the basis price differential between the Henry Hub and Columbia's service territory. Then additional amounts would be added to the price to compensate for known risks to accounts for price and usage fluctuations.

b. The early termination fee for residential customers will be charged at a rate of $10, for each month remaining in the agreement. However the total fee will be capped at $60. If a customer cancels their agreement with 3 months left, they would owe a fee of $30. If a customer cancels their agreement with 9 months left, they would owe a fee of $60.

c. Columbia will be taking on risk in offering the fixed price to customers. If a customer cancels their contract early Columbia will have not have revenue to offset this risk. Therefore, we wanted to come up with an early termination fee that would be a deterrent for customers cancelling their contract early. A $10 charge per month is a high enough charge without being overly punitive. Likewise the cap of $60 was created to prevent the early termination fee from being overly punitive.

d. Columbia currently enters into hedges to minimize the gas price volatility in the GCA. These hedges are approved by the Commission and the costs are recovered through the GCA. Columbia plans to use separate hedges for PPS and NSS. For PPS and NSS Columbia will purchase NYMEX futures to help manage the risk for the PPS and NSS programs. These will be completely separate from any of Columbia's current hedging programs and will be managed in a separate account with our broker. The hedges for PPS and NSS will not be recovered through the GCA. In order for PPS and NSS to work, the Commission's approval of the tariffs would constitute approval of Columbia's use and implementation of hedging by Columbia for those programs. Therefore, further Commission approval would not be sought prior to entering into hedge contracts.

e. A customer on an LG&E rate schedule would not be eligible for PPS because of the comparative wording of the contracts.

f. Management of the PPS and NSS programs should have no effect on the traditional GCA priced customers. As proposed the PPS and NSS program's costs will be separate from the GCA.

g. The index price option for PPS is not projected to change. Like the fixed prices, Columbia would file the index price with the Commission prior to offering the price to any customers. However this filing will be different in that it would not state the exact price customers will be charged. It will state the mechanism for determining the price as the index the price would be based on and the amount that would be added to the index each month to determine the price.

h. Columbia's preference would be to change the price with a one day filing with the commission. This would allow Columbia to offer prices closer to real time to customers. However it is Columbia's understanding that KRS 278.180 would require the price to be filed 30 days in advance of the price taking effect.

i. Columbia will file the contract form with the commission, but does not intend to file each individual contract.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 062:

Refer to Exhibit EAE-1. Explain the purpose of the Actual Volumes and Difference columns.

Response:

In Exhibit EAE-1, the Actual Volume column is there to illustrate how the actual volumes can be different than the average day volumes. The Difference column is there to visually show that this difference can be positive or negative in any given month. These calculations are needed later for the annual true up.

COLUMBIA GAS OF KENTUCKY, INC.
RESPONSE TO SECOND DATA REQUEST OF COMMISSION STAFF

Data Request 063:

Refer to Exhibit EAE-2. Explain why the amount in the column headed Total PGCC Credit of ($7,439,841) does not equal the total Annual Credit to the GCA of ($3,661,218) in the last line on the page, under the heading Annual Reconciliation.

Response:

The amounts should match. The exhibit had an inadvertent mistake in the formula. The total credit to the GCA should be $7,439,841 in this example. A revised version of Exhibit EAE-2 is attached that corrects the error in the formula on the Annual Credit to the GCA.

Columbia Gas of Kentucky, Inc.

Illustrative Example of the
Proposed Annual True Up Credit to the GCA for PPS Program

Line No.	Date	PPS WACOG ($/Mcf)	PPS Customer Count	Average Day Volumes	Total PPS Average Day Volumes	Actual Volumes	Difference	GCA Monthly Credit	Annual Adjust.	Total GCA Credit
		(1)	(2)	(3)	(4)=(2)*(3)	(5)	(6)=(4)-(5)	(7)=-(1)*(4)	(8)=-(1)*(6)	(9)=(7)+(8)
	Year 1									
1	July Activity	$6.4932	3,800	12.5	47,500.0	32,000.0	15,500.0	$ (308,427)	$ (100,645)	$ (409,072)
2	August Activity	$7.7440	4,150	13.0	53,950.0	32,800.0	21,150.0	$ (417,789)	$ (163,786)	$ (581,574)
3	September Activity	$7.2602	4,225	12.7	53,657.5	66,400.0	(12,742.5)	$ (389,564)	$ 92,513	$ (297,051)
4	October Activity	$5.7927	4,200	13.2	55,440.0	116,200.0	(60,760.0)	$ (321,147)	$ 351,964	$ 30,817
5	November Activity	$10.6035	4,200	13.1	55,020.0	71,400.0	(16,380.0)	$ (583,405)	$ 173,685	$ (409,719)
6	December Activity	$9.1845	4,800	12.2	58,560.0	17,600.0	40,960.0	$ (537,844)	$ (376,197)	$ (914,041)
7	January Activity	$6.4765	4,650	12.8	59,520.0	38,700.0	20,820.0	$ (385,481)	$ (134,841)	$ (520,322)
8	February Activity	$9.0236	4,700	12.9	60,630.0	12,600.0	48,030.0	$ (547,101)	$ (433,404)	$ (980,504)
9	March Activity	$8.2924	4,600	12.7	58,420.0	16,400.0	42,020.0	$ (484,442)	$ (348,447)	$ (832,889)
10	April Activity	$8.3342	4,550	13.0	59,150.0	12,450.0	46,700.0	$ (492,968)	$ (389,207)	$ (882,175)
11	May Activity	$7.8988	5,000	13.5	67,500.0	20,000.0	47,500.0	$ (533,169)	$ (375,193)	$ (908,362)
12	June Activity	$7.9180	5,100	13.6	69,360.0	45,900.0	23,460.0	$ (549,192)	$ (185,756)	$ (734,949)
13	TME June							$ (5,550,530)	$(1,889,312)	$ (7,439,841)

Annual Reconciliation

True-up occurs in June to make the credit to the PGC equivalent to the actual volumes less the sum of the average day volumes multiplied by the WACCOG for the 12 months ended June:

Sum of monthly credits to the GCA (Ln 13, Col 7)	($5,550,530)
Plus: Annual Adjustment (Ln 13, Col 8)	($1,889,312)
Total Annual Credit to the GCA	($7,439,841)