Columbia Gas® of Kentucky
A NiSource Company

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

April 30, 2012

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

RECEIVED

APR 30 2012

PUBLIC SERVICE
COMMISSION

Re: Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Case No. 2012 –

Dear Mr. Derouen:

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

Columbia proposes to decrease its current rates to tariff sales customers by ($1.9279) per Mcf effective with its June 2012 billing cycle on May 30, 2012. The decrease is composed of a decrease of ($1.9183) per Mcf in the Average Commodity Cost of Gas, an increase of $0.0069 per Mcf in the Average Demand Cost of Gas, and an increase of ($0.0165) per Mcf in the Refund Adjustment. Please feel free to contact me at 859-288-0242 or jmcoop@nisource.com if there are any questions.

Sincerely,

Judy Cooper

Judy M. Cooper
Director, Regulatory Policy

Enclosures

BEFORE THE
PUBLIC SERVICE COMMISSION
OF KENTUCKY

COLUMBIA GAS OF KENTUCKY, INC.

CASE 2012 -

GAS COST ADJUSTMENT AND REVISED RATES OF
COLUMBIA GAS OF KENTUCKY, INC. PROPOSED TO BECOME
EFFECTIVE JUNE 2012 BILLINGS

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

Line No.		March-12 CURRENT	June-12 PROPOSED	DIFFERENCE
1	Commodity Cost of Gas	$4.6630	$2.7447	($1.9183)
2	Demand Cost of Gas	$1.4588	$1.4657	$0.0069
3	Total: Expected Gas Cost (EGC)	$6.1218	$4.2104	($1.9114)
4	SAS Refund Adjustment	($0.0002)	($0.0002)	$0.0000
5	Balancing Adjustment	($0.3129)	($0.3129)	$0.0000
6	Supplier Refund Adjustment	($0.0162)	($0.0327)	($0.0165)
7	Actual Cost Adjustment	($0.1605)	($0.1605)	$0.0000
8	Gas Cost Incentive Adjustment	$0.0189	$0.0189	$0.0000
9	Cost of Gas to Tariff Customers (GCA)	$5.6509	$3.7230	($1.9279)
10	Transportation TOP Refund Adjustment	$0.0000	$0.0000	$0.0000
11	Banking and Balancing Service	$0.0210	$0.0210	$0.0000
12	Rate Schedule FI and GSO			
13	Customer Demand Charge	$6.6493	$6.6492	($0.0001)

Columbia Gas of Kentucky, Inc.
Gas Cost Adjustment Clause
Gas Cost Recovery Rate
Jun - Aug 12

Line No.	Description			Amount	Expires
1	Expected Gas Cost (EGC)	Schedule No. 1		$4.2104	
2	Actual Cost Adjustment (ACA)	Schedule No. 2	Case No. 2011-00284	($0.1605)	8-31-12
3	SAS Refund Adjustment (RA)	Schedule No. 5	Case No. 2011-00284	($0.0002)	8-31-12
4	Supplier Refund Adjustment (RA)	Schedule No. 4	Line 6	($0.0206)	05-31-13
			Case No. 2012-00038	($0.0040)	02-28-13
			Case No. 2011-00284	($0.0041)	08-31-12
			Case No. 2011-00431	($0.0040)	11-30-12
		Total Refunds		($0.0327)	
5	Balancing Adjustment (BA)	Schedule No. 3 Case No. 2012-00038		($0.3129)	8-31-12
6	Gas Cost Incentive Adjustment	Schedule No. 6 Case No 2012-00038		$0.0189	2-28-13
7	Gas Cost Adjustment				
8	Jun - Aug 12			$3.7230	
9	Expected Demand Cost (EDC) per Mcf				
10	(Applicable to Rate Schedule IS/SS and GSO)	Schedule No. 1, Sheet 4		$6.6492	

DATE FILED: April 30, 2012 **BY: J. M. Cooper**

Columbia Gas of Kentucky, Inc. Schedule No. 1

Expected Gas Cost for Sales Customers Sheet 1

Jun - Aug 12

Line No.	Description		Reference	Volume A/ Mcf (1)	Dth. (2)	Rate Per Mcf (3)	Per Dth (4)	Cost (5)
	Storage Supply							
	Includes storage activity for sales customers only							
	Commodity Charge							
1	Withdrawal				0		$0.0153	$0
2	Injection				3,088,000		$0.0153	$47,246
3	Withdrawals: gas cost includes pipeline fuel and commodity charges				0		$3.3196	$0
	Total							
4	Volume	= 3			0			
5	Cost	sum(1:3)						$47,246
6	Summary	4 or 5			0			$47,246
	Flowing Supply							
	Excludes volumes injected into or withdrawn from storage.							
	Net of pipeline retention volumes and cost. Add unit retention cost on line 18							
7	Non-Appalachian		Sch.1, Sht. 5, Ln. 4		533,000			$1,305,850
8	Appalachian Supplies		Sch.1, Sht. 6, Ln. 4		59,000			$157,000
9	Less Fuel Retention By Interstate Pipelines		Sch. 1,Sheet 7, Lines 21, 22		(105,000)			($330,040)
10	Total	7 + 8 + 9			487,000			$1,132,810
	Total Supply							
11	At City-Gate		Line 6 + 10		487,000			$1,180,056
	Lost and Unaccounted For							
12	Factor				-1.1%			
13	Volume		Line 11 * 12		(5,357)			
14	At Customer Meter		Line 11 + 13	459,978	481,643			
15	Less: Right-of-Way Contract Volume			141				
16	**Sales Volume**		Line 14-15	459,837				
	Unit Costs $/MCF							
	Commodity Cost							
17	Excluding Cost of Pipeline Retention		Line 11 / Line 16			$2.5662		
18	Annualized Unit Cost of Retention		Sch. 1,Sheet 7, Line 24			$0.1403		
19	Including Cost of Pipeline Retention		Line 17 + 18			$2.7065		
20	Uncollectible Ratio		CN 2009-00141			0.01410552		
21	Gas Cost Uncollectible Charge		Line 19 * Line 20			$0.0382		
22	Total Commodity Cost		line 19 + line 21			$2.7447		
23	Demand Cost		Sch.1, Sht. 2, Line 10			$1.4657		
24	Total Expected Gas Cost (EGC)		Line 22 + 23			$4.2104		

A/ BTU Factor = 1.0471 Dth/MCF

Columbia Gas of Kentucky, Inc. Schedule No. 1

GCA Unit Demand Cost Sheet 2

Jun - Aug 12

Line No.	Description		Reference		
1	Expected Demand Cost: Annual June 2012 - May 2013		Sch. No.1, Sheet 3, Ln. 41	$20,490,054	
2	Less Rate Schedule IS/SS and GSO Customer Demand Charge Recovery		Sch. No.1, Sheet 4, Ln. 10	-$376,292	
3	Less Storage Service Recovery from Delivery Service Customers			-$168,566	
4	Net Demand Cost Applicable	1 + 2 + 3		$19,945,196	
	Projected Annual Demand: Sales + Choice				
	At city-gate				
	In Dth			14,412,000	Dth
	Heat content			1.0471	Dth/MCF
5	In MCF			13,763,728	MCF
	Lost and Unaccounted - For				
6	Factor			1.1%	
7	Volume	5 * 6		151,401	MCF
8	Right of way Volumes			4,075	
9	At Customer Meter	5 - 7- 8		13,608,252	MCF
10	Unit Demand Cost (4/ 9)	To Sheet 1, line 23		$1.4657	per MCF

Columbia Gas of Kentucky, Inc.
Annual Demand Cost of Interstate Pipeline Capacity
June 2012 - May 2013

Schedule No. 1
Sheet 3

Line No.	Description		Dth	Monthly Rate $/Dth	# Months	Expected Annual Demand Cost
	Columbia Gas Transmission Corporation					
	Firm Storage Service (FSS)					
1	FSS Max Daily Storage Quantity (MDSQ)		220,880	$1.5090	12	$3,999,695
2	FSS Seasonal Contract Quantity (SCQ)		11,264,911	$0.0289	12	$3,906,671
	Storage Service Transportation (SST)					
3	Summer		110,440	$4.1850	6	$2,773,148
4	Winter		220,880	$4.1850	6	$5,546,297
5	Firm Transportation Service (FTS)		20,014	$6.0890	12	$1,462,383
6	Subtotal	sum(1:5)				$17,688,194
	Columbia Gulf Transmission Company					
11	FTS - 1 (Mainline)		28,991	$4.2917	12	$1,493,048
	Tennessee Gas					
21	Firm Transportation		20,506	$4.6238	12	$1,137,788
	Central Kentucky Transmission					
31	Firm Transportation		28,000	$0.5090	12	$171,024
41	**Total.** Used on Sheet 2, line 1					$20,490,054

Columbia Gas of Kentucky, Inc. Schedule No. 1
Gas Cost Adjustment Clause Sheet 4
Expected Demand Costs Recovered Annually From Rate Schedule IS/SS and GSO Customers
June 2012 - May 2013

Line No.	Description		Capacity: Daily Dth (1)	# Months (2)	Annualized Dth (3) = (1) x (2)	Units	Annual Cost (3)
1	Expected Demand Costs (Per Sheet 3)						$20,490,054
	City-Gate Capacity:						
	Columbia Gas Transmission						
2	Firm Storage Service - FSS		220,880	12	2,650,560		
3	Firm Transportation Service - FTS		20,014	12	240,168		
4	Central Kentucky Transportation		28,000	12	336,000		
5	Total	2 + 3 + 4			3,226,728	Dth	
6	Divided by Average BTU Factor				1.047	Dth/MCF	
7	Total Capacity - Annualized	Line 5/ Line 6			3,081,585	Mcf	
8	Monthly Unit Expected Demand Cost (EDC) of Daily Capacity Applicable to Rate Schedules IS/SS and GSO Line 1 / Line 7				$6.6492	/Mcf	
9	Firm Volumes of IS/SS and GSO Customers		4,716	12	56,592	Mcf	
10	Expected Demand Charges to be Recovered Annually from Rate Schedule IS/SS and GSO Customers	Line 8 * Line 9			to Sheet 2, line 2		$376,292

Columbia Gas of Kentucky, Inc.
Non-Appalachian Supply: Volume and Cost
Jun - Aug 12

Schedule No. 1
Sheet 5

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

		Total Flowing Supply Including Gas Injected Into Storage				Net Flowing Supply for Current Consumption	
Line No.	Month	Volume A/ Dth (1)	Cost (2)	Unit Cost $/Dth (3) = (2) / (1)	Net Storage Injection Dth (4)	Volume Dth (5) = (1) + (4)	Cost (6) = (3) x (5)
1	Jun-12	1,055,000	$2,431,000		(878,000)	177,000	
2	Jul-12	1,286,000	$3,175,000		(1,105,000)	181,000	
3	Aug-12	1,280,000	$3,258,000		(1,105,000)	175,000	
4	Total 1+2+3	3,621,000	$8,864,000	$2.45	(3,088,000)	533,000	$1,305,850

A/ Gross, before retention.

Columbia Gas of Kentucky, Inc.
Appalachian Supply: Volume and Cost
Jun - Aug 12

Schedule No. 1
Sheet 6

Line No.	Month		Dth (2)	Cost (3)
1	Jun-12		19,000	$49,000
2	Jul-12		20,000	$52,000
3	Aug-12		20,000	$56,000
4	Total	1 + 2 + 3	59,000	$157,000

Columbia Gas of Kentucky, Inc.
Annualized Unit Charge for Gas Retained by Upstream Pipelines
Jun - Aug 12

Schedule No. 1
Sheet 7

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

			Units	Jun - Aug 12	Sep - Nov 12	Dec - Feb 13	Mar - May 13	Annual June 2012 - May 2013
	Gas purchased by CKY for the remaining sales customers							
1	Volume		Dth	3,680,000	2,167,000	1,149,000	3,064,000	10,060,000
2	Commodity Cost Including Transportation			$9,021,000	$6,190,000	$5,208,000	$11,202,000	$31,621,000
3	Unit cost		$/Dth					$3.1432
	Consumption by the remaining sales customers							
11	At city gate		Dth	486,000	1,653,000	5,716,000	2,226,000	10,081,000
12	Lost and unaccounted for portion			1.10%	1.10%	1.10%	1.10%	
	At customer meters							
13	In Dth	(100% - 12) * 11	Dth	480,654	1,634,817	5,653,124	2,201,514	9,970,109
14	Heat content		Dth/MCF	1.0471	1.0471	1.0471	1.0471	
15	In MCF	13 / 14	MCF	459,034	1,561,281	5,398,839	2,102,487	9,521,641
16	Portion of annual	line 15, quarterly / annual		4.8%	16.4%	56.7%	22.1%	100.0%
	Gas retained by upstream pipelines							
21	Volume		Dth	105,000	82,000	141,000	99,000	427,000
	Cost			To Sheet 1, line 9				
22	Quarterly. Deduct from Sheet 1	3 * 21		$330,040	$257,746	$443,197	$311,181	$1,342,164
23	Allocated to quarters by consumption			$64,424	$220,115	$761,007	$296,618	$1,342,164
				To Sheet 1, line 18				
24	Annualized unit charge	23 / 15	$/MCF	$0.1403	$0.1410	$0.1410	$0.1411	$0.1410

COLUMBIA GAS OF KENTUCKY, INC.

Schedule No. 1

Sheet 8

DETERMINATION OF THE BANKING AND BALANCING CHARGE
FOR THE PERIOD BEGINNING JUNE 2012

Line No.	Description	Dth		Detail	Amount For Transportation Customers
1	Total Storage Capacity. Sheet 3, line 2	11,264,911			
2	Net Transportation Volume	8,395,694			
3	Contract Tolerance Level @ 5%	419,785			
4	Percent of Annual Storage Applicable				
5	to Transportation Customers			3.73%	
6	Seasonal Contract Quantity (SCQ)				
7	Rate			$0.0289	
8	SCQ Charge - Annualized			$3,906,671	
9	Amount Applicable To Transportation Customers				$145,719
10	FSS Injection and Withdrawal Charge				
11	Rate			0.0306	
12	Total Cost			$344,706	
13	Amount Applicable To Transportation Customers				$12,858
14	SST Commodity Charge				
15	Rate			0.0315	
16	Projected Annual Storage Withdrawal, Dth			8,502,000	
17	Total Cost			$267,813	
18	Amount Applicable To Transportation Customers				$9,989
19	Total Cost Applicable To Transportation Customers				$168,566
20	Total Transportation Volume - Mcf				17,898,999
21	Flex and Special Contract Transportation Volume - Mcf				(9,880,955)
22	Net Transportation Volume - Mcf	line 20 + line 21			8,018,044
23	Banking and Balancing Rate - Mcf.	Line 19 / line 22. To line 11 of the GCA Comparison			$0.0210

DETAIL SUPPORTING

DEMAND/COMMODITY SPLIT

Columbia Gas of Kentucky, Inc.
CKY Choice Program
100% Load Factor Rate of Assigned FTS Capacity
Balancing Charge
Jun - Aug 12

Line No.	Description		Contract Volume Dth Sheet 3 (1)	Retention (2)	Monthly demand charges $/Dth Sheet 3 (3)	# months A/ (4)	Assignment proportions lines 4, 5 (5)	Adjustment for retention on downstream pipe, if any (6) = 1 / (100%-col2)	Annual costs $/Dth (7) = 3 * 4 * 5 * 6	Annual costs $/MCF
	City gate capacity assigned to Choice marketers									
1	Contract									
2	CKT FTS/SST		28,000	0.536%						
3	TCO FTS		20,014	1.963%						
4	Total		48,014							
5										
6	Assignment Proportions									
7	CKT FTS/SST	1 / 3	58.32%							
8	TCO FTS	2 / 3	41.68%							
9										
10										
	Annual demand cost of capacity assigned to choice marketers									
11	CKT FTS				$0.5090	12	0.5832	1.0000	$3.5622	
12	TCO FTS				$6.0890	12	0.4168	1.0000	$30.4547	
13	Gulf FTS-1, upstream to CKT FTS				$4.2917	12	0.5832	1.0054	$30.1969	
14	TGP FTS-A, upstream to TCO FTS				$4.6238	12	0.4168	1.0200	$23.5895	
15										
16	Total Demand Cost of Assigned FTS, per unit								$87.8033	$91.9388
17										
18	100% Load Factor Rate (10 / 365 days)									$0.2519
19										
20										
	Balancing charge, paid by Choice marketers									
21	Demand Cost Recovery Factor in GCA, per Mcf per CKY Tariff Sheet No. 5									$1.0598
22	Less credit for cost of assigned capacity									($0.2519)
23	Plus storage commodity costs incurred by CKY for the Choice marketer									$0.0839
24										
25	Balancing Charge, per Mcf	sum(12:14)								$0.8918

COLUMBIA GAS OF KENTUCKY
CASE NO. 2012- Effective June 2012 Billing Cycle

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

	$/MCF	
Demand Component of Gas Cost Adjustment		
Demand Cost of Gas (Schedule No. 1, Sheet 1, Line 23)	$1.4657	
Demand ACA (Schedule No. 2) Case No. 2011-00284	($0.3730)	
Total Refund Adjustment (Schedule No. 4)	($0.0327)	
SAS Refund Adjustment (Schedule No. 5) Case No. 2011-00284	($0.0002)	
Total Demand Rate per Mcf	$1.0598	<--- to Att. E, line 21
Commodity Component of Gas Cost Adjustment		
Commodity Cost of Gas (Schedule No. 1, Sheet 1, Line 22)	$2.7447	
Commodity ACA (Schedule No. 2) Case No. 2011-00284	$0.2125	
Balancing Adjustment (Schedule No. 3)	($0.3129)	
Gas Cost Incentive Adjustment (Schedule No. 6)	$0.0189	
Total Commodity Rate per Mcf	$2.6632	
CHECK:	$1.0598	
	$2.6632	
COST OF GAS TO TARIFF CUSTOMERS (GCA)	$3.7230	

Calculation of Rate Schedule SVGTS - Actual Gas Cost Adjustment

Commodity ACA (Schedule No. 2)	$0.2125	
Balancing Adjustment (Schedule No. 3)	($0.3129)	
Gas Cost Incentive Adjustment (Schedule No. 6)	$0.0189	
Total Commodity Rate per Mcf	($0.0815)	

REFUND ADJUSTMENT

SCHEDULE NO. 4

COLUMBIA GAS OF KENTUCKY, INC.

SUPPLIER REFUND ADJUSTMENT

Line No.	Description	Amount
1	Tennessee Gas Pipeline PCB Settlement Payment	($54,948.15)
2	Columbia Gulf Transmission Rate Case Settlement	($225,240.79)
3	Interest on Refund Balances	$0.00
4	Total Refund	($280,188.94)
5	Projected Sales for the Twelve Months Ended May 31, 2013	13,608,252
6	**TOTAL SUPPLIER REFUND TO EXPIRE May 31, 2013**	**($0.0206)**

CKY RATE REFUND INTEREST CALCULATION
SELECTED INTEREST RATES
COMMERCIAL PAPER - 3-MONTH

RATE	MONTH	DAYS	x	DAILY RATE	x	Tenn. Gas Pipeline PCB Settlement	=	INTEREST
0.14	JANUARY 2012	31		(0.000009)		54,948.15		(15.33)
0.17	FEBRUARY 2012	29		(0.000009)		54,948.15		(14.34)
0.18	MARCH 2012	31		(0.000009)		54,948.15		(15.33)
0.20	APRIL 2011	30		(0.000009)		54,948.15		(14.84)
0.16	MAY 2011	31		(0.000009)		54,948.15		(15.33)
0.15	JUNE 2011	30		(0.000009)		54,948.15		(14.84)
0.14	JULY 2011	31		(0.000009)		54,948.15		(15.33)
0.16	AUGUST 2011	31		(0.000009)		54,948.15		(15.33)
0.14	SEPTEMBER 2011	30		(0.000009)		54,948.15		(14.84)
0.15	OCTOBER 2011	31		(0.000009)		54,948.15		(15.33)
0.14	NOVEMBER 2011	30		(0.000009)		54,948.15		(14.84)
0.14	DECEMBER 2011	31		(0.000009)		54,948.15		(15.33)
1.87	TOTAL					TOTAL		(181.01)
(0.000009)	DAILY RATE							

RATE	MONTH	DAYS	x	DAILY RATE	x	Columbia Gulf Rate Case Settlement Refund	=	INTEREST
0.14	JANUARY 2012	31		(0.000009)		225,240.79		(62.84)
0.17	FEBRUARY 2012	29		(0.000009)		225,240.79		(58.79)
0.18	MARCH 2012	31		(0.000009)		225,240.79		(62.84)
0.20	APRIL 2011	30		(0.000009)		225,240.79		(60.82)
0.16	MAY 2011	31		(0.000009)		225,240.79		(62.84)
0.15	JUNE 2011	30		(0.000009)		225,240.79		(60.82)
0.14	JULY 2011	31		(0.000009)		225,240.79		(62.84)
0.16	AUGUST 2011	31		(0.000009)		225,240.79		(62.84)
0.14	SEPTEMBER 2011	30		(0.000009)		225,240.79		(60.82)
0.15	OCTOBER 2011	31		(0.000009)		225,240.79		(62.84)
0.14	NOVEMBER 2011	30		(0.000009)		225,240.79		(60.82)
0.14	DECEMBER 2011	31		(0.000009)		225,240.79		(62.84)
1.87	TOTAL					TOTAL		(741.95)
(0.000009)	DAILY RATE							

Tennessee Gas Pipeline
an El Paso company

April 13, 2009

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Tennessee Gas Pipeline Company
Docket Nos. RP91-203-076 and RP92-132-064

Dear Ms. Bose:

Pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, Tennessee Gas Pipeline Company ("Tennessee") hereby submits an Offer of Settlement in the above-referenced dockets. Accordingly, Tennessee respectfully requests that a copy of this filing be transmitted to Presiding Administrative Law Judge Carmen A. Cintron ("Administrative Law Judge").

Included herewith for filing is an original and fourteen (14) copies of the following documents:

(1) Explanatory Statement Concerning Amendment to Stipulation and Agreement;
(2) Amendment to Stipulation and Agreement (including *pro forma* tariff sheets); and
(3) Supporting Exhibits A and B.

Copies of the above documents are being served in accordance with Rule 602(d)(1). In addition, in accordance with Rule 602(d)(2), Tennessee notifies all parties and participants in this proceeding that comments on the Offer of Settlement are due by May 4, 2009 and reply comments are due by May 14, 2009 unless otherwise ordered by provided by the Administrative Law Judge.[1]

If you have any questions regarding this filing, please contact the undersigned at 713-420-3496. Thank you for your assistance in this matter.

Respectfully submitted,

TENNESSEE GAS PIPELINE COMPANY

/s/ Melissa G. Freeman
Melissa G. Freeman
Senior Counsel

Enclosures
cc: All Parties and Participants

[1] Tennessee contemporaneously herewith in the above-captioned dockets submitted its Motion to Shorten Comment Period and Dispense with Answer Period on its Offer of Settlement to April 23rd and April 28th for comments and reply comments, respectively.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of	)	
	)	Docket Nos. RP91-203-076
Tennessee Gas Pipeline Company	)	RP92-132-064

EXPLANATORY STATEMENT CONCERNING AMENDMENT TO STIPULATION AND AGREEMENT

Pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602 (2007), Tennessee Gas Pipeline Company ("Tennessee") hereby submits this Explanatory Statement in support of the concurrently filed Amendment to Stipulation and Agreement ("Settlement"), which is submitted to resolve the issues in this proceeding for which settlement judge procedures ("Settlement Proceedings") were established by the Commission in its order issued on November 12, 2008.[1] Specifically, this Settlement resolves the issues regarding Tennessee's over-collected Recoverable Cost/Revenue Account under the Stipulation and Agreement filed with the Commission on May 15, 1995 related to the "PCB/HSL Project" as defined therein for the period beginning February 1, 1992 through the present. This Settlement is supported by all of the active participants in the Settlement Proceedings, including the Commission Staff, and they urge prompt approval of the Settlement, without modification or condition, by the Commission.

I. PROCEDURAL HISTORY

On May 15, 1995, Tennessee filed with the Commission in the above-captioned dockets a comprehensive settlement agreement ("Stipulation and Agreement" or "Stipulation") to resolve outstanding issues relating to Tennessee's recovery through rates charged to its

[1] *Tennessee Gas Pipeline Company*, 125 FERC ¶ 61,164 (2008) ("November 12th Settlement Conference Order").

customers of the costs of remediating polychlorinated biphenyl ("PCB") and other hazardous substance list ("HSL") contamination at specified locations on its pipeline system. The Stipulation established a PCB/HSL cost recovery mechanism that is to apply throughout the duration of Tennessee's federal and state mandated programs to assess and remediate the PCB/HSL contamination ("PCB/HSL Project" or "Project"). The Commission approved the Stipulation by Orders dated November 29, 1995, and February 20, 1996.[2]

As provided by the Stipulation, on May 30, 2008, Tennessee filed for an extension of the PCB Adjustment Period established by the Stipulation until June 30, 2010 ("2008 Filing"), to allow for recovery of ongoing remediation costs on its system. Tennessee stated that it has made significant progress to date toward completion of the targeted PCB/HSL Project, but that additional remediation and monitoring efforts will be required for the foreseeable future notwithstanding this progress. Tennessee also acknowledged that the existing cost recovery balance may very well exceed what is needed to complete the Project.[3] As such, Tennessee indicated its willingness to discuss with its customers the feasibility of amending the Stipulation to provide for an earlier disposition of some portion of the over-collected balance while providing protection should the retained RCRA balance be insufficient in the event more eligible costs than are predicted are ultimately incurred to complete the Project. Tennessee proposed to report back to the Commission on the results of any such discussions by October 1, 2008.

On June 30, 2008, the Commission issued an order accepting Tennessee's proposed tariff sheets reflecting a 24-month extension of the PCB Adjustment Period until July 1, 2010

[2] *Tennessee Gas Pipeline Co.*, 73 FERC ¶ 61,222 (1995); *Tennessee Gas Pipeline Co.*, 74 FERC ¶ 61,174 (1996).
[3] Stipulation, Article IV (B)(4)(b), p. 17. The Stipulation further provides for the establishment of a Recoverable Cost/Revenue Account ("RCRA") to keep track of the eligible costs incurred by Tennessee, the amount collected through the PCB surcharge, third party (insurance) recoveries and any carrying charges on the net balance in the RCRA. The balance in the RCRA is to be calculated after adjusting all cost and revenue amounts to 1992 dollars.

("June 30th Order").[4] The Commission conditioned its acceptance upon Tennessee meeting with its customers to discuss amending the Stipulation and reporting back to the Commission by October 1, 2008, as Tennessee proposed in its filing.

On October 1, 2008, Tennessee filed a report in compliance with the June 30th Order ("Status Report") wherein it described the status of its discussions with customers. Three parties filed comments in response to Tennessee's Status Report.[5] New Jersey Natural and the Tennessee Customer Group each suggested that the settlement discussions would be enhanced by Tennessee convening a meeting of all parties as opposed to the limited group and individual discussions held by Tennessee to date.

On November 12, 2008 in its November 12th Settlement Conference Order, the Commission found that Tennessee had complied with the Commission's June 30th Order to meet with its customers, but that sufficient progress had not been made toward settlement.[6] In an effort to assist the parties in their settlement efforts, the Commission ordered the appointment of a settlement judge.

On November 17, 2008, Tennessee filed its "Motion of Tennessee Gas Pipeline Company for Stay of Settlement Judge Procedures" requesting the Commission to stay the appointment of a settlement judge in light of the dramatic changes to the economic environment in which Tennessee was willing to informally pursue discussions with its customers as to the feasibility of amending the Stipulation in favor of the status quo under the Stipulation ("Motion for Stay").

On November 20, 2008, the Chief Administrative Law Judge, Curtis L. Wagner, Jr.,

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[4] *Tennessee Gas Pipeline Co.*, 123 FERC ¶ 61,318 (June 30, 2008).

[5] Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. (collectively "ConEd"), New Jersey Natural Gas Company ("New Jersey Natural") and the Tennessee Customer Group filed comments.

[6] 125 FERC ¶ 61,164.

issued an "Order of Chief Judge Holding Appointment of Settlement Judge in Abeyance Pending Commission Action on Motion to Stay Settlement Judge Procedures." Subsequently, on November 26, 2008, in response to the opposition of several parties to Tennessee's Motion for Stay,[7] the Commission issued an order denying Tennessee's request for stay and directing the Chief Administrative Law Judge to appoint a settlement judge to convene a settlement conference as soon as practicable ("November 26th Order").[8]

Following the December 4, 2008 appointment of Judge Carmen A. Cintron as the settlement judge in the proceeding, Tennessee and its customers participated in settlement conferences convened by Judge Cintron in Washington, D.C. on December 15, 2008, February 2, 2009, and February 18, 2009. This Settlement is the product of those settlement conferences.

II. TERMS OF THE SETTLEMENT

In order to resolve and settle the issues in this proceeding, the attached Settlement provides the following:[9]

Article I provides that the Settlement is intended to modify the underlying Stipulation only as expressly provided by the terms of the Settlement and that the Stipulation otherwise will remain in full force and effect.

Article II provides that Article IV of the Stipulation is modified to provide for interim refunds (hereinafter, "Interim Refunds") to shippers of $156.6 million ("Interim Refund Amount") which reflects Tennessee's representation of the balance in the Recoverable Cost/Revenue Account as of December 31, 2008, plus estimated carrying charges at an annual

[7] National Fuel Gas Distribution Corporation and The Dominion LDCs filed answers opposing Tennessee's Motion on the basis that settlement discussions should be continued with the aid of a Settlement Judge.
[8] *Tennessee Gas Pipeline Company*, 125 FERC ¶ 61,232 (2008) ("November 26th Order").
[9] This section is for explanatory purposes. While this section accurately describes the terms of the Settlement, if a dispute arises regarding any matter related to the interpretation of the Settlement, the terms of the Settlement shall control over this Explanatory Statement.

interest rate of 10 percent through June 30, 2009, net of $10 million to be retained by Tennessee for the customers' share of additional Eligible Costs ("Retained Amount").

The Interim Refund Amount is to be paid in quarterly installments over a three year period amortized at an annual interest rate of 8 percent with the first of the quarterly payments to be made on July 1, 2009. The subsequent quarterly payments will be made on the first business day of each calendar quarter thereafter over a three year period. The first six quarterly installments will be fixed at $9.60 million, and the last six quarterly installments will be fixed at $20.06 million to maintain an annual interest rate on the balance at 8 percent throughout the three year period. To the extent the effective date of the Settlement is later than June 10, 2009, the first quarterly installment will be paid with interest no earlier than July 1, 2009 and no later than 20 days after the effective date of the Settlement. Subsequent quarterly installments will only be impacted to the extent the effective date is delayed beyond the date the installment would otherwise be due in which case a similar adjustment will be made to the amount and timing of payment.

The Interim Refund Amount is to be allocated to shippers pro rata based on surcharge collections during the PCB Adjustment Period as provided by the Stipulation and further detailed in Exhibit B to the Settlement. Tennessee will make Interim Refunds by wire transfer to the individual shippers specified on Exhibit B unless the parties agree otherwise or the wire transfer information has not been provided to Tennessee in which event, Tennessee will issue the Interim Refunds at the parties' last known mailing address.

The Settlement provides that the Interim Refund Amount and the remaining balance of the Recoverable Cost/Revenue Account shall be accounted for through the Recoverable Cost/Revenue Account. Additionally, Tennessee may, without penalty, refund all or any portion of the Interim Refund Amount and/or the remaining balance of the Recoverable

Cost/Revenue Account to all shippers subject to the Stipulation at any time and from time to time during the term of the Stipulation. In the event Tennessee makes Interim Refunds early, Tennessee is entitled to re-determine the Interim Refund Amount in accordance with the Settlement. In addition, Tennessee shall be entitled to make Interim Refunds earlier than otherwise required to all shippers whose allocated share of the Interim Refund Amount does not exceed $10,000. Such early refunds shall have no adverse impact on the allocation to other shippers of the remaining Interim Refund Amount or their respective shares of any Additional Eligible Costs.

The Settlement further provides the manner in which Tennessee shall handle the incurrence or recognition of additional Eligible Costs for which the shippers' share exceeds the $10 million which has been retained.[10] Specifically, such additional customer share of Eligible Costs shall first be netted against any remaining balance in the Interim Refund Amount in equal amounts over the remaining quarterly installments. To the extent the remaining balance of the Interim Refund Amount is insufficient, Tennessee shall reinstate the PCB adjustment as provided under the Stipulation.

The Settlement provides for the underlying Stipulation to be modified to reflect that effective July 1, 2009, the carrying charges under the Stipulation shall be computed by using the greater of (1) an annual interest rate of 8%; or (2) the then-applicable FERC-prescribed interest rate for pipeline refunds. The 8% annual interest rate replaces the currently existing 10% annual interest rate under the Stipulation.

[10] It is Tennessee's opinion that the shippers' share of the Eligible Costs during the remaining term of the Stipulation will be adequately funded by the Retained Amount. In the unlikely event the Retained Amount is ultimately determined to be insufficient, the Settlement provides the manner in which a shortfall will be recovered.

Finally, the Settlement clarifies the language in the Stipulation to reflect that the Stipulation's term shall continue as long as (1) Tennessee is incurring Eligible Costs; or (2) cost recovery or the payment of refunds, including Interim Refunds, is incomplete.

Article III specifies the impact of the Commission's order approving the Settlement and the date upon which the Settlement becomes effective and binding. Article III also provides for the filing of the revised tariff sheets included as Exhibit A to the Settlement. Additionally, Article III of the Settlement specifies the clear and indisputable intent of the parties to enter into an Amendment to the Stipulation which is indivisible from the performance under the Stipulation and the applicable burden of proof for any changes to the Settlement during the term of the Stipulation.

III. SUPPORT FOR THE AMENDMENT

The Settlement represents an across-the-board compromise among the conflicting positions of Tennessee and its customers related to the underlying Stipulation and the parties' rights and obligations thereunder. Tennessee submits that this Settlement strikes an appropriate balance among these competing interests.

IV. INFORMATION TO BE PROVIDED WITH SETTLEMENT AGREEMENTS

By order issued October 23, 2003, the Chief Administrative Law Judge requires that the following five questions be answered as part of every Explanatory Statement that is submitted in support of a proposed settlement agreement. The questions, and Tennessee's responses, are as follows:

A. What are the issues underlying the settlement and what are the major implications?

The primary issue underlying the Settlement is Tennessee's over-collection of the Recoverable Cost/Revenue Account under the terms of the underlying Stipulation. Because Tennessee is currently incurring Eligible Costs under the Stipulation and anticipates incurring such costs for the foreseeable future, the Stipulation remains in effect. Although Tennessee reduced the PCB surcharge to $0.00 effective July 1, 2000, and has maintained it at that level to date, the Recoverable Cost/Revenue Account has outpaced Tennessee's incurrence of Eligible Costs under the Stipulation, resulting in an over-collected balance. Accordingly, at the request of Tennessee's customers and as required by the Commission's November 12th Settlement Conference Order, Tennessee and its customers undertook negotiations which resulted in this Settlement. Tennessee submits that the Settlement addresses the concerns raised by its customers with regard to Tennessee's over-collection of the Recoverable Cost/Revenue Account.

B. Whether any of the issues raise policy implications?

Tennessee does not believe that the Settlement presents any policy implications for the Commission.

C. Whether other pending cases may be affected?

This Settlement is tailored to address the specific issues in this proceeding, and it is the product of negotiation between Tennessee and its customers who were active participants in the Settlement Proceedings. Thus, the Settlement only addresses the specific issues contemplated by its terms and does not affect any pending cases.

D. Whether the settlement involves issues of first impression, or if there are any previous reversals on the issues involved?

Tennessee does not believe that the Settlement raises any issues of first impression nor is Tennessee aware of any reversals on the issues involved in the Settlement.

E. **Whether the proceeding is subject to the just and reasonable standard or whether there is Mobile-Sierra language?**

As identified in the Settlement, changes to the Settlement during the Term of the Stipulation will be subject to the Mobile-Sierra "public interest" standard.

V. CONCLUSION

WHEREFORE, for all the foregoing reasons, Tennessee respectfully requests that the Commission accept the Settlement without condition or modification.

Respectfully submitted,

TENNESSEE GAS PIPELINE COMPANY

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Dated: April 13, 2009

Tennessee Gas Pipeline Company
PCB/HSL Interim Refund Allocation
Docket Nos. RP91-203 and RP92-132

Line No.	Shipper Name	Holding Company	PCB Revenue Collected	%	Interim Refund Amount at $158.6 MM	Jul 1, 2009 refund with interest	Oct 1, 2009 refund with interest	Jan 1, 2010 refund	Total Dec. 18, 2009 Installment
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	BOWATER INC	AbitibiBowater Inc.	$53,591.61	0.0720%	$112,877.32	$7,107.18	$7,025.51	$8,007.42	$21,100.11
2	ADAMS RESOURCES MARKETING, LTD.	Adams Resources & Energy, Inc.	$2,276.40	0.0026%	$4,031.78	$4,183.38			$4,183.38
3	ADAMSVILLE CITY OF	ADAMSVILLE CITY OF	$15,461.23	0.0176%	$27,353.59	$1,742.50	$1,708.13	$1,679.42	$5,130.14
4	AFG INDUSTRIES INC	AGC Flat Glass North America	$116,762.80	0.1321%	$206,890.60	$13,169.60	$12,899.70	$12,682.98	$38,742.65
5	SOUTHSTAR ENERGY SERVICES LLC	AGL Resources & Piedmont Natural Gas	$11.41	0.0000%	$20.22	$20.98			$20.98
6	ATLANTA GAS LIGHT CO	AGL Resources Inc.	$885,807.29	1.0017%	$1,568,666.85	$99,770.71	$97,807.49	$96,163.49	$293,750.68
7	CHATTANOOGA GAS CO	AGL Resources Inc.	$644,810.81	0.7290%	$1,141,047.07	$72,617.60	$71,182.54	$69,980.00	$213,780.49
8	VIRGINIA NATURAL GAS INC	AGL Resources Inc.	$536,208.49	0.6067%	$950,098.74	$60,433.05	$59,239.33	$58,243.60	$177,916.78
9	ALCAN ALUMINUM CORPORATION	Alcan Inc	$35,602.45	0.0403%	$63,083.61	$4,012.62	$3,933.31	$3,867.19	$11,813.12
10	ALCOA, INC.	Alcoa, Inc.	$311,862.66	0.3529%	$552,580.21	$35,140.89	$34,454.14	$33,875.02	$103,478.04
11	REYNOLDS METALS COMPANY	Alcoa, Inc.	$108,758.24	0.1231%	$192,701.09	$12,257.51	$12,016.23	$11,813.28	$36,086.02
12	MOUNTAINEER GAS CO	Allegheny Energy	$111,826.00	0.1265%	$198,141.63	$12,603.28	$12,354.27	$12,146.61	$37,104.26
13	MOUNTAINEER GAS SERVICES INC	Allegheny Energy	$10,500.00	0.0119%	$18,604.84	$1,183.42	$1,160.03	$1,140.53	$3,483.97
14	CONSTELLATION NEW ENERGY - GAS DIV, LLC	Allegheny Energy	$4,482.84	0.0051%	$7,943.10	$8,241.60			$8,241.80
15	ALLIANCE GAS SERVICES INC.	Allegheny Energy	$31.48	0.0000%	$55.74	$57.84			$57.84
16	ALLENERGY MARKETING COMPANY, INC.	ALLENERGY MARKETING COMPANY, INC.	$576.31	0.0007%	$1,021.15	$1,059.55			$1,059.55
17	OST ENERGY TRADING, INC.	Ameren Corporation	$42,841.62	0.0485%	$75,910.02	$4,828.62	$4,733.00	$4,653.52	$14,215.13
18	CENTRAL ILLINOIS LIGHT COMPANY	Ameren Corporation	$1,433.10	0.0016%	$2,539.44	$2,634.93			$2,634.93
19	AEP ENERGY SERVICES, INC.	American Electric Power Company, Inc.	$3.90	0.0000%	$6.91	$7.17			$7.17
20	AMERICAN ENERGY MANAGEMENT, INC.	American Energy Management	$208.10	0.0002%	$368.87	$382.74			$382.74
21	AMGAS, INC.	AMGAS, INC.	$0.43	0.0000%	$0.76	$0.79			$0.79
22	AMKOR NATURAL GAS COMPANY	AMKOR NATURAL GAS COMPANY	$41,531.08	0.0470%	$73,588.40	$4,680.81	$4,588.29	$4,511.17	$13,780.28
23	WESTERN GAS RESOURCES, INC.	Anadarko Petroleum Corporation	$195,907.80	0.2217%	$347,127.11	$22,080.05	$21,643.62	$21,279.82	$65,003.49
24	KERR-MCGEE CORPORATION	Anadarko Petroleum Corporation	$6,164.01	0.0070%	$10,921.85	$694.72	$680.99	$669.54	$2,045.20
25	HOWELL GAS MANAGEMENT COMPANY	Anadarko Petroleum Corporation	$61.88	0.0001%	$109.62	$113.85			$113.95
26	ANADARKO ENERGY SERVICES COMPANY	Anadarko Petroleum Corporation	$22.44	0.0000%	$39.76	$41.26			$41.26
27	ORYX GAS MARKETING LIMITED PARTNERSHIP	Anadarko Petroleum Corporation	$10.44	0.0000%	$18.50	$19.19			$19.19
28	ANADARKO E&P COMPANY LP	Anadarko Petroleum Corporation	$1,012.23	0.0011%	$1,793.57	$1,861.01			$1,861.01
29	APACHE CORPORATION	APACHE CORPORATION	$6.28	0.0000%	$11.13	$11.55			$11.55
30	DOE RUN GAS TRANSMISSION COMPANY	Arch Chemicals, Inc.	$57,140.04	0.0647%	$101,245.65	$6,440.04	$6,312.76	$6,206.84	$18,959.48
31	ASHLAND PETROLEUM DIV. OF ASHLAND INC.	Ashland Inc.	$19,070.00	0.0216%	$33,789.94	$2,149.31	$2,106.83	$2,071.41	$6,327.55
32	ASHLAND EXPLORATION INC	Ashland Inc.	$10,641.68	0.0120%	$18,855.88	$1,199.38	$1,175.66	$1,155.92	$3,530.96
33	ASHLAND TOWN OF MISS	ASHLAND TOWN OF MISS	$3,968.03	0.0046%	$7,030.91	$7,295.31			$7,295.31
34	ATHENS ALABAMA UTILITY CITY OF	ATHENS ALABAMA UTILITY CITY OF	$33,164.95	0.0376%	$58,764.84	$3,737.90	$3,664.02	$3,602.43	$11,004.35
35	ATHENS TENNESSEE UTILITIES BOARD	ATHENS TENNESSEE UTILITIES BOARD	$82,868.59	0.0938%	$146,833.98	$9,339.81	$9,155.20	$9,001.32	$27,496.33
36	ATLAS GAS MARKETING INC	Atlas Energy Resources, LLC	$6,218.60	0.0070%	$11,018.49	$700.86	$687.01	$675.48	$2,063.34
37	ATMOS ENERGY CORPORATION (TN)	ATMOS Energy Corp.	$1,285,634.90	1.4547%	$2,278,003.20	$144,898.18	$142,035.11	$139,647.71	$426,581.97
38	ATMOS ENERGY CORPORATION (MS)	ATMOS Energy Corp.	$624,878.78	0.7070%	$1,107,216.22	$70,427.78	$69,035.71	$67,876.02	$207,339.61
39	ATMOS ENERGY CORPORATION (KY)	ATMOS Energy Corp.	$537,159.58	0.6078%	$951,785.92	$60,541.17	$59,344.52	$58,347.03	$178,232.72
40	ATMOS ENERGY MARKETING (LA)	ATMOS Energy Corp.	$2,893.34	0.0033%	$5,126.67	$5,319.46			$5,319.40
41	ATMOS ENERGY MARKETING, LLC	ATMOS Energy Corp.	$2,150.93	0.0024%	$3,811.21	$3,954.53			$3,954.53
42	ATMOS ENERGY CORPORATION (LA)	ATMOS Energy Corp.	$914.58	0.0010%	$1,620.54	$1,681.48			$1,681.48
43	AURORA NATURAL GAS, LLC	AURORA NATURAL GAS, LLC	$233.33	0.0003%	$413.43	$428.98			$428.98
44	VITOL GAS & ELECTRIC, L.L.C.	Avista Corporation	$22,570.00	0.0255%	$39,991.65	$2,543.78	$2,493.60	$2,451.50	$7,488.87
45	SPRAGUE ENERGY CORPORATION	Axel Johnson Inc. Company	$490.10	0.0006%	$868.39	$901.05			$901.05
46	ZENECA INC	AstraZeneca p.l.c.	$19,173.88	0.0217%	$33,973.65	$2,160.99	$2,118.28	$2,082.68	$6,361.95
47	BALDWYN CITY OF	BALDWYN CITY OF	$11,091.09	0.0125%	$19,652.19	$1,250.04	$1,225.33	$1,204.73	$3,680.10
48	BATESVILLE CITY OF	BATESVILLE CITY OF	$27,618.25	0.0312%	$48,936.40	$3,112.76	$3,051.22	$2,999.94	$9,163.91
49	JOHNS MANVILLE	Berkshire Hathaway Inc.	$10,863.07	0.0123%	$19,248.10	$1,224.34	$1,200.14	$1,179.96	$3,604.44
50	UTILICORP UNITED INC	Black Hills Corp. or Great Plains Energy	$204,226.00	0.2311%	$361,869.49	$23,017.78	$22,562.82	$22,183.57	$67,764.17
51	AGF DIRECT GAS SALES INC.	Black Hills Corp. or Great Plains Energy	$449.53	0.0005%	$794.76	$824.63			$824.63
52	BLACK HILLS ENERGY RESOURCES, INC.	Black Hills Corporation	$41,702.12	0.0473%	$74,033.31	$4,709.11	$4,616.03	$4,538.44	$13,863.58
53	AQUILA MERCHANT SERVICES, INC.	Black Hills Corporation	$39,281.72	0.0444%	$68,602.07	$4,427.30	$4,339.78	$4,266.84	$13,033.93
54	PEPPERELL POWER ASSOCIATES LIMITED PART	Black Hills Corporation	$3,072.00	0.0035%	$5,443.25	$5,647.94			$5,647.94
55	AQUILA ENERGY TRANSPORTATION CORPORATION	Black Hills Corporation	$2.29	0.0000%	$4.06	$4.21			$4.21
56	BLACKSTONE GAS CO	BLACKSTONE GAS CO	$13,362.76	0.0151%	$23,677.33	$1,506.07	$1,476.30	$1,451.49	$4,433.85
57	TEXAS GAS TRANSMISSION, LLC	Boardwalk Pipeline	$145,850.00	0.1648%	$258,075.73	$16,416.67	$16,091.20	$15,820.73	$48,327.61
58	GULF SOUTH PIPELINE COMPANY, LP	Boardwalk Pipeline	$502.57	0.0006%	$890.50	$923.99			$923.99
59	BOLIVAR CITY OF	BOLIVAR CITY OF	$45,575.27	0.0516%	$80,754.35	$5,136.62	$5,035.09	$4,950.46	$15,122.17
60	BOONEVILLE MUNICIPAL GAS SYSTEM	BOONEVILLE MUNICIPAL GAS SYSTEM	$43,712.00	0.0495%	$77,452.85	$4,926.62	$4,829.24	$4,748.07	$14,503.93
61	BORDEN INCORPORATED	Borden Incorporated	$87.50	0.0001%	$155.22	$161.05			$161.05
62	VASTAR RESOURCES, INC.	BP Energy Company	$165,365.80	0.1871%	$293,008.05	$18,637.77	$18,269.38	$17,962.30	$54,869.44
63	BP ENERGY COMPANY	BP Energy Company	$104,874.94	0.1187%	$185,825.76	$11,820.09	$11,586.37	$11,391.62	$34,797.08
64	VASTAR GAS MARKETING, INC.	BP Energy Company	$31,069.07	0.0352%	$55,050.98	$3,501.68	$3,432.47	$3,374.77	$10,308.92
65	CRANBERRY PIPELINE CORP	Cabot Oil & Gas Corporation	$1,177.09	0.0013%	$2,085.67	$2,164.11			$2,164.11
66	CALEDONIA NATURAL GAS DISTRICT	CALEDONIA NATURAL GAS DISTRICT	$4,022.39	0.0046%	$7,127.23	$7,395.25			$7,395.25
67	CALGON CARBON CORP	Calgon Carbon Corporation	$1,760.00	0.0020%	$3,118.53	$3,235.80			$3,235.80
68	CALPINE CORPORATION	CALPINE CORPORATION	$750.00	0.0008%	$1,328.92	$1,378.89			$1,378.89
69	CASEY, CITY OF	CASEY, CITY OF	$26,604.75	0.0304%	$47,072.26	$3,032.33	$2,072.40	$2,922.44	$8,827.17
70	CENTERPOINT ENERGY ENTEX	Centerpoint Energy	$268,552.78	0.3039%	$475,845.91	$30,267.59	$29,669.33	$29,170.63	$89,107.55
71	CENTERPOINT ENERGY ARKLA	Centerpoint Energy	$4,709.84	0.0053%	$8,343.56	$8,657.30			$8,657.30
72	CENTERVILLE TOWN OF	CENTERVILLE TOWN OF	$27,539.83	0.0312%	$48,761.60	$3,102.90	$3,041.57	$2,990.44	$9,134.91
73	CENTRAL HUDSON GAS & ELECTRIC CORP	CH Energy Group Incorporated	$690,081.82	0.7817%	$1,224,160.30	$77,866.74	$76,327.04	$75,044.68	$229,239.06
74	CHEROKEE WATER AND GAS DEPARTMENT	CHEROKEE WATER AND GAS DEPARTMENT	$6,166.77	0.0070%	$10,925.06	$694.92	$681.19	$669.74	$2,045.84
75	CHESAPEAKE ENERGY CORPORATION	Chesapeake Energy Corporation	$225.03	0.0003%	$398.73	$413.72			$413.72
76	TEXACO NATURAL GAS INC.	Chevron Corporation	$96,290.45	0.1090%	$170,616.06	$10,852.64	$10,638.03	$10,459.22	$31,949.79
77	CHEVRON USA INC.	Chevron Corporation	$11,160.08	0.0127%	$19,827.59	$1,261.19	$1,236.26	$1,215.49	$3,712.94
78	UNION OIL COMPANY OF CALIFORNIA	Chevron Corporation	$4,800.00	0.0054%	$8,505.07	$8,824.90			$8,824.90
79	UNOCAL ENERGY TRADING, INC.	Chevron Corporation	$735.77	0.0008%	$1,303.70	$1,352.73			$1,352.73
80	TEXACO ENERGY MARKETING L.P.	Chevron Corporation	$4.97	0.0000%	$8.81	$9.14			$9.14
81	CIMA ENERGY, LTD.	Cima Energy, Ltd.	$880.01	0.0010%	$1,594.54	$1,654.50			$1,654.50
82	PHIBRO, INC.	Citigroup, Inc.	$10,360.78	0.0117%	$18,358.07	$1,167.72	$1,144.64	$1,125.40	$3,437.76
83	CITIZENS GAS UTILITY DISTRICT	CITIZENS GAS UTILITY DISTRICT	$5,495.28	0.0062%	$9,736.99	$10,103.16			$10,103.15
84	COOKEVILLE GAS DEPT, CITY OF	City of Cookeville	$100,705.35	0.1139%	$178,436.64	$11,350.13	$11,125.70	$10,938.78	$33,414.70
85	DUNLAP GAS SYSTEM	City of Dunlap	$11,703.85	0.0132%	$20,737.93	$1,319.10	$1,293.02	$1,271.29	$3,883.41
86	LEXINGTON GAS SYSTEM	City of Lexington	$78,769.22	0.0891%	$139,552.06	$8,876.68	$8,701.21	$8,554.95	$26,132.82
87	SOUTH PITTSBURG, CITY OF	City of South Pittsburg	$43,688.74	0.0494%	$77,411.63	$4,924.00	$4,820.67	$4,745.54	$14,490.21
88	CLARION RIVER GAS COMPANY	CLARION RIVER GAS COMPANY	$1,341.24	0.0015%	$2,376.53	$2,465.90			$2,465.90
89	CLARKSVILLE GAS DEPT CITY OF	CLARKSVILLE GAS DEPT CITY OF	$318,159.83	0.3600%	$563,744.13	$35,858.62	$35,149.84	$34,559.03	$105,567.49
90	M&B GAS SERVICES, INC.	Clearfield Ohio Holdings, Inc.	$96,777.02	0.1095%	$171,478.20	$10,907.38	$10,691.79	$10,512.07	$32,111.24

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Line No.	Shipper Name	Holding Company	PCB Revenue Collected	%	Interim Refund Amount at $156.6 MM	Jul 1, 2009 refund with Interest	Oct 1, 2009 refund with Interest	Jan 1, 2010 refund	Total Dec. 18, 2009 Installment
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
91	PIKE NATURAL GAS CO	Clearfield Ohio Holdings, Inc.	$49,132.37	0.0556%	$87,057.18	$5,537.53	$5,428.07	$5,336.84	$16,302.44
92	CLIFTON CITY OF TENNESSEE	CLIFTON CITY OF TENNESSEE	$3,790.26	0.0043%	$6,726.55	$6,979.50			$6,979.50
93	COGEN ENERGY TECHNOLOGY LP	COGEN ENERGY TECHNOLOGY LP	$9,690.00	0.0110%	$17,169.61	$1,092.12	$1,070.54	$1,052.54	$3,215.20
94	COKINOS NATURAL GAS COMPANY	Cokinos Energy Corp.	$2,555.10	0.0029%	$4,527.30	$4,697.91			$4,697.91
95	COLLINWOOD CITY OF	COLLINWOOD CITY OF	$1,606.52	0.0018%	$2,846.66	$2,953.62			$2,953.62
96	COLONIAL ENERGY, INC.	Colonial Group, Inc.	$85,112.44	0.0963%	$150,809.80	$9,592.71	$9,403.10	$9,245.05	$28,240.86
97	PENNUNION ENERGY SERVICES, L.L.C.	Columbia Gas Systems	$9.17	0.0000%	$16.25	$16.86			$16.86
98	COMMONWEALTH ALUMINUM CONCAST, INC.	Commonwealth Industries, Inc.	$66,711.53	0.0755%	$118,205.47	$7,518.81	$7,370.19	$7,246.31	$22,135.32
99	COMMUNITY NATURAL GAS CO., INC.	COMMUNITY NATURAL GAS CO INC	$10,537.50	0.0119%	$18,671.29	$1,187.64	$1,164.17	$1,144.60	$3,496.41
100	COMSTOCK OIL & GAS INC	Comstock Resources Inc	$2.62	0.0000%	$4.64	$4.82			$4.82
101	ORANGE AND ROCKLAND UTILITIES INC	Con Edison, Inc.	$2,647,981.55	2.9961%	$4,691,931.16	$298,444.21	$292,545.72	$287,627.96	$878,617.40
102	CONSOLIDATED EDISON CO OF NEW YORK INC	Con Edison, Inc.	$1,360,468.74	1.5393%	$2,410,600.51	$153,333.40	$150,302.64	$147,776.28	$451,412.32
103	CONSOLIDATED EDISON SOLUTIONS, INC.	Con Edison, Inc.	$12.40	0.0000%	$21.97	$22.80			$22.80
104	ENGLEWOOD NATURAL GAS SYSTEM	ConnectUtilities, LLC	$3,566.52	0.0040%	$6,319.49	$6,557.12			$6,557.12
105	CONOCOPHILLIPS COMPANY	ConocoPhillips Company	$50,286.89	0.0569%	$89,102.02	$5,667.65	$5,555.62	$5,462.24	$16,685.52
106	CONOCOPHILLIPS COMPANY	ConocoPhillips Company	$324.58	0.0004%	$575.12	$596.75			$596.75
107	LOUISIANA LAND AND EXPLORATION CO (THE)	ConocoPhillips Company	$6.40	0.0000%	$11.34	$11.77			$11.77
108	BALTIMORE GAS AND ELECTRIC COMPANY	Constellation Energy Group Inc.	$334,372.29	0.3783%	$592,470.01	$37,685.67	$36,940.67	$36,320.05	$110,946.89
109	CANTERA GAS CO.	CONTINENTAL NATURAL GAS	$2,704.36	0.0031%	$4,791.86	$4,972.06			$4,972.08
110	CORINTH PUBLIC UTILITIES COMMISSION	CORINTH PUBLIC UTILITIES COMMISSION	$89,639.90	0.1014%	$158,832.01	$10,102.98	$9,903.28	$9,736.83	$29,743.10
111	COAST ENERGY GROUP, INC.	Cornerstone Propane Partners, L. P.	$6,333.20	0.0072%	$11,221.74	$713.79	$699.68	$687.92	$2,101.40
112	CORNING INC	CORNING INC	$122.88	0.0001%	$217.73	$225.92			$225.92
113	CORNING NATURAL GAS CORP	CORNING NATURAL GAS CORP	$211,896.00	0.2398%	$375,456.83	$23,882.01	$23,409.97	$23,016.48	$70,308.46
114	CORPUS CHRISTI GAS MARKETING, LP	CORPUS CHRISTI GAS MARKETING, LP	$139.24	0.0002%	$246.72	$256.00			$256.00
115	COUNCE NATURAL GAS CORPORATION	COUNCE NATURAL GAS CORPORATION	$1,005.75	0.0011%	$1,782.08	$1,849.09			$1,849.09
116	CROSSTEX ENERGY SERVICES, L.P.	CROSSTEX ENERGY LP	$34.02	0.0000%	$60.28	$62.55			$62.55
117	DECATUR ALABAMA CITY OF	DECATUR ALABAMA CITY OF	$373,703.34	0.4228%	$662,161.08	$42,118.72	$41,286.21	$40,592.26	$123,997.18
118	DELTA NATURAL GAS COMPANY INC	DELTA NATURAL GAS COMPANY INC	$212,499.70	0.2404%	$376,526.02	$23,950.06	$23,476.60	$23,082.08	$70,508.77
119	DEVON GAS SERVICES, L.P.	Devon Energy Corporation	$1,527.59	0.0017%	$2,706.72	$2,808.51			$2,808.51
120	SEAGULL MARKETING SERVICES INC.	Devon Energy Corporation	$1,002.72	0.0011%	$1,776.71	$1,843.62			$1,843.62
121	DEVON GAS SERVICES, L.P.	Devon Energy Corporation	$182.65	0.0002%	$323.59	$336.17			$336.17
122	DICKSON GAS AUTHORITY	DICKSON GAS AUTHORITY	$127,094.15	0.1447%	$226,614.82	$14,414.48	$14,129.56	$13,892.07	$42,436.11
123	DIRECT ENERGY MARKETING LTD	Direct Energy	$207.64	0.0002%	$367.92	$381.76			$381.76
124	DIRECT GAS SUPPLY CORPORATION	DIRECT GAS SUPPLY CORPORATION	$8,969.36	0.0101%	$15,892.72	$1,010.90	$990.92	$974.27	$2,976.09
125	THE EAST OHIO GAS COMPANY	Dominion Resources Inc.	$3,530,207.95	3.9944%	$6,255,246.25	$397,883.45	$390,018.98	$383,463.31	$1,171,365.72
126	DOMINION TRANSMISSION, INC.	Dominion Resources Inc.	$1,163,455.44	1.3164%	$2,061,514.56	$131,126.76	$128,536.90	$126,376.38	$386,042.04
127	PEOPLE'S NATURAL GAS COMPANY	Dominion Resources Inc.	$1,070,550.36	1.2113%	$1,896,897.14	$120,657.78	$118,272.88	$116,284.88	$355,215.53
128	HOPE GAS INC	Dominion Resources Inc.	$169,377.38	0.1603%	$242,399.14	$17,062.04	$17,607.70	$17,311.82	$52,882.45
129	VIRGINIA POWER ENERGY MARKETING, INC.	Dominion Resources Inc.	$41,096.34	0.0465%	$72,818.41	$4,631.70	$4,540.18	$4,463.84	$13,635.70
130	DOMINION EXPLORATION & PRODUCTION, INC.	Dominion Resources Inc.	$2,866.09	0.0032%	$5,078.40	$5,269.37			$5,269.37
131	VIRGINIA POWER SERVICES ENERGY CORP, INC	Dominion Resources Inc.	$2,386.07	0.0027%	$4,227.85	$4,386.84			$4,386.84
132	MIAMI VALLEY RESOURCES, INC.	DPL Inc.	$2,060.16	0.0023%	$3,650.36	$3,787.65			$3,787.65
133	HOWARD ENERGY CO., INC.	DTE Energy Company	$88.90	0.0001%	$157.52	$163.44			$163.44
134	DUKE ENERGY TRADING AND MARKETING, L.L.C	Duke Energy Corporation	$518,777.42	0.5870%	$919,210.36	$58,469.40	$57,313.78	$56,350.43	$172,133.70
135	DUKE ENERGY OHIO, INC. (REGULATED)	Duke Energy Corporation	$487,864.00	0.5520%	$864,441.18	$54,985.35	$53,898.52	$52,992.68	$161,876.43
136	DUKE ENERGY KENTUCKY, INC	Duke Energy Corporation	$62,910.00	0.0712%	$111,469.69	$7,090.35	$6,950.21	$6,833.38	$20,873.94
137	CINERGY RESOURCES, INC.	Duke Energy Corporation	$39,000.00	0.0441%	$69,103.70	$4,395.55	$4,308.69	$4,236.24	$12,940.49
138	PAN ENERGY GAS SERVICES, INC.	Duke Energy Corporation	$24,650.00	0.0279%	$43,677.08	$2,778.21	$2,723.30	$2,677.52	$8,179.03
139	ASSOCIATED NATURAL GAS INC	Duke Energy Corporation	$14,191.16	0.0161%	$25,145.17	$1,599.43	$1,567.82	$1,541.47	$4,708.72
140	DUKE ENERGY FUELS, L.P.	Duke Energy Corporation	$3,453.14	0.0039%	$6,118.58	$6,348.67			$6,348.67
141	DYNEGY MARKETING AND TRADE	Dynegy Inc.	$80,742.84	0.0914%	$143,066.88	$9,100.18	$8,920.32	$8,770.38	$26,790.90
142	DYNEGY GAS TRANSPORTATION, INC.	Dynegy Inc.	$38,193.81	0.0432%	$67,676.21	$4,304.68	$4,219.60	$4,148.67	$12,672.95
143	LOUISVILLE GAS & ELECTRIC CO.	E.ON-US	$613,620.00	0.6943%	$1,087,260.94	$69,158.84	$67,791.80	$66,652.30	$203,603.00
144	LG&E ENERGY MARKETING INC.	E.ON-US	$83,886.79	0.0949%	$148,638.14	$9,454.57	$9,267.60	$9,111.02	$27,834.18
145	EASTERN NATURAL GAS COMPANY	EASTERN NATURAL GAS COMPANY	$45,253.20	0.0512%	$80,183.08	$5,100.32	$4,999.51	$4,915.47	$15,015.30
146	EASTMAN CHEMICAL CO	Eastman Chemical Company	$154,861.32	0.1752%	$274,397.17	$17,453.85	$17,108.65	$16,821.28	$51,383.59
147	SITHE MYSTIC L.L.C.	EBG Holdings, LLC	$216,000.00	0.2444%	$382,724.17	$24,344.56	$23,863.37	$23,462.26	$71,670.20
148	EL PASO MARKETING, L.P.	El Paso Corporation	$795,949.51	0.9006%	$1,410,334.73	$89,708.63	$87,935.37	$86,457.30	$264,101.20
149	EASTEX HYDROCARBONS INC, DIV. OF EL PASO	El Paso Corporation	$151,327.84	0.1712%	$268,136.24	$17,055.60	$16,718.48	$16,437.47	$50,211.58
150	EL PASO GAS SERVICES COMPANY	El Paso Corporation	$44,567.91	0.0504%	$78,969.42	$5,023.08	$4,923.80	$4,841.04	$14,787.92
151	COASTAL MERCHANT ENERGY, L.P.	El Paso Corporation	$28,616.50	0.0324%	$50,705.28	$3,225.28	$3,161.51	$3,108.37	$9,495.14
152	SONAT MARKETING COMPANY, ET AL	El Paso Corporation	$26,423.00	0.0299%	$46,820.40	$2,978.18	$2,919.28	$2,870.22	$8,767.65
153	SONAT MARKETING COMPANY	El Paso Corporation	$22,929.78	0.0259%	$40,629.04	$2,584.33	$2,533.25	$2,490.67	$7,608.25
154	TENNESSEE GAS MARKETING CO.	El Paso Corporation	$21,662.95	0.0245%	$38,384.36	$2,441.55	$2,393.29	$2,353.06	$7,187.91
155	SONAT MARKETING COMPANY L.P.	El Paso Corporation	$10,549.61	0.0119%	$18,692.74	$1,189.01	$1,165.51	$1,145.92	$3,500.43
156	COASTAL GAS MARKETING COMPANY	El Paso Corporation	$6,769.25	0.0077%	$11,092.59	$762.82	$747.76	$735.18	$2,245.75
157	TENNECO MARKETING SERVICES COMPANY	El Paso Corporation	$6,091.23	0.0069%	$10,792.99	$686.52	$672.95	$661.64	$2,021.11
158	CHANNEL GAS MARKETING COMPANY	El Paso Corporation	$4,182.54	0.0047%	$7,410.99	$7,689.68			$7,689.68
159	SOUTHERN NATURAL GAS CO.	El Paso Corporation	$3,445.75	0.0039%	$6,105.49	$6,335.09			$6,335.09
160	HEATH PETRA RESOURCES INC.	El Paso Corporation	$900.73	0.0010%	$1,606.53	$1,667.04			$1,667.04
161	PREMIER GAS COMPANY	El Paso Corporation	$520.77	0.0006%	$922.75	$957.45			$957.45
162	EL PASO FIELD SERVICES, L.P.	El Paso Corporation	$446.00	0.0005%	$788.49	$818.14			$818.14
163	CORNERSTONE GAS RESOURCES, INC.	El Paso Corporation	$255.45	0.0003%	$452.63	$469.65			$469.65
164	EL PASO FIELD OPERATIONS COMPANY	El Paso Corporation	$41.00	0.0000%	$72.65	$75.38			$75.38
165	ELIZABETH NATURAL GAS, INC.	ELIZABETH NATURAL GAS, INC.	$5,349.81	0.0061%	$9,477.60	$9,833.90			$9,833.90
166	ELK RIVER PUBLIC UTILITY DISTRICT	Elk River Public Utility District	$101,639.77	0.1826%	$200,230.60	$18,200.55	$17,846.68	$17,540.71	$53,596.94
167	ENBRIDGE MARKETING (U.S.) L.P.	Enbridge US	$197,618.27	0.2236%	$350,157.77	$22,272.82	$21,832.58	$21,465.61	$65,571.02
168	ENBRIDGE MIDCOAST ENERGY, INC.	Enbridge US	$20,509.88	0.0232%	$36,341.24	$2,311.59	$2,265.90	$2,227.82	$6,805.31
169	ENBRIDGE PIPELINES (LA INTRASTATE) INC.	Enbridge US	$16.40	0.0000%	$29.06	$30.15			$30.15
170	ENCANA ENERGY SERVICES, INC.	EnCana Corporation	$792.79	0.0009%	$1,404.72	$1,457.55			$1,457.55
171	ENCINA GAS MARKETING COMPANY, LLC	ENCINA GAS MARKETING COMPANY, L.L.C.	$681.15	0.0008%	$1,206.91	$1,252.30			$1,252.30
172	ENERGY DEVELOPMENT CORP.	ENERGY DEVELOPMENT CORP	$386.51	0.0004%	$684.86	$710.61			$710.61
173	CONNECTICUT NATURAL GAS CORP	Energy East Corp.	$1,911,830.51	2.1632%	$3,387,552.92	$215,476.38	$211,216.32	$207,666.08	$634,357.78
174	NEW YORK STATE ELECTRIC & GAS CORP	Energy East Corp.	$1,714,805.24	1.9405%	$3,038,782.36	$193,290.78	$189,470.23	$186,285.61	$569,046.61
175	SOUTHERN CONNECTICUT GAS CO THE	Energy East Corp.	$1,418,709.54	1.6052%	$2,513,796.97	$159,897.62	$156,737.02	$154,102.60	$470,737.03
176	ROCHESTER GAS & ELECTRIC CORPORATION	Energy East Corp.	$1,201,839.11	1.3598%	$2,129,526.31	$135,454.84	$132,777.47	$130,545.67	$398,777.99
177	BERKSHIRE GAS COMPANY THE	Energy East Corp.	$814,127.30	0.9212%	$1,442,543.75	$91,757.29	$89,943.62	$88,431.80	$270,132.70
178	ENERGY EAST SOLUTIONS, INC.	Energy East Corp.	$1,271.12	0.0014%	$2,252.28	$2,336.97			$2,336.97
179	XBC ENERGY SERVICES	Energy East Corp.	$315.80	0.0004%	$559.82	$578.83			$578.83
180	TXU PORTFOLIO MANAGEMENT COMPANY LP	Energy Future Holdings Corporation	$468,410.06	0.5300%	$829,970.95	$52,792.77	$51,749.27	$50,879.46	$165,421.49
181	ENERGYVISION, LLC	Energy Vision, Llc	$4,225.16	0.0048%	$7,486.52	$7,768.05			$7,768.05

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	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
182	ENERVAL LLC	ENERVAL LLC	$485.94	0.0006%	$861.03	$893.41			$893.41
183	BELDEN & BLAKE CORPORATION	Enervest Management Partners	$25,552.02	0.0289%	$45,278.43	$2,878.94	$2,823.02	$2,776.57	$8,478.53
184	CLINTON ENERGY MANAGEMENT SERVICES, INC.	Enron Corp.	$42,930.75	0.0486%	$76,080.65	$4,888.57	$4,742.93	$4,683.21	$14,244.70
185	ENRON NORTH AMERICA CORP.	Enron Corp.	$38,678.18	0.0438%	$68,533.47	$4,359.27	$4,278.11	$4,201.29	$12,833.67
186	ENRON ENERGY SERVICES, INC.	Enron Corp.	$3,500.00	0.0040%	$6,201.61	$6,434.83			$6,434.83
187	EQUITABLE GAS CO	Equitable Resources Inc.	$1,602,946.13	1.8137%	$2,840,247.24	$180,662.38	$177,091.42	$174,114.77	$531,868.56
188	ERI SERVICES, INC.	Equitable Resources Inc.	$6,118.51	0.0060%	$10,841.65	$689.63	$676.00	$664.63	$2,030.28
189	EQUITABLE ENERGY, L.L.C.	Equitable Resources Inc.	$72.37	0.0001%	$128.24	$133.06			$133.06
190	ETOWAH UTILITIES DEPARTMENT	Etowah Utilities Department	$36,038.88	0.0408%	$63,858.83	$4,061.61	$3,981.52	$3,914.60	$11,957.93
191	EXXON MOBIL CORPORATION	Exxon Mobil Corp.	$65,126.41	0.0737%	$115,396.82	$7,340.16	$7,195.07	$7,074.19	$21,609.97
192	MOBIL NATURAL GAS INC	Exxon Mobil Corp.	$3,473.23	0.0039%	$6,154.18	$6,385.61			$6,385.61
193	FAYETTEVILLE GAS SYSTEM	Fayetteville Gas System	$46,359.41	0.0525%	$82,143.75	$5,225.00	$5,121.72	$5,035.63	$15,382.35
194	NORTHEAST OHIO NATURAL GAS CORP	First Energy Corporation	$5,514.14	0.0062%	$9,770.46	$10,137.07			$10,137.87
195	NORTHEAST OHIO GAS MARKETING, INC.	First Energy Corporation	$467.53	0.0003%	$829.17	$860.35			$860.35
196	FLAGG ENERGY DEVELOPEMENT CORP	FLAGG ENERGY DEVELOPEMENT CORP	$7,162.20	0.0081%	$12,690.63	$807.23	$791.27	$777.97	$2,376.46
197	FLORENCE GAS DEPARTMENT CITY OF	FLORENCE GAS DEPARTMENT CITY OF	$186,444.78	0.2110%	$330,359.59	$21,013.60	$20,598.15	$20,251.93	$61,863.68
198	FORD MOTOR CO	FORD MOTOR CO	$146,800.00	0.1661%	$260,113.40	$16,545.29	$16,218.25	$15,945.65	$48,709.19
199	FOREST HILL, VILLAGE OF	FOREST HILL, VILLAGE OF	$1,721.98	0.0019%	$3,051.16	$3,165.80			$3,165.90
200	FORTIS ENERGY MARKETING & TRADING GP	Fortis Inc.	$4,109.36	0.0045%	$7,281.34	$7,555.16			$7,555.16
201	FOUR SQUARE GAS COMPANY, INC	FOUR SQUARE GAS COMPANY, INC	$98.21	0.0001%	$170.48	$176.89			$176.89
202	FLORIDA POWER & LIGHT COMPANY	FPL Group Incorporated	$200.00	0.0002%	$354.38	$367.70			$367.70
203	GAINESBORO GAS SYSTEMS	GAINESBORO GAS SYSTEMS	$3,342.89	0.0038%	$5,923.23	$6,145.98			$6,145.98
204	GALLATIN NATURAL GAS SYSTEM	Gallatin Natural Gas System	$76,487.84	0.0865%	$135,528.01	$8,620.66	$8,450.27	$8,308.23	$25,379.16
205	GENERAL SHALE PRODUCTS CORP	General Shale Brick Inc.	$5,574.90	0.0063%	$9,878.21	$10,249.58			$10,249.58
206	GGR ENERGY	GGR ENERGY	$0.04	0.0000%	$0.07	$0.07			$0.07
207	GLOBAL COMPANIES LLC	Global Partners LP	$3,045.46	0.0034%	$5,396.22	$5,599.14			$5,599.14
208	GRAIN PROCESSING CORPORATION	GRAIN PROCESSING CORPORATION	$26,668.64	0.0302%	$47,250.34	$3,005.50	$2,946.09	$2,896.57	$8,848.16
209	GRAND ISLE, TOWN OF	GRAND ISLE, TOWN OF	$2,323.78	0.0026%	$4,117.45	$4,272.29			$4,272.29
210	GRANDVIEW TOWN OF	GRANDVIEW TOWN OF	$2,217.82	0.0025%	$3,929.74	$4,077.51			$4,077.51
211	GRAYSON, CITY OF	GRAYSON, CITY OF	$23,520.65	0.0266%	$41,676.00	$2,650.93	$2,598.53	$2,554.85	$7,804.30
212	GREAT LAKES ENERGY CORP.	GREAT LAKES ENERGY CORP.	$3,183.40	0.0036%	$5,640.63	$5,852.76			$5,852.76
213	RANGE RESOURCES - APPALACHIA, LLC	GREAT LAKES ENERGY PARTNERS, L.L.C.	$948.62	0.0011%	$1,680.85	$1,744.06			$1,744.06
214	GULF COAST ENERGY INC	Gulf Coast Energy, Inc.	$10.40	0.0000%	$18.43	$19.12			$19.12
215	H & N GAS, LTD.	H & N GAS, LTD.	$18,447.25	0.0209%	$32,686.48	$2,079.12	$2,038.03	$2,003.77	$6,120.92
216	HARDEMAN FAYETTE UTILITY DISTRICT	HARDEMAN FAYETTE UTILITY DISTRICT	$18,117.18	0.0205%	$32,101.01	$2,041.92	$2,001.60	$1,967.91	$6,011.88
217	HARDIN COUNTY GAS COMPANY	HARDIN COUNTY GAS COMPANY	$135.50	0.0002%	$240.09	$249.12			$249.12
218	HARRIMAN UTILITY BOARD	HARRIMAN UTILITY BOARD	$23,265.04	0.0263%	$41,223.09	$2,622.12	$2,570.29	$2,527.09	$7,719.49
219	HARRISONBURG, LOUISIANA, TOWN OF	HARRISONBURG, LOUISIANA, TOWN OF	$2,452.00	0.0028%	$4,344.68	$4,508.06			$4,508.06
220	HARTSELLE UTILITIES BOARD, THE CITY OF	HARTSELLE UTILITIES BOARD, THE CITY OF	$28,959.93	0.0328%	$51,313.89	$3,263.97	$3,199.45	$3,145.67	$9,609.09
221	HAWKINS COUNTY UTILITY DISTRICT	Hawkins County Utility District	$40,363.94	0.0457%	$71,520.46	$4,549.27	$4,459.35	$4,384.40	$13,393.02
222	HEMPHILL CITY OF	HEMPHILL CITY OF	$1,971.00	0.0022%	$3,493.60	$3,624.98			$3,624.98
223	HENDERSON, CITY OF	HENDERSON, CITY OF	$25,798.04	0.0292%	$45,707.73	$2,907.38	$2,849.91	$2,802.01	$8,559.29
224	HESS ENERGY INC.	Hess Corporation	$78,641.73	0.0890%	$139,344.48	$8,863.42	$8,688.23	$8,542.19	$26,093.84
225	HESS ENERGY SERVICES COMPANY, LLC	Hess Corporation	$35.64	0.0000%	$63.15	$65.52			$65.52
226	CALPINE PRODUCER SERVICES, L.P.	HIGHLAND ENERGY COMPANY	$183.86	0.0002%	$325.79	$338.04			$338.04
227	PYRON METAL POWDERS, INC.	Hoganas AB	$6,468.22	0.0073%	$11,460.97	$729.01	$714.60	$702.59	$2,146.20
228	HOHENWALD CITY OF	HOHENWALD CITY OF	$17,605.17	0.0201%	$31,648.60	$2,006.76	$1,967.00	$1,934.03	$5,907.87
229	HOLLY SPRINGS, CITY OF	HOLLY SPRINGS, CITY OF	$38,058.04	0.0431%	$67,434.05	$4,289.38	$4,204.60	$4,133.92	$12,627.90
230	HOLYOKE GAS & ELEC DEPT CITY OF	HOLYOKE GAS & ELEC DEPT CITY OF	$336,020.16	0.3802%	$595,404.82	$37,872.49	$37,123.81	$36,499.01	$111,496.31
231	ALLIED SIGNAL INC	Honeywell	$208,893.30	0.2363%	$370,092.72	$23,540.21	$23,074.92	$22,687.06	$69,302.19
232	HUMPHREYS COUNTY UTILITY DISTRICT	HUMPHREYS COUNTY UTILITY DISTRICT	$81,014.48	0.0917%	$143,548.69	$9,130.84	$8,950.30	$8,799.92	$26,881.12
233	HUNT PETROLEUM CORPORATION	HUNT PETROLEUM CORP	$501.67	0.0006%	$888.91	$922.34			$922.34
234	HUNTSVILLE UTILITIES GAS SYSTEM CITY OF	HUNTSVILLE UTILITIES GAS SYSTEM CITY OF	$607,048.66	0.6869%	$1,075,623.24	$68,418.21	$67,065.87	$65,938.59	$201,422.67
235	IDAHO POWER COMPANY	Idacorp Inc.	$3,600.00	0.0041%	$6,378.80	$6,618.68			$6,618.68
236	INDEPENDENT ENERGY MARKETING INC	INDEPENDENT ENERGY MARKETING INC	$1,120.00	0.0013%	$1,984.52	$2,059.14			$2,059.14
237	INFINITE ENERGY, INC.	INFINITE ENERGY, INC.	$5.04	0.0000%	$8.93	$9.26			$9.26
238	THE PEOPLES GAS LIGHT & COKE COMPANY	Integrys Energy Group Inc.	$46,397.00	0.0525%	$82,210.37	$5,229.23	$5,125.87	$5,039.72	$15,394.82
239	PEOPLES ENERGY RESOURCES CORP.	Integrys Energy Group Inc.	$6,319.10	0.0071%	$11,196.75	$712.20	$698.13	$686.39	$2,096.72
240	INVENTORY MGMT & DISTRIBUTION CO, LLC	INVENTORY MGMT & DISTRIBUTION CO, LLC	$354.00	0.0004%	$627.25	$650.84			$650.84
241	IROQUOIS ENERGY MANAGEMENT, INC.	IROQUOIS ENERGY MANAGEMENT, INC.	$1,622.13	0.0018%	$2,874.24	$2,982.32			$2,982.32
242	IROQUOIS GAS TRANSMISSION SYSTEM	IROQUOIS GAS TRANSMISSION SYSTEM	$45,929.30	0.0520%	$81,381.65	$5,176.52	$5,074.20	$4,988.91	$15,239.64
243	IUKA MISSISSIPPI CITY OF	IUKA MISSISSIPPI CITY OF	$11,804.85	0.0134%	$20,917.00	$1,330.49	$1,304.20	$1,282.27	$3,916.96
244	J. M. HUBER CORPORATION	J. M. Huber Corporation	$7,400.00	0.0084%	$13,111.09	$834.03	$817.54	$803.80	$2,455.37
245	JAMESTOWN NATURAL GAS SYSTEM	Jamestown Natural Gas System	$23,231.43	0.0263%	$41,163.52	$2,618.33	$2,566.57	$2,523.43	$7,708.34
246	JEFFERSON/COCKE CO. PUBLIC UTILITY DIST.	JEFFERSON/COCKE CO. PUBLIC UTILITY DIST.	$92,504.35	0.1048%	$164,049.26	$10,434.84	$10,228.59	$10,056.60	$30,720.08
247	JOSEPH ENERGY INC	JOSEPH ENERGY INC	$10.40	0.0000%	$18.43	$19.12			$19.12
248	KENTUCKY-OHIO GAS ACQUISITION CORP.	KENTUCKY-OHIO GAS ACQUISITION CORP.	$510.00	0.0006%	$903.68	$937.65			$937.65
249	K N MARKETING, INC.	Kinder Morgan	$492.34	0.0006%	$872.37	$905.18			$905.18
250	NORSTAR ENERGY LIMITED PARTNERSHIP	Kinder Morgan Inc.	$5,443.53	0.0062%	$9,645.33	$10,008.05			$10,008.05
251	KNOXVILLE UTILITIES BOARD	KNOXVILLE UTILITIES BOARD	$712,181.81	0.8058%	$1,261,907.60	$80,267.38	$78,680.83	$77,358.32	$236,306.53
252	KOCH ENERGY SERVICES COMPANY	Koch Industries, Inc.	$34.91	0.0000%	$61.86	$64.18			$64.18
253	KOCH MIDSTREAM SERVICES COMPANY	Koch Industries, Inc.	$0.24	0.0000%	$11.06	$11.47			$11.47
254	LAWRENCEBURG CITY OF	LAWRENCEBURG CITY OF	$17,749.60	0.0201%	$31,450.10	$2,000.48	$1,960.94	$1,927.98	$5,889.40
255	LAWRENCE-COLBERT COUNTIES GAS DISTRICT	LAWRENCE-COLBERT COUNTIES GAS DISTRICT	$7,354.47	0.0083%	$13,031.31	$828.90	$812.51	$798.85	$2,440.26
256	LENOIR CITY UTILITIES BOARD	Lenoir City Utilities Board	$23,316.24	0.0264%	$41,313.81	$2,627.89	$2,575.95	$2,532.66	$7,736.48
257	LEWISBURG GAS DEPARTMENT	Lewisburg Gas Department	$57,710.18	0.0653%	$102,256.07	$6,504.30	$6,375.74	$6,268.57	$19,148.61
258	LINDEN CITY OF	LINDEN CITY OF	$7,179.72	0.0081%	$12,721.07	$809.20	$793.21	$779.87	$2,382.28
259	FULTON COGENERATION ASSOCIATES, L.P.	Lion Capital Management Group	$102,310.00	0.1158%	$181,282.03	$11,530.98	$11,303.08	$11,113.07	$33,947.12
260	LIVINGSTON GAS SYSTEM	LIVINGSTON GAS SYSTEM	$17,783.66	0.0201%	$31,528.22	$2,005.45	$1,965.81	$1,932.76	$5,904.02
261	LOBELVILLE CITY OF	LOBELVILLE CITY OF	$4,693.02	0.0052%	$8,138.32	$8,444.36			$8,444.36
262	LOUDON UTILITIES GAS DEPARTMENT	LOUDON UTILITIES GAS DEPARTMENT	$111,728.80	0.1264%	$197,971.11	$12,592.64	$12,343.64	$12,136.16	$37,072.94
263	LOUIS DREYFUS ENERGY CORP	Louis Dreyfus Group	$1,981.62	0.0022%	$3,511.58	$3,643.62			$3,643.62
264	LOUISIANA MUNICIPAL GAS AUTHORITY	LOUISIANA MUNICIPAL GAS AUTHORITY	$86.77	0.0001%	$153.75	$159.53			$159.53
265	LOCKPORT ENERGY ASSOCIATES LP	LS Power Group	$1,540.40	0.0017%	$2,729.42	$2,832.06			$2,832.06
266	MADISONVILLE GAS SYSTEM	MADISONVILLE GAS SYSTEM	$3,840.20	0.0043%	$6,804.41	$7,060.29			$7,060.29
267	MARATHON PETROLEUM COMPANY LLC	Marathon Oil Corporation	$16,350.00	0.0185%	$28,970.40	$1,842.76	$1,806.32	$1,775.96	$5,425.04
268	MARSHALL, CITY OF	MARSHALL, CITY OF	$23,636.00	0.0267%	$41,878.61	$2,663.81	$2,611.10	$2,567.27	$7,842.26
269	MARTINSVILLE, IL CITY OF	MARTINSVILLE, IL CITY OF	$7,622.00	0.0085%	$13,320.22	$847.84	$831.09	$817.12	$2,496.05
270	MASONITE CORP	Masonite Corp	$12,744.00	0.0144%	$22,580.95	$1,436.33	$1,407.94	$1,384.27	$4,228.54
271	CAPITOL DISTRICT ENERGY CENTER COGEN	Maxim Power Corporation	$46,364.50	0.0524%	$82,135.06	$5,224.44	$5,121.18	$5,035.10	$15,380.72
272	DTE ENERGY TRADING, INC.	MCN Energy	$23,600.84	0.0267%	$41,818.09	$2,659.66	$2,607.39	$2,563.56	$7,830.91

Tennessee Gas Pipeline Company
PCB/HSL Interim Refund Allocation
Docket Nos. RP91-203 and RP92-132

Line No.	Shipper Name	Holding Company	PCB Revenue Collected	%	Interim Refund Amount of $159.0 MM	Jul 1, 2009 refund with interest	Oct 1, 2009 refund with interest	Jan 1, 2010 refund	Total Dec. 18, 2009 Instalment
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
273	MERIDIAN MARKETING CORP.	MERIDIAN MARKETING CORP.	$646.38	0.0007%	$1,145.31	$1,188.38			$1,188.38
274	KOCH ENERGY TRADING, LP	Merill Lynch	$15,959.44	0.0181%	$28,278.37	$1,798.73	$1,763.18	$1,733.54	$5,295.45
275	MG NATURAL GAS CORP	MG NATURAL GAS CORP	$145.10	0.0002%	$257.10	$266.77			$266.77
276	MIDDLE TENNESSEE NATURAL GAS UTIL DIST.	MIDDLE TENNESSEE NATURAL GAS UTIL DIST.	$361,928.50	0.4095%	$641,297.38	$40,791.62	$39,985.34	$39,319.25	$120,090.22
277	MIRANT ENERGY TRADING, LLC	Mirant Corporation	$2,700.10	0.0031%	$4,784.44	$4,984.38			$4,984.38
278	BETHLEHEM STEEL CORPORATION	Mittal Steel USA	$118,825.00	0.1344%	$210,544.79	$13,392.33	$13,127.62	$12,906.96	$39,426.90
279	MONSANTO COMPANY	MONSANTO COMPANY	$591.28	0.0007%	$1,047.66	$1,087.08			$1,087.08
280	MONTEAGLE PUBLIC UTILITY BOARD	MONTEAGLE PUBLIC UTILITY BOARD	$4,502.72	0.0051%	$7,978.33	$8,278.35			$8,278.35
281	MOREHEAD UTILITY PLANT BOARD	MOREHEAD UTILITY PLANT BOARD	$34,905.79	0.0395%	$61,849.20	$3,934.10	$3,856.34	$3,791.52	$11,581.97
282	MORGANTOWN CITY OF	MORGANTOWN CITY OF	$30,856.00	0.0349%	$54,671.08	$3,477.55	$3,408.82	$3,351.52	$10,237.89
283	DARTMOUTH POWER ASSOCIATES L.P.	Morris Energy Group	$25,218.00	0.0285%	$44,683.51	$2,842.23	$2,786.05	$2,739.22	$8,367.50
~~284~~	~~MOULTON CITY OF~~	~~MOULTON CITY OF~~	~~$9,000.81~~	~~0.0102%~~	~~$15,947.58~~	~~$1,014.39~~	~~$994.34~~	~~$977.63~~	~~$2,986.30~~
285	MT PLEASANT GAS SYSTEM	MT PLEASANT GAS SYSTEM	$22,823.80	0.0258%	$40,441.25	$2,572.39	$2,521.54	$2,479.16	$7,573.08
286	MURPHY EXPLORATION & PRODUCTION COMPANY	Murphy Oil Corp.	$1,375.24	0.0016%	$2,436.77	$2,528.41			$2,528.41
287	WESTVACO CORPORATION	MWV Corporation	$79,982.28	0.0905%	$141,684.28	$9,012.25	$8,834.12	$8,685.63	$26,531.99
288	ORCHARD GAS CORPORATION	NATIONAL ENERGY & GAS TRANSMISSION, INC.	$47,230.08	0.0534%	$83,688.60	$5,323.13	$5,217.91	$5,130.21	$15,671.25
289	NATIONAL FUEL GAS DISTRIBUTION CORP.	National Fuel Gas Company	$6,479,853.98	7.3318%	$11,481,586.19	$730,320.38	$715,885.00	$703,852.03	$2,150,057.41
290	NATIONAL FUEL GAS SUPPLY CORP	National Fuel Gas Company	$59,821.90	0.0677%	$105,997.83	$6,742.29	$6,609.03	$6,497.94	$19,849.26
291	NATIONAL FUEL RESOURCES INC	National Fuel Gas Company	$18,033.11	0.0204%	$31,952.68	$2,032.46	$1,992.27	$1,958.78	$5,983.50
292	NATIONAL GAS & OIL CORP	NATIONAL GAS & OIL CORP	$18,134.20	0.0205%	$32,131.91	$2,043.85	$2,003.45	$1,969.77	$6,017.08
293	BOSTON GAS CO	National Grid USA	$4,104,016.43	4.6436%	$7,271,862.57	$462,548.41	$453,405.76	$445,784.68	$1,361,738.86
294	NIAGARA MOHAWK POWER CORPORATION	National Grid USA	$2,930,458.17	3.3157%	$5,192,448.58	$330,281.11	$323,752.83	$318,311.02	$972,344.97
295	COLONIAL GAS CO	National Grid USA	$1,844,504.10	2.0871%	$3,268,417.25	$207,897.38	$203,788.12	$200,362.74	$612,048.25
296	ENERGYNORTH NATURAL GAS INC	National Grid USA	$1,270,528.67	1.4376%	$2,251,283.10	$143,196.37	$140,365.97	$138,006.63	$421,568.97
297	KEYSPAN ENERGY DELIVERY NEW YORK	National Grid USA	$1,187,131.42	1.3432%	$2,103,465.81	$133,797.20	$131,152.58	$128,948.10	$393,897.88
298	THE NARRAGANSETT ELECTRIC COMPANY	National Grid USA	$974,881.20	1.1031%	$1,727,381.83	$109,875.25	$107,703.48	$105,893.16	$323,471.89
299	THE NARRAGANSETT ELECTRIC COMPANY	National Grid USA	$817,236.64	0.9247%	$1,448,053.17	$92,107.72	$90,287.14	$88,769.54	$271,164.40
300	ESSEX COUNTY GAS CO	National Grid USA	$586,674.80	0.6638%	$1,039,523.02	$66,121.95	$64,814.99	$63,725.56	$194,662.40
301	LONG ISLAND LIGHTING CO	National Grid USA	$373,712.81	0.4228%	$662,177.88	$42,119.79	$41,287.28	$40,593.28	$124,000.33
302	BOSTON-EL PASO ENERGY MARKETING CO.	National Grid USA	$133,549.83	0.1511%	$236,635.56	$15,051.91	$14,754.39	$14,506.39	$44,312.70
303	BOSTON-ENRON	National Grid USA	$133,468.33	0.1510%	$236,491.15	$15,042.72	$14,745.39	$14,497.84	$44,285.65
304	NEW ENGLAND POWER COMPANY	National Grid USA	$83,017.30	0.0939%	$147,097.50	$9,356.57	$9,171.63	$9,017.47	$27,545.68
305	ESSEX-BOSTON	National Grid USA	$39,194.12	0.0443%	$69,447.66	$4,417.42	$4,330.11	$4,257.33	$13,004.86
306	ESSEX-ENRON	National Grid USA	$27,037.00	0.0306%	$47,906.58	$3,047.24	$2,987.01	$2,936.80	$8,971.05
307	ESSEX-EL PASO ENERGY MARKETING CO.	National Grid USA	$27,036.51	0.0306%	$47,905.72	$3,047.19	$2,986.66	$2,936.75	$8,970.69
308	SELECT ENERGY NEW YORK, INC.	National Grid USA	$1,709.62	0.0019%	$3,029.26	$3,143.18			$3,143.18
309	PROVIDENCE ENERGY SERVICES INC.	National Grid USA	$7.65	0.0000%	$13.50	$14.07			$14.07
310	NATURAL GAS OF KENTUCKY	NATURAL GAS OF KENTUCKY	$119.33	0.0001%	$211.44	$219.39			$219.39
311	NESI INTEGRATED ENERGY RESOURCES, INC.	NESI INTEGRATED ENERGY RESOURCES, INC.	$0.33	0.0000%	$0.58	$0.60			$0.60
312	NEW ALBANY CITY OF	NEW ALBANY CITY OF	$54,714.80	0.0619%	$96,948.70	$6,166.71	$6,044.82	$5,943.22	$18,154.74
313	NJR ENERGY SERVICES COMPANY	New Jersey Resources	$58,708.18	0.0665%	$104,183.86	$6,626.92	$6,495.94	$6,386.75	$19,509.61
314	NEW JERSEY NATURAL GAS CO	New Jersey Resources	$6,829.58	0.0077%	$12,101.26	$769.74	$754.52	$741.84	$2,266.10
315	NEXEN PETROLEUM SALES U.S.A. INC.	Nexen Inc.	$667.04	0.0008%	$1,181.83	$1,228.37			$1,228.37
316	NICOR GAS COMPANY	Nicor Inc.	$4,096,740.82	4.6354%	$7,258,986.50	$461,729.40	$452,602.94	$444,995.35	$1,359,327.68
317	BAY STATE GAS COMPANY	NiSource Inc.	$2,498,095.86	2.8265%	$4,426,392.56	$281,550.03	$275,984.96	$271,346.06	$828,881.04
318	NORTHERN INDIANA PUBLIC SERVICE COMPANY	NiSource Inc.	$2,308,104.97	2.6094%	$4,086,323.06	$259,922.71	$254,785.13	$250,502.56	$765,210.40
319	COLUMBIA GAS OF OHIO INC	NiSource Inc.	$1,159,600.91	1.3118%	$2,054,507.69	$130,683.06	$128,100.60	$125,946.63	$384,729.90
320	COLUMBIA GAS OF PENNSYLVANIA INC	NiSource Inc.	$1,001,812.11	1.1386%	$1,775,100.53	$112,910.54	$110,678.77	$108,818.42	$332,407.73
321	NORTHERN UTILITIES INC	NiSource Inc.	$505,368.28	0.5718%	$895,439.11	$56,957.06	$55,831.26	$54,892.82	$167,681.14
322	COLUMBIA GAS OF KENTUCKY INC	NiSource Inc.	$242,090.22	0.2739%	$428,957.15	$27,285.09	$26,745.78	$26,296.22	$80,327.10
323	COLUMBIA ENERGY SERVICES	NiSource Inc.	$207,766.71	0.2351%	$368,121.87	$23,415.49	$22,952.66	$22,566.80	$68,935.02
324	COLUMBIA GAS TRANSMISSION CORPORATION	NiSource Inc.	$24,150.60	0.0273%	$42,782.20	$2,721.92	$2,668.12	$2,623.28	$8,013.33
325	ENERGYUSA-TPC CORP.	NiSource Inc.	$24,047.78	0.0272%	$42,610.01	$2,710.34	$2,656.70	$2,612.11	$7,979.21
326	COLUMBIA ENERGY MARKETING CORPORATION	NiSource Inc.	$6.27	0.0000%	$11.11	$11.53			$11.53
327	NOBLE ENERGY MARKETING, INC.	Noble Energy, Inc.	$95,608.53	0.1083%	$169,567.24	$10,785.83	$10,572.84	$10,394.93	$31,753.39
328	NOBLE GAS PIPELINE, INC.	Noble Energy, Inc.	$320.73	0.0004%	$568.30	$589.67			$589.67
329	NORANDAL USA, INC.	Norandal Usa, Inc.	$17,100.00	0.0193%	$30,299.31	$1,927.28	$1,889.18	$1,857.43	$5,673.88
330	PROJECT PENNY PRODUCERS, THE	Nasso	$85,334.38	0.0965%	$151,203.11	$9,617.72	$9,427.62	$9,269.18	$28,314.50
331	NORTH ALABAMA GAS DISTRICT	NORTH ALABAMA GAS DISTRICT	$121,511.40	0.1375%	$215,304.90	$13,695.11	$13,424.41	$13,198.77	$40,318.29
332	YANKEE GAS SERVICES COMPANY	Northeast Utilities Service Company	$1,558,827.88	1.7638%	$2,762,071.03	$175,689.73	$172,217.08	$169,322.38	$517,229.17
333	NORTHWEST ALABAMA GAS DISTRICT	NORTHWEST ALABAMA GAS DISTRICT	$10,560.00	0.0119%	$18,711.15	$1,190.18	$1,166.65	$1,147.04	$3,503.88
334	NSTAR GAS COMPANY	NSTAR	$2,050,600.87	2.3202%	$3,633,403.07	$231,113.39	$226,545.25	$222,737.35	$680,395.99
335	PIVOTAL UTILITY HOLDINGS, INC.	NUI Corp.	$670,938.15	0.7591%	$1,188,826.38	$75,618.96	$74,124.29	$72,878.37	$222,621.62
336	NUI ENERGY, INC.	NUI Corp.	$6.12	0.0000%	$10.84	$11.25			$11.25
337	NYCOTEX GAS TRANSPORT	NYCOTEX GAS TRANSPORT	$3,360.00	0.0038%	$5,953.55	$6,177.43			$6,177.43
338	OAK RIDGE UTILITY DISTRICT	OAK RIDGE UTILITY DISTRICT	$110,062.00	0.1245%	$195,017.72	$12,404.68	$12,159.49	$11,955.11	$36,519.28
339	OCCIDENTAL CHEMICAL CORPORATION	Occidental Petroleum Corporation	$6,010.11	0.0068%	$10,649.25	$677.38	$663.99	$652.83	$1,994.19
340	OXY USA INC.	Occidental Petroleum Corporation	$225.47	0.0003%	$399.51	$414.53			$414.53
341	VINTAGE PETROLEUM INC	Occidental Petroleum Corporation	$52.98	0.0001%	$93.88	$97.41			$97.41
342	OLIN CORPORATION	Olin Corporation	$2,380.32	0.0027%	$4,217.66	$4,376.27			$4,376.27
343	OLIVE HILL CITY OF	OLIVE HILL CITY OF	$7,930.71	0.0090%	$14,052.90	$894.52	$876.84	$862.10	$2,633.45
344	ONEOK ENERGY SERVICES COMPANY, L.P.	ONEOK, Inc	$33,011.95	0.0380%	$59,558.67	$3,788.28	$3,713.40	$3,650.98	$11,152.66
345	ONYX GATHERING COMPANY, L. C.	ONYX GATHERING COMPANY, L. C.	$35.76	0.0000%	$63.36	$65.75			$65.75
346	OPTIMUM ENERGY SOURCES, INC.	OPTIMUM ENERGY SOURCES, INC.	$10.95	0.0000%	$19.40	$20.13			$20.13
347	OSRAM SYLVANIA, INC.	Osram Sylvania, Inc.	$13,764.42	0.0156%	$24,389.03	$1,551.34	$1,520.67	$1,495.11	$4,567.12
348	PARSONS, CITY OF	PARSONS, CITY OF	$18,437.48	0.0209%	$32,669.17	$2,078.02	$2,036.90	$2,002.71	$6,117.67
349	PELICAN GAS MANAGEMENT, INC.	PELICAN GAS MANAGEMENT, INC.	$0.08	0.0000%	$0.14	$0.15			$0.15
350	PEMEX GAS Y PETROQUIMICA BASICA	PEMEX	$133,200.00	0.1507%	$236,015.70	$15,012.48	$14,715.76	$14,468.40	$44,196.62
351	NORTH SHORE GAS COMPANY	Peoples Energy Corporation	$10,425.27	0.0118%	$18,472.43	$1,174.99	$1,151.77	$1,132.41	$3,459.17
352	DELMARVA POWER & LIGHT CO	Pepco Holdings Inc	$31,415.76	0.0355%	$55,665.24	$3,540.76	$3,470.77	$3,412.43	$10,423.95
353	PERRY GAS COMPANIES, INC.	Perry Gas Companies, Inc.	$320.72	0.0004%	$568.28	$589.65			$589.65
354	PERRY GAS PROCESSORS, INC.	Perry Gas Companies, Inc.	$76.00	0.0001%	$134.66	$139.73			$139.73
355	PETRO SOURCE GAS VENTURES	PETRO SOURCE GAS VENTURES	$85.25	0.0001%	$151.05	$156.73			$156.73
356	PETROCOM ENERGY GROUP, LTD.	Petrocom Energy Group, LTD	$5,297.10	0.0060%	$9,385.90	$9,738.84			$9,738.84
357	KCS ENERGY MARKETING INC	Petrohawk Energy Corporation	$285.53	0.0003%	$505.93	$524.95			$524.95
358	SELKIRK COGEN PARTNERS, L. P.	PG&E Corporation	$661,927.91	0.7490%	$1,172,893.23	$74,603.45	$73,128.85	$71,899.66	$219,631.96
359	PG&E TEXAS VGM, L.P.	PG&E Corporation	$84,168.91	0.0952%	$149,134.18	$9,486.14	$9,298.64	$9,142.34	$27,927.12
360	NEGT ENERGY TRADING-GAS CORPORATION	PG&E Corporation	$15,830.76	0.0179%	$28,050.84	$1,784.23	$1,748.96	$1,719.59	$5,252.76
361	PIEDMONT NATURAL GAS COMPANY INC	Piedmont Natural Gas Company, Inc.	$2,129,679.63	2.4096%	$3,773,300.10	$240,017.05	$235,272.92	$231,318.32	$706,608.29
362	PITTSBURGH CORNING CORPORATION	Pittsburgh Corning Corporation	$77,053.43	0.0872%	$136,530.18	$8,684.41	$8,512.75	$8,369.67	$25,566.83
363	PITTSFIELD GENERATING COMPANY L.P.	Pittsfield Generating Company, LP	$141,869.23	0.1605%	$251,378.02	$15,989.56	$15,673.51	$15,410.08	$47,073.13

Tennessee Gas Pipeline Company
PCB/HSL Interim Refund Allocation
Docket Nos. RP91-203 and RP92-132

Line No.	Shipper Name	Holding Company	PCB Revenue Collected	%	Interim Refund Amount at $159.0 MM	Jul 1, 2009 refund with Interest	Oct 1, 2009 refund with Interest	Jan 1, 2010 refund	Total Dec. 15, 2009 Installment
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
364	POGO PRODUCING COMPANY	Plains Exploration & Production Company	$3,680.96	0.0041%	$6,486.79	$6,730.73			$6,730.73
365	POLARIS PIPELINE CORP THE	POLARIS PIPELINE CORP THE	$10.44	0.0000%	$18.60	$19.10			$19.19
366	PONTOTOC MISSISSIPPI, CITY OF	PONTOTOC MISSISSIPPI, CITY OF	$35,062.07	0.0397%	$62,163.14	$3,954.07	$3,676.92	$3,810.77	$11,640.76
367	PORTLAND, TENNESSEE CITY OF	PORTLAND, TENNESSEE CITY OF	$46,764.34	0.0529%	$82,843.63	$5,280.51	$5,166.35	$5,078.53	$15,513.39
368	POWELL CLINCH UTILITY DISTRICT	Powell Clinch Utility District	$69,748.21	0.0789%	$123,688.13	$7,861.06	$7,705.60	$7,576.16	$23,142.91
369	PPL GAS UTILITIES CORPORATION	PPL	$456,660.74	0.5169%	$809,622.78	$51,492.10	$50,474.32	$49,626.02	$151,692.34
370	PRIOR INTRASTATE CORP	PRIOR INTRASTATE CORP	$30.33	0.0000%	$53.74	$55.76			$55.76
371	PROCTER AND GAMBLE PAPER PRODUCTS CO	Proctor & Gamble Company	$611,419.94	0.6918%	$1,083,368.68	$68,010.88	$67,648.80	$66,413.41	$202,073.09
372	PROGAS INC.	PROGAS INC	$1.40	0.0000%	$2.59	$2.68			$2.68
373	PROJECT ORANGE ASSOCIATES LLC	Project Orange Associates LP	$60,000.00	0.0670%	$106,313.38	$6,762.38	$6,628.71	$6,517.30	$19,908.39
374	PROVENCAL VILLAGE OF	PROVENCAL VILLAGE OF	$1,205.63	0.0014%	$2,136.07	$2,216.40			$2,216.40
375	PS ENERGY GROUP, INC.	PS Energy Group Inc.	$1,108.05	0.0013%	$2,043.08	$2,118.91			$2,118.91
376	PUBLIC SERVICE ELECTRIC AND GAS CO	Public Service Enterprise Group, Inc.	$1,857,403.19	2.1016%	$3,291,113.64	$209,341.05	$205,203.25	$201,764.09	$616,298.39
377	PULASKI CITY OF	PULASKI CITY OF	$3,134.70	0.0035%	$5,554.34	$5,763.21			$5,763.21
378	RANGE ENERGY SERVICES COMPANY	Range Energy Services Company	$1,832.21	0.0021%	$3,246.47	$3,368.65			$3,368.65
379	PAWTUCKET POWER ASSOCIATES L.P.	Red Rock Power Partners	$24,198.62	0.0274%	$42,877.29	$2,727.34	$2,673.43	$2,628.49	$8,029.26
380	RELIANT ENERGY SERVICES, INC.	Reliant Energy Inc.	$22,811.46	0.0258%	$40,419.40	$2,571.00	$2,520.18	$2,477.82	$7,568.99
381	RELIANT ENERGY HL&P	Reliant Energy Inc.	$107.02	0.0001%	$189.63	$196.76			$196.76
382	RENAISSANCE ENERGY (U.S.) INC.	RENAISSANCE ENERGY (U.S.) INC.	$217.31	0.0002%	$385.05	$399.53			$399.53
383	RESOURCE ENERGY SERVICES CO., LLC	RESOURCE ENERGY SERVICES CO., LLC	$2,839.62	0.0032%	$5,031.32	$5,220.52			$5,220.52
384	ROANOKE GAS COMPANY	RGC Resources Inc.	$173,219.30	0.1960%	$306,914.08	$19,522.23	$19,136.38	$18,814.70	$57,473.20
385	RICHMOND, CITY OF VIRGINIA	RICHMOND, CITY OF VIRGINIA	$57,391.20	0.0649%	$101,690.80	$6,468.35	$6,340.60	$6,233.02	$19,042.77
386	RIDGETOP NATURAL GAS, CITY OF	RIDGETOP NATURAL GAS, CITY OF	$2,384.94	0.0027%	$4,225.85	$4,384.76			$4,384.76
387	RILEY NATURAL GAS COMPANY	RILEY NATURAL GAS COMPANY	$577.93	0.0007%	$1,024.03	$1,062.54			$1,062.54
388	RIPLEY CITY OF	RIPLEY CITY OF	$42,868.09	0.0485%	$75,940.87	$4,830.44	$4,734.97	$4,655.38	$14,220.79
389	ROCKWOOD WATER SEWER & GAS	ROCKWOOD WATER SEWER & GAS	$31,437.63	0.0356%	$55,704.02	$3,543.22	$3,473.18	$3,414.81	$10,431.21
390	RUSSELLVILLE, ALABAMA GAS BOARD CITY OF	RUSSELLVILLE, ALABAMA GAS BOARD CITY OF	$30,617.96	0.0346%	$54,251.64	$3,450.84	$3,382.83	$3,325.77	$10,169.24
391	SAINT-GOBAIN CONTAINERS L.L.C.	Saint-Gobain Corporation	$72,000.00	0.0815%	$127,576.00	$8,114.85	$7,954.46	$7,820.76	$23,890.07
392	RHONE-POULENC AG COMPANY	Sanofi-Aventis	$4,680.00	0.0053%	$8,292.44	$8,604.28			$8,604.28
393	RHONE-POULENC BASIC CHEMICALS	Sanofi-Aventis	$4,580.05	0.0052%	$8,149.01	$8,455.45			$8,455.45
394	SANTA FE MINERALS INC	Santa Fe Minerals Inc.	$750.52	0.0008%	$1,329.84	$1,379.85			$1,379.85
395	SAVANNAH CITY OF	SAVANNAH CITY OF	$28,866.32	0.0327%	$51,147.93	$3,253.42	$3,189.11	$3,135.61	$9,578.03
396	PUBLIC SERVICE CO. OF NO. CAROLINA, INC.	SCANA Corporation	$174,698.15	0.1977%	$309,545.85	$10,689.56	$19,300.40	$18,975.99	$57,855.98
397	SCANA ENERGY MARKETING, INC.	SCANA Corporation	$14,135.18	0.0160%	$25,047.75	$1,593.24	$1,561.76	$1,531.49	$4,690.48
398	SCOTTSVILLE, KY CITY OF	SCOTTSVILLE, KY CITY OF	$25,763.40	0.0292%	$45,649.91	$2,903.70	$2,846.50	$2,798.48	$8,548.46
399	SEITEL GAS & ENERGY CORP.	Seitel Inc.	$8,449.77	0.0096%	$14,972.06	$952.34	$933.52	$917.83	$2,803.69
400	SEMPRA ENERGY TRADING LLC	Sempra Energy	$149,417.85	0.1691%	$284,751.85	$18,840.33	$16,507.47	$16,230.00	$49,577.81
401	SEMPRA ENERGY TRADING SERVICES CORP.	Sempra Energy	$69,637.23	0.0788%	$123,388.49	$7,848.66	$7,693.42	$7,564.11	$23,106.08
402	SENATOBIA CITY OF	SENATOBIA CITY OF	$43,820.32	0.0496%	$76,769.48	$4,883.16	$4,786.69	$4,706.17	$14,375.95
403	SEVIER COUNTY UTILITY DISTRICT	Sevier County Utility District	$49,410.44	0.0559%	$87,564.03	$5,569.77	$5,459.68	$5,367.91	$16,397.30
404	SIPCO GAS TRANSMISSION CORP	Sevier County Utility District	$50.02	0.0001%	$88.63	$91.98			$91.98
405	SHEFFIELD, ALABAMA CITY OF	SHEFFIELD, ALABAMA CITY OF	$55,187.23	0.0624%	$97,785.68	$6,219.95	$6,097.01	$5,994.52	$18,311.48
406	SHELL ENERGY NORTH AMERICA (US), L.P.	Shell Oil Company	$169,866.79	0.1922%	$300,985.22	$19,146.06	$18,766.04	$18,451.20	$56,362.90
407	CATEX CORAL ENERGY, L.L.C.	Shell Oil Company	$31,040.66	0.0360%	$50,417.06	$3,588.63	$3,517.70	$3,458.57	$10,564.90
408	CATEX VITOL GAS, INC.	Shell Oil Company	$24,471.37	0.0277%	$43,360.67	$2,758.08	$2,703.56	$2,658.12	$8,119.76
409	PENNZOIL PRODUCTS COMPANY	Shell Oil Company	$2,400.00	0.0027%	$4,252.54	$4,412.46			$4,412.45
410	SHELL ENERGY SERVICES, LLC	Shell Oil Company	$0.74	0.0000%	$1.31	$1.36			$1.36
411	SHUQUALAK TOWN OF	SHUQUALAK TOWN OF	$3,507.57	0.0040%	$6,215.03	$6,448.75			$6,448.75
412	SMITH PRODUCTION INC	Smith Production Inc.	$856.28	0.0010%	$1,517.23	$1,574.28			$1,574.28
413	SOLUTIA, INC.	Solutia, Inc.	$16,826.00	0.0190%	$29,813.82	$1,896.40	$1,858.91	$1,827.57	$5,582.88
414	SOMERSET GAS SERVICE	SOMERSET GAS SERVICE	$1,043.00	0.0012%	$1,848.00	$1,817.58			$1,817.58
415	SOUTH JERSEY RESOURCES GROUP, LLC	South Jersey Industries	$5,842.42	0.0066%	$10,352.12	$658.46	$645.46	$634.61	$1,938.55
416	SOUTHERN INDIANA GAS & ELECTRIC CO	Southern Indiana Gas and Electric Company	$117,560.68	0.1330%	$208,339.99	$13,252.08	$12,990.15	$12,771.80	$39,014.03
417	TRUNKLINE GAS COMPANY, LLC	Southern Union Company	$426.00	0.0005%	$754.83	$783.21			$783.21
418	SOUTHWEST GAS DISTRIBUTORS INC	SOUTHWEST GAS DISTRIBUTORS INC	$19.07	0.0000%	$33.78	$35.08			$35.08
419	UNION GAS LIMITED	Spectra Energy Corporation	$2,619.00	0.0030%	$4,640.58	$4,815.09			$4,815.09
420	EAST TENNESSEE NATURAL GAS COMPANY	Spectra Energy Partners	$7,481.28	0.0085%	$13,256.00	$843.19	$826.52	$812.63	$2,482.34
421	SPRINGFIELD CITY OF	SPRINGFIELD CITY OF	$89,082.39	0.1009%	$157,844.17	$10,040.16	$9,841.70	$9,670.27	$29,558.11
422	STAND ENERGY CORPORATION	Stand Energy Corporation	$251.57	0.0003%	$445.76	$462.62			$462.62
423	DISTRIGAS OF MASSACHUSETTS LLC	Suez Energy North America	$464,702.78	0.5258%	$823,402.05	$52,374.93	$51,339.70	$50,476.76	$154,191.39
424	SUPERIOR NATURAL GAS CORPORATION	SUPERIOR NATURAL GAS CORPORATION	$969.83	0.0011%	$1,718.49	$1,783.05			$1,783.05
425	SWEETWATER UTILITIES BOARD	SWEETWATER UTILITIES BOARD	$9,511.41	0.0108%	$16,853.16	$1,072.00	$1,050.81	$1,033.14	$3,155.95
426	T W PHILLIPS GAS & OIL CO	T W Phillips Gas and Oil Company	$276,059.20	0.3124%	$489,148.44	$31,113.81	$30,498.03	$29,985.99	$91,598.23
427	TECO GAS MARKETING COMPANY	TECO Energy	$460.54	0.0005%	$816.20	$846.90			$846.90
428	KINDER MORGAN TEJAS PIPELINE, L.P.	Tejas Gas Marketing Company	$10.40	0.0000%	$18.43	$19.12			$19.12
429	TENNESSEE AIR NATIONAL GUARD	TENNESSEE AIR NATIONAL GUARD	$4,906.93	0.0056%	$8,694.64	$9,021.60			$9,021.60
430	TENNESSEE VALLEY AUTHORITY	TENNESSEE VALLEY AUTHORITY	$1,914.93	0.0022%	$3,393.05	$3,520.65			$3,520.65
431	TEXAS GENERAL LAND OFFICE	TEXAS GENERAL LAND OFFICE	$13.84	0.0000%	$24.52	$25.46			$25.46
432	TEXAS-OHIO GAS INC	Texas-Ohio Gas Inc.	$13,722.23	0.0155%	$24,314.29	$1,546.88	$1,516.01	$1,490.53	$4,553.13
433	TEXEX ENERGY PARTNERS, LTD.	TEXEX ENERGY PARTNERS, LTD.	$11,509.48	0.0130%	$20,393.63	$1,297.18	$1,271.55	$1,250.18	$3,818.92
434	UNION CARBIDE CORPORATION	The Dow Chemical Company	$203,390.27	0.2301%	$360,395.75	$22,924.04	$22,470.93	$22,093.23	$67,488.20
435	UCAR CARBON COMPANY INC	The Dow Chemical Company	$50,968.65	0.0577%	$90,307.28	$5,744.28	$5,630.72	$5,536.08	$16,911.08
436	TIMKEN COMPANY, THE	The Timken Company	$57,259.27	0.0648%	$101,457.29	$6,453.49	$6,325.93	$6,219.60	$18,999.03
437	LATROBE STEEL COMPANY	The Watermill Group & Hicks Holdings, LLC	$6,099.60	0.0069%	$10,807.82	$687.46	$673.88	$662.55	$2,023.89
438	WILLIAMS GAS MARKETING, INC.	The Williams Company Inc.	$8,706.05	0.0099%	$15,426.16	$981.23	$961.83	$945.66	$2,888.72
439	TRANSCO ENERGY MARKETING COMPANY (TEMCO)	The Williams Company Inc.	$3,464.46	0.0039%	$8,120.02	$8,351.10			$8,351.10
440	TRANSCO GAS MKTG CO AGT FOR TRANSCO PL	The Williams Company Inc.	$3,029.26	0.0034%	$5,367.61	$5,569.36			$5,569.36
441	TISHOMINGO NATURAL GAS DEPT TOWN OF	TISHOMINGO NATURAL GAS DEPT TOWN OF	$3,848.68	0.0044%	$6,819.44	$7,076.08			$7,076.08
442	TORCH ENERGY MARKETING INC	Torch Energy Advisors Inc.	$344.94	0.0004%	$611.20	$634.18			$634.18
443	TORCH GAS, LC	TORCH GAS, LC	$9.36	0.0000%	$16.58	$17.21			$17.21
444	OCEAN STATE POWER	TransCanada Corporation	$276,871.58	0.3133%	$490,585.89	$31,205.17	$30,588.38	$30,074.23	$91,867.78
445	OCEAN STATE POWER II	TransCanada Corporation	$240,000.00	0.2715%	$425,253.52	$27,049.51	$26,514.86	$26,069.18	$79,633.55
446	TRANSCANADA ENERGY MARKETING USA, INC.	TransCanada Corporation	$147,378.16	0.1668%	$261,137.84	$16,610.46	$16,282.13	$16,008.45	$48,901.03
447	TRANSCANADA GAS SERVICES INC.	TransCanada Corporation	$8,862.53	0.0100%	$15,703.42	$998.86	$979.12	$962.66	$2,940.64
448	TRIAD ENERGY RESOURCES CORP.	Triad Energy Resources Corporation	$356.13	0.0004%	$631.02	$654.75			$654.75
449	TRONOX LLC	Tronox	$98,465.60	0.1114%	$174,470.64	$11,097.72	$10,878.37	$10,695.52	$32,671.61
450	TUSCUMBIA, AL WATER WORKS & GAS BOARD	TUSCUMBIA, AL WATER WORKS & GAS BOARD	$24,370.42	0.0276%	$43,181.69	$2,746.70	$2,692.41	$2,647.15	$8,086.26
451	PG ENERGY INC.	UGI Corporation	$1,076,420.47	1.2179%	$1,907,298.32	$121,319.37	$118,921.40	$116,922.50	$357,163.27
452	UGI UTILITIES, INC.	UGI Corporation	$262,169.40	0.2966%	$464,535.25	$29,548.14	$28,964.10	$28,477.20	$86,989.50
453	HONESDALE GAS COMPANY	UGI Corporation	$88,399.04	0.1000%	$156,633.34	$9,963.13	$9,766.20	$9,602.04	$29,331.37
454	PG ENERGY SERVICES INC.	UGI Corporation	$5,612.63	0.0064%	$9,944.90	$10,318.94			$10,318.94

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For Settlement Purpose Only
11/9/2009 DRAFT
Appendix A

Tennessee Gas Pipeline Company
PCB/HSL Interim Refund Allocation
Docket Nos. RP91-203 and RP92-132

Line No.	Shipper Name	Holding Company	PCB Revenue Collected	%	Interim Refund Amount at $156.6 MM	Jul 1, 2009 refund with Interest	Oct 1, 2009 refund with Interest	Jan 1, 2010 refund	Total Dec. 16, 2009 Installment
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
455	UNICOI COUNTY UTILITY DISTRICT	UNICOI COUNTY UTILITY DISTRICT	$21,304.78	0.0241%	$37,749.68	$2,401.18	$2,353.72	$2,314.18	$7,069.08
456	UNITED STATES DEPARTMENT OF ENERGY	UNITED STATES DEPARTMENT OF ENERGY	$101,860.84	0.1153%	$180,500.62	$11,481.27	$11,264.34	$11,065.17	$33,800.77
457	FITCHBURG GAS AND ELECTRIC LIGHT CO	Unitil Corporation	$360,065.93	0.4074%	$637,997.10	$40,581.70	$39,779.67	$39,110.83	$110,472.20
458	UNITED STATES GYPSUM COMPANY	USG Corporation	$65,391.45	0.0740%	$115,868.44	$7,370.03	$7,224.35	$7,102.82	$21,607.31
459	USGEN NEW ENGLAND, INC.	USGEN NEW ENGLAND, INC.	$24,780.00	0.0240%	$43,807.43	$2,792.80	$2,737.88	$2,691.64	$8,222.16
460	VAIL TRADING, L.L.C.	VAIL TRADING COMPANY	$64,724.83	0.0732%	$114,665.26	$7,294.90	$7,150.71	$7,030.51	$21,476.12
461	SIGCORP ENERGY SERVICES, INC.	Vectren Corporation	$20,004.91	0.0226%	$35,446.49	$2,254.68	$2,210.11	$2,172.07	$6,637.76
462	VERNON PARISH, GAS UTILITY	VERNON PARISH, GAS UTILITY	$912.44	0.0010%	$1,016.75	$1,677.55			$1,677.55
463	VINA GAS BOARD OF THE TOWN OF	VINA GAS BOARD OF THE TOWN OF	$1,715.44	0.0019%	$3,039.50	$3,153.87			$3,153.87
464	VISTA RESOURCES INC	Vista Resources Inc.	$2,041.80	0.0023%	$3,817.84	$3,753.09			$3,753.89
465	VISY PAPER, INC.	Visy Industies	$3.31	0.0000%	$5.86	$6.00			$6.09
466	WALNUT TOWN OF	WALNUT TOWN OF	$5,469.00	0.0062%	$9,690.47	$10,054.88			$10,054.88
467	SELMER UTILITY DIVISION	Walter Oil and Gas Corporation	$18,230.10	0.0206%	$32,301.73	$2,054.85	$2,014.04	$1,980.10	$6,048.87
468	WALTER OIL & GAS CORPORATION	Walter Oil and Gas Corporation	$460.00	0.0005%	$815.07	$845.72			$845.72
469	WARD MANUFACTURING INC	Ward Manufacturing	$1,526.50	0.0017%	$2,704.70	$2,806.50			$2,806.60
470	WAYNESBORO CITY OF	WAYNESBORO CITY OF	$6,697.29	0.0076%	$11,866.87	$754.83	$739.91	$727.47	$2,222.21
471	WHEELED ELECTRIC POWER COMPANY	Wepco	$2.19	0.0000%	$3.88	$4.03			$4.03
472	WEST TENNESSEE PUBLIC UTILITY DISTRICT	WEST TENNESSEE PUBLIC UTILITY DISTRICT	$166,667.81	0.1888%	$295,871.35	$18,807.05	$18,435.32	$18,125.46	$55,367.02
473	WESTFIELD, CITY OF, GAS & ELECTRIC LIGHT	WESTFIELD, CITY OF, GAS & ELECTRIC LIGHT	$155,100.84	0.1766%	$274,981.05	$17,490.99	$17,146.26	$16,857.08	$51,493.33
474	WEYERHAEUSER COMPANY	Weyerhaeuser Company	$1,250.50	0.0014%	$2,216.75	$2,299.07			$2,299.07
475	WASHINGTON GAS LIGHT CO	WGL Holdings Inc.	$165,110.56	0.1868%	$292,557.70	$18,609.00	$18,241.18	$17,934.57	$54,784.75
476	CALEDONIA POWER I, LLC	Wood Group Power Solutions	$7,080.32	0.0080%	$12,510.11	$795.74	$780.01	$766.90	$2,342.66
477	E PRIME INC.	Xcel Energy Inc	$4,850.75	0.0055%	$8,595.00	$8,918.21			$8,918.21
478	CENERPRISE, INC.	Xcel Energy Inc	$2,122.30	0.0024%	$3,760.59	$3,902.00			$3,902.00
479	NORTH AMERICAN ENERGY CONSERVATION INC.	York Research Corporation	$1,479.94	0.0017%	$2,622.29	$2,720.90			$2,720.90
480	YUMA GAS CORPORATION	YUMA GAS CORPORATION	$558.70	0.0006%	$990.12	$1,027.35			$1,027.35
481	Grand Total		$88,380,220	100.0000%	$156,600,000	$10,452,411	$9,732,863	$9,569,071	$29,754,146

137 FERC ¶ 61,177
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Columbia Gulf Transmission Company — Docket Nos. RP11-1435-000, RP11-1435-002, RP11-1435-003, RP11-1435-004, RP11-1435-006, RP11-24-000, RP11-24-004 (consolidated)

ORDER APPROVING SETTLEMENT,
AND ACCEPTING AND REJECTING TARIFF RECORDS

(Issued December 1, 2011)

1. On September 9, 2011, Columbia Gulf Transmission Company (Columbia Gulf) filed a Stipulation and Agreement of Settlement (Settlement Agreement or Settlement) to resolve all issues in the above-referenced consolidated proceeding. On October 4, 2011, the Presiding Administrative Law Judge (ALJ) certified the Settlement Agreement as uncontested to the Commission in light of the severance of the only contesting party from the Settlement.[1] Therefore, as discussed below, the Commission approves the uncontested Settlement Agreement. Also, as detailed further, the Commission accepts to be effective May 1, 2011, the tariff record that Columbia Gulf filed to comply with the Commission's April 29, 2011 order on the technical conference[2] in this proceeding, and the Commission rejects as moot certain other tariff records.[3]

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[1] *Columbia Gulf Transmission Co.*, 137 FERC ¶ 63,001 (2011) (October 4 Order).

[2] *Columbia Gulf Transmission Co.*, 135 FERC ¶ 61,106 (2011) (April 29 Order).

[3] The tariff records are identified in the Appendix.

I. Background

2. On October 28, 2010, Columbia Gulf filed a request under section 4 of the Natural Gas Act[4] (NGA) to implement a general rate increase (October 28 Filing). As part of the October 28 Filing, Columbia Gulf included both Primary and Preferred Cases. The Primary Case proposed to maintain Columbia Gulf's existing Mainline and Onshore rate zone structure and allocate costs between those zones. The Preferred Case proposed to combine the Mainline and Onshore Rate Zones into a single Market Rate Zone. Columbia Gulf currently provides firm service in the Mainline Zone under Rate Schedule FTS-1.[5] It provides firm service in its Offshore Zone, Onshore Zone, and Offsystem-Onshore Zone under Rate Schedule FTS-2. Columbia Gulf's Preferred Case would remove the Onshore Zone from Rate Schedule FTS-2 and include both that zone and the existing Mainline Zone in Rate Schedule FTS-1. Columbia Gulf also proposed a new short-term firm reservation rate for firm service with contract terms of less than one year. The maximum short-term firm reservation rate would equal 250 percent of the firm reservation rate in the applicable zone. In addition, Columbia Gulf proposed a number of new and revised non-rate tariff provisions. The proposed non-rate tariff provisions were identical in both the Primary and Preferred Cases.

3. On November 30, 2010, the Commission accepted and suspended the tariff records associated with the Primary Case to be effective May 1, 2011, subject to refund.[6] The Commission established a hearing to consider rate issues and a technical conference to consider the non-rate tariff proposals and a hearing to consider rate issues.

4. On February 2, 2011, the Commission issued an order, approving Columbia Gulf's October 1, 2010 proposal in Docket No. RP11-24-000 to implement a new firm daily delivery point scheduling variance service under Rate Schedule SVS.[7] While the Commission approved the terms and conditions under which Columbia Gulf proposed to provide that service, the Commission consolidated Docket No. RP11-24-000 with Columbia Gulf's Docket No. RP11-1435-000 general section 4 rate case for purposes of considering the justness and reasonableness of the rate proposed by Columbia Gulf for SVS service and the extent to which costs should be allocated to SVS service in designing Columbia Gulf's other rates.

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[4] 15 U.S.C. § 717c (2006).

[5] "FTS" means "Firm Transportation Service."

[6] *Columbia Gulf Transmission Co.*, 133 FERC ¶ 61,182 (2010) (November 30 Order).

[7] *Columbia Gulf Transmission Co.*, 134 FERC ¶ 61,082 (2011).

5. Commission Staff conducted the technical conference on January 18, 2011. On February 4, 2011, Columbia Gulf submitted comments, offering to make various modifications to its non-rate tariff proposals in response to the comments, questions and concerns raised at the technical conference. Thereafter, the parties submitted two rounds of comments on Columbia Gulf's non-rate tariff proposals.

6. On April 29, 2011, the Commission issued an order on the technical conference. The Commission generally accepted Columbia Gulf's proposed non-rate tariff proposals, including its flow control requirements and Enhanced Firm Transportation service, subject to its incorporation of the modifications proposed by Columbia Gulf in its February 4 clarification filing.[8] The Commission found, however, that Columbia Gulf had not justified its proposals to require uniform hourly takes at delivery points and hourly scheduling penalties for violation of that requirement, and rejected those proposals. Finally, the Commission required Columbia Gulf to revise its proposed unauthorized gas penalty by limiting the penalty to receipts in excess of scheduled volumes delivered into a pool.

7. On May 25, 2011, Columbia Gulf filed a request for rehearing of the April 29 Order's treatment of the proposed hourly scheduling and unauthorized gas penalties. On May 31, 2011, as supplemented by the errata filed on June 3, 2011, and an additional filing on June 21, 2011, Columbia Gulf submitted tariff records[9] in order to comply with the rulings of the April 29 Order on its non-rate tariff proposals.[10]

8. On September 9, 2011, Columbia Gulf filed the instant Settlement Agreement, together with *pro forma* tariff records showing the changes to Columbia Gulf's tariff provided for in the Settlement.

II. Settlement Agreement Terms

9. The Settlement Agreement consists of fifteen numbered articles, and four lettered appendices, in terms substantially as follows:

10. Article I provides the background and procedural history of the case.

11. Article II provides that Columbia Gulf's existing Mainline and Onshore Zones will be combined into a single Market Zone with postage stamp rates, and firm service in

[8] April 29 Order, 135 FERC ¶ 61,106 at P 1-3.

[9] Identified in the Appendix of this order.

[10] In response to protests regarding the May 31 and June 3 Filings, Columbia Gulf further revised its compliance filing on June 21, 2011.

the new Market Zone would be provided under Rate Schedule FTS-1. This article describes the applicable base transportation rates, transportation retainage adjustment, depreciation and net salvage, allocation of Rayne compressor costs, and refunds.

12. Article III provides for the addition of a reservation charge credit provision to Columbia Gulf's tariff.

13. Article IV provides that Columbia Gulf will withdraw its proposal in Docket No. RP11-1435-000 to implement a short-term firm rate as applicable to the Settling Parties as set forth in Article XV of the Settlement Agreement and will refund all monies, with Commission prescribed interest, collected in excess of the applicable settlement rates. The short-term firm rate will remain effective for the Contesting Parties, subject to refund, pending the Commission's resolution, with respect to such parties, of pending issues in Docket Nos. RP11-1435-000 and RP11-24-000.

14. Article V provides that FTS-2 shippers paying maximum recourse rates as of July 31, 2011, will have their FTS-2 service agreement reservation rates capped for the term of the agreement at the rate set forth in Appendix B of the Settlement Agreement. Article V further provides that the rate cap will only apply to transportation service using receipt and delivery points in the existing Onshore Zone. Article V also provides that during the Settlement term, Columbia Gulf will credit to shippers with maximum rate Market Zone firm transportation service any revenues above the rate cap received from existing FTS-2 shippers' and their replacement shippers' use of primary and secondary points outside of the Onshore Zone. Finally, Article V describes additional limits on the extent to which the FTS-2 rate cap applies to releases of FTS-2 capacity.

15. Article VI describes Columbia Gulf's treatment of post employment benefits other than pensions, pension expenses, and regulatory expenses. The Settlement Agreement rates reflect a total annual funding amount of $0.5 million for Columbia Gulf's post-retirement benefits other than pensions (PBOP) expenses, which include Columbia Gulf's direct PBOP expenses as well as its share of the PBOP expenses applicable to the shared service company employees as reflected in the monthly intercompany invoices. To the extent actual PBOP accruals, beginning April 1, 2011 and continuing in the years until the effective date of rates established either in Columbia Gulf's next rate case under NGA section 4 or in any proceeding under NGA section 5 that includes these costs, whichever occurs first, differ on an annual basis from the $0.5 million annual funding amount, a regulatory asset (Account No. 182.3) or liability account (Account No. 254) will be recorded for the difference and deferred until the next rate case. Article VI also provides additional details on the funding, recordation and disbursement of Columbia Gulf's pension and PBOP expenses.

16. Article VII states that in any general rate case filed within five-years of the Settlement's effective date, or in the first such case filed after five years from such date if no general rate case has been previously filed, to the extent that Columbia Gulf seeks to

continue the postage stamp rate design for the Market Zone, Columbia Gulf will file an alternate case that shows the existing Mainline and Onshore Zones as separate rate zones. Moreover, Columbia Gulf will maintain its books and records necessary to support the two-zone case. In such future general rate case, Columbia Gulf will: (1) have the right to select the postage-stamp rate design as its Preferred case; (2) maintain the allocation of net plant costs associated with the Rayne Compressor Station as set forth in section 2.4 of the Settlement Agreement; and (3) provide a cost and revenue analysis of the existing Onshore Zone to determine how Columbia Gulf's actual revenues compare to the revenue requirement for those facilities. Article VII also describes whether or not any difference between such Onshore Zone costs and revenues will be absorbed by Columbia Gulf. Article VII further states that in its next general rate proceeding, Columbia Gulf will have no refund obligation for Settling Parties with respect to rates lower than the maximum postage-stamp Market Zone rate set forth in the Settlement. Finally, Article VII states that its obligations will be of no force and effect if new rates result from a Commission-initiated NGA section 5 proceeding as a result of the cost and revenue study set forth in Article VIII. Article XII provides that Article VII will be effective for a minimum period of five years.

17. Article VIII: (1) requires that Columbia Gulf file a cost and revenue study no earlier than April 1, 2014, and no later than May 1, 2017, and sets forth the contents of the study; (2) describes certain refund protections that are provided by the Settlement Agreement; and (3) states the circumstances under which Columbia Gulf's obligation to file a cost and revenue study is terminated.

18. Article IX provides that, with respect to the Settling Parties, Columbia Gulf will file to amend its tariff to remove the following provisions and refund all monies, with Commission-prescribed interest, collected pursuant to those provisions: (1) unauthorized gas penalties, flow control requirements, Enhanced Firm Transportation service accepted in the April 29 technical conference order; and (2) Scheduling Variance Service accepted in Docket No. RP11-24-000; and delivery point scheduling penalties accepted in Docket No. RP07-174-000.[11] Such provisions will remain in effect for any contesting party pending the outcome of further litigation or settlement. In addition, this article states that Columbia Gulf will withdraw its request for rehearing regarding the April 29 Order's rejection of the proposed non-rate tariff provisions regarding hourly scheduling and unauthorized gas penalties.

19. Article X provides that neither Columbia Gulf nor any other Settling Party (or assignee, successor or affiliate thereof) will seek to modify Columbia Gulf's base recourse rates unless such modified base recourse rates would go into effect on or

[11] *Columbia Gulf Transmission Co.*, 119 FERC ¶ 61,268 (2007), *order on reh'g*, 124 FERC ¶ 61,121 (2008).

subsequent to April 1, 2014. The article further explains that, during the term of the Settlement Agreement, Columbia Gulf will not file to implement the tariff changes regarding: (1) hourly scheduling and unauthorized gas penalties and uniform hourly flow obligations that are the same or analogous to those that the Commission rejected by the April 29 Order; (2) Scheduling Variance Service and delivery point scheduling penalties that are the same or analogous to those accepted by the Commission, as referred to in Article IX; or (3) a short-term firm rate that is the same or analogous to that accepted by the Commission, as referred to in Article IV.

20. Article XI sets forth the definitions of "Settling Party" and "Contesting Party." The article provides that a Settling Party shall be bound by an order which approves this Settlement without any condition or modification that materially and adversely affects the Settling Party. The article provides that a Contesting Party is not entitled to any of the benefits, or subject to any of the burdens imposed in the Settlement Agreement and may be severed from the Settlement Agreement. If the Commission severs a Contesting Party, that party will be free to pursue through litigation the rates applicable to its direct interest. The article specifies the maximum rate that will apply in a right-of-first refusal procedure or capacity release where a different maximum rate applies to Settling and Contesting Parties.

21. Article XII explains that the provisions of the Settlement Agreement are not severable. Article XII also sets forth conditions that determine the effective date and, with the exception of the 5-year minimum effectiveness of Article VII, the expiration date of the agreement.

22. Article XIII provides that Columbia Gulf reserves the right to make a filing to place into effect the interim reservation rates set forth on Appendix B of the Settlement Agreement, and states that such interim rates will remain in effect until the Settlement Agreement rates become effective or the Commission places other rates into effect.

23. Article XIV contains the Settlement Agreement's "reservations" provisions. This article provides that the Settlement Agreement shall be privileged if it does not become effective and shall not be admissible in evidence or in any way used against any person in any proceeding. The standard of review for any changes to the terms of the Settlement Agreement shall be the just and reasonable standard and not the public interest standard. No participant shall be deemed to have approved, accepted, agreed or consented to any principle or method of regulation or ratemaking underlying or supposed to underlie any of the provisions of the Settlement Agreement. The provisions of the Settlement Agreement shall not be construed against any party as the drafter and are not severable. Finally, this article provides that in the event of conflict between terms contained in the Settlement Agreement and those of the Explanatory Statement, the terms of the Settlement Agreement control.

24. Article XV sets forth the time frame for Columbia Gulf to file actual tariff records implementing the Settlement Agreement's *pro forma* tariff records.

III. Comments, Objections and Severance

25. On September 12, 2011, Columbia Gulf filed a request to suspend the procedural schedule and a request for a shortened answer period of three days to its request for suspension. On September 13, 2011, the Chief ALJ granted Columbia Gulf's request.

26. On September 15, 2011, Total Gas & Power North America, Inc. (Total) filed in opposition to Columbia Gulf's request for suspension. Total argued that suspension of the procedural schedule would cause real and substantive harm to Total and cause unnecessary delay in the establishment of just and reasonable rates applicable to Total. However, Total stated that, as long as it is severed from the Settlement Agreement, it would avoid taking action that interfered with Columbia Gulf reaching a settlement with its other shippers.

27. On September 16, 2011, Columbia Gulf filed an answer to Total's opposition, stating that Total should be severed from the settled proceeding so that the non-contesting parties could obtain the benefits of the Settlement Agreement.

28. On September 16, 2011, the Chief ALJ issued an order temporarily suspending procedural schedule and an order to show cause why Total should not be severed from the above-captioned dockets. On September 22, 2011, Columbia Gulf filed a response, stating that no reason exists why Total should not be severed from this proceeding at the earliest available opportunity, provided that the hearing schedule remains suspended with respect to the other participants. The Cities of Charlottesville and Richmond, Virginia, NiSource Distribution Companies[12] and Baltimore Gas & Electric Company submitted comments concurring that Total should be severed from this proceeding at the earliest possible time.

29. On September 27, 2011, Tennessee Valley Authority submitted comments in support of the Settlement Agreement. On September 29, 2011, Columbia Gulf, Commission Trial Staff, Washington Gas Light Company, BG&E, NiSource Distribution Companies,[13] the City of Charlottesville, Virginia, the Easton Utilities Commission, and

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[12] Columbia Gas of Kentucky, Inc., Columbia Gas of Maryland, Inc., Columbia Gas of Ohio, Inc., Columbia Gas of Pennsylvania, Inc., and Columbia Gas of Virginia, Inc.

[13] Columbia Gas of Kentucky, Inc., Columbia Gas of Maryland, Inc., Columbia Gas of Ohio, Inc., Columbia Gas of Pennsylvania, Inc., and Columbia Gas of Virginia, Inc.

the City of Richmond, Virginia submitted comments in support of the Settlement Agreement. On that same day, the Indicated Shippers[14] filed comments supporting or not opposing the Settlement Agreement.

30. On September 29, 2011 Total filed comments contesting the Settlement Agreement, stating that the proposed settlement rates are not supported by substantial evidence and are unjust and unreasonable as they relate to Total. Total also stated that it should be severed from the proceeding to litigate its interest.

31. On September 30, 2011, the Chief ALJ issued an order suspending the procedural schedule for the non-contesting parties and severing Total from the rest of the proceedings.[15] The Chief ALJ found that "[s]everance will allow Total an opportunity to go forward with the prosecution of its case and will enable the settling parties to enjoy the rate certainty and finality" of Commission approval of the Settlement Agreement.[16] The Chief ALJ also stated that the hearing on the severed proceeding will be conducted in Docket Nos. RP11-1435-000 and RP11-24-000. On October 4, 2011, the Presiding ALJ certified the settlement to the Commission as uncontested in light of the severance of Total.

IV. **Discussion**

32. The Commission approves the Settlement Agreement for the non-contesting parties under section 602(g) of the Commission's regulations[17] as fair and reasonable and in the public interest.

33. The Commission also approves the Chief ALJ's decision to sever Total from these proceedings so that it may continue to prosecute its case before the Commission in Docket Nos. RP11-1435-000 and RP11-24-000. The Commission understands that Total has raised a number of objections to the rates established by the terms of the Settlement Agreement, which require further investigation to resolve on the merits. The consenting parties, however, regard the rate certainty provided by the Settlement Agreement, including the moratorium on rate changes until April 1, 2014, and other benefits provided

[14] Indicated Shippers joining in these Initial Comments are BP Energy Company, BP America Production Company, ConocoPhillips Company, ExxonMobil Gas & Power Marketing Company, a division of Exxon Mobil Corporation, Interstate Gas Supply, Inc., Marathon Oil Company and Shell Energy North America (US), L.P.

[15] *Columbia Gulf Transmission Co.*, 136 FERC ¶ 63,020 (2011).

[16] *Id.* 4.

[17] 18 C.F.R. § 385.602(g) (2011).

by the Settlement Agreement, as preferable to the costs and uncertainty entailed in any litigation relating to Columbia Gulf's section 4 rate case.[18]

34. Here, the consenting parties have chosen to settle rather than litigate, and approval of the Settlement Agreement for those parties is consistent with the Commission's policy of encouraging settlements. In light of the resolution of the issues in the above captioned dockets, this order terminates Docket Nos. RP11-1435-006 and RP11-24-004.

35. The Commission also accepts the tariff records Columbia Gulf filed on May 31, 2011 to comply with the April 29 Order, as corrected by its June 21, 2011 Filing.[19] The accepted tariff records are identified in the Appendix to this order. The Commission also rejects the tariff records included in the May 31 and June 3, 2011 Filings which were superseded by the corrected tariff record included in the June 21, 2011 Filing.[20] When Columbia Gulf files actual tariff records to implement the Settlement Agreement, it must also revise all relevant tariff records to clearly identify which tariff records are applicable only to the contesting party and which tariff records are applicable to all shippers other than the contesting party.

The Commission orders:

(A) The tariff records Columbia Gulf filed on May 31, 2011 to comply with the April 29 Order, as corrected by its June 21, 2011 Filing are hereby accepted to be effective May 1, 2011, as identified in the Appendix of this order.

(B) The tariff records included in Columbia Gulf's May 31 and June 3, 2011 Filings which were replaced by a tariff record included in the June 21, 2011 Filing are hereby rejected as moot, as identified in the Appendix of this order.

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[18] *See Panhandle Eastern Pipeline Company v. Federal Energy Regulatory Commission,* 95 F.3d 62, 74 (1996) (Parties settle in order to avoid the risk that they might do worse by litigating, both because they might lose and because winning might come at a high cost; both parties to a Settlement accept the risk that they might have done better by fighting.)

[19] The rates included in the accepted tariff record will remain subject to refund with respect to Total.

[20] The rejected tariff records are also identified in the Appendix.

(C) The uncontested Settlement Agreement is hereby approved as fair and reasonable and in the public interest.

By the Commission. Commissioner Spitzer is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

Appendix
Columbia Gulf Transmission Company
NGA Gas
Columbia Gulf Tariffs

Tariff Records Accepted to be effective May 1, 2011.

RP11-1435-002:

Currently Effective Rates, FTS-1 Rates, 5.0.0
Currently Effective Rates, FTS-2 Rates, 5.0.0
Currently Effective Rates, EFT Rates, 1.0.0
Rate Schedules, Rate Schedule FTS-1, 5.0.0
Rate Schedules, Rate Schedule FTS-2, 5.0.0
Rate Schedules, Rate Schedule PAL, 2.0.0
Rate Schedules, Rate Schedule EFT, 1.0.0
Gen. Terms and Conditions, , 5.0.0
Gen. Terms and Conditions, Definitions, 3.0.0
Gen. Terms and Conditions, Requests for Service, 2.0.0
Gen. Terms and Conditions, Auctions of Available Firm Service, 2.0.0
Gen. Terms and Conditions, Nominating, Scheduling and Monitoring, 3.0.0
Gen. Terms and Conditions, Capacity Allocation, 3.0.0
Gen. Terms and Conditions, Flexible Primary and Secondary Receipt and Delivery Points, 2.0.0
Gen. Terms and Conditions, Maximum Daily Obligation, 2.0.0
Gen. Terms and Conditions, Interruptions of Service, 3.0.0
Gen. Terms and Conditions, Critical Period Notices and Operational Flow Orders, 3.0.0
Gen. Terms and Conditions, Penalties, 3.0.0
Gen. Terms and Conditions, Measurement, 1.0.0
Gen. Terms and Conditions, Negotiated Rates, 2.0.0
Service Agreement Forms, FTS, EFT and ITS, 2.0.0

RP11-1435-004:

Gen. Terms and Conditions, Operating Conditions, 3.0.2

Tariff Records Rejected as Moot:

RP11-1435-002:
Gen. Terms and Conditions, Operating Conditions, 3.0.0

RP11-1435-003:
Gen. Terms and Conditions, Operating Conditions, 3.0.1

PIPELINE COMPANY TARIFF SHEETS

Currently Effective Rates
Applicable to Rate Schedule FTS
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment		Electric Power Costs Adjustment		Annual Charge Adjustment 2/	Total Effective Rate	Daily Rate
			Current	Surcharge	Current	Surcharge			
Rate Schedule FTS									
Reservation Charge 3/	$	5.637	0.386	0.005	0.064	-0.003	-	6.089	0.2002
Commodity									
Maximum	¢	1.04	0.80	0.25	0.84	0.06	0.18	3.17	3.17
Minimum	¢	1.04	0.80	0.25	0.84	0.06	0.18	3.17	3.17
Overrun	¢	19.57	2.07	0.27	1.05	0.05	0.18	23.19	23.19

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively. For rates by function, see Section 5.15.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ Minimum reservation charge is $0.00.

Currently Effective Rates
Applicable to Rate Schedule FSS
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment		Electric Power Costs Adjustment		Annual Charge Adjustment 2/	Total Effective Rate	Daily Rate
			Current	Surcharge	Current	Surcharge			
Rate Schedule FSS									
Reservation Charge 3/	$	1.509	-	-	-	-	-	1.509	0.0496
Capacity 3/	¢	2.89	-	-	-	-	-	2.89	2.89
Injection	¢	1.53	-	-	-	-	-	1.53	1.53
Withdrawal	¢	1.53	-	-	-	-	-	1.53	1.53
Overrun 3/	¢	10.91	-	-	-	-	-	10.91	10.91

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively.
2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.
3/ In addition to the above reflected Base Tariff Reservation Charge (MDSQ) and Capacity (SCQ) Rate, shippers utilizing the Eastern Market Expansion (EME) facilities for FSS service will pay an additional incremental reservation charge of $2.625 per Dth per month, for a total FSS MDSQ reservation charge of $4.130 and an additional 3.91 cents per Dth per month, for a total FSS SCQ capacity rate of 6.80 cents. If EME customers incur an overrun for FSS services that is provided under their EME Project service agreements, they will pay an additional 12.54 cents for such overruns, for a total FSS overrun rate of 23.44 cents. The additional EME demand charges and EME overrun charges can be added to the Total Effective Rate above to develop the EME Total Effective Rate.

Currently Effective Rates
Applicable to Rate Schedule SST
Rate Per Dth

		Base Tariff Rate 1/	Transportation Cost Rate Adjustment		Electric Power Costs Adjustment		Annual Charge Adjustment 2/	Total Effective Rate	Daily Rate
			Current	Surcharge	Current	Surcharge			
Rate Schedule SST									
Reservation Charge 3/4/	$	5.467	0.386	0.005	0.064	-0.003	-	5.919	0.1946
Commodity									
Maximum	¢	1.02	0.80	0.25	0.84	0.06	0.18	3.15	3.15
Minimum	¢	1.02	0.80	0.25	0.84	0.06	0.18	3.15	3.15
Overrun 4/	¢	18.99	2.07	0.27	1.05	0.05	0.18	22.61	22.61

1/ Excludes Account 858 expenses and Electric Power Costs which are recovered through Columbia's Transportation Costs Rate Adjustment (TCRA) and Electric Power Costs Adjustment (EPCA), respectively. For rates by function, see Section 5.15.

2/ ACA assessed where applicable pursuant to Section 154.402 of the Commission's Regulations.

3/ Minimum reservation charge is $0.00.

4/ In addition to the above reflected Base Tariff SST Demand Rate, shippers utilizing the Eastern Market Expansion (EME) facilities for Rate Schedule SST service will pay an additional demand charge of $12.186 per Dth per month, for a total SST reservation charge of $17.625. If EME customers incur an overrun for SST services that is provided under their EME Project service agreements, they will pay an additional 40.07 cents for such overruns, for a total overrun rate of 58.97 cents. The applicable EME demand charge and EME overrun charge can be added to the Total Effective Rate above to calculate the EME Total Effective Rates.

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

Rate Schedule FTS-1	Base Rate (1)	Annual Charge Adjustment 1/ (2)	Total Effective Rate (3)	Daily Rate (4)
Market Zone				
Reservation Charge				
Maximum	4.2917	-	4.2917	0.1411
Minimum	0.000	-	0.000	0.000
Commodity				
Maximum	0.0109	0.0018	0.0127	0.0127
Minimum	0.0109	0.0018	0.0127	0.0127
Overrun				
Maximum	0.1520	0.0018	0.1538	0.1538
Minimum	0.0109	0.0018	0.0127	0.0127

1/ Pursuant to 18 C.F. R. § 154.402. Rate applies to all Gas delivered. When transportation involves more than one zone, rate will be applied only one time.

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.7504		$12.1229	$16.3405	$16.6314	$18.3503	$19.4843	$24.4547
L		$5.0941						
1	$8.7060		$8.3414	$11.1329	$15.8114	$15.6260	$17.6356	$21.6916
2	$16.3406		$11.0654	$5.7084	$5.3300	$6.8689	$9.4859	$12.2575
3	$16.6314		$8.7447	$5.7553	$4.1249	$6.4085	$11.6731	$13.4872
4	$21.1425		$19.4839	$7.3648	$11.2429	$5.4700	$5.9240	$8.4896
5	$25.2282		$17.6984	$7.7303	$9.3742	$6.0880	$5.7043	$7.4396
6	$29.1846		$20.3275	$13.9551	$15.3850	$10.8692	$5.6613	$4.8846

Daily Base Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1891		$0.3986	$0.5372	$0.5468	$0.6033	$0.6406	$0.8040
L		$0.1675						
1	$0.2862		$0.2742	$0.3660	$0.5198	$0.5137	$0.5798	$0.7131
2	$0.5372		$0.3638	$0.1877	$0.1752	$0.2258	$0.3119	$0.4030
3	$0.5468		$0.2875	$0.1892	$0.1356	$0.2107	$0.3838	$0.4434
4	$0.6951		$0.6406	$0.2421	$0.3696	$0.1798	$0.1948	$0.2791
5	$0.8294		$0.5819	$0.2541	$0.3082	$0.2002	$0.1875	$0.2446
6	$0.9595		$0.6683	$0.4588	$0.5058	$0.3573	$0.1861	$0.1606

Maximum Reservation Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.7504		$12.1229	$16.3405	$16.6314	$18.3503	$19.4843	$24.4547
L		$5.0941						
1	$8.7060		$8.3414	$11.1329	$15.8114	$15.6260	$17.6356	$21.6916
2	$16.3406		$11.0654	$5.7084	$5.3300	$6.8689	$9.4859	$12.2575
3	$16.6314		$8.7447	$5.7553	$4.1249	$6.4085	$11.6731	$13.4872
4	$21.1425		$19.4839	$7.3648	$11.2429	$5.4700	$5.9240	$8.4896
5	$25.2282		$17.6984	$7.7303	$9.3742	$6.0880	$5.7043	$7.4396
6	$29.1846		$20.3275	$13.9551	$15.3850	$10.8692	$5.6613	$4.8846

Notes:

1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000 Daily Reservation.

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2751	$0.2625	$0.3124
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.2339	$0.2385	$0.2723
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0757	$0.1214	$0.1345
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.1012	$0.1400	$0.1528
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0468	$0.0662	$0.1073
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0659	$0.0653	$0.0811
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.1014	$0.0549	$0.0334

Minimum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0050		$0.0133	$0.0195	$0.0237	$0.0268	$0.0302	$0.0364
L		$0.0030						
1	$0.0060		$0.0099	$0.0165	$0.0197	$0.0228	$0.0274	$0.0318
2	$0.0185		$0.0105	$0.0030	$0.0046	$0.0074	$0.0118	$0.0161
3	$0.0225		$0.0187	$0.0044	$0.0020	$0.0099	$0.0136	$0.0181
4	$0.0268		$0.0223	$0.0105	$0.0123	$0.0046	$0.0064	$0.0110
5	$0.0302		$0.0274	$0.0118	$0.0136	$0.0064	$0.0064	$0.0084
6	$0.0364		$0.0318	$0.0161	$0.0181	$0.0104	$0.0059	$0.0038

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0050		$0.0133	$0.0195	$0.0237	$0.2769	$0.2643	$0.3142
L		$0.0030						
1	$0.0060		$0.0099	$0.0165	$0.0197	$0.2357	$0.2403	$0.2741
2	$0.0185		$0.0105	$0.0030	$0.0046	$0.0775	$0.1232	$0.1363
3	$0.0225		$0.0187	$0.0044	$0.0020	$0.1030	$0.1418	$0.1546
4	$0.0268		$0.0223	$0.0105	$0.0123	$0.0486	$0.0680	$0.1091
5	$0.0302		$0.0274	$0.0118	$0.0136	$0.0677	$0.0671	$0.0829
6	$0.0364		$0.0318	$0.0161	$0.0181	$0.1032	$0.0567	$0.0352

Notes:

1/ Includes a per Dth charge for (ACA) Annual Charge Adjustment of $0.0018

2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32. For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.

3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0000.

FUEL AND EPCR

F&LR 1/, 2/, 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.56%		1.46%	2.11%	2.55%	3.02%	3.39%	4.00%
L		0.35%						
1	0.67%		1.10%	1.80%	2.13%	2.58%	3.09%	3.51%
2	2.15%		1.16%	0.34%	0.52%	0.86%	1.36%	1.77%
3	2.61%		2.17%	0.52%	0.24%	1.14%	1.57%	2.03%
4	3.10%		2.41%	1.15%	1.35%	0.53%	0.75%	1.20%
5	3.50%		3.09%	1.37%	1.58%	0.75%	0.74%	0.91%
6	4.15%		3.51%	1.79%	2.03%	1.13%	0.62%	0.38%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0035		$0.0134	$0.0208	$0.0258	$0.0312	$0.0355	$0.0426
L		$0.0012						
1	$0.0047		$0.0094	$0.0172	$0.0211	$0.0262	$0.0320	$0.0368
2	$0.0208		$0.0101	$0.0011	$0.0031	$0.0068	$0.0124	$0.0169
3	$0.0258		$0.0211	$0.0031	$0.0000	$0.0099	$0.0147	$0.0196
4	$0.0312		$0.0242	$0.0100	$0.0122	$0.0032	$0.0056	$0.0106
5	$0.0355		$0.0320	$0.0124	$0.0147	$0.0056	$0.0055	$0.0073
6	$0.0426		$0.0368	$0.0169	$0.0196	$0.0098	$0.0041	$0.0015

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.21%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, NET, NET-284 and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.

Currently Effective Rates
Applicable to Rate Schedule FTS
Rate per Dth

	Base Tariff Rate	Annual Charge Adjustment	Total Effective Rate	Daily Rate
Rate Schedule FTS				
Reservation Charge 1/	$ 0.509	-	0.509	0.0167
Commodity				
Maximum	¢ 0.00	0.18	0.18	0.18
Minimum	¢ 0.00	0.18	0.18	0.18
Overrun	¢ 1.67	0.18	1.85	1.85

1/ Minimum reservation charge is $0.00.

RETAINAGE PERCENTAGES

Transportation Retainage	1.963%
Gathering Retainage	0.524%
Storage Gas Loss Retainage	0.230%
Ohio Storage Gas Lost Retainage	0.180%
Columbia Processing Retainage/1	0.000%

1/ The Columbia Processing Retainage shall be assessed separately from the processing retainage applicable to third party processing plants set forth in Section 25.3 (f) of the General Terms and Conditions.

RETAINAGE PERCENTAGE

Transportation Retainage	0.536%

PROPOSED TARIFF SHEETS

COLUMBIA GAS OF KENTUCKY, INC.

CURRENTLY EFFECTIVE BILLING RATES

SALES SERVICE	Base Rate Charge $	Gas Cost Adjustment[1/] Demand $	Gas Cost Adjustment[1/] Commodity $	Total Billing Rate $	
RATE SCHEDULE GSR					
Customer Charge per billing period	12.35			12.35	
Delivery Charge per Mcf	1.8715	1.0598	2.6632	5.5945	R
RATE SCHEDULE GSO					
Commercial or Industrial					
Customer Charge per billing period	25.13			25.13	
Delivery Charge per Mcf -					
First 50 Mcf or less per billing period	1.8715	1.0598	2.6632	5.5945	R
Next 350 Mcf per billing period	1.8153	1.0598	2.6632	5.5383	R
Next 600 Mcf per billing period	1.7296	1.0598	2.6632	5.4526	R
Over 1,000 Mcf per billing period	1.5802	1.0598	2.6632	5.3032	R
RATE SCHEDULE IS					
Customer Charge per billing period	583.39			583.39	
Delivery Charge per Mcf					
First 30,000 Mcf per billing period	0.5467		2.6632 [2/]	3.2099	R
Over 30,000 Mcf per billing period	0.2905		2.6632 [2/]	2.9537	R
Firm Service Demand Charge					
Demand Charge times Daily Firm Volume (Mcf) in Customer Service Agreement		6.6492		6.6492	R
RATE SCHEDULE IUS					
Customer Charge per billing period	331.50			331.50	
Delivery Charge per Mcf					
For All Volumes Delivered	0.7750	1.0598	2.6632	4.4980	R

1/ The Gas Cost Adjustment, as shown, is an adjustment per Mcf determined in accordance with the "Gas Cost Adjustment Clause" as set forth on Sheets 48 through 51 of this Tariff. The Gas Cost Adjustment applicable to a customer who is receiving service under Rate Schedule GS or IUS and received service under Rate Schedule SVGTS shall be $4.2104 per Mcf only for those months of the prior twelve months during which they were served under Rate Schedule SVGTS

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

I – Increase R - Reduction

DATE OF ISSUE: April 30, 2012

DATE EFFECTIVE: May 30, 2012
(June Unit 1 Billing)

ISSUED BY: Herbert A Miller, Jr.

President

CURRENTLY EFFECTIVE BILLING RATES

(Continued)

TRANSPORTATION SERVICE	Base Rate Charge $	Gas Cost Adjustment[1/] Demand $	Gas Cost Adjustment[1/] Commodity $	Total Billing Rate $	
RATE SCHEDULE SS					
Standby Service Demand Charge per Mcf					
Demand Charge times Daily Firm					
Volume (Mcf) in Customer Service Agreement		6.6492		6.6492	R
Standby Service Commodity Charge per Mcf			2.6632	2.6632	R
RATE SCHEDULE DS					
Administrative Charge per account per billing period				55.90	
Customer Charge per billing period [2/]				583.39	
Customer Charge per billing period (GDS only)				25.13	
Customer Charge per billing period (IUDS only)				331.50	
Delivery Charge per Mcf[2/]					
First 30,000 Mcf	0.5467			0.5467	
Over 30,000 Mcf	0.2905			0.2905	
– Grandfathered Delivery Service					
First 50 Mcf or less per billing period				1.8715	
Next 350 Mcf per billing period				1.8153	
Next 600 Mcf per billing period				1.7296	
All Over 1,000 Mcf per billing period				1.5802	
– Intrastate Utility Delivery Service					
All Volumes per billing period				0. 7750	
Banking and Balancing Service					
Rate per Mcf		0.0210		0.0210	
RATE SCHEDULE MLDS					
Administrative Charge per account each billing period				55.90	
Customer Charge per billing period				200.00	
Delivery Charge per Mcf				0.0858	
Banking and Balancing Service					
Rate per Mcf		0.0210		0.0210	

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

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

I – Increase R - Reduction

DATE OF ISSUE: April 30, 2012

DATE EFFECTIVE: May 30, 2012 (June Unit 1 Billing)

ISSUED BY: Herbert A Miller, Jr

President

COLUMBIA GAS OF KENTUCKY, INC.

Revised Sheet No. 7
P.S.C. Ky. No. 5

CURRENTLY EFFECTIVE BILLING RATES

RATE SCHEDULE SVGTS		**Billing Rate** $
General Service Residential		
Customer Charge per billing period		12.35
Delivery Charge per Mcf		1.8715
General Service Other - Commercial or Industrial		
Customer Charge per billing period		25.13
Delivery Charge per Mcf -		
First 50 Mcf or less per billing period		1.8715
Next 350 Mcf per billing period		1.8153
Next 600 Mcf per billing period		1.7296
Over 1,000 Mcf per billing period		1.5802
Intrastate Utility Service		
Customer Charge per billing period		331.50
Delivery Charge per Mcf		$ 0.7750
Actual Gas Cost Adjustment 1/		
For all volumes per billing period per Mcf	($ 0.0815)	
RATE SCHEDULE SVAS		
Balancing Charge – per Mcf	$ 0.8918	

R

I – Increase R - Reduction

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

DATE OF ISSUE: April 30, 2012

DATE EFFECTIVE: May 30, 2012
(June Unit 1 Billing)

ISSUED BY: Herbert A. Miller, Jr.

President