GREAT PLAINS
NATURAL GAS CO.
A Division of MDU Resources Group, Inc.

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Fergus Falls, MN 56538-0176
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May 31, 2013

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Cost of Gas Adjustment (COG)
June 2013

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and two (2) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (87th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (87th Revised Sheet No. 8), showing the June 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.1046 per mcf for residential and firm general service customers and an increase of $0.2666 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for June 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.0523 since the last COG filing due to a decrease in the market price of gas.

Attachment C explains the reasons for the change in the market price of gas.

Attachment D shows the calculation of the gas cost reconciliation (GCR) adjustment that will apply during the period of June 1, 2013 through May 31, 2014. The total GCR is $0.9614 per mcf for residential and general service customers and $0.0274 per mcf for interruptible customers. The effect of this change is a decrease of $0.0523 for residential and general service customers and an increase of $0.3189 for interruptible customers.

Great Plains submitted a check for $600.00 on January 2, 2013 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the $50.00 filing fee associated with this month's COG filing.

Great Plains respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Director of Regulatory Affairs

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
87th Revised Sheet No. 1.1
Canceling 86th Revised Sheet No.1.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$6.6872	$7.9612
			Over 10 MCF	1.0540		7.7412
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$6.6872	$8.8612
			Over 10 MCF	1.9540		8.6412
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$4.2302	$5.3693
			Next 2,600 MCF	0.8931		5.1233
			Over 3,000 MCF	0.7411		4.9713
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$4.2302	$6.2693
			Next 2,600 MCF	1.7931		6.0233
			Over 3,000 MCF	1.6411		5.8713
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$4.2302	$5.4693
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

Date Filed: May 31, 2013

Effective Date: Service rendered on and after June 1, 2013

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
87th Revised Sheet No. 8
Canceling 86th Revised Sheet No. 8

COST OF GAS

Summary:	Firm				Interruptible		
	Est. Wtd. Demand Costs	Average Commodity	GCR Adj.	Est. Wtd. Total Firm	Average Commodity	GCR Adj.	Total Int.
Base Rate	$0.0658	$5.1191	$0.0000	$5.1849	$5.1191	$0.0000	$5.1191
Accumulated Adj.	1.4722	(0.8790)	1.0137	1.6069	(0.8640)	(0.2915)	(1.1555)
Current Adj.	0.0000	(0.0523)	(0.0523)	(0.1046)	(0.0523)	0.3189	0.2666
Total Adj.	1.4722	(0.9313)	0.9614	1.5023	(0.9163)	0.0274	(0.8889)
Total Rate:	$1.5380	$4.1878	$0.9614	$6.6872	$4.2028	$0.0274	$4.2302

Date Filed:	May 31, 2013	**Effective Date:**	Service rendered on and after June 1, 2013
Issued By:	Tamie A. Aberle Director - Regulatory Affairs	**Case No.:**	

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JUNE 2013

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A	8,000		$3.4671	12	$332,842	$0.2373
FT-A - Zone 1-1	500		3.4671	5	8,668	0.0062
FT-A - Zone 1-2	4,500		4.5871	5	103,210	0.0736
FT-A Seasonal	2,000		3.7671	5	37,671	0.0269
TFX Seasonal	2,000		15.1530	5	151,530	0.1080
TFX - Winter	13,000		15.1530	5	984,945	0.7023
TFX - Summer	13,000		5.6830	7	517,153	0.3687
LMS Demand 2/						0.0150
Total Demand Charges					$2,136,019	1.5380
Estimated Weighted Average Commodity Cost	1,402,522	1/	4.1878		5,873,482	4.1878
Gas Cost Reconciliation Adjustment						0.9614
Total Current Firm Gas Cost					$8,009,501	6.6872
Base Cost of Gas						5.1849
Accumulated Adjustment						$1.5023

Interruptible	
Estimated Weighted Average Commodity Cost	$4.1878
Gas Cost Reconciliation Adjustment	0.0274
LMS Demand 2/	0.0150
Total Current Interruptible Gas Cost	4.2302
Base Cost of Gas	5.1191
Accumulated Adjustment	($0.8889)

1/ Three year normalized average mcf sales
2/ Amount divided by 2010-2012 average interruptible sales volumes plus 2010-2012 average normalized firm sales volumes.

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	$1.0000	12	$30,000	$0.0150

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JUNE 2013

Rates Effective June 1, 2013	$/Dk	
FT-A - Zone 1-1	$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	4.1878	Per dk

Base Rate Effective September 1, 1981		
Demand Charge	$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf

Base Rate Calculation

Firm		
Demand 1/	$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	$5.1849	Per Mcf

Interruptible:		
Commodity	$5.1191	Per Mcf

1/ Demand base rate calculation: 4,768 X 12 X $0.8100 / 707,222

Northern Natural Gas Company
FERC Gas Tariff
Sixth Revised Volume No. 1

Fifth Revised Sheet No. 50
Superseding
Fourth Revised Sheet No. 50

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET TF12 Base	TF12 Variable	TF5	FIELD-TO-FIELD/MARKET DEMARCATION TFF
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	10.230	13.866	15.153	9.853

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0377	0.0208			0.0175	0.0000	0.0377	0.0208
Field	Market	0.0377	0.0208	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ Maximum and Minimum rates include ACA of $0.0018 and the Market Area Electric Compression charge of $0.0000 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where Applicable, Field Area Electric Compression charge of $0.0000 and ACA will be added to the mileage based rates.

Northern Natural Gas Company
FERC Gas Tariff
Sixth Revised Volume No. 1

Fifth Revised Sheet No. 51
Superseding
Fourth Revised Sheet No. 51

RATE SCHEDULES TFX and LFT

RESERVATION RATES	MARKET-TO-MARKET Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD Nov-Mar
Base Tariff Rates 1/	$5.683	$15.153	$5.473	$9.853

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0377	0.0208			0.0175	0.0000	0.0377	0.0208
Field	Market	0.0377	0.0208	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

GULF COAST	Reservation 1/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ Minimum
MOPS Gathering	1.0514	0.0000	0.0018	0.0018	0.0018	0.0018
MOPS Transmission	1.5337	0.0000	0.0018	0.0018	0.0018	0.0018
Tivoli - Downstream	0.6827	0.0000	0.0018	0.0018	0.0018	0.0018
Other Gulf Coast	4.8169	0.0000	0.0018	0.0018	0.0018	0.0018

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ Maximum and Minimum rates include ACA of $0.0018 and the Market Area Electric Compression charge of $0.0000 where applicable.
4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
5/ Where applicable, Field Area Compression charge of $0.0000 and ACA will be added to the mileage based rates.
6/ Maximum and Minimum rates include ACA of $0.0018.

RATE SCHEDULES TF, TFX, LFT, GST, TI, & FDD

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.87%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.33% 4/ 5/
FDD Storage Fuel	1.55%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0000
Field Area	$0.0000

1/ Northern will adjust its Fuel percentages and electric compression commodity rates in accordance with Sections 53A and 53B, respectively, of the General Terms and Conditions of this Tariff.

2/ Fuel shall be determined by Mileage Indicator Districts (MIDS) for the Field Area.

3/ Fuel charged in the Field and Market Areas for a pooling transaction or for processing plant transactions will not exceed the fuel charged on a unified Field-to-Market transaction having the same initial Field receipt point and ultimate Market delivery point, i.e., the total fuel collected for transactions that go into and out of pooling points or processing plants in either the Field Area or the Market Area will be no greater than the fuel collected on the total path between the original receipt point and the ultimate delivery point, subject to the shipper(s) providing Northern the requisite information.

4/ The Unaccounted For percentage utilizes the most recent twelve-month period ending December 31, 2012.

5/ Sheet No. 54A identifies the specific transportation transactions exempt from fuel and unaccounted-for retention charges.

6/ The Out-of-Balance Fuel Percentage for deliveries in MIDS 1-7 shall be the applicable Section 1 Mainline Fuel percentage, and for deliveries in MIDS 8-16B shall be the applicable Section 2 Mainline Fuel percentage.

In the event facilities have been abandoned, Northern shall have the right to file to reduce the applicable MID fuel percentage(s) on a common basis for all transactions affected by the abandonment to reflect the reduction in use for the remainder of the PRA period. In the event such abandoned facilities (gas compressors) have been replaced with electric compressors installed after October 1, 1998, and Northern reduces the applicable MID fuel percentages, Northern has the right to file to increase the applicable electric compression commodity rate.

RATE SCHEDULES FDD, PDD, IDD & SMS

Rate Schedule FDD		
Maximum Reservation Fee	1.7140	1/
Maximum Capacity Fee	0.3567	1/
Injection Charge - Firm	0.0149	
Withdrawal Charge - Firm	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule PDD		
Maximum Capacity Fee	0.3567	1/
Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule IDD		
Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule SMS		
Reservation Fee	2.1800	
Commodity Rate	0.0208	

1/ Minimum Rate is zero.

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
Category 1 (Contract Term of Less than 3 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.7671
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.8871
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$2.1400
Zone 2-2 Minimum Rate	$0.0000
Category 2 (Contract Term of 3 Years to less than 5 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.6171
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.7371
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.9900
Zone 2-2 Minimum Rate	$0.0000
Category 3 (Contract Term of 5 or more Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.4671
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.5871
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.8400
Zone 2-2 Minimum Rate	$0.0000

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

Rate Schedule	Base Tariff Rate	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
Commodity Rates				
FT-A – Maximum Rates				
Zone 1-1	$0.0130	$0.0018	$0.0148	0.36%
Zone 1-2	$0.0130	$0.0018	$0.0148	0.47%
Zone 2-2	$0.0130	$0.0018	$0.0148	0.11%
Minimum Rate	$0.0130	$0.0018	$0.0148	
IT and AOT				
Zone 1-1	$0.1368	$0.0018	$0.1386	0.36%
Zone 1-2	$0.1737	$0.0018	$0.1755	0.47%
Zone 2-2	$0.0834	$0.0018	$0.0852	0.11%
Minimum Rate	$0.0130	$0.0018	$0.0148	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0018 per Dekatherm shall be added to other charges under Company's Rate Schedules.

2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: 0.06% for Zone 1-1, 0.08 % for Zone 1-2, and 0.02% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted for percentages.

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	$1.0000		$1.0000
LMS – Daily Overrun Rate	$0.1737		$0.1737
LMS – Load Management Cost Reconciliation Adjustment		$0.0001	

1/ Pursuant to Section 27 of the General Terms and Conditions of this Tariff, a mechanism is established to reconcile through surcharges or credits to the Rate Schedule LMS rate, as appropriate, differences between the cost to maintain Company's line pack gas and the amounts Company receives or pays for such gas arising out of the purchase and sale of such gas.

Rate Schedule	Maximum Rate Per Dekatherm	Minimum Rate Per Dekatherm
PAL		
NPL, OPL, and APL Service:		
Daily Commodity Rate	$0.1737	$0.0000
RPL Service:		
Daily Reservation Rate	$0.1737	$0.0000

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
June 2013

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for much of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The June monthly price for the NNG-Ventura Index is expected to decrease slightly from the previous month index. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month, commonly known as bid week, and reported by Platt's Inside FERC's Gas Market Report published the beginning of each month.

There was slight volatility in the price of gas in the day market during the month of May. Factors contributing to the slight decrease in the price of natural gas include the decreased consumption of gas for space heating, partially offset by an increase in power generation demand for cooling, which is typical for a shoulder month of natural gas usage. Energy Information Administration (EIA) reported storage levels nationwide as of May 17, 2013 were 3.9 percent below the five-year average and 24.9 percent below last year's balance.

The Department of Energy's (DOE) Energy Information Administration (EIA) provides various publications on energy issues. The information is available on the DOE website: http://www.eia.doe.gov.

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 16.

Independent Statistics & Analysis
U.S. Energy Information Administration

May 2013

Short-Term Energy Outlook (STEO)

Highlights

- Falling crude oil prices contributed to a decline in the U.S. regular gasoline retail price from a year-to-date high of $3.78 per gallon on February 25 to $3.52 per gallon on April 29. EIA expects the regular gasoline price will average $3.53 per gallon over the summer (April through September), down $0.10 per gallon from last month's STEO. The annual average regular gasoline retail price is projected to decline from $3.63 per gallon in 2012 to $3.50 per gallon in 2013 and to $3.39 per gallon in 2014. Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the projected levels.

- After increasing to $119 per barrel in early February 2013, the Brent crude oil spot price fell to a low of $97 per barrel in mid-April 2013 and then recovered to $105 per barrel on May 3. EIA expects that the Brent crude oil spot price will average $104 per barrel over the second half of 2013 and $101 per barrel in 2014. The projected discount of West Texas Intermediate (WTI) crude oil to Brent, which increased to a monthly average of more than $20 per barrel in February 2013, fell to below $9 per barrel in April. EIA expects the discount to increase in the near term and average $13 per barrel in 2013 and $9 per barrel in 2014.

- Natural gas working inventories ended April 2013 at an estimated 1.82 trillion cubic feet (Tcf), about 0.80 Tcf below the level at the same time a year ago and 0.13 Tcf below the five-year average (2008-12). EIA expects the Henry Hub natural gas spot price, which averaged $2.75 per million British thermal units (MMBtu) in 2012, will average $3.80 per MMBtu in 2013 and $4.00 per MMBtu in 2014, about 27 cents per MMBtu and 40 cents per MMBtu higher than forecast in last month's STEO, respectively.

- The projected increasing cost of natural gas relative to coal contributes to higher levels of electricity generation from coal. The share of total generation fueled by coal is forecast to increase from 37.4 percent in 2012 to 40.1 percent in 2013. Conversely, the share of generation fueled by natural gas declines from 30.4 percent in 2012 to 27.8 percent in 2013.

Global Crude Oil and Liquid Fuels

EIA estimates that global liquid fuels consumption outpaced production in the first quarter of 2013, resulting in an average draw in global liquid fuel stocks of 1.2 million barrels per day (bbl/d), which is much higher than the average 0.3-million-bbl/d draw over the last 5 years but consistent with the average 1.1-million-bbl/d draw over the last 10 years. EIA expects world oil production to exceed consumption in the second quarter of 2013, resulting in an average 0.5-million-bbl/d build in global oil stocks, which is consistent with the recent decline in crude oil prices. EIA expects the world oil market to tighten somewhat in the third quarter of 2013 as world demand reaches its summer peak, and to loosen again in the last quarter of the year as world supply grows.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by 0.7 million bbl/d in 2012 to reach 89.0 million bbl/d. EIA expects growth will be higher over the next two years because of a moderate recovery in global economic growth so that world consumption grows by 0.9 million bbl/d in 2013 and by 1.2 million bbl/d in 2014.

Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. EIA expects refinery crude oil inputs in China to increase in 2013 as new refining capacity continues to come on line and investment in the property market and infrastructure sectors expands. Recent indicators of weaker industrial data at the beginning of 2013 signaled slower economic growth than in prior years and a downside risk to robust oil demand growth. EIA estimates that liquid fuels consumption in China increased by 380,000 bbl/d in 2012. Projected consumption in China will increase by 450,000 bbl/d in 2013 and by 470,000 bbl/d in 2014, albeit still lower than the average annual growth of about 520,000 bbl/d from 2004 through 2012.

OECD liquid fuels consumption fell by 0.6 million bbl/d in 2012. EIA projects OECD consumption to decline by an additional 0.4 million bbl/d in 2013 and 0.2 million bbl/d in 2014, largely because of declining consumption in Europe and Japan.

Non-OPEC Supply. EIA projects non-OPEC liquid fuels production will increase by 1.1 million bbl/d in 2013 and by 1.8 million bbl/d in 2014, an upward revision in the 2014 growth rate of 0.2 million bbl/d from last month's STEO. North America accounts for most of the projected growth in non-OPEC supply over the next two years because of continued production growth from U.S. tight oil formations and Canadian oil sands. EIA expects non-OPEC supply to also grow in Central and South America by an average of 160,000 bbl/d each year over the next two years, as Brazil and Colombia bring new production on line.

Unplanned production outages in non-OPEC countries averaged 0.9 million bbl/d in April 2013, virtually unchanged from the previous month. Syria, Yemen, and South Sudan accounted for more than three-quarters of the total unplanned non-OPEC supply disruption. EIA expects supply disruptions to persist in Syria and Yemen over the forecast period. Projected production

in Syria and Yemen average about 120,000 bbl/d and 140,000 bbl/d, respectively, over the next two years. EIA expects total non-OPEC outages to abate in the second half of this year due to South Sudan resuming oil production. South Sudan restarted limited oil output at an oil field in Unity State last month. Work is being done to restart production at additional fields in Unity State and the Upper Nile State, although technical challenges may cause delays or constrain production volumes.

OPEC Supply. Projected OPEC total supply falls by 0.5 million bbl/d in 2013 and then rises by 0.1 million bbl/d in 2014. Most of the decline in 2013 comes from Saudi Arabia in response to non-OPEC supply growth, while Iraq and Angola account for most of the increase in 2014.

EIA estimates that OPEC surplus capacity, which is concentrated in Saudi Arabia, averaged about 2.7 million bbl/d in the first quarter of 2013. This was higher than the 2.1-million-bbl/d average during the same period last year but lower than the average 3.8 million bbl/d from 2009 through 2011. EIA projects OPEC surplus capacity will increase to an average of 4.6 million bbl/d in the fourth quarter of 2014. These estimates do not include additional capacity that may be available in Iran but is currently off line because of the effects of U.S. and EU sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories at the end of 2012 totaled 2.65 billion barrels, equivalent to 57.9 days of supply. Projected OECD oil inventories stay relatively steady in 2013, again ending the year at 2.65 billion barrels. Projected inventories increase to 2.70 billion barrels (59.0 days of supply) at the end of 2014.

Crude Oil Prices. Concerns over global economic growth, seasonal declines in international refinery runs, and increases in North Sea oil production have contributed to a drop in Brent crude oil prices from $109 per barrel on April 1 to a low of $97 per barrel on April 17. EIA projects the Brent crude oil spot price will fall from an average of $112 per barrel in 2012 to annual averages of $106 per barrel and $101 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels from non-OPEC countries. After averaging $94 per barrel in 2012, the forecast WTI crude oil spot price averages $93 per barrel in 2013 and $92 per barrel in 2014. By 2014, several pipeline projects from the Midcontinent to the Gulf Coast refining centers are expected to come on line, reducing the cost of transporting crude oil to refiners, which is reflected in a narrowing in the price discount of WTI to Brent.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures contracts for August 2013 delivery traded during the five-day period ending May 2, 2013 averaged $93.41 per barrel. Implied volatility averaged 22 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in August 2013 at $77 per barrel and $113 per barrel, respectively. Last year at this time, WTI for August 2012 delivery averaged $105 per barrel and implied volatility averaged 23 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $86 per barrel and $130 per barrel.

U.S. Crude Oil and Liquid Fuels

Total U.S. liquid fuels consumption during the first quarter of 2013 averaged 190,000 bbl/d higher than the same period last year, the first year-over-year increase in quarterly consumption in two years. Colder weather contributed to an estimated 280,000-bbl/d increase in liquefied petroleum gas and a 120,000-bbl/d increase in distillate fuel consumption. These gains were partially offset by declines in the other major petroleum products, including a 90,000-bbl/d drop in gasoline consumption.

The U.S. crude oil production forecast has been revised upward by 120,000 bb/d in 2013 and 310,000 bbl/d in 2014 from last month's STEO. Production will rise from an average of 7.1 million bbl/d in the first quarter of 2013 to 8.5 million bbl/d in the fourth quarter of 2014. The growing supply of domestic light crude oil in the Midcontinent has already prompted both midstream and downstream changes. Pipelines like Seaway that were once used to carry imported oil up from Gulf Coast ports to reach Midwest refiners have been reversed and are moving inland crude oil down to the Gulf, and their capacity is being dramatically expanded. New pipeline infrastructure is also under construction, including the southern portion of the Keystone XL project, which is slated to be in operation by year-end, and more has been proposed. There have also been major developments in rail transport, where shipments of crude increased dramatically in 2012 compared to 2011. Significant changes in the refining industry are expected over the next few years to accommodate this fast-growing domestic supply of light-sweet crude oil (see This Week in Petroleum, May 1, 2013).

U.S. Liquid Fuels Consumption. After relatively strong growth in the first quarter of 2013 because of cold weather, projected total liquid fuels consumption grows more modestly, increasing by an average 80,000 bbl/d (0.4 percent) in 2013 and unchanged in 2014. Motor gasoline and jet fuel consumption remain flat in 2013 and 2014 as forecast increases in travel growth are offset by fuel economy improvements. Distillate fuel oil consumption, which fell by 160,000 bbl/d (4.0 percent) in 2012, increases by 60,000 bbl/d (1.7 percent) in 2013 and 10,000 bbl/d (0.2 percent) in 2014. Liquefied petroleum gases consumption increases by 70,000 bbl/d in 2013 but then falls by 10,000 bbl/d in 2014.

U.S. Liquid Fuels Supply. EIA expects U.S. crude oil production to rise from an average 6.5 million bbl/d in 2012 to 7.4 million bbl/d in 2013 and 8.2 million bbl/d in 2014. Drilling in tight oil plays in the onshore Williston, Western Gulf, and Permian basins is expected to account for the bulk of forecast production growth over the next two years.

EIA has increased its short-term forecast for U.S. Lower 48 states onshore oil production, largely because of continued exploration success seen in some of the major plays in the Permian Basin. Operators in the Bone Spring, Spraberry, and Wolfcamp plays are achieving greater success in finding sweet spots and hydraulically fracturing horizontal wells. EIA expects improvements in drilling and completing horizontal wells from multiwell drilling pads in the Permian Basin, which

give operators greater access to large areas of resources in a number of stacked plays from a single surface location.

Since reaching 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil and petroleum products, have been falling. Total net imports fell to 7.4 million bbl/d in 2012, and EIA expects imports to continue declining to an average of 5.7 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at more than 60 percent in 2005 and fell to an average of 40 percent in 2012. EIA expects the net import share to fall to 30 percent in 2014, which would be the lowest level since 1985.

U.S. Petroleum Product Prices. EIA expects that regular-grade gasoline retail prices, which averaged $3.69 per gallon last summer, will average $3.53 per gallon during the current summer (April through September) driving season, about $0.10 per gallon lower than forecast in last month's STEO. The projected monthly average regular retail gasoline price falls from $3.57 per gallon in April to $3.48 per gallon in September. Diesel fuel prices, which averaged $3.95 per gallon last summer, are projected to fall to an average of $3.88 per gallon this summer. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by 30 cents per gallon or more.

As is the case with crude oil, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts. New York Harbor RBOB futures contracts for August 2013 delivery traded over the five-day period ending May 2 averaged $2.73 per gallon. The probability that the RBOB futures price will exceed $3.10 per gallon (consistent with a U.S. average regular gasoline retail price above $3.75 per gallon) in August 2013 is about 11 percent.

Natural Gas

Natural gas spot prices generally increased through March and most of April, hitting a 20-month high in recent weeks. An unusually cold March triggered price increases after three months of stagnant prices, as space-heating demand increased through much of the country and led to large storage withdrawals. Prices continued to rise in April as lingering cold in the Midwest kept market tight. The Henry Hub spot price averaged $4.17 per MMBtu in April, the highest monthly average price since July 2011. EIA expects Henry Hub spot prices will fall through September as natural gas markets loosen with lower summer demand. Going into the summer, EIA expects production to be slightly higher than last year's levels, while summer electric power demand is projected to be lower than last year's record-high levels.

Working natural gas stocks at the end of March 2013 were an estimated 1,683 Bcf, 32 percent lower than the 2,477 Bcf in working storage at the same time last year but roughly in line with earlier years. The very warm winter of 2011-12 contributed to the very high inventory at the start of last year's summer injection season (between the end of March and the end of

October). Consequently, the forecast 2,113-Bcf build in working gas inventories during this summer's injection season is significantly higher than the 1,453 Bcf added last year and in line with longer historical experience. Higher natural gas prices this year contribute to lower natural gas consumption for electricity generation and the higher storage build.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 70.2 Bcf/d and 69.6 Bcf/d in 2013 and 2014, respectively. Colder winter temperatures forecast for 2013 and 2014 (compared with the record-warm temperatures in 2012) are expected to increase the amount of natural gas used for residential and commercial space heating. The projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 22.8 Bcf/d in 2013 and 22.2 Bcf/d in 2014.

U.S. Natural Gas Production and Imports. Natural gas marketed production is projected to increase from 69.2 Bcf/d in 2012 to 69.9 Bcf/d in 2013, and 70.1 Bcf/d in 2014. Onshore production increases over the forecast period, while federal Gulf of Mexico production declines. Natural gas pipeline gross imports, which have declined over the past five years, are projected to remain near their 2012 level over the forecast period. Liquefied natural gas (LNG) imports are expected to remain at minimal levels of less than 0.5 Bcf/d in both 2013 and 2014.

U.S. Natural Gas Inventories. As of April 26, 2013, working gas stocks totaled 1,777 Bcf, which is 795 Bcf less than at the same time in 2012, 118 Bcf below the five-year (2008-12) average, and 51 Bcf above the four-year (2008-11) average excluding last year's very unusual experience according to EIA's *Weekly Natural Gas Storage Report*. EIA projects working gas stocks at the end of this summer's stock-build season (end of October) will reach 3,796 Bcf, about 134 Bcf below the level at the same time last year.

U.S. Natural Gas Prices. Natural gas spot prices averaged $4.17 per MMBtu at the Henry Hub in April 2013, up 36 cents from the $3.81-per-MMBtu average seen the previous month. EIA expects the Henry Hub price will increase from an average of $2.75 per million Btu in 2012 to $3.80 per MMBtu in 2013 and $4.00 per MMBtu in 2014.

Natural gas futures prices for August 2013 delivery (for the five-day period ending May 2, 2013) averaged $4.34 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for August 2013 contracts at $3.22 per MMBtu and $5.84 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for August 2012 averaged $2.46 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were $1.52 per MMBtu and $3.96 per MMBtu.

Coal

Based on preliminary data and estimates for the first quarter of 2013, U.S. coal exports, which had been steadily growing since 2009 on an annual basis, were down 1.3 million short tons (MMst) compared with the same period in 2012. Coal exports from the Richards Bay coal terminal in South Africa, a major U.S. competitor for the European market, increased by 6.5 percent during the first four months of 2013 compared with same period last year. EIA expects U.S. coal exports to decline from 126 MMst in 2012 to 105 MMst in 2013 and 106 MMst in 2014.

U.S. Coal Consumption. EIA expects total coal consumption will increase by 7.3 percent from 890 MMst in 2012 to 955 MMst in 2013 as consumption in the electric power sector rises due to higher electricity demand and higher natural gas prices. Consumption grows at a more modest pace of 2.2 percent to 976 MMst in 2014.

U.S. Coal Supply. Coal production is expected to increase by 1.0 percent in 2013, from 1,016 MMst in 2012 to 1,027 MMst in 2013, as inventory draws, combined with an increase in coal imports, meet most of the growth in consumption. However, coal production is forecast to grow by 3.5 percent in 2014 to 1,063 MMst as inventories stabilize in the face of increasing consumption.

Production is further diminished by the projected decline in exports from 126 MMst in 2012 to 105 MMst in 2013 and 106 MMst in 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), falling international coal prices, and increasing production in other coal-exporting countries are the primary reasons for the expected decline in U.S. coal exports.

U.S. Coal Prices. Delivered coal prices to the electric power industry increased steadily over a 12-year period through 2012, when the delivered coal price averaged $2.40 per MMBtu. EIA forecasts average delivered coal prices of $2.40 per MMBtu in 2013 and $2.44 per MMBtu in 2014.

Electricity

The National Oceanic and Atmospheric Administration's (NOAA) Climate Prediction Center has updated the methodology behind its degree-day outlook based on the new 1981-2010 30-year normals. Projected U.S. cooling degree days for 2013 and 2014 are 3.9 percent and 3.6 percent higher, respectively, compared with last month's forecast. Consequently, projected residential and commercial electricity sales for 2013 and 2014 are about 0.5 percent higher than in last month's STEO.

U.S. Electricity Consumption. During the first four months of 2013, EIA estimates that total U.S. retail sales of electricity to the residential sector averaged 5.4 percent more than residential

electricity sales during the same months last year. Despite the upward revision to NOAA's cooling-degree-day forecast, projected U.S. cooling degree days during the upcoming summer's hottest months (June, July, and August) are 7.3 percent lower than summer of 2012. These lower temperatures relative to last year contribute to a 3.6-percent decline in U.S. residential electricity sales during the summer peak cooling months. For the entire year, U.S. residential retail electricity sales increase by 1.1 percent during 2013 and by 0.5 percent in 2014.

U.S. Electricity Generation. EIA expects total U.S. electricity generation will grow by 1.4 percent in 2013 and by 1.0 percent in 2014. The increasing cost of natural gas relative to coal contributes to higher levels of electricity generation from coal. Generators are running their existing coal capacity at higher rates so far this year compared with the same months in 2012. This trend is expected to continue, leading to an 8.7-percent increase in U.S. electricity generation from coal during 2013. The share of total generation fueled by coal is forecast to increase from 37.4 percent in 2012 to 40.1 percent in 2013, still below coal's 42.3-percent fuel share in 2011. Conversely, the rising cost of natural gas pushes the share of generation fueled by natural gas down from 30.4 percent in 2012 to 27.8 percent in 2013, compared with a share of 24.7 percent in 2011.

U.S. Electricity Retail Prices. After an increase of 1.4 percent during 2012, EIA expects U.S. retail residential electricity prices will grow by 2.6 percent in 2013 and by 2.3 percent in 2014.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewable energy consumption for power and heat generation to increase by 3.3 percent in 2013. While hydropower declines by 2.2 percent, nonhydropower renewables grow by an average of 7.1 percent in 2013. In 2014, the growth in renewables consumption for power and heat generation is projected to continue at a rate of 4.4 percent, as a 1.8-percent increase in hydropower is combined with a 6.0-percent increase in nonhydropower renewables.

EIA currently estimates that wind capacity will increase by 7 percent this year to nearly 63,000 megawatts, and reach almost 73,000 megawatts in 2014. However, electricity generation from wind is projected to increase by 19 percent in 2013, as capacity that came on line at the end of 2012 is available for the entire year in 2013. Wind-powered generation is projected to grow by 8 percent in 2014.

EIA expects continued robust growth in the generation of solar energy, both from central-station and distributed capacity, although the total amount remains a small share of total U.S. generation. Central-station capacity, which until recently experienced little growth compared with distributed capacity, is projected to more than double between 2012 and 2014. Photovoltaics (PV) accounted for all central-station solar growth in 2012, but EIA expects that several large solar thermal generation projects will enter service in 2013 and 2014. However, PV

is still expected to account for the majority of central station and distributed capacity additions in 2013 and 2014.

U.S. Liquid Biofuels. Smaller corn harvests due to widespread drought resulted in U.S. fuel ethanol production falling from an average of approximately 900,000 bbl/d (13.8 billion gallons per year) in the first half of 2012 to 820,000 bbl/d (12.6 billion gallons per year) from July 2012 through March 2013. Ethanol production recovered somewhat in April, averaging about 840,000 bbl/d, driven largely by increasing Renewable Fuel Standard (RFS) targets and strong demand for Renewable Identification Numbers (RINs) used. EIA expects ethanol production to remain near current levels of about 840,000 bbl/d through mid-2013 before recovering to pre-drought production levels, averaging 860,000 bbl/d for the year. Ethanol production is expected to rise in 2014, averaging 930,000 bbl/d. Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons per year) in 2012, is forecast to average about 74,000 bbl/d in 2013 and 82,000 bbl/d in 2014 (1.3 billion gallons per year). This forecast assumes that the 2014 renewable fuel volume obligations for biodiesel and advanced biofuel are identical to those in 2013.

In 2013, the RFS requires refiners and importers of gasoline and diesel fuel to deliver RINs to the U.S. Environmental Protection Agency equivalent to 9.63 percent of the gasoline or diesel fuel they sell domestically (not counting the biofuels blended into it). The market price of ethanol RINs increased dramatically during the first quarter of 2013, from $0.05 per gallon at the start of the year to as high as $1.05 per gallon on March 11, and has averaged about $0.70 per gallon during April 2013. The increase in the ethanol RIN price provides an economic incentive for two changes in the market. First, a higher ethanol RIN price should lower the market price of E85 gasoline relative to E10 gasoline, thereby stimulating E85 sales. Second, an ethanol RIN price equal to or near the biodiesel RIN price may motivate increased blending of biodiesel.

At the retail level, EIA expects diesel fuel prices to be most affected by higher RIN prices as biodiesel blending yields only about one-third of the RINs required and diesel fuel refiners and blenders must make up for the shortfall by purchasing the now higher-priced RINs.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels declined by 4 percent in 2012, and projects increases of 2.6 percent in 2013 and 0.6 percent in 2014. The increase in emissions over the forecast period primarily reflects the projected increase in coal use for electricity generation, especially in 2013 as it rebounds from the 2012 decline.

U.S. Economic Assumptions

EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the U.S. economic projections in the STEO. The GI model used in this STEO assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) will soon be replaced by a combination of income tax increases and spending

cuts that are implemented in 2014. The GI model also assumes there will be an agreement reached to increase the amount of debt that can be issued by the U.S. Treasury (the debt ceiling) in the near term.

U.S. Current Trends. Recent economic indicators have been mixed. The U.S. Bureau of Economic Analysis reported that real gross domestic product (GDP) increased at an annual rate of 2.5 percent in the first quarter of 2013 (that is, from the fourth quarter to the first quarter). This was well above the 0.4-percent growth in the final quarter of 2012, but below the expectations of many forecasters. Consumer spending and residential investment showed strong gains, while net exports and government expenditures showed quarterly reductions. The U.S. Department of Labor also reported that initial unemployment insurance claims dropped by 18,000 in the week ending April 27, 2013 to 324,000 (on a seasonally adjusted basis), down from 371,000 at the same time in 2012. Total nonfarm payroll employment increased by 165,000 in April, near the average employment growth of 169,000 per month over the last 12 months. The U.S. Census Bureau reported that new orders for manufactured durable goods fell 5.7 percent from February to March, following a 4.3-percent increase from January to February. Industrial production rose by 0.4 percent in March after having increased 1.1 percent in February according to the Federal Reserve.

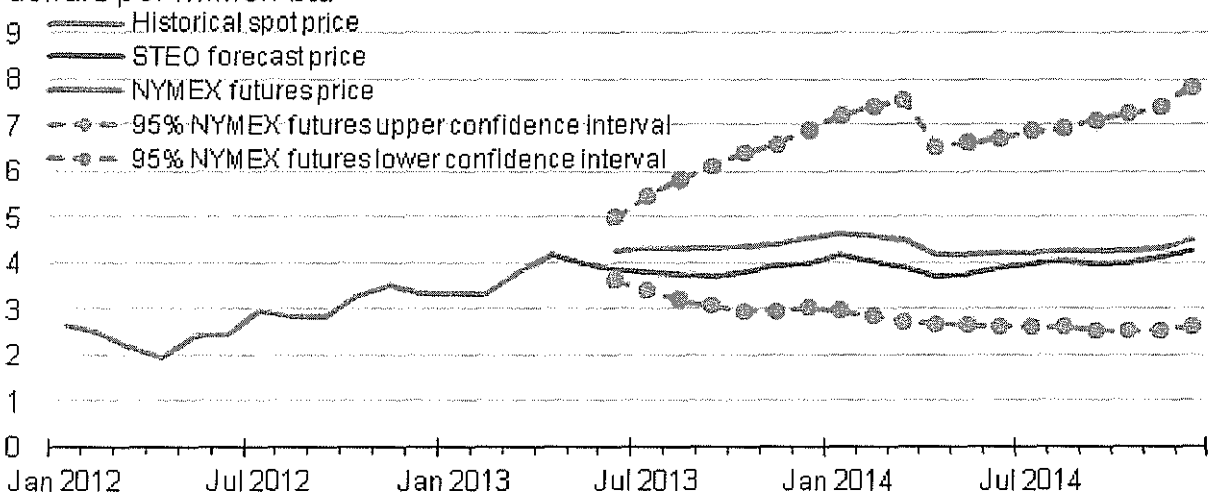
U.S. Production. This STEO assumes 1.8 percent U.S. real GDP growth in 2013, rising to 2.7 percent in 2014. Year-on-year real GDP growth begins to accelerate in 2014, eventually rising to 3.0 percent in its final quarter. Forecast real disposable income increases 0.9 percent in 2013 and 3.4 percent in 2014. Total industrial production grows at a faster rate than real GDP in 2013 and 2014, at 3.0 percent and 2.9 percent, respectively.

U.S. Income and Expenditures. Private fixed investment growth averages 6.7 percent and 8.2 percent over 2013 and 2014. This is driven partly by business equipment and software spending, as well as increasing expenditures on buildings. Real consumption expenditures grow faster than real GDP in 2013, at 2.1 percent, but slow below the rate of real GDP growth in 2014, at 2.3 percent. Export growth nearly doubles from 2.6 percent to 5.1 percent over the same two years. Government expenditures fall 2.6 percent in 2013, but are essentially unchanged in 2014.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 7.7 percent over most of 2013, then gradually falls to 7.1 percent at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.5 percent in both 2013 and 2014. Consistent with an improving housing sector, housing starts grow an average of 24 percent and 28 percent over 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

Henry Hub Natural Gas Price

dollars per million btu

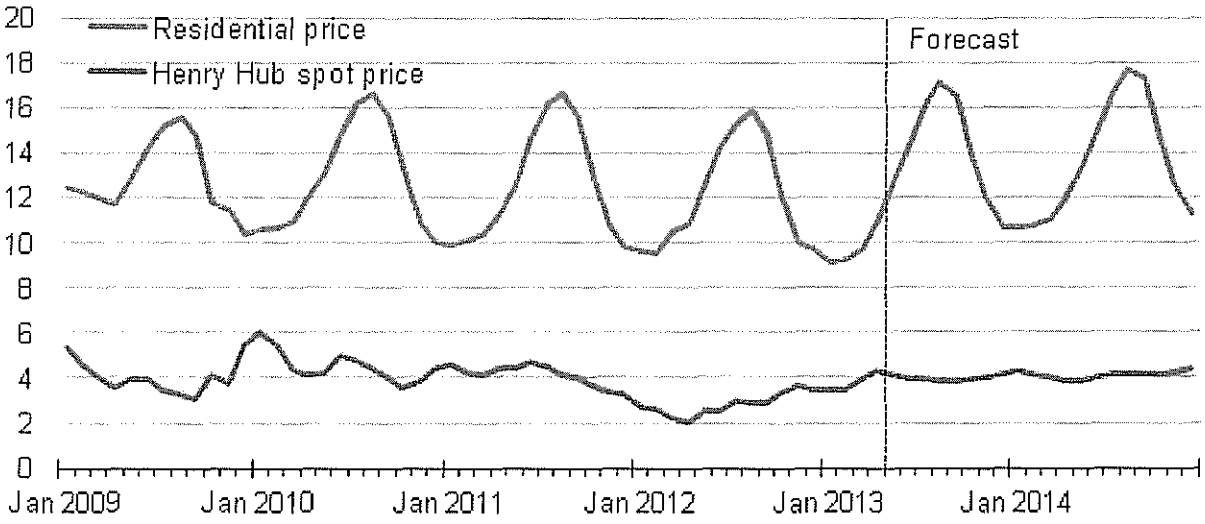


Note: Confidence interval derived from options market information for the 5 trading days ending May 2, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

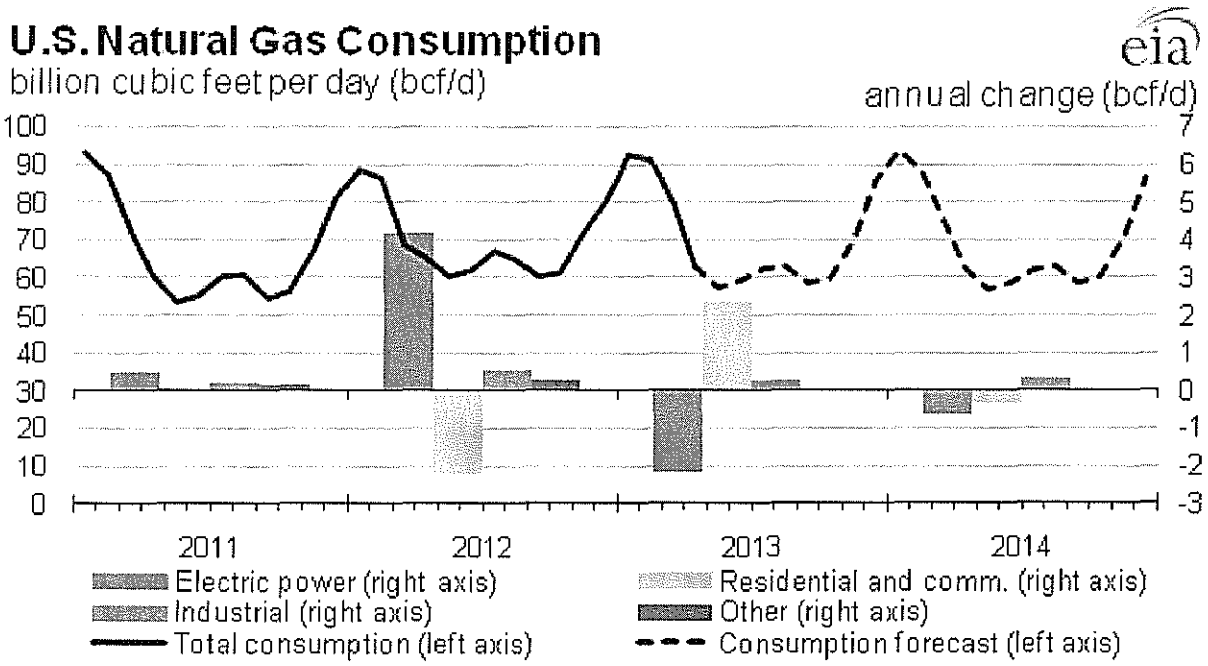
Source: Short-Term Energy Outlook, May 2013

U.S. Natural Gas Prices

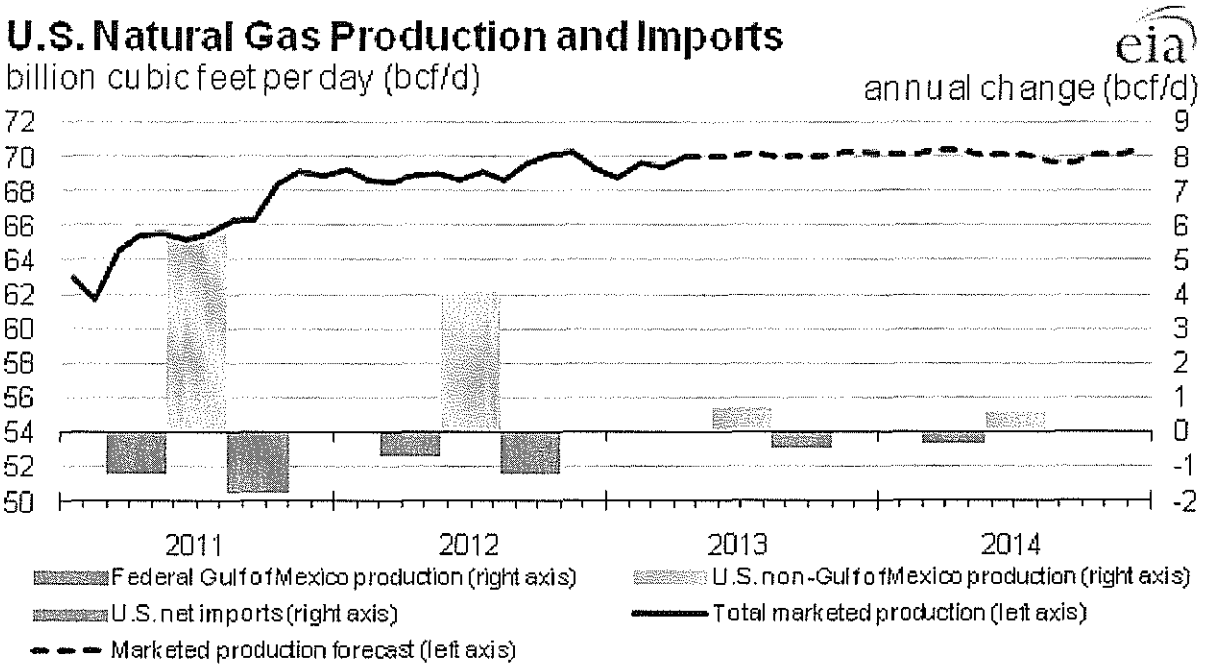
dollars per thousand cubic feet



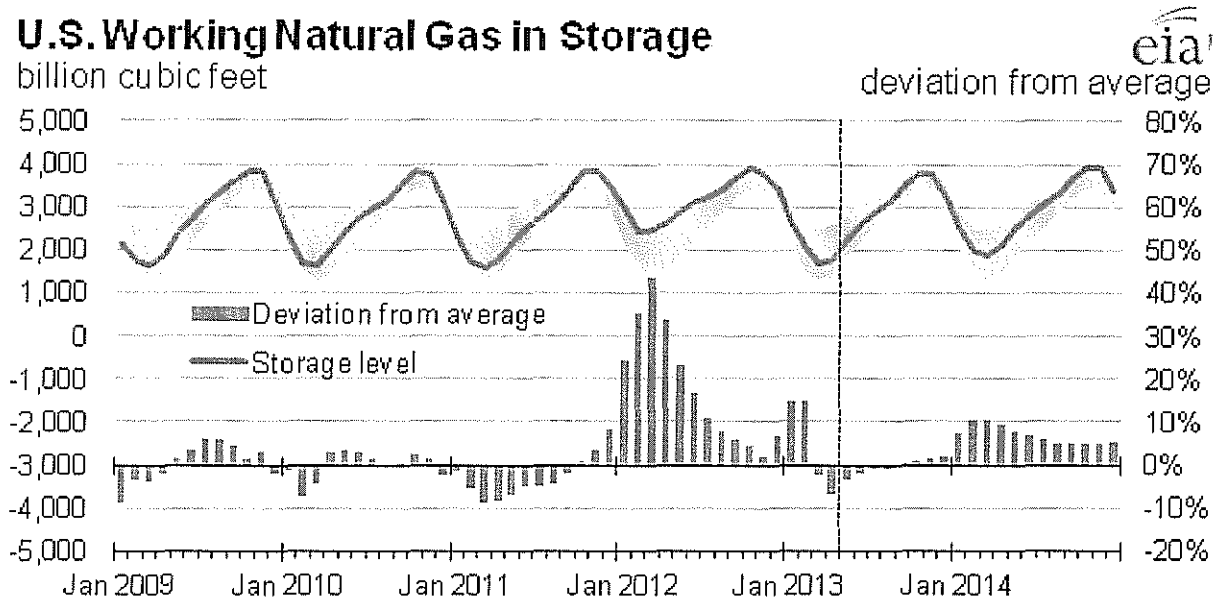
Source: Short-Term Energy Outlook, May 2013



Source: Short-Term Energy Outlook, May 2013



Source: Short-Term Energy Outlook, May 2013



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.
Source: Short-Term Energy Outlook, May 2013

GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
FIRM
TO BE EFFECTIVE JUNE 1, 2013 THROUGH MAY 31, 2014

(Over)/under recovered gas costs @ April 30, 2013:			$303,311
Less projected recovery from rates already established:			
	Volume	Rate	Amount
May	12,900	$1.0137	$13,077
Additional recovery required			$290,234
Projected sales volumes (mcf)			
June 2013		9,000	
July		8,200	
August		8,400	
September		11,100	
October		20,100	
November		33,200	
December		46,300	
January 2014		52,500	
February		42,000	
March		36,200	
April		22,000	
May		12,900	
Total			301,900
Total gas cost reconciliation adjustment to be effective June 1, 2013 through May 31, 2014			$0.9614

GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE
TO BE EFFECTIVE JUNE 1, 2013 THROUGH MAY 31, 2014

(Over)/under recovered gas costs @ April 30, 2013:			$4,747
Less projected recovery from rates already established:			
	Volume	Rate	Amount
May	23,700	($0.2915)	($6,909)
Additional recovery required			$11,656
Projected sales volumes (mcf)			
June 2013		13,700	
July		13,100	
August		14,200	
September		21,000	
October		37,000	
November		41,800	
December		49,600	
January 2014		56,500	
February		49,000	
March		47,400	
April		58,700	
May		23,700	
Total			425,700
Total gas cost reconciliation adjustment to be effective June 1, 2013 through May 31, 2014			$0.0274

GREAT PLAINS NATURAL GAS CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
FIRM

	(Over) Under Recovery	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount		Net Change	Cumulative Balance
Balance @ April 30, 2012									**$311,764**
May	$30,099	$2,016	$32,115	13,137	$0.5102	$6,702		$25,413	337,177
June	52,819	2,192	55,011	6,558	1.0137	4,625	2/	50,386	387,563
July	57,568	2,542	60,110	5,777	1.0137	5,856		54,254	441,817
August	58,888	2,918	61,806	5,142	1.0137	5,212		56,594	498,411
September	26,138	3,308	29,446	6,241	1.0137	6,326		23,120	521,531
October	36,902	3,454	40,356	10,186	1.0137	10,326		30,030	551,561
November	8,143	3,651	11,794	20,404	1.0137	20,684		(8,890)	542,671
December	7	3,572	3,579	31,222	1.0137	31,650		(28,071)	514,600
January 2013	(22,865)	3,361	(19,504)	49,730	1.0137	50,411		(69,915)	444,685
February	(16,652)	2,861	(13,791)	50,381	1.0137	51,071		(64,862)	379,823
March	(96)	2,401	2,305	40,689	1.0137	41,246		(38,941)	340,882
April	(1,762)	2,126	364	37,423	1.0137	37,935		(37,571)	303,311
Total	$229,189	$34,402	$263,591	276,890		$272,044		($8,453)	
Balance @ April 30, 2013									**$303,311**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 4,017.3 dk @ $0.5102 and 2,540.6 dk @ $1.0137.

GREAT PLAINS NATURAL GAS CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	(Over) Under Recovery	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change	Cumulative Balance
Balance @ April 30, 2012								**($72,396)**
May	($11,426)	($557)	($11,983)	23,670	($0.0178)	($422)	($11,561)	(83,957)
June	(6,055)	(637)	(6,692)	13,697	(0.2915)	(1,509) 2/	(5,183)	(89,140)
July	(16,584)	(671)	(17,255)	13,109	(0.2915)	(3,821)	(13,434)	(102,574)
August	(2,356)	(765)	(3,121)	14,195	(0.2915)	(4,138)	1,017	(101,557)
September	(20,241)	(754)	(20,995)	21,085	(0.2915)	(6,146)	(14,849)	(116,406)
October	325	(859)	(534)	37,029	(0.2915)	(10,794)	10,260	(106,146)
November	6,923	(784)	6,139	41,796	(0.2915)	(12,184)	18,323	(87,823)
December	(3,340)	(652)	(3,992)	49,581	(0.2915)	(14,452)	10,460	(77,363)
January 2013	(4,644)	(579)	(5,223)	56,465	(0.2915)	(16,460)	11,237	(66,126)
February	935	(501)	434	48,952	(0.2915)	(14,270)	14,704	(51,422)
March	7,505	(399)	7,106	47,360	(0.2915)	(13,806)	20,912	(30,510)
April	18,396	(252)	18,144	58,708	(0.2915)	(17,113)	35,257	4,747
Total	($30,562)	($7,410)	($37,972)	425,647		($115,115)	$77,143	
Balance @ April 30, 2013								**$4,747**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 9,072.9 dk @ ($0.0178) and 4,623.6 dk @ ($0.2915).

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

	1/	2/	3/	Total
May 2012				
Cost of Gas - Actual	$9.70500	$6.65610	$9.70500	
Cost of Gas - Recovered	5.71790	5.91190	5.91190	
(Over) Under recovery per dk	$3.98710	$0.74420	$3.79310	
dk billed	4,161	6,737	2,239	13,137
(Over) Under recovery	$16,592	$5,014	$8,494	$30,099
June 2012				
Cost of Gas - Actual	$14.11440	$9.70500	$14.11440	
Cost of Gas - Recovered	6.17420	5.71790	5.71790	
(Over) Under recovery per dk	$7.94020	$3.98710	$8.39650	
dk billed	2,541	246	3,771	6,558
(Over) Under recovery	$20,173	$981	$31,665	$52,819
July 2012				
Cost of Gas - Actual	$16.09770	$14.11440	$16.09770	
Cost of Gas - Recovered	5.91750	6.17420	6.17420	
(Over) Under recovery per dk	$10.18020	$7.94020	$9.92350	
dk billed	2,247	167	3,363	5,777
(Over) Under recovery	$22,876	$1,324	$33,368	$57,568
August 2012				
Cost of Gas - Actual	$17.56860	$16.09770	$17.56860	
Cost of Gas - Recovered	6.26580	5.91750	5.91750	
(Over) Under recovery per dk	$11.30280	$10.18020	$11.65110	
dk billed	2,047	215	2,880	5,142
(Over) Under recovery	$23,139	$2,192 4/	$33,558	$58,888
September 2012				
Cost of Gas - Actual	$15.04900	$17.56860	$15.04900	
Cost of Gas - Recovered	6.25750	6.26580	6.26580	
(Over) Under recovery per dk	$8.79150	$11.30280	$8.78320	
dk billed	2,618	1,693	1,930	6,241
(Over) Under recovery	$23,019	($13,830)	$16,949	$26,138
October 2012				
Cost of Gas - Actual	$7.02920	$15.04900	$7.02920	
Cost of Gas - Recovered	6.36214	6.25750	6.25750	
(Over) Under recovery per dk	$0.66706	$8.79150	$0.77170	
dk billed	4,659	3,682	1,845	10,186
(Over) Under recovery	$3,108	$32,371	$1,423	$36,902

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

	1/	2/	3/	Total
November 2012				
Cost of Gas - Actual	$5.80680	$7.02920	$5.80680	
Cost of Gas - Recovered	5.24660	6.36214	6.36214	
(Over) Under recovery per dk	$0.56020	$0.66706	($0.55534)	
dk billed	7,919	8,704	3,781	20,404
(Over) Under recovery	$4,436	$5,806	($2,100)	$8,143
December 2012				
Cost of Gas - Actual	$5.07830	$5.80680	$5.07830	
Cost of Gas - Recovered	5.51780	5.24660	5.24660	
(Over) Under recovery per dk	($0.43950)	$0.56020	($0.16830)	
dk billed	11,608	11,544	8,070	31,222
(Over) Under recovery	($5,102)	$6,467	($1,358)	$7
January 2013				
Cost of Gas - Actual	$4.67930	$5.07830	$4.67930	
Cost of Gas - Recovered	5.08730	5.51780	5.51780	
(Over) Under recovery per dk	($0.40800)	($0.43950)	($0.83850)	
dk billed	17,963	27,820	3,947	49,730
(Over) Under recovery	($7,329)	($12,227)	($3,309)	($22,865)
February 2013				
Cost of Gas - Actual	$4.93020	$4.67930	$4.93020	
Cost of Gas - Recovered	5.13230	5.08730	5.08730	
(Over) Under recovery per dk	($0.20210)	($0.40800)	($0.15710)	
dk billed	18,169	31,564	648	50,381
(Over) Under recovery	($3,672)	($12,878)	($102)	($16,652)
March 2013				
Cost of Gas - Actual	$5.27000	$4.93020	$5.27000	
Cost of Gas - Recovered	5.06910	5.13230	5.13230	
(Over) Under recovery per dk	$0.20090	($0.20210)	$0.13770	
dk billed	15,247	19,606	5,836	40,689
(Over) Under recovery	$3,063	($3,962)	$804	($96)
April 2013				
Cost of Gas - Actual	$5.16230	$5.27000	$5.16230	
Cost of Gas - Recovered	5.67900	5.06910	5.06910	
(Over) Under recovery per dk	($0.51670)	$0.20090	$0.09320	
dk billed	12,706	23,209	1,508	37,423
(Over) Under recovery	($6,565)	$4,663	$141	($1,762)

1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.
4/ Includes annual unbilled adjustment.

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	1/	2/	3/	Total
May 2012				
Cost of Gas - Actual	$1.10280	$1.95470	$1.10280	
Cost of Gas - Recovered	1.80010	2.01220	2.01220	
(Over) Under recovery per dk	($0.69730)	($0.05750)	($0.90940)	
dk billed	7,244	10,052	6,374	23,670
(Over) Under recovery	($5,051)	($578)	($5,797)	($11,426)
June 2012				
Cost of Gas - Actual	$1.52330	$1.10280	$1.52330	
Cost of Gas - Recovered	2.25540	1.80010	1.80010	
(Over) Under recovery per dk	($0.73210)	($0.69730)	($0.27680)	
dk billed	4,624	377	8,696	13,697
(Over) Under recovery	($3,385)	($263)	($2,407)	($6,055)
July 2012				
Cost of Gas - Actual	$0.89460	$1.52330	$0.89460	
Cost of Gas - Recovered	2.05310	2.25540	2.25540	
(Over) Under recovery per dk	($1.15850)	($0.73210)	($1.36080)	
dk billed	4,628	506	7,975	13,109
(Over) Under recovery	($5,361)	($370)	($10,852)	($16,584)
August 2012				
Cost of Gas - Actual	$2.06570	$0.89460	$2.06570	
Cost of Gas - Recovered	2.45780	2.05310	2.05310	
(Over) Under recovery per dk	($0.39210)	($1.15850)	$0.01260	
dk billed	4,298	679	9,218	14,195
(Over) Under recovery	($1,685)	($787) 4/	$116	($2,356)
September 2012				
Cost of Gas - Actual	$2.27750	$2.06570	$2.27750	
Cost of Gas - Recovered	2.40720	2.45780	2.45780	
(Over) Under recovery per dk	($0.12970)	($0.39210)	($0.18030)	
dk billed	6,519	6,704	7,862	21,085
(Over) Under recovery	($846)	($17,978)	($1,418)	($20,241)
October 2012				
Cost of Gas - Actual	$2.54430	$2.27750	$2.54430	
Cost of Gas - Recovered	2.43750	2.40720	2.40720	
(Over) Under recovery per dk	$0.10680	($0.12970)	$0.13710	
dk billed	15,710	16,026	5,293	37,029
(Over) Under recovery	$1,678	($2,079)	$726	$325

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	1/	2/	3/	Total
November 2012				
Cost of Gas - Actual	$3.75710	$2.54430	$3.75710	
Cost of Gas - Recovered	3.72050	2.43750	2.43750	
(Over) Under recovery per dk	$0.03660	$0.10680	$1.31960	
dk billed	18,102	20,619	3,075	41,796
(Over) Under recovery	$663	$2,202	$4,058	$6,923
December 2012				
Cost of Gas - Actual	$3.78990	$3.75710	$3.78990	
Cost of Gas - Recovered	3.99170	3.72050	3.72050	
(Over) Under recovery per dk	($0.20180)	$0.03660	$0.06940	
dk billed	22,526	20,491	6,564	49,581
(Over) Under recovery	($4,546)	$750	$456	($3,340)
January 2013				
Cost of Gas - Actual	$3.61940	$3.78990	$3.61940	
Cost of Gas - Recovered	3.56120	3.99170	3.99170	
(Over) Under recovery per dk	$0.05820	($0.20180)	($0.37230)	
dk billed	22,641	38,891	(5,067)	56,465
(Over) Under recovery	$1,318	($7,848)	$1,887	($4,644)
February 2013				
Cost of Gas - Actual	$3.57120	$3.61940	$3.57120	
Cost of Gas - Recovered	3.60620	3.56120	3.56120	
(Over) Under recovery per dk	($0.03500)	$0.05820	$0.01000	
dk billed	16,552	24,688	7,712	48,952
(Over) Under recovery	($579)	$1,437	$77	$935
March 2013				
Cost of Gas - Actual	$3.87840	$3.57120	$3.87840	
Cost of Gas - Recovered	3.54300	3.60620	3.60620	
(Over) Under recovery per dk	$0.33540	($0.03500)	$0.27220	
dk billed	21,615	21,980	3,765	47,360
(Over) Under recovery	$7,250	($769)	$1,025	$7,505
April 2013				
Cost of Gas - Actual	$4.27760	$3.87840	$4.27760	
Cost of Gas - Recovered	4.15290	3.54300	3.54300	
(Over) Under recovery per dk	$0.12470	$0.33540	$0.73460	
dk billed	22,635	27,368	8,705	58,708
(Over) Under recovery	$2,823	$9,179	$6,395	$18,396

1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.
4/ Includes annual unbilled adjustment.