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

705 West Fir Ave.
Mailing Address:
P.O. Box 176
Fergus Falls, MN 56538-0176
1-877-267-4764

May 1, 2013

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

Re: Cost of Gas Adjustment (COG)
May 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 (86th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (86th Revised Sheet No. 8), showing the May 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.0991 per mcf for residential and firm general service customers and an increase of $0.1022 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for May 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.1020 since the last COG filing. There has been a decrease in pipeline charges of $0.0029 per mcf due to a change in the three year normalized mcf sales volumes.

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

Attachment D shows the calculation of the balancing account since April 30, 2012.

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.

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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
86th Revised Sheet No. 1.1
Canceling 85th 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	$6.7918	$8.0658
			Over 10 MCF	1.0540		7.8458
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$6.7918	$8.9658
			Over 10 MCF	1.9540		8.7458
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.9636	$5.1027
			Next 2,600 MCF	0.8931		4.8567
			Over 3,000 MCF	0.7411		4.7047
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$3.9636	$6.0027
			Next 2,600 MCF	1.7931		5.7567
			Over 3,000 MCF	1.6411		5.6047
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.9636	$5.2027
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 1, 2013

Effective Date: Service rendered on and after May 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
86th Revised Sheet No. 8
Canceling 85th 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.	1.4751	(0.9810)	1.0137	1.5078	(0.9662)	(0.2915)	(1.2577)
Current Adj.	(0.0029)	0.1020	0.0000	0.0991	0.1022	0.0000	0.1022
Total Adj.	1.4722	(0.8790)	1.0137	1.6069	(0.8640)	(0.2915)	(1.1555)
Total Rate:	$1.5380	$4.2401	$1.0137	$6.7918	$4.2551	($0.2915)	$3.9636

Date Filed: May 1, 2013

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MAY 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/	4.2401		5,946,834	4.2401
Gas Cost Reconciliation Adjustment						1.0137
Total Current Firm Gas Cost					$8,082,853	6.7918
Base Cost of Gas						5.1849
Accumulated Adjustment						$1.6069

Interruptible	
Estimated Weighted Average Commodity Cost	$4.2401
Gas Cost Reconciliation Adjustment	(0.2915)
LMS Demand 2/	0.0150
Total Current Interruptible Gas Cost	3.9636
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.1555)

1/ Three year normalized average Dk 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
MAY 2013

Rates Effective May 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:	4.2401	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

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

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

RATE SCHEDULE TF

	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
		TF12		
RESERVATION RATES	TF12 Base	Variable	TF5	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.

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.

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
May 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 May monthly price for the NNG-Ventura Index is expected to increase 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.

The colder than normal weather experienced in March continued through April over a widespread portion of the US, extending the demand of natural gas for space heating. This colder weather prolonged the withdrawal from national storage, reducing the inventory to levels that are below the five year average. These two factors were likely the main reasons for the increase in the commodity price of natural gas. Energy Information Administration (EIA) reported storage levels nationwide as of April 19, 2013 were 5.1 percent below the five-year average and 31.8 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 18.

Independent Statistics & Analysis
U.S. Energy Information Administration

April 2013

Short-Term Energy and Summer Fuels Outlook (STEO)

Highlights

- During the April-through-September summer driving season this year, regular gasoline retail prices are forecast to average $3.63 per gallon. The projected monthly average regular retail gasoline price falls from $3.69 per gallon in May to $3.57 per gallon in September. EIA expects regular gasoline retail prices to average $3.56 per gallon in 2013 and $3.39 per gallon in 2014, compared with $3.63 per gallon in 2012. The July 2013 New York harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged $2.97 per gallon for the five trading days ending April 4, 2013. Based on the market value of futures and options contracts, there is a 12 percent probability that its price at expiration will exceed $3.35 per gallon, consistent with a monthly average regular-grade gasoline retail price exceeding $4.00 per gallon in July 2013. (see EIA Summer Fuels Outlook slideshow)

- EIA expects that the Brent crude oil spot price, which averaged $112 per barrel in 2012 and rose to $119 per barrel in early February 2013, will average $108 per barrel in 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, is forecast to average $14 per barrel in 2013 and $9 per barrel in 2014, as planned new pipeline capacity lowers the cost of moving mid-continent crude oil to the Gulf Coast refining centers.

- Natural gas working inventories ended March 2013 at an estimated 1.69 trillion cubic feet (Tcf), about 0.79 Tcf below the level at the same time a year ago and 0.41 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 $3.52 per MMBtu in 2013 and $3.60 per MMBtu in 2014.

- With actual and forecast natural gas prices in the first 9 months of 2013 well above those during the comparable 2012 period, electricity generators using natural gas are expected to lose some of the market share gained from coal generation in 2012.

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 1.3 million barrels per day (bbl/d). Projected world liquid fuels consumption grows by an annual average of 1.0 million bbl/d in 2013 and 1.3 million bbl/d in 2014, lower by 140,000 bbl/d in 2013 and 200,000 bbl/d in 2014 compared with last month's STEO. Countries outside the Organization for Economic Cooperation and Development (OECD) drive expected consumption growth. Projected world supply increases by 0.6 million bbl/d in 2013 and 2.1 million bbl/d in 2014, reflecting a 100,000 bbl/d reduction in 2013 and a 40,000 bbl/d increase in 2014 from last month's STEO. Most of the supply growth comes from North America and other countries that are not members of the Organization of the Petroleum Exporting Countries (OPEC).

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 in 2013 and 2014 due to a moderate recovery in global economic growth. World consumption reaches 90.0 million bbl/d in 2013 and 91.3 million bbl/d in 2014.

Non-OECD Asia is the leading regional 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 signal slower growth than in prior years. EIA estimates that liquid fuels consumption in China increased by 380,000 bbl/d in 2012. Projected consumption increases by 450,000 bbl/d in 2013 and by 510,000 bbl/d in 2014. This compares with average annual growth of 540,000 bbl/d from 2004 through 2010.

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 because of declining consumption in Europe.

Non-OPEC Supply. EIA projects non-OPEC liquids production will increase by 1.1 million bbl/d in 2013 and by another 1.6 million bbl/d in 2014. North America accounts for almost all 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.

Unplanned production outages in non-OPEC countries averaged 0.9 million bbl/d in March 2013. Syria, Yemen, and South Sudan accounted for more than three-quarters of the total unplanned non-OPEC supply disruption.

South Sudan has restarted production at oil fields in Unity State. The resumption comes almost a month after Sudan and South Sudan agreed to withdraw military forces from a designated border zone and establish a legislative body to oversee the disputed Abyei region. Barring political issues or technical difficulties that may delay the pace of the ramp up, EIA expects

combined oil output in both countries will average 190,000 bbl/d in 2013 and 420,000 bbl/d in 2014.

OPEC Supply. OPEC member countries, particularly Saudi Arabia, cut crude oil production heavily in the fourth quarter of 2012. EIA estimates that Saudi Arabia cut crude oil production from an average of 9.9 million bbl/d during the third quarter of 2012 to 9.0 million bbl/d in the first quarter of 2013.

Projected OPEC supply falls by 0.4 million bbl/d in 2013 and then rises by 0.5 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 has lowered its expectations for oil production in Nigeria this year. Oil theft and pipeline vandalism escalated in the last quarter of 2012 and continue to curb production this year. Crude oil output in Nigeria averaged 2.0 million bbl/d in the first quarter of 2013, which is 120,000 bbl/d lower than in the same time period last year, despite new production coming on line.

EIA estimates that OPEC surplus capacity, which is concentrated in Saudi Arabia, continued at about 2.8 million bbl/d in the first quarter of 2013, an increase of 0.7 million bbl/d compared with the year-ago level but still 0.2 million bbl/d lower than the previous three-year average. Projected OPEC surplus capacity averages 2.9 million bbl/d in 2013 and 3.4 million bbl/d in 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 fall slightly and end 2013 at 2.60 billion barrels (56.2 days of supply). Inventories increase to 2.66 billion barrels (57.8 days of supply) by the end of 2014.

Crude Oil Prices. EIA projects the Brent crude oil spot price will fall from an average of $112 per barrel in 2012 to annual averages of $108 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 WTI crude oil price will average $94 per barrel in 2013 and $92 per barrel in 2014. By 2014, several pipeline projects from the mid-continent 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 drop in the price discount of WTI to Brent.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures contracts for July 2013 delivery traded during the five-day period ending April 4, 2013, averaged $96.35 per barrel, down about $8 per barrel from a year ago. Implied volatility averaged 18 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in July 2013 at $82 per barrel and $113 per

barrel, respectively. Last year at this time, WTI for July 2012 delivery averaged $104 per barrel and implied volatility averaged 26 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $83 per barrel and $131 per barrel.

U.S. Crude Oil and Liquid Fuels

Growing domestic crude oil production has contributed to lower crude oil imports (see *This Week in Petroleum*, March 20, 2013). At 8.5 million bbl/d, U.S. crude oil gross imports in 2012 were the lowest for any year since 1997. EIA expects that U.S. crude oil production will exceed U.S. crude oil gross imports as early as the end of 2013, the first time this will have occurred since February 1995.

U.S. Liquid Fuels Consumption. Total liquid fuels consumption fell from an annual average of 20.8 million bbl/d in 2005 to 18.6 million bbl/d in 2012. Total liquid fuels consumption grows only slightly in this forecast, increasing by 60,000 bbl/d (0.3 percent) in 2013 and by 30,000 bbl/d (0.2 percent) in 2014. Distillate fuel oil consumption, which fell by 160,000 bbl/d in 2012, increases at an average annual rate of 50,000 bbl/d in 2013 and 20,000 bbl/d in 2014. Distillate fuel consumption growth is driven by increases in industrial output and winter weather in the Northeast, which is forecast to be colder in comparison with the mild winter months during 2012. The other source of liquid fuels consumption growth is liquefied petroleum gases (LPG); this forecast reflects continued growth in petrochemical activity and assumptions of normal weather compared to the mild winter of the previous year. LPG consumption increases by 50,000 bbl/d in 2013 and a further 10,000 bbl/d in 2014. Motor gasoline and jet fuel consumption remain relatively flat in 2013 and 2014, as increasing travel is offset by fuel economy improvements.

U.S. Liquid Fuels Supply. EIA expects U.S. crude oil production to continue to grow rapidly over the next two years, increasing from an average 6.5 million bbl/d in 2012 to 7.3 million bbl/d in 2013 and 7.9 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.

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 6.0 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 32 percent in 2014, which would be the lowest level since 1985.

Summer Transportation Fuels Outlook

U.S. Gasoline and Diesel Fuel Prices. EIA expects that regular-grade gasoline retail prices, which averaged $3.69 per gallon last summer, will average $3.63 per gallon during the current summer (April through September) driving season. The projected monthly average regular retail gasoline price falls from $3.69 per gallon in May to $3.57 per gallon in September. Diesel fuel prices, which averaged $3.95 per gallon last summer, are projected to fall slightly to an average of $3.94 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 25 cents per gallon or more.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in both crude oil prices and wholesale margins. The retail price projections reflect falling prices for the cost of crude oil, best represented by the Brent crude oil price, which averages about $108 per barrel ($2.56 per gallon) this summer compared with the $109-per-barrel ($2.60-per-gallon) average of last summer. Crude oil prices that differ from EIA's forecast would be reflected in the price of motor fuels. Each dollar per barrel of sustained change in crude oil prices relative to the forecast translates into approximately a 2.4-cent-per-gallon change in product prices, absent the consideration of factors specific to the gasoline and diesel fuel markets.

EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the Brent crude oil price) will average 37 cents per gallon this summer, about 3 cents per gallon lower than last summer but 4 cents per gallon higher than the previous five-summer average. Forecast wholesale diesel fuel margins are 51 cents per gallon, 4 cents per gallon above last summer's level and 9 cents per gallon higher than the previous five-summer average.

As in the case of 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 July 2013 delivery traded over the five-day period ending April 4 averaged $2.97 per gallon. The probability that the RBOB futures price will exceed $3.35 per gallon (consistent with a U.S. average regular gasoline retail price above $4.00 per gallon) in July 2013 is about 12 percent.

Motor Gasoline. During this summer season (April through September), projected motor gasoline consumption declines by 20,000 bbl/d (0.2 percent) from last summer's average of 8.9 million bbl/d. Year-over-year increases in highway travel, projected to be 0.3 percent, are more than offset by an increase in fleet-wide fuel efficiency. Finished motor gasoline is supplied by four sources: domestic refinery output, fuel ethanol blending, net imports of gasoline and gasoline blending components, and primary inventories. EIA expects that domestic refinery production, including gasoline blendstock output, will increase by 20,000 bbl/d from last summer. Fuel ethanol blending into gasoline is projected to increase by 5,000 bbl/d from last

summer's level to 865,000 bbl/d, which is about 9.7 percent of total gasoline consumption. Projected total gasoline net imports (including blending components) average 260,000 bbl/d, down slightly from that of last summer.

At the onset of the summer driving season (April 1), total gasoline stocks, at 220 million barrels, are 1 million barrels above the level of a year ago and the same as the previous five-year average for beginning-of-season stocks. Stock withdrawals have not been a significant motor gasoline supply source for the summer season in recent years, having averaged only 65,000 bbl/d during the previous five summer seasons. This summer, the projected average total gasoline stock draw is 56,000 bbl/d, compared with a 98,000-bbl/d draw last summer. Moreover, the seasonal pattern is different from that of last summer, which saw a steady draw on inventories throughout the season. This summer, total gasoline inventories are projected to stabilize mid-season, resulting in end-of-season inventories of 209.5 million barrels, 8.8 million barrels above last year's level and 1.7 million barrels above the previous five-year average.

Diesel Fuel. Projected consumption of distillate fuel, which includes diesel fuel and heating oil, averages 3.7 million bbl/d this summer, up 20,000 bbl/d (0.6 percent) from last summer. That growth is driven by increasing manufacturing output and foreign trade.

Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. EIA expects refinery output of distillate fuel will average 4.6 million bbl/d this summer, up 70,000 bbl/d from last summer. Biodiesel has been a small but growing part of the distillate pool. Biodiesel blending averaged 68,000 bbl/d last summer and is forecast to average about 82,000 bbl/d this summer. Projected distillate fuel net exports average 830,000 bbl/d this summer, down from the record 940,000 bbl/d last summer.

Distillate inventories are projected to start the summer at 112.4 million barrels, down substantially from the 133.8 million barrels recorded at the start of last summer and the previous five-year average of 136.6 million barrels. Distillate inventories typically build during the summer season in preparation for the heating season. This summer, the build is forecast to average about 110,000 bbl/d compared to the anomalous 35,000 bbl/d draw recorded last summer, but similar to the previous five-year average summer build of 71,000 bbl/d. End-of-summer stocks are 133.1 million barrels, up slightly from the 127.4 million barrels recorded at the end of last summer, but well below the five-year end-of-summer average of 149.6 million barrels.

Natural Gas

Following years of strong growth, pipeline capacity additions slowed in 2012. While additions were limited, more than half were located in the Northeast, where capacity constraints often create bottlenecks and price imbalances. Of the 367 miles of new pipeline added in 2012, 245 miles were in the Northeast. The two largest projects in 2012, the Appalachian Gateway Project

and the Sunrise Project, both move natural gas from production areas in the Marcellus Shale to northeastern consuming regions.

Natural gas production in Pennsylvania averaged 6.1 billion cubic feet per day (Bcf/d) in 2012, up from 3.6 Bcf/d in 2011, according to Pennsylvania state data released in February 2013. The increase occurred despite a drop in the number of new natural gas wells started during the year. The increase was largely due to a backlog of wells that had been drilled before 2012 but not brought on line because of infrastructure constraints. As infrastructure became available, these wells were brought on line.

March 2013 was about 17 percent colder than forecast in last month's STEO, which contributed to an increase in the average 2013 total natural gas consumption forecast of 0.3 Bcf/d. The colder-than-expected temperatures also led to larger-than-expected storage withdrawals. Working gas inventory net withdrawal of 94 Bcf for the week ending March 29, 2013, was the largest net withdrawal for this time of year since the start of EIA's weekly storage data collection in 2002. Estimated end-of-March working gas inventories are 273 Bcf below the level forecast in last month's STEO.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 70.3 Bcf/d and 70.1 Bcf/d in 2013 and 2014, respectively. Forecasts for closer-to-average winter temperatures in 2013 and 2014 (compared with the record-warm temperatures in 2012) will lead to increases in natural gas used for residential and commercial space heating. The projected increase in natural gas prices contributes to a decline in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 22.9 Bcf/d in 2013 and 22.8 Bcf/d in 2014.

U.S. Natural Gas Production and Imports. Projected natural gas marketed production increases from 69.1 Bcf/d in 2012 to 69.3 Bcf/d in 2013, and 69.4 Bcf/d in 2014. Onshore production increases slightly 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 March 29, 2013, working gas stocks totaled 1,687 Bcf, which is 779 Bcf less than at the same time in 2012, and 37 Bcf below the five-year (2008-12) average, 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 3,793 Bcf, about 137 Bcf below the level at the same time last year.

U.S. Natural Gas Prices. Natural gas spot prices averaged $3.81 per MMBtu at the Henry Hub in March 2013, up nearly 48 cents from the $3.33 per MMBtu average seen the previous three months. EIA expects the Henry Hub price will increase from an average of $2.75 per million Btu in 2012 to $3.52 per MMBtu in 2013 and $3.60 per MMBtu in 2014.

Natural gas futures prices for July 2013 delivery (for the five-day period ending April 4, 2013) averaged $4.07 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for June 2013 contracts at $3.16 per MMBtu and $5.23 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for July 2012 averaged $2.40 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were $1.56 per MMBtu and $3.69 per MMBtu.

Coal

Based on estimates for the first quarter of 2013, coal production has continued to decline. Total production is down 9.9 million short tons (MMst) from the previous quarter and 22.7 MMst from the same period in 2012. The largest year-over-year decline was in the Western region, where production fell by 17.3 MMst (12 percent). Smaller declines were experienced in the Interior (2 percent) and Appalachian (6 percent) producing regions.

U.S. Coal Consumption. EIA projects total coal consumption will increase from 889 MMst in 2012 to 948 MMst in 2013 and 957 MMst in 2014. EIA expects consumption in the electric power sector to increase over the forecast period as a result of higher electricity demand and higher natural gas prices.

U.S. Coal Supply. Coal production is expected to increase by 0.5 percent in 2013 as primary and secondary inventory draws, combined with an increase in coal imports, meet most of the growth in consumption. Coal production is forecast to grow by 2.0 percent in 2014.

Coal exports totaled 126 MMst in 2012, surpassing the previous peak of 113 MMst exported in 1981. EIA expects the United States will export 107 MMst in 2013 and 109 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 an 11-year period through 2011, when the delivered coal price averaged $2.39 per MMBtu (a 5-percent increase from 2010). The delivered coal price averaged $2.40 per MMBtu in 2012, and EIA forecasts average delivered coal prices of $2.41 per MMBtu in 2013 and $2.45 per MMBtu in 2014.

Electricity

Electricity generated from nuclear power during 2012 averaged 2,102 gigawatthours per day, which was the lowest level since 2003. In addition to normal refueling outages at various

nuclear plants, there were a handful of extended outages last year. Unit 3 at the Turkey Point plant in Florida was out of service last year between late February and October. The Fort Calhoun reactor in Nebraska has been off line for the past two years but may be restarted later this summer. Southern California's San Onofre Units 2 and 3 were off line for most of 2012 and as of yet do not have a planned restart schedule. Two nuclear reactors, the Kewaunee plant in Wisconsin and Crystal River Unit 3 in Florida, are scheduled to be permanently retired.

U.S. Electricity Consumption. EIA projects U.S. residential sales of electricity during the upcoming summer months (June, July, and August) will average 5 percent below sales during the summer of 2012. Forecast U.S. cooling degree days during June, July, and August 2013 are about 11 percent lower than last summer and about 5 percent lower than the prior 10-year average. For the entire year, U.S. residential electricity sales increase by 0.5 percent during 2013 and by 0.8 percent in 2014. U.S. retail electricity sales to the commercial sector increase by 1.0 percent in 2013 and by 0.8 percent in 2014. Industrial electricity sales increase by 1.4 percent and 1.2 percent in 2013 and 2014, respectively.

U.S. Electricity Generation. EIA expects total U.S. generation of electricity will grow by 1.0 percent in 2013 and by 0.9 percent in 2014. EIA expects generators to increase their use of existing coal capacity, leading to a 7.8-percent increase in U.S. coal generation during 2013. This increase, which results because of the increasing cost of natural gas relative to coal, raises the share of total generation fueled by coal from 37.4 percent 2012 to 39.9 percent in 2013, but 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 28.0 percent this year, compared with a share of 24.7 percent in 2011.

U.S. Electricity Retail Prices. Rising costs of infrastructure upgrades continue to drive increases in residential electricity rates, although lower fuel prices in recent years have kept growth in retail rates relatively modest. After an increase of 1.4 percent during 2012, EIA expects U.S. retail residential electricity prices will grow by 2.8 percent in 2013 and by 2.3 percent in 2014.

Renewables and Carbon Dioxide Emissions

U.S. Electricity Generation from Renewables. EIA projects electric power sector renewable energy consumption to increase by 3.4 percent in 2013. While hydropower declines by 4.0 percent, nonhydropower renewables grow by an average of 13.3 percent in 2013. In 2014, the growth in electric power sector renewables is projected to continue at a rate of 5.9 percent, as a 3.0-percent increase in hydropower is combined with a 9.3-percent increase in nonhydropower renewables.

EIA currently estimates that wind capacity will increase by 6 percent in 2013 and by 14 percent in 2014. However, electricity generation from wind is projected to increase by 16 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 9 percent in 2014.

EIA expects a continuation of 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 to 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. Fuel ethanol production averaged 865,000 bbl/d (13.3 billion gallons) in 2012, its lowest average since 2009. EIA expects ethanol production to remain near current levels of about 800,000 bbl/d through mid-2013 before recovering to pre-drought production levels, averaging 850,000 bbl/d for the year. Ethanol production is expected to rise in 2014, averaging 920,000 bbl/d. Despite the forecast increase in ethanol production, EIA expects the drawdown of banked renewable identification numbers (RINs), as the average ethanol share of the gasoline pool increases only modestly between 2012 and 2014. Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons) in 2012 is forecast to average about 80,000 bbl/d (1.2 billion gallons) in both 2013 and 2014. This forecast assumes that the 2014 renewable fuel volume obligations for biodiesel and advanced biofuel are identical to those in 2013.

The Renewable Fuels Standard requires refiners and importers of gasoline and diesel fuel to purchase RINs equivalent to 9.63 percent of the fuel (without biofuel) they sell domestically. A RIN is created when a gallon of biofuel is produced or imported. The RIN is assigned to the biofuel and is sold with it. The RIN is separated from the biofuel when a company blends the biofuel into gasoline blendstock, finished gasoline, or diesel fuel. Once a RIN is separated it can be sold by the blender to the refiner or importer.

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 close to $0.70 per gallon over the last 2 weeks. The ethanol RIN price increase was motivated by the projected shortfall of RINs needed under the RFS because of the E10 gasoline ethanol blend wall. 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.

Refiners and importers now pay a higher price for ethanol RINs than they did last year. The higher RIN costs may be passed on to wholesale gasoline and diesel fuel prices. 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 nearly 4 percent in 2012, and projects increases of 2.4 percent in 2013 and 0.3 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

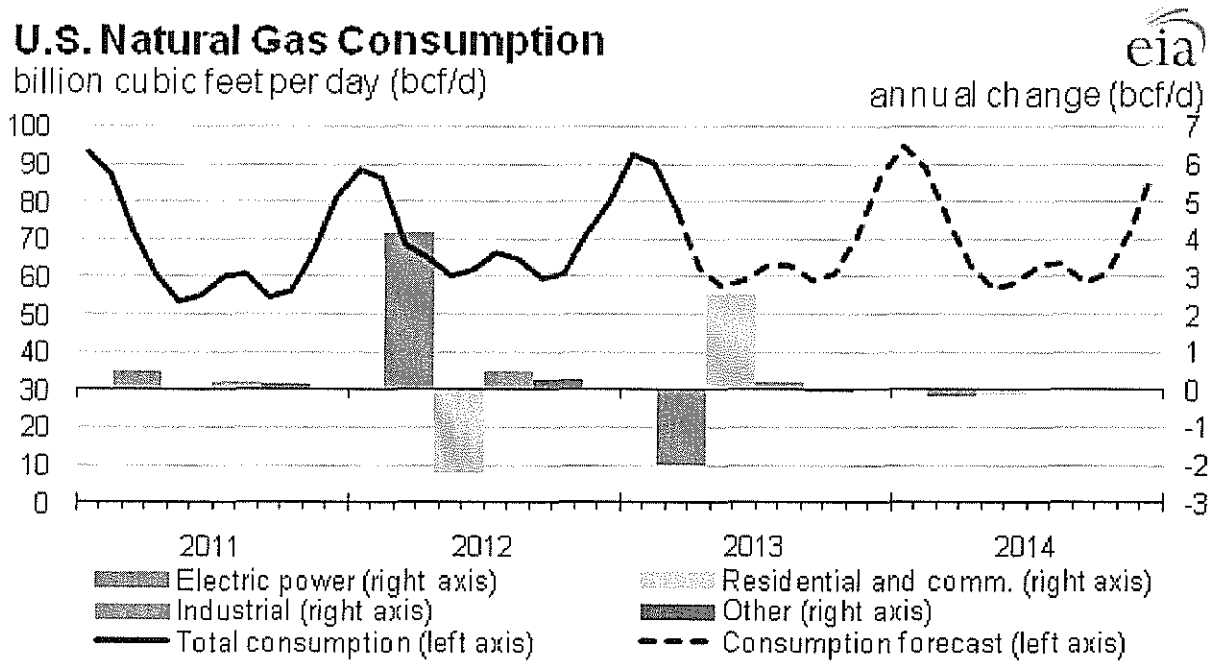
EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. The GI model used in this STEO assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) will soon be replaced by 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 indicators continue to show signs of moderate economic growth. The U.S. Census Bureau reported that new orders for manufactured durable goods rose 5.7 percent from January to February, reversing a 3.8-percent fall from December to January. Excluding defense, new durable goods orders increased 4.5 percent, but excluding transportation, new orders fell 0.5 percent. The Federal Reserve Banks of Dallas, New York, and Richmond all reported modestly improving conditions for manufacturing in their respective districts in March. However, the Federal Reserve Bank of Kansas City reported that manufacturing activity fell in their district. According to the Department of Labor, payroll employment increased by 88,000 in March, a sharp reduction in employment growth compared with January and February's employment growth of 148,000 and 268,000 jobs, respectively. However, the March unemployment rate was down slightly from its February level as the labor force participation rate declined.

U.S. Production. The STEO assumes 1.7 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 percent in its final quarter. A combination of higher energy prices and increased taxes suppress real disposable income growth to 1.0 percent in 2013, but the growth rate rises to an average of 3.5 percent in 2014. Total industrial production grows at a faster rate than real GDP in 2013 and 2014, at 3.0 percent each year. Industrial production growth in the manufacturing sector is 3.4 percent in 2013, but accelerates to 3.6 percent in 2014.

U.S. Income and Expenditures. Private fixed investment growth averages 5.3 and 8.9 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 slightly faster than real GDP in 2013, at 2.0 percent, but slow below the rate of real GDP growth in 2014, at 2.3 percent. Exports nearly double from 2.8 to 5.2 percent, over the same two years. Government expenditures fall 2.2 percent in 2013 and 0.3 percent in 2014.

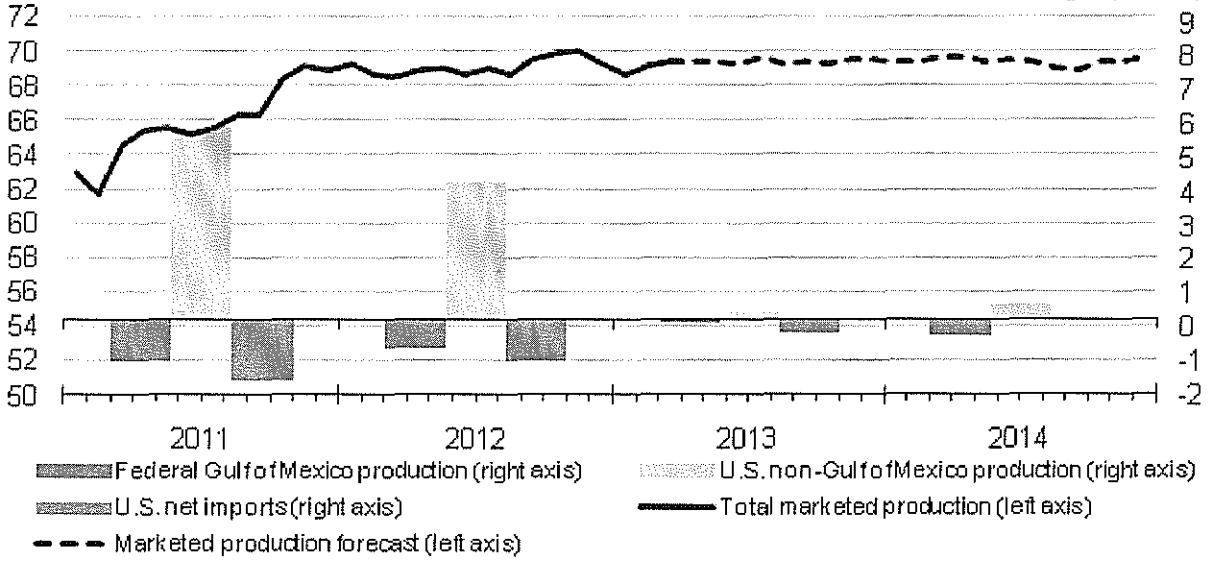
U.S. Employment, Housing, and Prices. The unemployment rate in the forecast gradually falls from 7.6 percent in March 2013 to 7.2 percent in December 2014. This is accompanied by nonfarm employment growth averaging 1.4 percent in 2013 and 1.6 percent in 2014. Consistent with an improving housing sector, housing starts grow an average of 22 percent and 31 percent over 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.



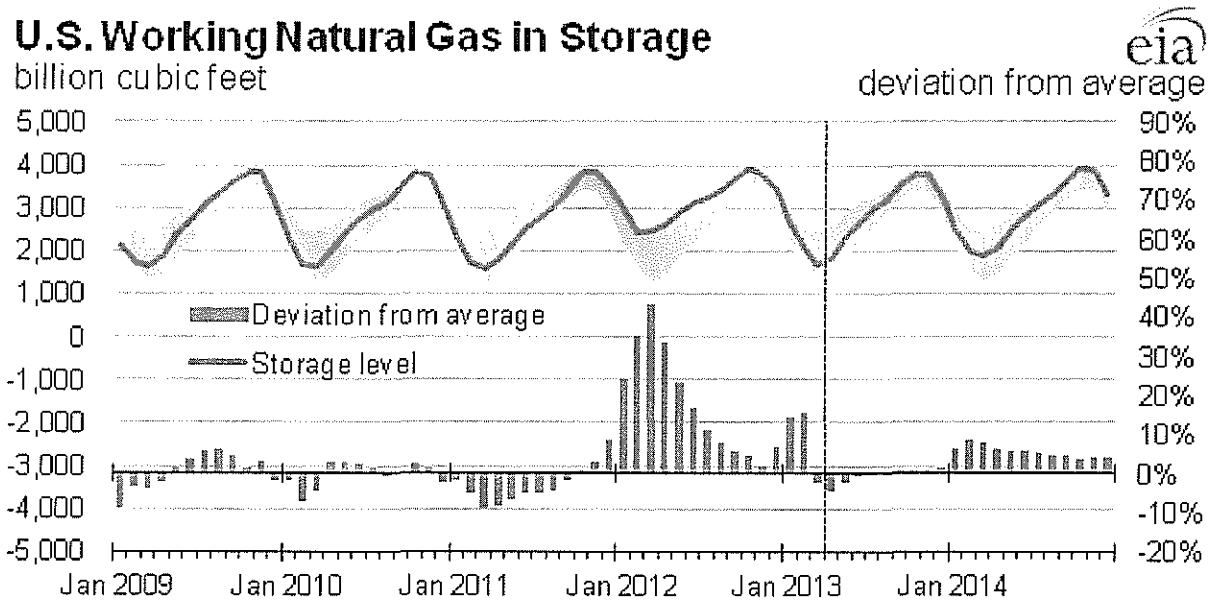
Source: Short-Term Energy Outlook, April 2013

U.S. Natural Gas Production and Imports

billion cubic feet per day (bcf/d) annual change (bcf/d)



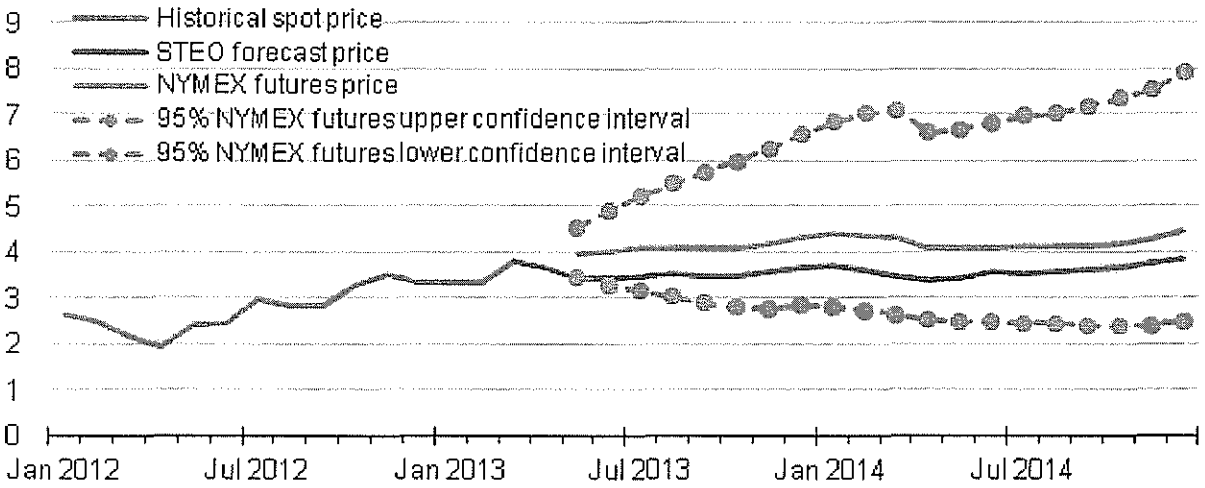
Source: Short-Term Energy Outlook, April 2013



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

Henry Hub Natural Gas Price

dollars per million btu

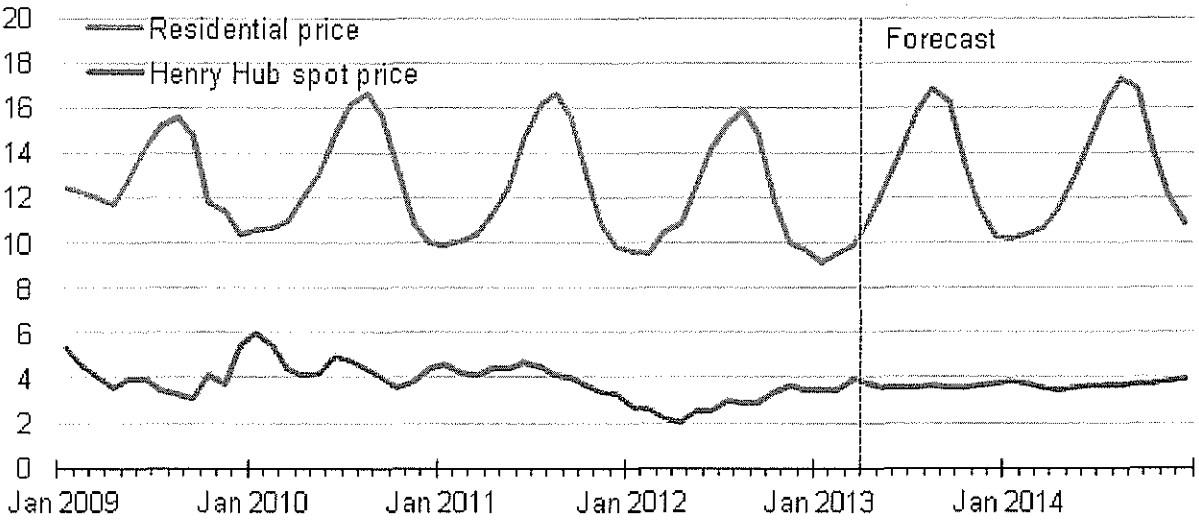


Note: Confidence interval derived from options market information for the 5 trading days ending April 4, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, April 2013

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, April 2013

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount		Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2012										**$311,764**
May	$30,099	$0	$2,016	$32,115	13,138	$0.5102	$6,702		$25,413	337,177
June	52,819	0	2,192	55,011	6,558	1.0137	4,625	2/	50,386	387,563
July	57,568	0	2,542	60,110	5,776	1.0137	5,855		54,255	441,818
August	58,888	0	2,918	61,806	5,143	1.0137	5,213		56,593	498,411
September	26,138	0	3,308	29,446	6,241	1.0137	6,327		23,119	521,530
October	36,902	0	3,454	40,356	10,185	1.0137	10,325		30,031	551,561
November	8,143	0	3,651	11,794	20,404	1.0137	20,684		(8,890)	542,671
December	7	0	3,572	3,579	31,222	1.0137	31,650		(28,071)	514,600
January 2013	(22,865)	0	3,361	(19,504)	49,729	1.0137	50,410		(69,914)	444,686
February	(16,652)	0	2,861	(13,791)	50,381	1.0137	51,071		(64,862)	379,824
March	(96)	0	2,401	2,305	40,689	1.0137	41,246		(38,941)	340,883
Balance @ March 31, 2013										**$340,883**

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	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2012									**($72,396)**
May	($11,426)	$0	($557)	($11,983)	23,670	($0.0178)	($422)	($11,561)	(83,957)
June	(6,055)	0	(637)	(6,692)	13,697	(0.2915)	(1,509) 2/	(5,183)	(89,140)
July	(16,584)	0	(671)	(17,255)	13,108	(0.2915)	(3,821)	(13,434)	(102,574)
August	(2,356)	0	(765)	(3,121)	14,195	(0.2915)	(4,138)	1,017	(101,557)
September	(20,241)	0	(754)	(20,995)	21,085	(0.2915)	(6,146)	(14,849)	(116,406)
October	325	0	(859)	(534)	37,029	(0.2915)	(10,794)	10,260	(106,146)
November	6,923	0	(784)	6,139	41,796	(0.2915)	(12,184)	18,323	(87,823)
December	(3,340)	0	(652)	(3,992)	49,581	(0.2915)	(14,452)	10,460	(77,363)
January 2013	(4,644)	0	(579)	(5,223)	56,465	(0.2915)	(16,460)	11,237	(66,126)
February	934	0	(501)	433	48,952	(0.2915)	(14,270)	14,703	(51,423)
March	7,505	0	(399)	7,107	47,360	(0.2915)	(13,805)	20,912	(30,511)
Balance @ March 31, 2013									**($30,511)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 9,073.4 dk @ ($0.0178) and 4,623.6 dk @ ($0.2915).