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

705 West Fir Ave.
Mailing Address:
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January 2, 2014

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

Re: Cost of Gas Adjustment (COG)
January 2014

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 (94th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (94th Revised Sheet No. 8), showing the January 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.9632 per mcf for residential and firm general service customers and an increase of $0.9698 per mcf for large and small interruptible customers.

Attachment B shows the calculations supporting the gas costs for January 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.9701 per mcf for residential and firm general service customers and has increased $0.9698 per mcf for large and small interruptible customers since the last COG filing. There has been a decrease in pipeline charges of $0.0069 per mcf. The net effect of these changes is an increase of $0.9632 per mcf for residential and firm general service customers.

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, 2013.

Great Plains also submits herewith its check for $600.00 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment will cover the filing fee associated with the monthly COG filings.

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
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
94th Revised Sheet No. 1.1
Canceling 93rd 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	$7.3367	$8.6107
			Over 10 MCF	1.0540		8.3907
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$4.8990	$6.0381
			Next 2,600 MCF	0.8931		5.7921
			Over 3,000 MCF	0.7411		5.6401
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$4.8990	$6.1381
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: January 2, 2014

Effective Date: Service rendered on and after January 1, 2014

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
94th Revised Sheet No. 8
Canceling 93rd 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.	1.4595	(1.2323)	0.9614	1.1886	(1.2173)	0.0274	(1.1899)
Current Adj.	(0.0069)	0.9701	0.0000	0.9632	0.9698	0.0000	0.9698
Total Adj.	1.4526	(0.2622)	0.9614	2.1518	(0.2475)	0.0274	(0.2201)
Total Rate	$1.5184	$4.8569	$0.9614	$7.3367	$4.8716	$0.0274	$4.8990

Date Filed: January 2, 2014

Effective Date: Service rendered on and after January 1, 2014

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JANUARY 2014

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A - Zone 1-1	8,000		$3.3978	12	$326,189	$0.2326
FT-A - Zone 1-1	5,000		3.6918	5	92,295	0.0658
FT-A Seasonal	2,000		3.6918	5	36,918	0.0263
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/						0.0147
Total Demand Charges					$2,109,030	1.5184
Estimated Weighted Average Commodity Cost	1,402,522	1/	4.8569		6,811,909	4.8569
Gas Cost Reconciliation Adjustment						0.9614
Total Current Firm Gas Cost					$8,920,939	7.3367
Base Cost of Gas						5.1849
Accumulated Adjustment						$2.1518

Interruptible	
Estimated Weighted Average Commodity Cost	$4.8569
Gas Cost Reconciliation Adjustment	0.0274
LMS Demand 2/	0.0147
Total Current Interruptible Gas Cost	4.8990
Base Cost of Gas	5.1191
Accumulated Adjustment	($0.2201)

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	$0.9800	12	$29,400	$0.0147

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JANUARY 2014

Rates Effective January 1, 2014	$/Dk	
FT-A - Zone 1-1 (Category 1)	$3.6918	Per dk/Mo.
FT-A - Zone 1-1 (Category 3)	3.3978	Per dk/Mo.
FT-A - Seasonal	3.6918	Per dk/Mo.
TFX	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	0.9800	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	4.8569	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	$3.6918
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.7894
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$2.0972
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	$3.5448
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.6424
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.9502
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	$3.3978
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.4954
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.8032
Zone 2-2 Minimum Rate	$0.0000

Rate Schedule	Base Tariff Rate	Fuel and Loss Retention Percentages 2/
Commodity Rates 1/		
FT-A – Maximum Rates		
Zone 1-1	$0.0127	0.00%
Zone 1-2	$0.0127	0.00%
Zone 2-2	$0.0127	0.00%
Minimum Rate	$0.0127	
IT and AOT		
Zone 1-1	$0.1341	0.00%
Zone 1-2	$0.1702	0.00%
Zone 2-2	$0.0816	0.00%
Minimum Rate	$0.0127	

1/ Pursuant to Section 19 of the General Terms and Conditions, the maximum and minimum commodity rates shall be increased to include the Commission-authorized Annual Charge Adjustment unit rate as published on the Commission's Web Site located at http://www.ferc.gov.

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: 0.00% for Zone 1-1, 0.00 % for Zone 1-2, and 0.00% 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	$0.9800		$0.9800
LMS – Daily Overrun Rate	$0.1702		$0.1702
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	$0.1702	$0.0000
RPL Service:		
Daily Reservation Rate	$0.1702	$0.0000

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	0.0359	0.0190			0.0175	0.0000	0.0359	0.0190
Field	Market	0.0359	0.0190	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

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 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/ The Maximum and Minimum rates include the Market Area Electric Compression charge of $0.0000 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.
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, the Field Area Electric Compression charge of $0.0000 and the ACA unit surcharge as set forth on FERC's website at http://www.ferc.gov 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	0.0359	0.0190			0.0175	0.0000	0.0359	0.0190
Field	Market	0.0359	0.0190	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

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	0.0000	0.0000	0.0000	0.0000
MOPS Transmission	1.5337	0.0000	0.0000	0.0000	0.0000	0.0000
Tivoli - Downstream	0.6827	0.0000	0.0000	0.0000	0.0000	0.0000
Other Gulf Coast	4.8169	0.0000	0.0000	0.0000	0.0000	0.0000

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 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/ The Maximum and Minimum rates include the Market Area Electric Compression charge of $0.0000 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.
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, the Field Area Compression charge of $0.0000 and the ACA unit surcharge as set forth on FERC's website at http://www.ferc.gov will be added to the mileage based rates.
6/ In addition to the Maximum and Minimum rates, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.

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

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	1.31%
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
January 2014

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for the majority of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The January 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.

Cold weather covered most of the United States during portions of December, resulting in increased demand on the residential and commercial sector. The cold weather not only increased demand, but also resulted in reduced production from well freeze offs, therefore causing a significant increase in the index price of natural gas. The EIA reported storage levels nationwide as of December 20, 2013, were 9.2 percent below the five-year average and 16.1 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 17.

Independent Statistics & Analysis
U.S. Energy Information Administration

December 2013

Short-Term Energy Outlook (STEO)

Highlights

- After falling by more than 40 cents per gallon from the beginning of September through mid-November, weekly U.S. average regular gasoline retail prices increased by 8 cents per gallon to reach $3.27 per gallon on December 2, 2013, due in part to unplanned refinery maintenance and higher crude oil prices. The annual average regular gasoline retail price, which was $3.63 per gallon in 2012, is expected to average $3.50 per gallon in 2013 and $3.43 per gallon in 2014.

- The North Sea Brent crude oil spot price averaged near $110 per barrel for the fifth consecutive month in November. EIA expects the Brent crude oil price to average $108 per barrel in December and decline gradually to $104 per barrel in 2014. Projected West Texas Intermediate (WTI) crude oil prices average $95 per barrel during 2014.

- The discount of the WTI crude oil spot price to Brent, which averaged more than $20 per barrel in February 2013 and fell below $4 per barrel in July, recovered to an average of $9 per barrel in October and $14 per barrel in November. In addition, the spot discount of Light Louisiana Sweet (LLS), a key Gulf Coast light sweet crude oil, to Brent increased from an average of $3 per barrel in September to almost $11 per barrel in November. The opening of a large LLS discount to Brent and the increasing convergence of LLS and WTI prices result from pipeline expansions and reversals that have reduced bottlenecks in the Midcontinent, continuing growth in domestic light oil production, and a seasonal decline in crude oil runs at U.S. Gulf Coast refineries. Brent crude oil prices continue to be supported by ongoing supply outages in Libya and tightness in global light crude oil markets. EIA expects the WTI discount to Brent to average $12 per barrel during the fourth quarter of 2013 and $9 per barrel in 2014.

- Estimated U.S. crude oil production averaged 8.0 million barrels per day (bbl/d) in November, the highest monthly level since November 1988. EIA expects U.S. crude oil production will average 7.5 million bbl/d in 2013 and 8.5 million bbl/d in 2014.

- Natural gas working inventories ended November at an estimated 3.61 trillion cubic feet (Tcf), 0.19 Tcf below the level at the same time a year ago and 0.11 Tcf below the previous five-year average (2008-12). EIA expects that the Henry Hub natural gas spot price, which averaged $2.75 per million British thermal units (MMBtu) in 2012, will average $3.69 per MMBtu in 2013 and $3.78 per MMBtu in 2014.

Global Crude Oil and Liquid Fuels

Total global liquid fuels production was 90.6 million bbl/d in November, 0.9 million bbl/d higher than in November 2012. Crude oil production by members of the Organization of the Petroleum Exporting Countries (OPEC) averaged 29.3 million bbl/d in November, the lowest level in more than two years. Continued unrest in Libya and, to a lesser extent, routine maintenance and ongoing supply disruptions in Nigeria constrained OPEC crude oil production. Unplanned supply outages among OPEC members rose to 2.5 million bbl/d in November, accounting for more than 80% of global outages. Global supply disruptions remained above 3.0 million bbl/d in November for the fourth month in a row.

Non-OPEC countries produced 55.3 million bbl/d of liquid fuels in November, 1.7 million bbl/d higher than in November 2012. EIA projects continued non-OPEC liquid fuels production growth in 2014 of 1.8 million bbl/d, contributing to a decline in the call on OPEC crude oil and stocks (world consumption less non-OPEC production and OPEC non-crude oil production).

EIA's forecast of Iran's crude oil production remains unchanged. Since the announcement of a Joint Plan of Action (JPA) between Iran and the five permanent members of the United Nations Security Council plus Germany (P5+1) does not remove the existing sanctions affecting Iranian crude oil sales, EIA did not adjust its outlook on Iran's crude oil supply. EIA will continue to monitor and evaluate the situation, which could be affected by any future agreement that is reached between Iran and the P5+1.

Global Liquid Fuels Consumption. EIA projects global consumption to grow annually by 1.1 million bbl/d in 2013 and 1.2 million bbl/d in 2014, from a base of 89.2 million bbl/d in 2012. China, the Middle East, Central & South America, and other countries outside of the Organization for Economic Cooperation and Development (OECD) will account for nearly all consumption growth over the forecast period. EIA expects OECD liquid fuels consumption in 2013 to remain at its 2012 level and then decline by 0.1 million bbl/d in 2014.

Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. China's economic growth after 2011 remains strong but more moderate, compared with the preceding decade, leading to smaller increases in liquids fuel consumption in 2013 and 2014. EIA estimates that China's liquid fuels consumption will be 380,000 bbl/d higher in 2013 than it was in 2012 and projects an additional increase of 400,000 bbl/d in 2014.

Non-OPEC Supply. EIA estimates that non-OPEC liquid fuels production averaged 55.3 million bbl/d in November, up 0.3 million bbl/d from October. EIA projects non-OPEC supply will average 54.2 million bbl/d in 2013 and 55.9 million bbl/d in 2014. Growing non-OPEC liquid fuels production will contribute to a declining call on OPEC crude oil, from an average of 30.3 million bbl/d in 2013 to 29.4 million bbl/d in 2014.

EIA estimates the greatest non-OPEC supply growth will be in North America, where projected liquid fuels production increases by 1.5 million bbl/d in 2013 and another 1.3 million bbl/d in 2014. The majority of the production growth is from U.S. onshore tight oil formations and Canadian oil sands. EIA expects smaller production growth from a number of other areas, including Africa, Central & South America, and Asia & Oceania.

Of the 3.0 million bbl/d of global unplanned supply disruptions in November, approximately 0.5 million bbl/d occurred among non-OPEC producers, which saw a decrease of nearly 0.2 million bbl/d in outages compared with October. Disrupted volumes in Brazil, Canada, and the United States all returned by November, driving the decline in total non-OPEC outages. Syria accounted for more than half of all unplanned outages in non-OPEC countries.

OPEC Supply. EIA expects total OPEC liquid fuels production to decline by 0.8 million bbl/d in 2013 to an average of 35.9 million bbl/d and projects another 0.6-million-bbl/d decline in 2014. The declines in 2013 mostly reflect supply outages among some OPEC producers, along with lower production by Saudi Arabia during the first half of 2013. EIA expects supply disruptions in Libya to persist through 2014, keeping around 1 million bbl/d off the global oil market.

The JPA between Iran and members of the P5+1 group will not affect OPEC's output, as the sanctions affecting Iran's oil sector remain in place. EIA's forecast of Iran's crude oil production remains unchanged because the JPA with Iran and the P5+1 group does not directly allow for additional Iranian oil sales. The JPA does suspend sanctions on associated insurance and transportation services; however, EIA expects limited short-term effects on Iranian oil exports.

Total OPEC crude oil unplanned disruptions in November averaged 2.5 million bbl/d, a small increase over October's 2.3 million bbl/d. Supply disruptions in Libya increased to nearly 1.4 million bbl/d in November, the highest level since the Libyan civil war in 2011. In Iraq, unplanned supply disruptions fell below 0.2 million bbl/d in November, as attacks on the Kirkuk-Ceyhan pipeline between Iraq and Turkey decreased.

EIA projects total OPEC surplus crude oil production capacity in the fourth quarter of 2013 to be 2.2 million bbl/d, which is 0.5 million bbl/d above the average from the third quarter of 2013 and 0.2 million bbl/d lower than the fourth quarter of 2012. EIA projects OPEC surplus crude oil production capacity will reach 4.2 million bbl/d in the fourth quarter of 2014 and average 3.2 million bbl/d for the year, an increase of 1.1 million bbl/d over the estimated 2013 average. These estimates do not include additional capacity that may be available in Iran but is currently offline because of the effects of U.S. and European Union sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial inventories at the end of 2012 totaled 2.6 billion barrels, equivalent to 57.7 days of supply. EIA projects OECD inventories to be 2.6 billion barrels at the end of both 2013 and 2014.

Crude Oil Prices. Brent crude oil spot prices fell from a monthly average of $112 per barrel in September 2013 to $108 per barrel in November. EIA expects the Brent crude oil price to continue to weaken as non-OPEC supply growth exceeds growth in world consumption. The Brent crude oil price is projected to average $108 per barrel in December 2013 and $104 per barrel in 2014.

The forecast WTI crude oil spot price, which averaged $106 per barrel during September, fell to an average of $94 per barrel in November. EIA expects that WTI crude oil prices will average $96 per barrel during the fourth quarter of 2013 and $95 per barrel during 2014. The discount of WTI crude oil to Brent crude oil, which averaged $18 per barrel in 2012 and then fell to below $4 per barrel in July 2013, averaged $14 per barrel during November. EIA expects the WTI discount to average $12 per barrel during the fourth quarter of 2013 and $9 per barrel during 2014, as new pipeline capacity is added from Cushing to the Gulf Coast.

In addition to an increase in the WTI discount to Brent, U.S. Gulf Coast crude oil grades reached record discounts to international benchmarks in November. Prior to this autumn, discounted crude oil prices had generally been limited to the U.S. Midcontinent, where crude oil production growth had outpaced the capacity of pipeline infrastructure to bring that production to refining centers on the U.S. Gulf Coast. However, pipeline capacity expansions and pipeline reversals have alleviated transportation bottlenecks from the Midcontinent to the Gulf Coast for the time being, causing greater convergence of LLS and WTI prices. This additional infrastructure, continued growth in U.S. light crude oil production, and a seasonal decline in crude oil runs at U.S. Gulf Coast refineries resulted in increases in the net availability of domestic crude oil in the U.S. Gulf Coast. This situation is applying downward pressure to crude oil prices in the U.S. Gulf Coast market, which requires increasingly fewer crude oil imports to balance. The spot discount of LLS, a key Gulf Coast light sweet crude oil grade, to Brent increased from an average of $3 per barrel in September to almost $11 per barrel in November. Likewise, the discount of the Mars spot price, a medium Gulf Coast crude oil grade, to international marker Dubai increased from an average of $4 per barrel in September to $13 per barrel in November.

Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the forecast levels (*Market Prices and Uncertainty Report*). WTI futures contracts for March 2014 delivery traded during the five-day period ending December 5, 2013, averaged $96 per barrel. Implied volatility averaged 19%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in March 2014 at $82 per barrel and $112 per barrel, respectively. Last year at this time, WTI for March 2013 delivery averaged $89 per barrel and implied volatility averaged 28%. The corresponding lower and upper limits of the 95% confidence interval were $71 per barrel and $113 per barrel.

U.S. Crude Oil and Liquid Fuels

After reaching $3.68 per gallon on July 22, 2013, the average U.S. regular gasoline retail price fell almost 50 cents per gallon to $3.19 per gallon by November 11, 2013. Rising export demand for petroleum products, higher crude oil prices, and both planned and unplanned refinery maintenance in the Northeast and Gulf Coast helped to tighten gasoline markets, with gasoline prices increasing to $3.27 per gallon as of December 2, 2013. Despite recent price increases, EIA expects that the wrap-up of refinery maintenance and strong export demand for diesel fuel will contribute to refinery runs continuing near November levels during the remaining weeks of 2013, once again putting downward pressure on regular gasoline retail prices, which EIA expects to average $3.23 per gallon during December 2013.

Motor gasoline consumption, which fell by 600,000 bbl/d (6.5%) between its 2007 peak and 2012, showed some strength in the third quarter of 2013, increasing by 180,000 bbl/d (2.0%) over the same period last year. The Federal Highway Administration's monthly report of motor vehicle travel indicates year-over-year growth of 1.5% in the third quarter, compared with an increase in daily average travel of 0.4% during the first half of the year. As a result, EIA has raised the forecasts for total motor gasoline consumption for both 2013 and 2014 by 40,000 bbl/d from last month's STEO.

U.S. Liquid Fuels Consumption. In 2012, total U.S. liquid fuels consumption declined by 390,000 bbl/d (2.1%), with all of the major liquid fuels contributing with the exception of liquefied petroleum gases. In 2013, however, estimated total liquid fuels consumption increases by 310,000 bbl/d (1.7%), with transportation fuels accounting for much of that growth. Motor gasoline consumption is expected to grow by 90,000 bbl/d (1.0%) in 2013 and distillate fuel oil consumption increases by 80,000 bbl/d (2.2%). In 2014, total consumption of liquid fuels declines by 20,000 bbl/d (0.1%). EIA expects gasoline consumption to fall by 0.4% as continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth, which outpaces growth in highway travel. Distillate consumption, however, rises by 1.2%, buoyed by continued increases in imports of non-petroleum goods and distillate-weighted manufacturing activity.

Ethane consumption increases by an average of 50,000 bbl/d in 2014 as ethylene plant capacity expansions contribute to an increase in ethane cracking capacity. The growth in ethane consumption in 2014 is partially offset by lower propane and other liquefied petroleum gas consumption because of the projected 4.0% decline in heating degree days.

U.S. Liquid Fuels Supply. EIA expects U.S. crude oil production to rise from an average of 6.5 million bbl/d in 2012 to 7.5 million bbl/d in 2013 and 8.5 million bbl/d in 2014. The continued focus on drilling in tight oil plays in the onshore Bakken, Eagle Ford, and Permian regions is expected to account for the bulk of the forecast production growth. Offshore production from the Gulf of Mexico is forecast to average 1.3 million bbl/d in 2013 and 1.4 million bbl/d in 2014.

New pipeline capacity for transporting natural gas liquids (NGLs) from producing regions such as the Marcellus shale to Gulf Coast petrochemical plants contributes to an increase in NGL supply over the forecast. EIA has raised the 2014 forecast for liquefied petroleum gas production by 60,000 bbl/d from last month's STEO.

Liquid fuel inventories have fallen over the last two months, with the largest reported declines in liquefied petroleum gas, distillate fuel, total motor gasoline, and jet fuel. November saw several planned and unplanned refinery outages on the East and Gulf Coasts, including Phillips 66's Bayway refinery, Motiva's Norco refinery, and Chevron's Pascagoula refinery among others. As refiners wrap up maintenance for 2013, EIA expects finished product stocks to recover in December, with the exception of a continued draw on liquefied petroleum gas.

Since reaching an annual average high of 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil and petroleum products, have been falling. The share of total U.S. consumption met by liquid fuel net imports peaked at more than 60% in 2005 and fell to an average of 40% in 2012. EIA expects the net import share to decline to 28% 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 $3.24 per gallon during November, will average $3.23 per gallon in December 2013. Led by falling Brent crude oil prices, the projected U.S. annual average regular gasoline retail price falls from $3.63 per gallon in 2012 to an average of $3.50 per gallon in 2013 and $3.43 per gallon in 2014. Diesel fuel prices, which averaged $3.97 per gallon in 2012, are projected to average $3.92 per gallon in 2013 and $3.77 per gallon in 2014.

Natural Gas

Natural gas production in the northeastern United States rose from 2.1 billion cubic feet per day (Bcf/d) in 2008 to 12.3 Bcf/d in 2013. This trend has reduced the cost and increased the supply of natural gas in the Northeast. This additional supply has encouraged greater use of natural gas in the Northeast, especially for power generation, and has also reduced net inflows of natural gas into the region from other regions such as the Gulf of Mexico, the Midwest, and eastern Canada. Regional environmental incentives, in addition to greater supply and lower prices, have contributed to the increased use of natural gas for power generation. Both of the Northeast's regional transmission organizations, the Independent System Operator of New England (ISO-NE) and the New York Independent System Operator (NYISO), have seen a dramatic shift since 2001 away from petroleum- and coal-fired generation to predominantly natural gas-fired output in 2012 and 2013.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.6 Bcf/d in 2012, will average 70.7 Bcf/d and 69.6 Bcf/d in 2013 and 2014, respectively. Colder winter temperatures in 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. However, the projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 24.9 Bcf/d in 2012 to 22.3 Bcf/d in 2013 and 22.1 Bcf/d in 2014.

U.S. Natural Gas Production and Trade. Natural gas marketed production is projected to increase from 69.2 Bcf/d in 2012 to 70.4 Bcf/d in 2013 and 71.4 Bcf/d in 2014. Natural gas pipeline gross imports, which have fallen over the past five years, are projected to fall by 0.5 Bcf/d in 2013 and remain flat in 2014. Liquefied natural gas (LNG) imports are expected to remain at minimal levels of around 0.3 Bcf/d in 2013 and 0.2 Bcf/d 2014.

U.S. Natural Gas Inventories. Natural gas working inventories fell by 162 Bcf to 3,614 Bcf during the week ending November 29, 2013. This was the largest weekly net withdrawal for the month of November since publication of weekly storage data began in 1994. Colder-than-normal temperatures during the week resulted in increased heating demand, prompting larger-than-normal withdrawals in all three regions, including a particularly large withdrawal in the Producing Region. Stocks are now 200 Bcf less than year-ago levels and 104 Bcf less than the five-year (2008-2012) average.

U.S. Natural Gas Prices. Natural gas spot prices averaged $3.64/MMBtu at the Henry Hub in November, down 4 cents from the previous month's price. Despite an overall month-over-month decline, prices in the final days of November rose above $3.80/MMBtu in response to colder weather. EIA expects the Henry Hub price will average $3.69/MMBtu for the year, compared with $2.75/MMBtu in 2012. Henry Hub prices are expected to rise to an annual average of $3.78/MMBtu in 2014.

Natural gas futures prices for March 2014 delivery (for the five-day period ending December 5, 2013) averaged $3.98 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for March 2014 contracts at $3.01 per MMBtu and $5.26 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for March 2013 averaged $3.62 per MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $2.62 per MMBtu and $5.00 per MMBtu.

Coal

Low natural gas prices, weak electricity demand growth, and the need to comply with the implementation of the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS) regulations have led several power producers to recently announce plans for the retirements of coal-fired facilities. On November 14, 2013 the Tennessee Valley Authority (TVA) announced that it was retiring eight coal-fired units with over 3,000 megawatts (MW) of generating capacity. The current retirement plans are an addition to TVA's retirement plans publicized in 2011. South Carolina Electric & Gas (SCEG) announced that it had ceased

operations at its Canadys Station generating facility earlier in the month. The 300-MW plant's closing is part of SCEG's efforts to reduce emissions and comply with MATS regulations. Consumers Energy (CE) has recently petitioned the Michigan Public Service Commission (MPSC) to approve a bond issue to cover costs pertaining to the closure, decommission and demolition of three coal-fired power plants. CE stated that the units would be shut down because the installation of additional emissions controls necessary to achieve compliance with EPA environmental regulations would be uneconomical. MPSC approval of the bond issue is expected before the end of 2013.

U.S. Coal Supply. Coal production for the first ten months of 2013 was estimated to total 837 million short tons (MMst), 15 MMst (1.8%) lower than in the same period of 2012. EIA projects total coal production of 1,008 MMst in 2013 with inventory draws of nearly 37 MMst fulfilling most of the growth in consumption in 2013. Coal production is forecast to grow 2.5% to 1,033 MMst in 2014 as inventories stabilize and consumption increases.

U.S. Coal Consumption. EIA expects total coal consumption for 2013 to reach 928 MMst (a 4.4% increase over 2012). The increase was primarily a result of increased consumption in the electric power sector due to higher natural gas prices. Projected consumption grows more slowly (2.2%) to 948 MMst in 2014.

U.S. Coal Exports. EIA estimates that exports for the first three quarters of 2013 totaled 90 MMst, which was 8.1% (8 MMst) lower than the same period last year. EIA expects exports to total 118 MMst in 2013, down 7 MMst from last year. Exports are projected to total 107 MMst in 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing coal output in other coal-exporting countries, and falling international coal prices are the primary reasons for the expected decline in U.S. coal exports.

U.S. Coal Prices. EIA expects nominal annual average coal prices to the electric power industry to fall for the first time since 2000, from $2.40 per MMBtu in 2012 to $2.35 per MMBtu in 2013. EIA forecasts average delivered coal prices of $2.39 per MMBtu in 2014.

Electricity

So far this year (through October 2013), the electricity industry has added 10.0 gigawatts (GW) of new generating capacity. Much of this new capacity (6.2 GW) is fueled by natural gas. Renewable energy sources are used in 2.3 GW of the new capacity while two new coal plants (1.5 GW) have also started producing electricity this year. However, these new sources for power generation have been more than offset by 11.1 GW of retired capacity. Coal-fired and nuclear plants comprise the largest proportion of year-to-date retired capacity (3.8 GW and 3.6 GW, respectively). A total of 2.3 GW of natural-gas-fired capacity has been retired so far this year.

U.S. Electricity Consumption. Electricity sales during 2013 have experienced little, if any, growth. Consumption of electricity in the residential and commercial sectors will have grown by an estimated 0.8% and 0.7%, respectively. Residential sales showed particularly strong growth during the first quarter, while summer consumption was lower in most regions. EIA expects sales of electricity to the industrial sector will have fallen by 2.3% during 2013. Much of this decline in industrial consumption of electricity occurred in the Northeast and Midwest.

U.S. Electricity Generation. EIA expects total U.S. electricity generation during 2013 will be 0.2% higher than 2012, and generation during 2014 will be 0.4% higher than this year. Despite the retirements of existing capacity during the past year, generation from coal and nuclear plants is projected to be 5.4% and 1.3% higher, respectively. The increase in coal-fired generation reflects increased fuel costs for generation using natural gas. EIA expects this trend will continue next year, albeit at a slower pace, with coal generation growing by 1.9% and natural gas generation falling by 0.8%.

U.S. Electricity Retail Prices. The rising cost of generation fuels, particularly natural gas, contributes to a projected increase in the residential price of electricity. During the upcoming winter months, EIA expects the U.S. residential electricity price to average 11.9 cents per kilowatthour, which is 2.1% higher than in the winter of 2012-13.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewable energy consumption for electricity and heat generation in all sectors to increase by 3.6% in 2013. While hydropower declines by 1.8%, nonhydropower renewables used for electricity and heat generation grow by an average of 7.0% in 2013. In 2014, the growth in renewables consumption for electric power and heat generation is projected to continue at a rate of 2.2%, as a 0.9% increase in hydropower is combined with a 2.9% increase in non-hydropower renewables.

EIA estimates that wind capacity will increase by 2.2% in 2013 to about 60 gigawatts (GW) at the end of this year and will total more than 66 GW at the end of 2014. Electricity generation from wind is projected to increase by 17.6% in 2013 and by 2.4% in 2014, contributing more than 4% of total electricity generation.

EIA expects continued robust growth in the generation of solar energy, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.4% by 2014. Utility-scale capacity, which until recently experienced little growth compared with customer-sited distributed generation capacity, is projected to more than double between 2012 and 2014. Photovoltaics (PV) accounted for all utility-scale solar growth in 2012, but EIA expects that several large solar thermal generation projects will enter service in 2013 and 2014.

U.S. Liquid Biofuels. On November 15, 2013, the U.S. Environmental Protection Agency (EPA) released its Notice of Proposed Rulemaking for the 2014 Renewable Fuel Standard (RFS). While EPA has set requirements for cellulosic biofuels well below the legislated volume targets for such fuels in past RFS program years, the proposed rule for the 2014 RFS program is the first time that the agency is seeking to set total renewable fuel and advanced biofuel requirements below the legislated targets.

Ethanol and biodiesel production have recovered from last year's drought. Ethanol production increased from an average of 825,000 bbl/d in November 2012 to 900,000 bbl/d during November 2013 and is forecast to average 900,000 bbl/d during 2014. Biodiesel production, which averaged 64,000 bbl/d (1.0 billion gallons per year) in 2012, has been rising this year and reached a record-high average daily rate of 101,000 bbl/d in September. Biodiesel is forecast to average about 86,000 bbl/d in 2013 and 84,000 bbl/d in 2014.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels declined by 3.9% in 2012 from the previous year, and projects increases of 1.9% in 2013 and 0.4% in 2014. The increase in emissions over the forecast period primarily reflects projected growth in coal use for electricity generation in response to higher natural gas prices relative to coal.

U.S. Economic Assumptions

The U.S. Department of Labor reported that initial weekly unemployment insurance claims were 298,000 in the week ending November 30, a decrease of 23,000 from the previous week's figure, and the four-week moving average fell to just over 322,000. ISM's Chicago PMI fell slightly to 63.0 in November, but the three-month moving average was the highest since October 2011. However, the U.S. Census Bureau reported that new orders for manufactured durable goods fell 2.0% in October, although this was driven primarily by decreases in defense and aircraft orders. The Federal Reserve Board reported that U.S. industrial production fell in October by 0.1%, following a 0.7% gain in September.

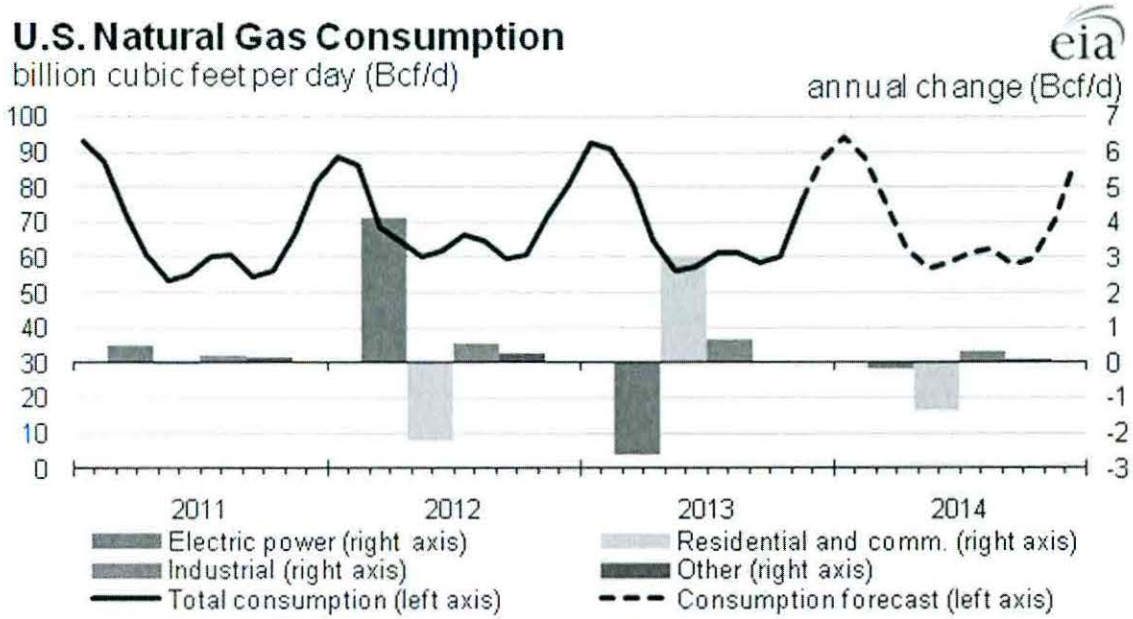
EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. The GI simulation assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) are replaced by a combination of tax and spending changes that are implemented in 2014.

U.S. Production and Income. Forecast U.S. real GDP grows by 1.7% in 2013 and 2.4% in 2014. Forecast real disposable income increases 0.7% in 2013 and 3.1% in 2014. Total industrial production grows almost one percentage point faster than real GDP in 2013 at 2.4%, and is projected to grow 2.6% in 2014.

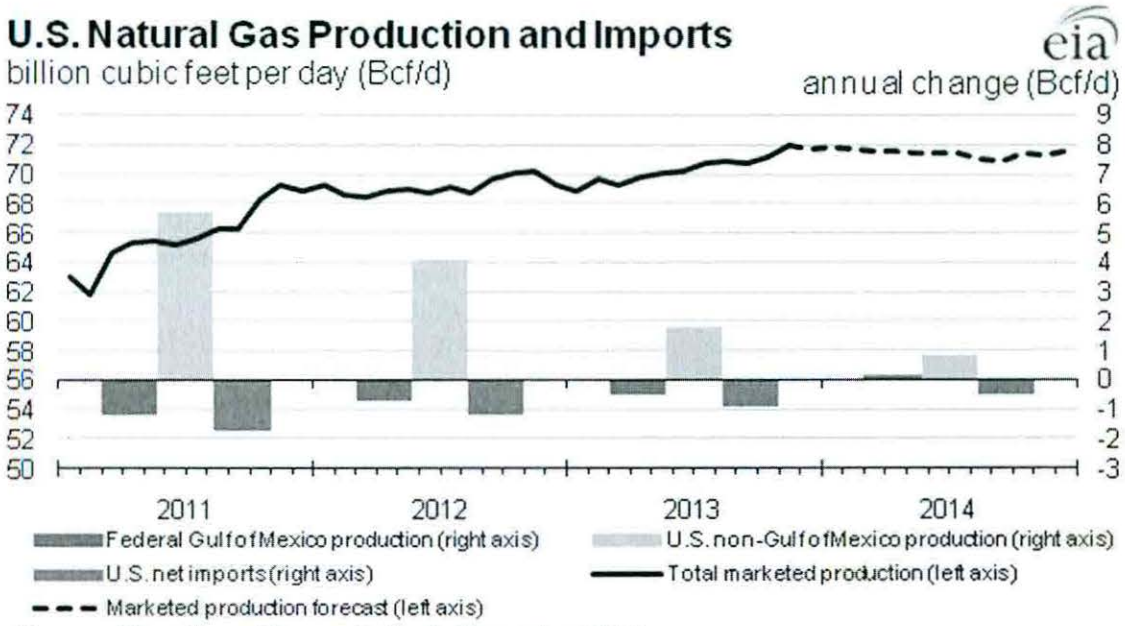
U.S. Expenditures. Private real fixed investment growth averages 4.5% and 6.9% over 2013 and 2014, respectively. Real consumption expenditures grow faster than real GDP in 2013, at 1.9%,

and match the rate of real GDP growth in 2014, at 2.4%. Export growth more than doubles from 2.2% to 4.9% over the same two years. Government expenditures fall 2.2% in 2013, and rise by 0.2% in 2014.

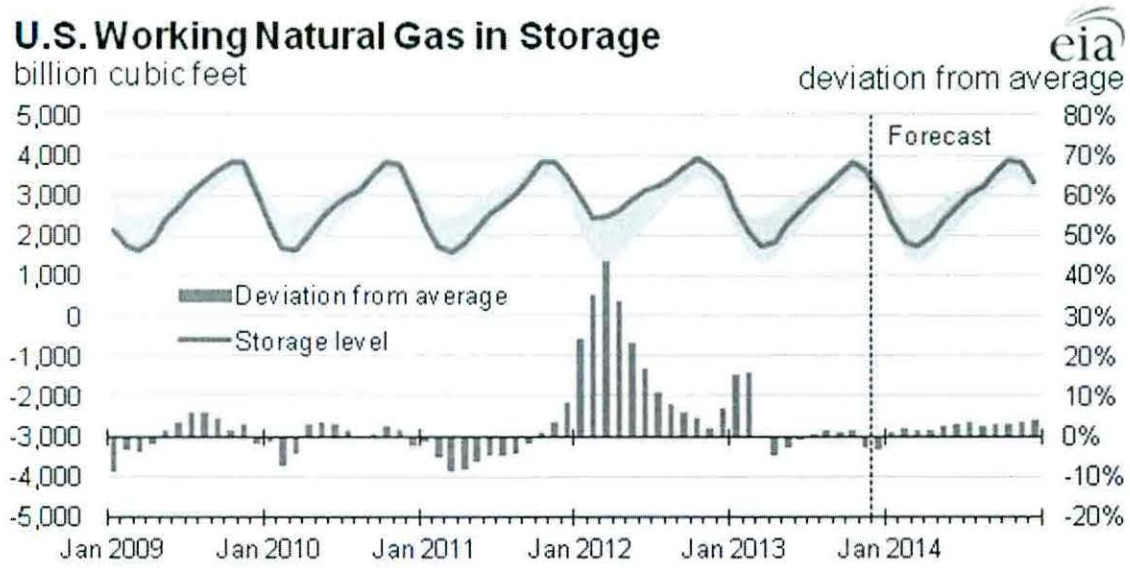
U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 7.5% over 2013, and gradually falls to 6.7% at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.6% in both 2013 and 2014. Consistent with an improving housing sector, housing starts grow an average of 16.6% and 24.0% in 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.



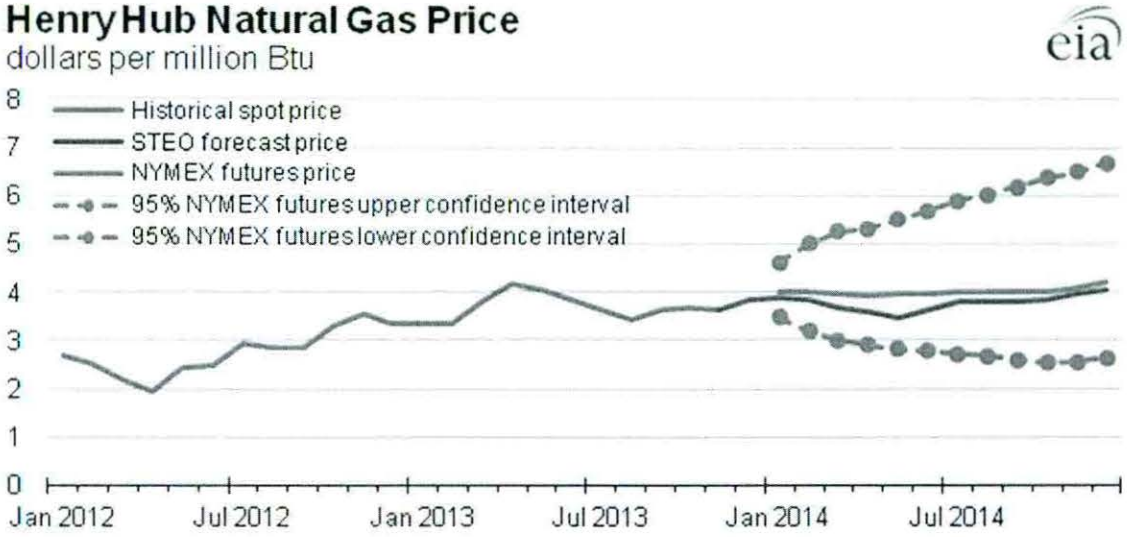
Source: Short-Term Energy Outlook, December 2013.



Source: Short-Term Energy Outlook, December 2013.

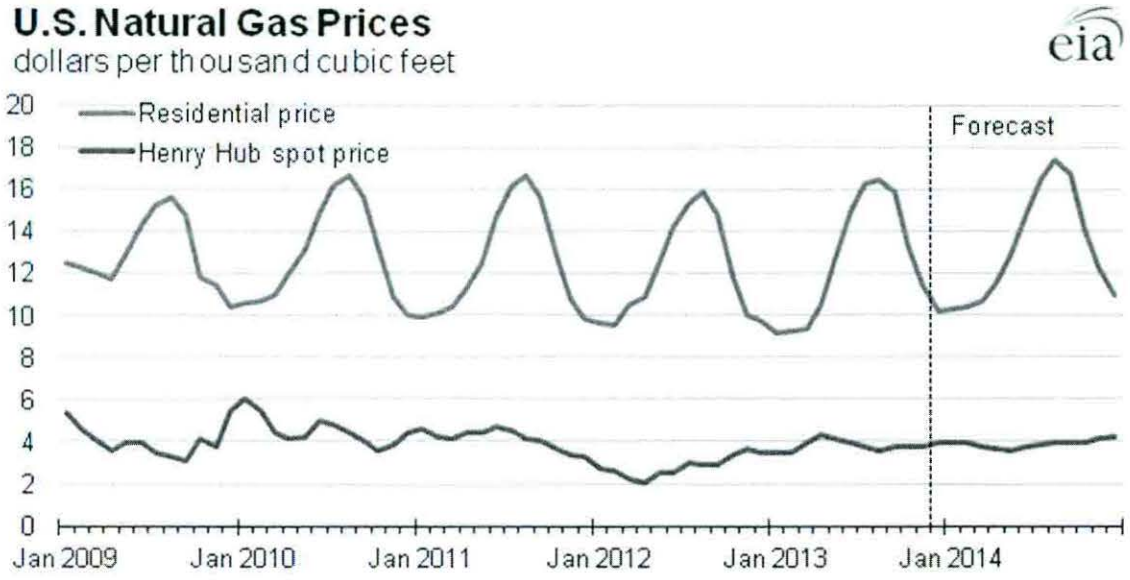


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.
Source: Short-Term Energy Outlook, December 2013.



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

Source: Short-Term Energy Outlook, December 2013.



Source: Short-Term Energy Outlook, December 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, 2013										**$303,311**
May	($12,469)	0	$1,860	($10,609)	21,400	$1.0137	$21,692		($32,301)	271,010
June	4,837	0	1,626	6,463	9,214	0.9614	9,167	2/	(2,704)	268,306
July	19,011	0	1,601	20,612	6,004	0.9614	5,772		14,840	283,146
August	16,638	(17,889)	1,701	450	5,505	0.9614	5,293		(4,843)	278,303
September	296	0	1,658	1,954	5,691	0.9614	5,471		(3,517)	274,786
October	5,896	0	1,625	7,521	8,206	0.9614	7,889		(368)	274,418
November	1,647	0	1,618	3,265	21,099	0.9614	20,285		(17,020)	257,398
Total	$35,856	(17,889)	$11,689	$29,656	77,119		$75,569		($45,913)	
Balance @ November 30, 2013										**$257,398**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 5,911.4 Mcf @ $1.0137 and 3,302.1 Mcf @ $0.9614.

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, 2013									**$4,747**
May	($19,391)	0	($4)	($19,395)	49,736	($0.2915)	($14,498)	($4,897)	(150)
June	(13,383)	0	(46)	(13,429)	23,704	0.0274	(4,253) 2/	(9,176)	(9,326)
July	(9,266)	0	(115)	(9,381)	17,577	0.0274	482	(9,863)	(19,189)
August	(1,454)	0	(188)	(1,642)	14,808	0.0274	406	(2,048)	(21,237)
September	(28,851)	0	(203)	(29,054)	16,181	0.0274	443	(29,497)	(50,734)
October	4,119	0	(416)	3,703	26,694	0.0274	731	2,972	(47,762)
November	5,534	0	(395)	5,139	56,950	0.0274	1,560	3,579	(44,183)
Total	($62,692)	0	($1,367)	($64,059)	205,650		($15,129)	($48,930)	
Balance @ November 30, 2013									**($44,183)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 15,372.2 Mcf @ ($0.2915) and 8,331.7 Mcf @ $0.0274.