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

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January 31, 2014

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

Re: Cost of Gas Adjustment (COG)
February 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 (95th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (95th Revised Sheet No. 8), showing the February 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $2.6711 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for February 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $2.6711 per mcf for all customers since the last COG filing.

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 submitted a check for $600.00 on January 2, 2014 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the $50.00 filing fee associated with this month's COG filing.

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

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

Sincerely,

Tamie A. Aberle
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
95th Revised Sheet No. 1.1
Canceling 94th Revised Sheet No.1.1
Page 1 of 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	$10.0078	$11.2818
			Over 10 MCF	1.0540		11.0618
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$7.5701	$8.7092
			Next 2,600 MCF	0.8931		8.4632
			Over 3,000 MCF	0.7411		8.3112
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$7.5701	$8.8092
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 31, 2014

Effective Date: Service rendered on and after February 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
95th Revised Sheet No. 8
Canceling 94th 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.	1.4526	(0.2622)	0.9614	2.1518	(0.2475)	0.0274	(0.2201)
Current Adj.	0.0000	2.6711	0.0000	2.6711	2.6711	0.0000	2.6711
Total Adj.	1.4526	2.4089	0.9614	4.8229	2.4236	0.0274	2.4510
Total Rate	$1.5184	$7.5280	$0.9614	$10.0078	$7.5427	$0.0274	$7.5701

Date Filed: January 31, 2014

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
FEBRUARY 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/	7.5280		10,558,186	7.5280
Gas Cost Reconciliation Adjustment						0.9614
Total Current Firm Gas Cost					$12,667,216	10.0078
Base Cost of Gas						5.1849
Accumulated Adjustment						$4.8229

Interruptible	
Estimated Weighted Average Commodity Cost	$7.5280
Gas Cost Reconciliation Adjustment	0.0274
LMS Demand 2/	0.0147
Total Current Interruptible Gas Cost	7.5701
Base Cost of Gas	5.1191
Accumulated Adjustment	$2.4510

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
FEBRUARY 2014

Rates Effective February 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:	7.5280	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

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
Category 1 (Contract Term of Less than 3 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.6918
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

	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/				Field Mileage 5/		Carlton			
TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Rate per 100 miles		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
February 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 February 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.

Prolonged cold weather throughout much of the continental United States and associated higher than normal demand of natural gas has drawn storage levels to the lowest level in the last five years. The combination of these factors has increased the index price of gas for the upcoming month. The EIA reported storage levels nationwide as of January 24, 2014 were 16.6 percent below the five-year average and 22.5 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 on pages 2 through 17.

Independent Statistics & Analysis
U.S. Energy Information Administration

January 2014

Short-Term Energy Outlook (STEO)

Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2015.

- After falling to the lowest monthly average of 2013 in November, U.S. regular gasoline retail prices increased slightly to reach an average of $3.28 per gallon (gal) during December. The annual average regular gasoline retail price, which was $3.51/gal in 2013, is expected to fall to $3.46/gal in 2014 and $3.39/gal in 2015.

- The North Sea Brent crude oil spot price in December averaged near $110 per barrel (bbl) for the sixth consecutive month. EIA expects the Brent crude oil price to decline gradually to average $105/bbl and $102/bbl in 2014 and 2015, respectively. Projected West Texas Intermediate (WTI) crude oil prices average $93/bbl during 2014 and $90/bbl during 2015.

- EIA expects liquid fuels production from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) to grow year-over-year by a record high of 1.9 million barrels per day (bbl/d) in 2014. The United States and Canada together are projected to account for almost 70% of total non-OPEC supply growth this year.

- EIA estimates U.S. total crude oil production averaged 7.5 million bbl/d in 2013, an increase of 1.0 million bbl/d from the previous year. Projected domestic crude oil production continues to increase to 8.5 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The 2015 forecast would mark the highest annual average level of production since 1972.

- Natural gas working inventories on December 27 totaled 2.97 trillion cubic feet (Tcf), 0.56 Tcf below the level at the same time a year ago and 0.29 Tcf below the previous five-year average (2008-12). EIA expects that the Henry Hub natural gas spot price, which averaged $3.73 per million British thermal units (MMBtu) in 2013, will average $3.89/MMBtu in 2014 and $4.11/MMBtu in 2015.

- Coal production, which fell by almost 9% between 2011 and 2013, is expected to increase by 36 million short tons (MMst) (3.6%) in 2014 as higher natural gas prices favor the dispatch of coal-fired power plants and the drawdown of coal inventory ends. In 2015, however, forecast coal-fired production falls by 2.5% with declining coal use in the electric power sector as retirements of coal-fired power plants rise due to the implementation of the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards.

Global Crude Oil and Liquid Fuels

EIA expects production from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) to grow year-over-year by a record high of 1.9 million bbl/d in 2014. OPEC crude oil production is forecast to decline by 0.5 million bbl/d in 2014, mostly as a result of some OPEC producers cutting back production to accommodate non-OPEC supply growth. The projected decline in production by some OPEC producers increases in surplus crude oil production capacity, which grows from an average of 2.2 million bbl/d in 2013 to 2.7 million bbl/d in 2014. The call on OPEC crude oil and global stocks (world consumption less non-OPEC production and OPEC non-crude oil production) falls from an average 30.4 million bbl/d in 2013 to 29.6 million bbl/d in 2014.

In 2015, EIA forecasts that non-OPEC supply growth will moderate to 1.5 million bbl/d, slightly above projected global consumption growth of about 1.4 million bbl/d. The call on OPEC crude oil and global stocks falls by 0.2 million bbl/d as projected OPEC non-crude liquids increase by 0.1 million bbl/d. Some OPEC producers are expected to reduce production to accommodate higher production from Libya, Iraq, and Angola, leading to an increase in forecast surplus crude oil production capacity to an average of 3.7 million bbl/d in 2015.

EIA estimates that global unplanned supply disruptions averaged 2.6 million bbl/d in 2013, 0.7 million bbl/d higher than the previous year. OPEC producers contributed most of the total outage volume (1.8 million bbl/d). Global supply disruptions reached a high of 3.1 million bbl/d at the end of 2013 and remain close to that level at the start of 2014. Supply disruptions present considerable uncertainty over the forecast period because the issues underpinning the disruptions in most countries remain unresolved.

Global Liquid Fuels Consumption. EIA estimates that global consumption grew by 1.2 million bbl/d in 2013, exceeding 91 million bbl/d by the second half of the year. EIA expects global consumption to grow by a similar pace of 1.2 million bbl/d in 2014 and 1.4 million bbl/d in 2015, exceeding 93 million bbl/d by the second half of 2015.

Countries outside of the Organization for Economic Cooperation and Development (OECD) account for nearly all consumption growth over the forecast period, with year-over-year growth of 1.3 million bbl/d in 2014 and 1.4 million bbl/d in 2015. China is the single leading contributor to projected global consumption growth, increasing by 400,000 bbl/d in 2014 and 430,000 bbl/d in 2015. China's economic and oil consumption growth has moderated compared with levels before 2012, when GDP growth exceeded 9% and annual oil consumption growth averaged 790,000 bbl/d during 2009-11.

On the other hand, EIA expects OECD consumption to decline by roughly 0.1 million bbl/d in 2014 and remain flat in 2015. The projected decline in OECD consumption is led by Japan and Europe. EIA expects Japan's oil consumption to decrease annually by 120,000 bbl/d in 2014 and

170,000 bbl/d in 2015, as the country continues to increase natural gas consumption in the electricity sector and returns some nuclear power plants to service. EIA projects that Europe's consumption continues to decline by 100,000 bbl/d in 2014 and 50,000 bbl/d in 2015, a slower decline compared with previous years.

Non-OPEC Supply. EIA estimates that non-OPEC production grew by 1.4 million bbl/d in 2013, exceeding 55 million bbl/d by the end of the year. EIA expects non-OPEC production to grow annually by 1.9 million bbl/d in 2014 and 1.5 million bbl/d in 2015, reaching 58 million bbl/d in the second half of 2015. North America contributes the most growth to non-OPEC supply over the forecast period.

EIA forecasts production from the United States and Canada to grow by an annual average of 0.98 million bbl/d and 0.25 million bbl/d, respectively, over the next two years. Brazil's production is expected to grow by an annual average of 0.15 million bbl/d over the next two years, attributed to new deepwater fields. Kazakhstan's production is also expected to grow by an annual average of 0.13 million bbl/d over the next two years, although most of the growth comes in 2015 as output grows at the Kashagan oil field.

Unplanned supply disruptions among non-OPEC producers averaged 0.8 million bbl/d in 2013, a slight decline from 0.9 million bbl/d in 2012 but still considerably above the 2011 level of 0.5 million bbl/d. Non-OPEC supply disruptions declined to an average of 0.6 million bbl/d during the last two months of 2013. South Sudan, Syria, and Yemen accounted for more than 70% of the total disrupted volumes among non-OPEC producers in 2013.

EIA expects Syria and Yemen to continue to account for a large portion of non-OPEC supply disruptions over the next two years as the issues underpinning the disruptions remain unresolved. The disruption volume in South Sudan fell during 2013, from an average of 330,000 bbl/d in the first quarter to below 100,000 bbl/d in the fourth quarter of 2013. However, in late December of 2013, armed conflict escalated in South Sudan, causing the shut in of some oil fields and increasing the disruption volume by around 50,000 bbl/d.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 30 million bbl/d in 2013, a decline of 0.9 million bbl/d from the previous year, mostly as a result of increased outages in Libya, Nigeria, and Iraq. EIA expects OPEC crude oil production to continue to decline by 0.5 million bbl/d in 2014, as some OPEC countries, led by Saudi Arabia, reduce production to accommodate the non-OPEC supply growth in 2014. Although overall OPEC production in 2015 is forecast to remain close to its 2014 level, some key member countries continue to reduce their output to accommodate assumed recovery from production outages in Libya and growing production from other OPEC member countries, notably Iraq and Angola.

Unplanned crude oil supply disruptions among OPEC producers averaged 1.8 million bbl/d in 2013, nearly double the amount from the previous year. OPEC disruptions increased in the second half of 2013, reaching 2.5 million bbl/d by the end of the year due to increased outages

in Libya. At the beginning of January 2014, EIA estimates that OPEC outages are still at elevated levels, contributing to considerable uncertainty over the forecast period.

EIA estimates that OPEC surplus crude oil production capacity averaged 2.2 million bbl/d in 2013, 0.1 million bbl/d above the previous year but still 0.9 million bbl/d below the previous three-year average (2010-12). EIA expects surplus crude oil production capacity to increase over the forecast period, averaging 2.7 million bbl/d in 2014 and 3.7 million bbl/d in 2015. 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 oil inventories at the end of 2013 totaled 2.6 billion barrels, equivalent to about 56 days of supply. EIA projects OECD oil inventories also to be 2.6 billion barrels at the end of 2014 and 2015.

Crude Oil Prices. Brent crude oil spot prices averaged between $108/bbl and $112/bbl for the sixth consecutive month in December 2013 at $111/bbl. EIA expects the Brent crude oil price to weaken as non-OPEC supply growth exceeds growth in world consumption. The Brent crude oil price is projected to average $105/bbl and $102/bbl in 2014 and 2015, respectively.

The forecast WTI crude oil spot price, which fell from an average of $106/bbl during September to $94/bbl in November, increased to $98/bbl in December as a result of strong U.S. refinery runs. EIA expects that WTI crude oil prices will average $93/bbl in 2014 and $90/bbl during 2015. The discount of WTI crude oil to Brent crude oil, which averaged $18/bbl in 2012 and then fell to below $4/bbl in July 2013, averaged $12/bbl during the fourth quarter of 2013.

EIA expects the discount of the WTI crude oil price to Brent to average $12/bbl in 2014, $3/bbl higher than projected in last month's STEO. This increase in the projected WTI discount reflects increasing uncertainty of the existing refinery infrastructure's ability to absorb growing production of light sweet crude oil in North America at current prices. Because of pipeline capacity expansions and pipeline reversals, there is now ample capacity to ship crude oil via pipeline from the previous bottleneck in the U.S. Midcontinent to the U.S. Gulf Coast. As a result, the Light Louisiana Sweet (LLS) crude oil benchmark on the Gulf Coast, which was priced at a premium to Brent for much of the last two years, has recently begun tracking WTI prices and selling at a discount to Brent. Thus, EIA expects the recent convergence of Gulf Coast crude oil prices with WTI to persist over the forecast period, with Gulf Coast crude oil prices moving in step with the WTI price plus a pipeline transport cost. At this price level, Gulf Coast crudes such as LLS and medium-grade Mars will, trade at historically wide discounts to similar international benchmarks such as Brent and Dubai, respectively. EIA expects North American price discounts to continue into 2015 at levels similar to 2014, as new infrastructure comes online to meet additional production growth.

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 April 2014 delivery, traded during the five-day period ending January 2, 2014, averaged $98/bbl. Implied volatility averaged 16%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in April 2014 at $86/bbl and $113/bbl, respectively. Last year at this time, WTI for April 2013 delivery averaged $93/bbl and implied volatility averaged 26%. The corresponding lower and upper limits of the 95% confidence interval were $74/bbl and $117/bbl.

U.S. Crude Oil and Liquid Fuels

After reaching $3.68/gal on July 22, 2013, the average U.S. regular gasoline retail price fell almost 50 cents/gal to $3.19/gal by November 11, 2013. Continuing strong demand for gasoline in November and December and higher crude oil prices contributed to U.S. weekly average regular gasoline prices increasing to $3.33/gal as of December 30, 2013. Despite recent price increases, EIA expects that high levels of refinery runs, lower crude oil prices, and strong export demand for diesel fuel will contribute to downward pressure on regular gasoline retail prices, which EIA expects to average $3.29/gal during January 2014.

U.S. Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 380,000 bbl/d (2.1%) in 2013. Consumption of liquefied petroleum gases registered the largest gain, increasing by 150,000 bbl/d (6.7%). Motor gasoline consumption grew by 110,000 bbl/d (1.2%), the largest increase since 2004. Stronger-than-expected growth in highway travel during the second half of 2013 contributed to that increase. Distillate fuel consumption increased 90,000 bbl/d (2.5%), reflecting colder weather and domestic economic growth.

Projected total liquid fuels consumption is flat in 2014. Motor gasoline consumption falls by 10,000 bbl/d (0.1%) as the recent strong growth in highway travel slows and continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth. Distillate fuel oil consumption rises 40,000 bbl/d (1.2%) in 2014. Growing distillate demands from transportation and industrial use are offset by milder winter weather and declining heating oil use. Ethane consumption increases by an average of 60,000 bbl/d (5.8%) in 2014 as ethylene plant capacity expansions contribute to an increase in ethane cracking capacity. In 2015, total liquid fuels consumption increases by 90,000 bbl/d (0.5%) driven primarily by increasing demand for liquefied petroleum gas and distillate fuel oil.

U.S. Liquid Fuels Supply. EIA expects strong crude oil production growth, primarily concentrated in the Bakken, Eagle Ford, and Permian regions, continuing through 2015. Forecast production increases from an estimated 7.5 million bbl/d in 2013 to 8.5 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The highest historical annual average U.S. production level was 9.6 million bbl/d in 1970.

Production from the Bakken formation in North Dakota and Montana averaged 0.88 million bbl/d in 2013, and surpassed 1 million bbl/d in December 2013. Production in the Eagle Ford

formation in South Texas surpassed 1 million bbl/d in May 2013, reaching an estimated 1.23 million bbl/d in December 2013.

The Permian Basin in West Texas and New Mexico includes a variety of thick, overlapping formations such as the Spraberry, Bone Springs, and Wolfcamp. Crude oil producers are investing heavily in research and implementation of hydraulic fracturing in both vertical and horizontal wells. The stacked formations of the Permian allow vertical wells to reach several productive zones, while several horizontal wells drilled from the same surface location can target different formations or several pay zones within the same formation. EIA forecasts production in the Permian Basin, which averaged 1.32 million bbl/d in 2013, to grow more than any other region in the United States through 2015.

U.S. Federal Gulf of Mexico (GOM) oil production averaged 1.27 million bbl/d in 2013, unchanged from 2012. EIA forecasts 1.38 million bbl/d GOM production in 2014 and 1.59 million bbl/d in 2015. Production growth in 2014 comes from eight projects expected to come online: Jack, St. Malo, Entrada, Big Foot, Tubular Bells, Atlantis Phase 2, Hadrian South, and Lucius. Further production growth in 2015 comes from an additional 10 projects: Axe, Cardamom Deep, Dalmation, Deimos South, Kodiak, Pony, Samurai, West Boreas, Winter, and Mars B.

The growth in domestic production has contributed to a significant decline in petroleum imports. The share of total U.S. liquid fuels consumption met by net imports peaked at more than 60% in 2005 and fell to an average of 33% in 2013. EIA expects the net import share to decline to 24% in 2015, which would be the lowest level since 1970.

U.S. Petroleum Product Prices. EIA expects that regular gasoline retail prices, which averaged $3.24/gal during November and $3.28/gal in December, will average $3.29/gal in January 2014. Led by falling Brent crude oil prices, the projected U.S. annual average regular gasoline retail price, which fell from $3.63/gal in 2012 to an average of $3.51/gal in 2013, will continue to fall to $3.46/gal in 2014 and $3.39 in 2015. Diesel fuel prices, which averaged $3.92/gal in 2013, are projected to average $3.81/gal in 2014 and $3.72/gal in 2015.

Natural Gas

Cold weather in December had significant effects on demand, supply, and prices across the country. Cold weather led to a net withdrawal of 285 billion cubic feet (Bcf) for the week ending Friday, December 13. This was the largest storage withdrawal since recordkeeping began in 1994. Another larger-than-normal storage withdrawal of 177 Bcf occurred the following week. Widespread freeze-offs occurred in December and disrupted production for several days in the Piceance Basin in Utah and Wyoming, the Uinta Basin in Utah, the San Joaquin Basin in California, and the Williston Basin in North Dakota. Imports from Canada helped mitigate the loss of supply. During the month, prices rose across most of the country, and the Henry Hub

price averaged about $0.60/MMBtu higher than the previous month's average. Price effects were also seen in regional markets, particularly in New England. At the Algonquin Citygate, which serves Boston consumers, prices spiked to $33.14/MMBtu on Friday, December 13.

U.S. Natural Gas Consumption. EIA expects that total natural gas consumption to average a record high 71.2 billion cubic feet per day (Bcf/d) in 2013, an increase of 1.5 Bcf/d (2.1%) from the previous year. Projected natural gas consumption falls by 1.6 Bcf/d (2.2%) in 2014 because of the forecast 4.6% decline in heating degree days and lower natural gas use by the electric power sector. In 2015, natural gas consumption increases by 1.4 Bcf/d with growth in use by the industrial and electric power sectors. 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 21.7 Bcf/d in 2014. However, as retirements of coal power plants rise in 2015 in response to the implementation of the Mercury and Air Toxics Standards, EIA expects natural gas consumption in the power sector to increase to 22.6 Bcf/d.

U.S. Natural Gas Production and Trade. EIA expects natural gas marketed production will grow at an average rate of 2.1% in 2014 and 1.3% in 2015. Rapid Marcellus production growth is causing natural gas forward prices in the Northeast to fall even with or below Henry Hub prices outside of peak-demand winter months. Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, where prices are closer to the Henry Hub spot price. EIA projects Gulf of Mexico production will continue a long-term decline and fall slightly in 2014 and moderately in 2015.

LNG imports have declined over the past several years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. Several companies are planning to build liquefaction capacity to export LNG from the United States. The first of the new facilities to liquefy gas produced in the lower-48 states for export is expected to partially come online in the fourth quarter of 2015.

Growing domestic production over the past several years has replaced pipeline imports from Canada, while exports to Mexico have increased. EIA expects these trends will continue through 2015. EIA projects net imports of 3.0 Bcf/d in 2014 and 2.5 Bcf/d in 2015, which would be the lowest level since 1986. Over the longer term, the EIA Annual Energy Outlook 2014 projects the United States will be a net exporter of natural gas beginning in 2018.

U.S. Natural Gas Inventories. Natural gas working inventories fell by 97 Bcf to 2,974 Bcf during the week ending December 27, 2013. Colder-than-normal temperatures during the month resulted in increased heating demand, prompting larger-than-normal withdrawals, and the highest withdrawal on record. Stocks are now 562 Bcf less than last year at this time and 289 Bcf less than the five-year (2008-12) average for this time of year.

U.S. Natural Gas Prices. Natural gas spot prices averaged $4.24/MMBtu at the Henry Hub in December, up 60 cents from November, likely the result of colder-than-normal weather during

the month. Prices averaged $3.73/MMBtu for 2013 overall. Projected Henry Hub natural gas prices average $3.89/MMBtu in 2014 and $4.11/MMBtu in 2015.

Natural gas futures prices for April 2014 delivery (for the five-day period ending December 5, 2013) averaged $4.19/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for April 2014 contracts at $3.21/MMBtu and $5.46/MMBtu, respectively. At this time a year ago, the natural gas futures contract for April 2013 averaged $3.38/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $2.42/MMBtu and $4.73/MMBtu.

Coal

U.S. Coal Supply. Coal production for 2013 was estimated to total 1,001 million short tons (MMst), 15 MMst (1.5%) lower than in 2012. EIA estimates inventory draws of nearly 43 MMst for the year, fulfilling most of the growth in consumption in 2013. Coal production is forecast to grow 3.6% to 1,037 MMst in 2014 as inventories stabilize and consumption increases. Coal production in 2015 is projected to fall 2.5% to 1,012 MMst.

U.S. Coal Consumption. EIA expects total coal consumption for 2013 to reach 924 MMst, a 3.9% 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 (3.3%) to 955 MMst in 2014. Despite increases in electricity demand in 2015, coal consumption is projected to decline by 2.6%. The decline is primarily a result of the implementation of the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards regulations.

U.S. Coal Exports. EIA estimates that exports for 2013 totaled 118 MMst, which was 5.9% (7 MMst) lower than 2012. Exports are projected to total 105 MMst in both 2014 and 2015. 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. Nominal annual average coal prices to the electric power industry fell for the second consecutive year, from $2.38/MMBtu in 2012 to $2.35/MMBtu in 2013. EIA forecasts average delivered coal prices of $2.38/MMBtu in 2014 and $2.39/MMBtu in 2015.

Electricity

Electricity sales have stagnated in recent years, and consumption has declined in some sectors. During 2013, EIA estimates the average U.S. residential customer used 10,870 kilowatthours (kWh) of electricity, which is 2.2% lower than the average level of consumption between 2008 and 2012. In contrast, residential electricity consumption per customer grew an average of 1.2% per year between 1990 and 2005. Year-to-year fluctuations in residential electricity use

are driven primarily by weather patterns. However, the overall growth trend has been slowing in recent years. Improvements in appliance and lighting efficiency are one reason for this slowdown. Efficiency standards for general use light bulbs that began in 2012 and become fully implemented in 2014 have led to more widespread use of compact fluorescent and LED lighting, which use about 75% less energy than traditional incandescent bulbs.

U.S. Electricity Consumption. Improvements in energy efficiency are likely to continue affecting growth in electricity consumption. EIA expects the average sales of electricity per residential customer to fall by 1.1% in 2014 and by 0.4% in 2015. Energy efficiency also impacts sales of electricity to the commercial sector, which are expected to decline by 0.5% this year but grow by 0.3% in 2015. Improved economic conditions, especially in the chemicals and primary metals industries, drive a 2.2% increase in industrial electricity sales during 2014 and a 2.5% increase in 2015.

U.S. Electricity Generation. EIA estimates that total U.S. electricity generation averaged 11.1 terawatthours per day in 2013, and projects growth of 0.3% and 1.0% in 2014 and 2015, respectively. Natural-gas-fired generation accounts for a 26.8% share of total generation during 2014, down from 27.5% in 2013 as a result of rising natural gas prices. In contrast, the share of generation fueled by coal increases from 39.1% in 2013 to 40.2% in 2014. As the retirements of coal power plants pick up in 2015 in response to the implementation of the Mercury and Air Toxics Standards, EIA expects the share of coal to fall to 38.6% of total generation while the natural gas share rises back to 27.6%.

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. EIA expects the U.S. residential price of electricity to average 12.4 cents/kWh during 2014, an increase of 2.0% from 2013. Residential electricity prices increase 2.0% during 2015.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects both hydropower and nonhydropower renewables used for electricity and heat generation will grow by about 3.0% in 2014. In 2015, the growth in renewables consumption for electric power and heat generation is projected to continue at a rate of 4.7%, as a 2.2% increase in hydropower is combined with a 6.1% increase in nonhydropower renewables.

EIA estimates that wind capacity will increase by 8.8% in 2014 to about 66 gigawatts (GW) by the end of the year and will increase 14.6% to total more than 75 GW at the end of 2015. Electricity generation from wind is projected to increase by 2.2% in 2014 and by 11.4% in 2015, contributing more than 5% of total electricity generation by the end of 2015.

EIA expects continued robust growth in the generation of solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.4% by 2015.

While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity has taken off in the last few years, more than doubling in both 2012 and 2013. EIA currently projects that utility-scale solar capacity will increase by approximately 40% between year-end 2013 and year-end 2015, with photovoltaic (PV) capacity accounting for about 85% of that growth. However, customer-sited PV capacity growth, which the STEO does not forecast, is still projected to exceed utility-scale solar growth between 2013 and 2015 according to EIA's *Annual Energy Outlook 2014*.

EIA projects that solar PV electric capacity will continue to grow in 2014 and 2015 in both the electric power and end-use sectors, and will dominate growth in solar thermal electric capacity, due in part to significant cost declines that the PV industry has experienced in recent years. However, in October 2013, Arizona's 250-megawatt Solana generation station became the first major solar thermal electric power plant to enter service since 2007 – and the only operational solar thermal plant with integrated thermal storage. EIA expects that additional projects currently under construction will continue to come on line in 2014.

U.S. Liquid Biofuels. Ethanol and biodiesel production have recovered from last year's drought. Ethanol production increased from an average of 825,000 bbl/d in December 2012 to an estimated 920,000 bbl/d during December 2013 and is forecast to average 913,000 bbl/d during 2014. Biodiesel production, which averaged 64,000 bbl/d (1.0 billion gallons per year) in 2012, rose to a record-high level of 101,000 bbl/d (132 million gallons) in October 2013. Biodiesel production averaged about 87,000 bbl/d in 2013 and is forecast to average 84,000 bbl/d in both 2014 and 2015.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.1% in 2013 from the previous year. Emissions are forecast to rise 0.7% in 2014, followed by no change in 2015. The increase in emissions in 2013 primarily reflected growth in coal use for electricity generation in response to higher natural gas prices relative to coal. Coal emissions are projected to decline by 2.5% in 2015 as the power sector responds to the Mercury and Air Toxics Standards regulations by increasing coal plant retirements.

U.S. Economic Assumptions

The U.S. Bureau of Economic Analysis reported that real GDP increased at an annual rate of 4.1% during the third quarter, revised upward from 2.8% and 3.6% in its previous two estimates. The U.S. Department of Labor reported that initial weekly unemployment insurance claims were 339,000 in the week ending December 28, a decrease of 2,000 from the previous week's figure, and the four-week moving average rose to 357,000. The U.S. Census Bureau reported that new

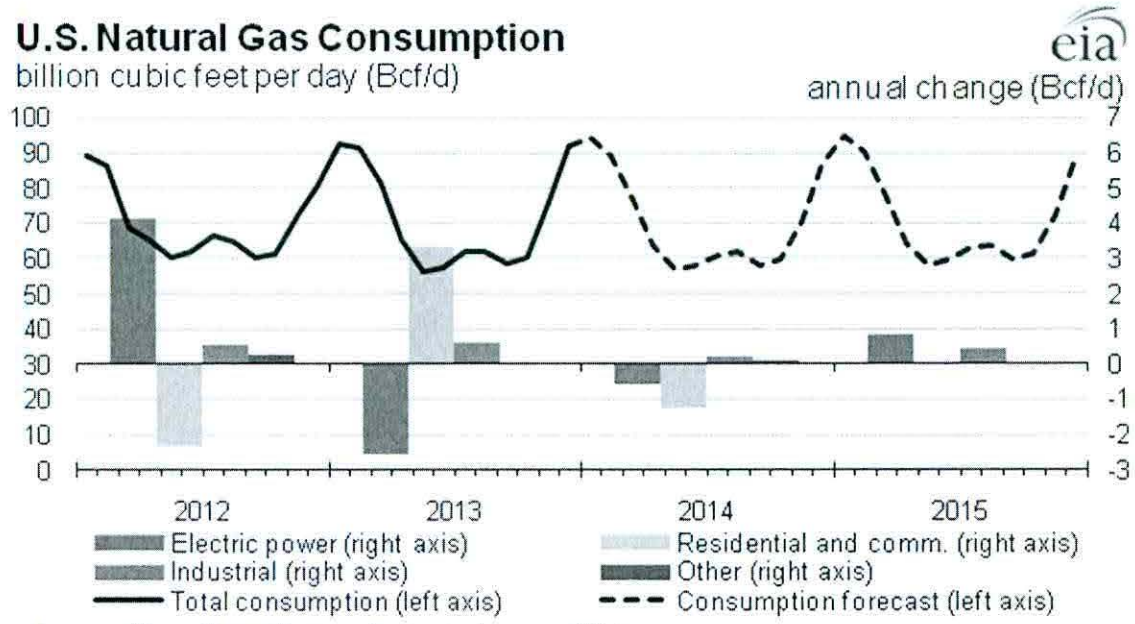
orders for manufactured durable goods rose 3.5% in November, following a 0.7% decrease in October. The Federal Reserve Board reported that U.S. industrial production rose in November by 1.1%, following an upwardly revised 0.1% gain in October.

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.

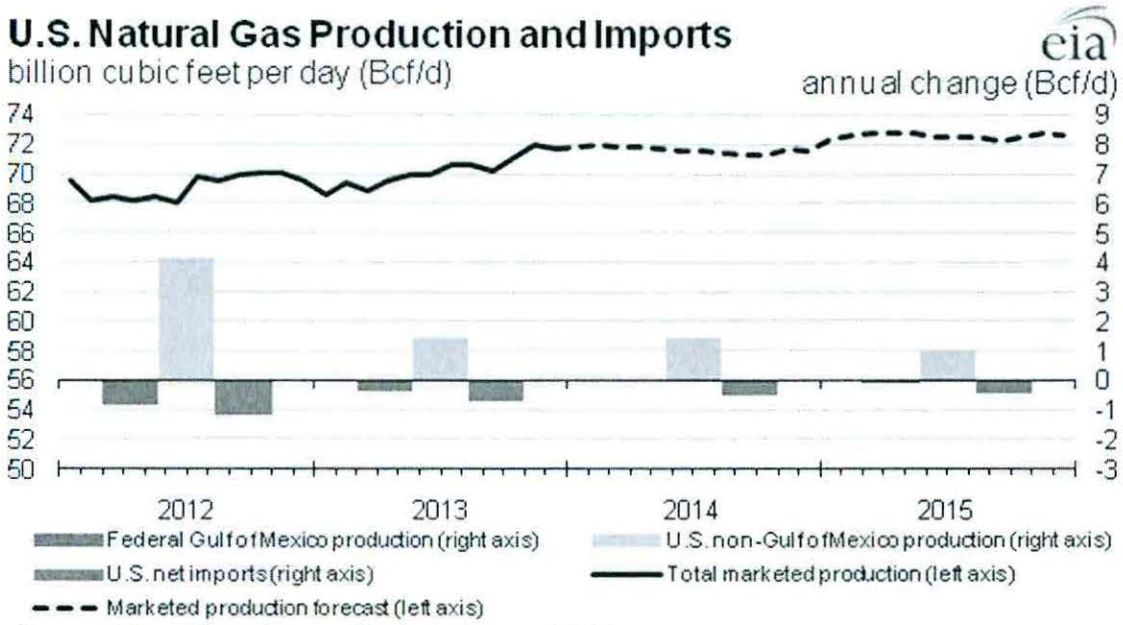
U.S. Production and Income. Forecast U.S. real GDP grows by 2.4% in 2014 and 3.1% in 2015. Forecast real disposable income increases 3.2% per year in both 2014 and 2015. Total industrial production grows at 2.2% in 2014, and is projected to grow 3.5% in 2015.

U.S. Expenditures. Private real fixed investment growth averages 6.4% and 8.4% over 2014 and 2015, respectively. Real consumption expenditures grow faster than real GDP in 2014, at 2.6%, but are below the rate of real GDP growth in 2015, at 2.8%. Export growth is 4.9% and 5.1% over the same two years. Government expenditures fall 0.3% in 2014, but increase by 0.3% in 2015.

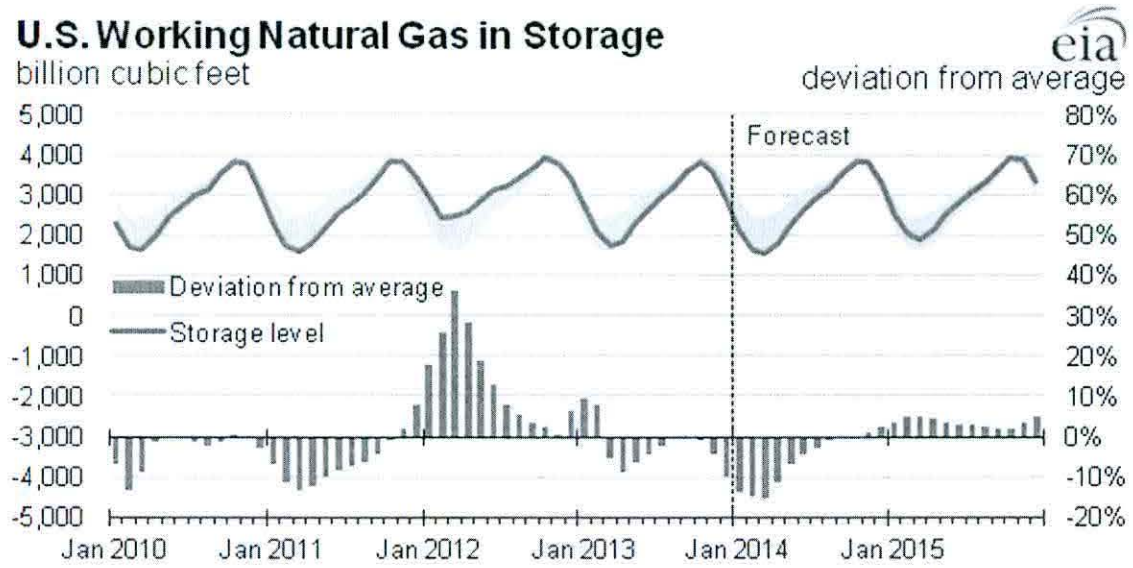
U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 6.6% over 2014, and gradually falls to 5.9% at the end of 2015. This is accompanied by nonfarm employment growth averaging 1.7% in 2014 and 1.8% in 2015. Housing starts grow an average of 23.3% and 29.9% in 2014 and 2015, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.



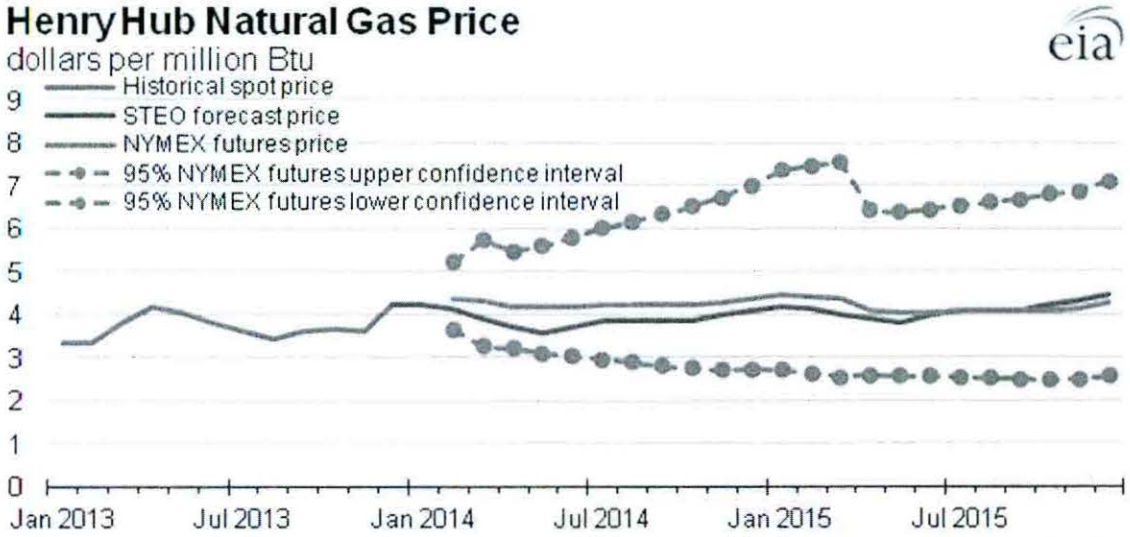
Source: Short-Term Energy Outlook, January 2014.



Source: Short-Term Energy Outlook, January 2014.

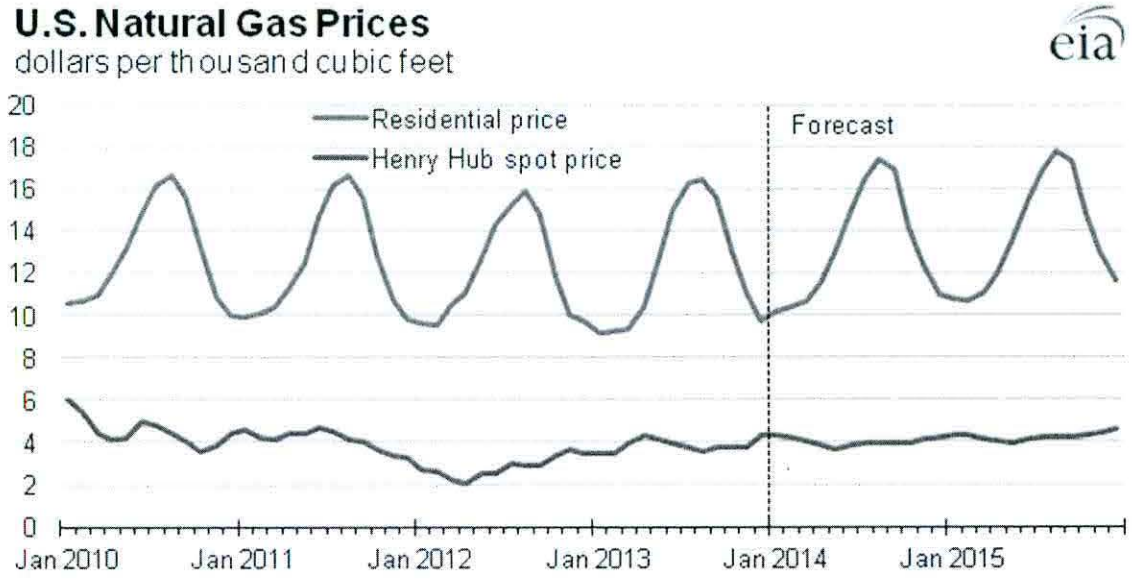


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.
Source: Short-Term Energy Outlook, January 2014.



Note: Confidence interval derived from options market information for the 5 trading days ending Jan. 2, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, January 2014.



Source: Short-Term Energy Outlook, January 2014.

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 2013	($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
December	45	0	1,501	1,546	42,237	0.9614	40,607		(39,060)	218,338
Total	$35,901	(17,889)	$13,190	$31,202	119,356		$116,176		($84,973)	
Balance @ December 31, 2013										**$218,338**

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 2013	($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)
December	13,820	0	(373)	13,447	81,821	0.0274	2,242	11,205	(32,978)
Total	($48,872)	0	($1,740)	($50,612)	287,471		($12,887)	($37,725)	
Balance @ December 31, 2013									**($32,978)**

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.